System Plan Framework (SPF)

B-1-1

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EB-2026-0164

SECTION 1.0 – SPF – INTRODUCTION TO THE SYSTEM PLANS FRAMEWORK

1.0.1 THE SYSTEM PLANS

The sections contained in this Exhibit form Hydro One's five-year Transmission and Distribution system plans for the 2028 to 2032 planning period, and Hydro One Sault Ste. Marie LP's (HOSSM) six-year system plan for the 2027 to 2032 planning period.[1] The Transmission System Plan (TSP), Distribution System Plan (DSP), and General System Plan (GSP) collectively comprise the System Plans.

The System Plans have been prepared in accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Cost of Service Rate Applications (December 16, 2025), Transmission Chapter 2 Filing Requirements for Revenue Requirement Applications (October 30, 2025) and Chapter 5 Filing Requirements for Distribution System Plans for Electricity Distribution Cost of Service Rate Applications (December 16, 2025), as applicable. To assist parties in their review, Hydro One has provided applicable references to the Filing Requirements in the Tables of Concordance which are provided in the Overview sections of each of the System Plans. Furthermore, the System Plans continue to be responsive to the OEB's March 16, 2018, direction to apply for rates for the Transmission and Distribution business segments in a single application.

Although Hydro One Transmission, HOSSM and Hydro One Distribution are distinct and their approved revenue requirements are established separately, many planning and operational elements are common, and are described here in the System Plans Framework (SPF) section. Aspects reflecting the unique transmission and distribution businesses are detailed in the individual plans through the TSP and DSP. Unique aspects of General Plant planning are described in the GSP with costs allocated to Hydro One Transmission and Distribution.

[1] EB-2026-0170, Decision and Order, 14 July 2026: The OEB approved HOSSM's 2027 revenue requirement on an interim basis; 2027 to 2032 is being rebased as part of this Application.

The System Plans are organized into four chapters, as follows, with the chapter content shown in Table 1 and Table 2 below:

[Chapter 1] - The SPF summarizes the overall planning process and drivers for Hydro One and HOSSM, reflecting common context, practices, inputs and considerations reflected in each of the TSP, DSP, and GSP. The contents of Chapter 1 are as follows:

Table 1 - SPF Chapter Sections, Content

Exhibit B1
System Plans Framework
1.0, Introduction to the System Plans Framework
1.1, System Plans Framework Overview
1.2, Coordination Through Regional Planning
1.3, Third-Party Reports
1.4, Productivity Framework
1.5, Performance Measurement and Outcomes
1.6, Customer and Indigenous Communities Engagement
1.7, Investment Planning Process
1.8, Managing Market Cost Pressure

[Chapters 2 - 4] - These chapters provide the TSP, DSP, and GSP, respectively. Each chapter provides an overview of Hydro One's or HOSSM's respective network systems and the various system-specific factors and outcomes that were considered by Hydro One in developing its capital expenditure plans.

Each of Chapters 2 - 4 contain parallel subsections that detail specific asset information and life-cycle optimization strategies, which determine the portfolio of investments required to achieve the specific outcomes in each of the System Plans. These chapters detail Hydro One's and HOSSM's capital expenditure plans, including factors such as asset information, benchmarking, productivity, performance management, and other capital planning drivers and considerations, including customer needs and preferences.

The table below provides a roadmap of related sections across Chapters 2 - 4.

Table 2 - TSP, DSP and GSP Chapters - Sections, Content

Exhibit B2	Exhibit B3	Exhibit B4
Transmission System Plan	**Distribution System Plan**	**General Plant System Plan**
2.0, Transmission System Plan	3.0, Distribution System Plan	4.0, General Plant System Plan
2.1, Overview	3.1, Overview	4.1, Overview
2.2, Asset Information and Lifecycle Strategies	3.2, Asset Information and Lifecycle Strategies	4.2, Asset Information and Lifecycle Strategies
2.3, Benchmarking and Other Studies	3.3, Benchmarking and Other Studies	4.3, Benchmarking and Other Studies
2.4, Transmission System Reliability	3.4, Connecting DER Resources	4.4, [blank]
2.5, Performance Measurement and Outcomes	3.5, Performance Measurement and Outcomes	4.5, [blank]
2.6, Other Capital Planning Factors and Considerations	3.6, Other Capital Planning Factors and Considerations	4.6, Other Capital Planning Factors and Considerations
2.7, Investment Planning Process	3.7, Investment Planning Process	4.7, Investment Planning Process
2.8, Capital Expenditures and Trends	3.8, Capital Expenditures – and Trends	4.8, Capital Expenditures and Trends
2.9, Capital Expenditure Variances	3.9, Capital Expenditure Variances	4.9, Capital Expenditure Variances
2.10, HOSSM Capital System Plan	3.10, Capital Work Execution Strategy	4.10, Capital Work Execution Strategy
2.11, Capital Work Execution Strategy	3.11, Material Investment Summary Documents	4.11, Material Investment Summary Documents
2.12, Material Investment Summary Documents		

The culmination of these factors and inputs are the capital expenditure plans, which are the product of the asset life-cycle optimization strategies identified in TSP Section 2.2, DSP Section 3.2 and GSP Section 4.2, and the investment planning process as described in SPF Section 1.7 (and further described in TSP Section 2.7, DSP Section 3.7 and GSP Section 4.7). Chapters 2 – 4 provide Investment Summary Documents (ISDs) detailing specific planned capital expenditures. The ISDs are informed and guided by the

overarching drivers of the System Plans, including comprehensive customer engagement, benchmark performance and other inputs described in Chapter 1. They are also the product of factors that are specific to the transmission and distribution systems and common assets, as set out in the respective chapters of the System Plans.

The ISDs provide details regarding investments with forecast spending over $4M for Hydro One Transmission and $0.29M for HOSSM in the TSP, and over $1M for Hydro One Distribution in the DSP. The GSP includes ISDs where the Transmission-allocated portion exceeds $4M or Distribution-allocated portion exceeds $1M during any year within the planning period.[2]

[2] Determined pursuant to Section 2.1.5 of the OEB's Transmission Chapter 2 Filing Requirements for Revenue Requirement Applications (October 30, 2025), and Section 2.0.8 of the Chapter 2 Filing Requirements for Electricity Distribution Cost of Service Rate Applications (December 16, 2025).

SECTION 1.1 – SPF – SYSTEM PLANS FRAMEWORK OVERVIEW

1.1.1 INTRODUCTION

The sections contained in this Exhibit form Hydro One's five-year Transmission and Distribution system plans for the 2028 to 2032 planning period, and Hydro One Sault Ste. Marie LP's (HOSSM) six-year system plan for the 2027 to 2032 planning period.[1] The Transmission System Plan (TSP), Distribution System Plan (DSP), and General Plant System Plan (GSP) collectively comprise the System Plans.

The System Plans provide comprehensive and detailed explanations of Hydro One's capital investment plans for its transmission and distribution systems and how these plans are aligned with the principles and expectations articulated by the Ontario Energy Board (OEB) in the Renewed Regulatory Framework (RRF)[2].

To prepare the System Plans, Hydro One engaged its direct transmission and distribution customers. Hydro One has carefully considered and set out its proposed investment plans over the course of the planning period, with a view to ensuring they are appropriate in their focus, scope and pacing, having regard to the needs and preferences of customers, the stewardship of the power system, and the objectives of the Company.

Although Hydro One Transmission, HOSSM and Hydro One Distribution are distinct, many planning and operational elements are common, and are described here in the System Plans Framework (SPF) section (Exhibit B-01-01).

1.1.1.1 FORMAT OF THE SYSTEM PLANS

As outlined in SPF Section 1.0, the System Plans comprise four chapters:

- **Chapter 1** sets out the common SPF, including the overall planning process, customer engagement and regional planning, and other inputs or common

[1] EB-2026-0170, Decision and Order, 14 July 2026: The OEB approved HOSSM's 2027 revenue requirement on an interim basis; 2027 to 2032 is being rebased as part of this Application.
[2] OEB, Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.

processes, the contents of which are set out in Table 1 and summarized in Section 1.1.3 below; and

- **Chapters 2 to 4** present the TSP, DSP and GSP, respectively, addressing system-specific factors, including asset management and life-cycle optimization strategies, capital expenditure plans, and Investment Summary Documents. These plans and investments reflect the processes and inputs described in Chapter 1.

Table 1 - SPF Chapter Sections, Content

Exhibit B1 **System Plans Framework**	**Section in This Exhibit**
1.0, Introduction to the System Plans Framework	-
1.1, System Plans Framework Overview	-
1.2, Coordination Through Regional Planning	1.1.3.1
1.3, Third-Party Reports	1.1.3.2
1.4, Productivity Framework	1.1.3.3
1.5, Performance Measurement and Outcomes	1.1.3.4
1.6, Customer, Stakeholder and Indigenous Communities Engagement	1.1.3.5
1.7, Investment Planning Process	1.1.3.6
1.8, Managing Market Cost Pressure	1.1.3.7

Unless otherwise specified, the asset information contained in the System Plans is as of December 31, 2025.

1.1.1.2 RESPONSIVENESS TO OEB DECISIONS

Exhibit A-02-04 summarizes relevant directions and settlement commitments from past OEB proceedings and explains the steps Hydro One has taken to address them as part of this Application. Each of these aspects is elaborated upon throughout the System Plans.

This Exhibit is organized as follows:

- Section 1.1.2 provides an overview of Hydro One's system
- Section 1.1.3 provides an overview of each of the SPF sections and their common influence on the TSP, DSP and GSP.

1.1.2 HYDRO ONE AND HOSSM'S SYSTEM

Hydro One and HOSSM's transmission systems and Hydro One's distribution system play a vital role in Ontario's electricity system and the customers they serve.

1.1.2.1 THE TRANSMISSION SYSTEM

Hydro One's and HOSSM's transmission system transmits electricity throughout the Province of Ontario between supply points (i.e., generation) and delivery points (i.e., load customers, distribution systems) and is generally comprised of three types of infrastructure: transmission lines, transmission stations and system operations facilities.

Hydro One's transmission system interconnects with transmission systems in five neighboring jurisdictions in Canada and the United States (Manitoba, Quebec, Minnesota, Michigan and New York) and enables electricity transactions with those jurisdictions through interconnections. Therefore, the transmission system is subject to the Independent Electricity System Operator's (IESO) Market Rules, the OEB's Transmission System Code (TSC), and other mandatory industry standards such as those established by the North American Electric Reliability Corporation and Northeast Power Coordinating Council.

Hydro One's and HOSSM's transmission system is deemed to be critical infrastructure for the Province of Ontario because of its scale and service territory.[3] The transmission system has been referred to as the "backbone" of Ontario's electricity system.[4] Given the potential downstream impacts that can result from a transmission system failure, the reliability of Hydro One's and HOSSM's transmission system is essential to the province's economy and service quality of Ontario electricity customers.

Additional discussion regarding the transmission system and service area, planning considerations and proposed investments are provided in the TSP (Exhibit B-02-01).

[3] See Ontario Critical Infrastructure Assurance Program Strategy | ontario.ca
[4] Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7, p.83.

1.1.2.2 THE DISTRIBUTION SYSTEM

Hydro One's distribution system plays a critical role in Ontario's electricity system and in the daily lives of the customers and communities it serves. The distribution system delivers electricity from transmission delivery points to end-use customers across urban, suburban, rural, and remote areas of Ontario. The system is comprised of distribution lines, distribution stations, substations, protection and control equipment, and supporting system operations and information technology infrastructure.

Hydro One operates one of the largest and most geographically diverse distribution systems in North America. The size, scope, and configuration of the distribution system are characterized by long feeder lengths, significant rural and radial supply, and exposure to severe weather, which together create unique operational, reliability, and asset management challenges. While the predominantly radial design of the distribution system enables cost-effective service to low-density areas, it also limits redundancy and increases the likelihood that asset failures translate directly into customer interruptions.

The distribution system is subject to a comprehensive regulatory and standards framework, including the OEB's Distribution System Code (DSC), conditions of Hydro One's distribution license and applicable provincial and federal requirements. Distribution planning must also respond to evolving public policy objectives, including electrification, economic growth, integration of distributed energy resources, and resilience. The distribution system is recognized as critical infrastructure for the Province of Ontario, and its safe and reliable operation is essential to customer service quality and public safety.

Additional discussion regarding the distribution system and service area, planning considerations and proposed investments are provided in the DSP (Exhibit B-03-01).

1.1.2.3 THE GENERAL PLANT

Hydro One's General Plant assets provide the shared operational resources and enabling capabilities required to execute its Transmission and Distribution work programs and deliver safe and reliable electricity service across Ontario.

Fleet assets enable field crews to reach work locations, transport personnel, tools and materials, perform construction and maintenance activities, and respond to outages and major storms. Facilities & Real Estate assets provide the work centres, garages, warehouses, administrative spaces, transmission facilities, training campuses, fleet repair shops, helicopter hangars, and control centres required to deploy crews, protect equipment, manage materials, and maintain business continuity. Digital & Technology Solutions provide the information technology, operational technology, data analytics, artificial intelligence, and security capabilities required to operate the grid, manage work programs, support customers, and conduct corporate operations.

General Plant assets are essential to the safe and reliable operation of Hydro One's electricity system because Transmission and Distribution work cannot be delivered without suitable vehicles, equipment, facilities, digital systems, security capabilities, and control-centre infrastructure. System Operations relies on the Integrated System Operations Centre and the Back-up Ontario Grid Control Centre to monitor, control, coordinate, and restore the electricity system on a continuous basis. Operational technology provides real-time visibility and control of the grid, while physical and cybersecurity systems protect critical facilities, operational environments, corporate systems, and information from intrusion, cyber threats, unauthorized access, and other security risks.

Additional discussion regarding General Plant assets, planning considerations and proposed investments are provided in the GSP (Exhibit B-04-01).

1.1.3 OVERVIEW OF THE SPF SECTIONS

This section provides an overview of each of the SPF sections and their common influence on the TSP, DSP and GSP.

1.1.3.1 COORDINATION THROUGH REGIONAL PLANNING (SPF SECTION 1.2)

Regional planning is a foundational input into Hydro One's and HOSSM's investment planning processes and is an OEB-established process developed through amendments to the TSC and DSC and subsequently enhanced through the OEB's regional planning

review process. Hydro One participates as the lead transmitter in many planning regions and works collaboratively with the IESO, local distribution companies, customers, and other transmission asset owners through Technical Working Groups. Hydro One Transmission is the lead transmitter in 20 of Ontario's 21 regional planning regions, while HOSSM serves as the lead transmitter for the East Lake Superior Region.

The regional planning process provides a structured and transparent mechanism for identifying electricity system needs, developing alternatives, evaluating solutions and recommending investments. The process includes Needs Assessments, Scoping Assessments, Integrated Regional Resource Plans, and Regional Infrastructure Plans. Regional planning evaluates both wires and non-wires alternatives, considers load forecasts, asset condition, customer growth, reliability requirements, regional development needs, and broader bulk system planning considerations.

This process aligns with OEB expectations that infrastructure planning be coordinated on a regional basis and integrated with broader electricity system planning. It also aligns with Ontario's Integrated Energy Plan, which emphasizes coordinated long-term planning among electricity sector participants and across energy systems.

Regional planning outputs directly inform Hydro One's investment plans by identifying system access, system service and asset renewal needs that are subsequently incorporated into the capital plans proposed in the TSP and DSP. Further details regarding the regional planning framework, planning cycles, stakeholder roles, regional planning reports and associated investment recommendations are provided in SPF Section 1.2 Additional discussion regarding how regional planning informs the proposed capital plans is provided in TSP Section 2.6, TSP Section 2.12 investment summary documents, TSP Section 2.10 (HOSSM), DSP Section 3.6, DSP Section 3.11 investment summary documents, and the associated regional planning reports attached to SPF Section 1.2.

1.1.3.2 THIRD-PARTY REPORTS (SPF SECTION 1.3)

Hydro One relies on independent third-party studies, benchmarking, and independent expert reviews to inform and validate elements of its investment planning and business

practices. These reports provide external perspectives on customer engagement, asset management practices, project delivery, productivity, supply chain management, vegetation management, compensation benchmarking and procurement practices.

The use of independent experts supports transparency and evidence-based decision-making by providing external review of key planning assumptions, methodologies and business practices. Notable examples include customer engagement studies conducted by Innovative Research Group (IRG), transmission project execution reviews by E Source, benchmarking studies by Guidehouse and First Quartile, vegetation management reviews by CN Utility Consulting, and supply chain practice reviews by Wood Mackenzie.

These independent assessments help demonstrate that Hydro One's planning processes and business practices are consistent with industry best practices and support the reasonableness of the proposed investment plans. The associated reports are provided in TSP Section 2.3, DSP Section 3.3, GSP Section 4.3, and throughout other evidence sections of the Application.

1.1.3.3 PRODUCTIVITY FRAMEWORK (SPF SECTION 1.4)

The Productivity Framework is Hydro One's enterprise-wide process for identifying, implementing, measuring and governing productivity initiatives that reduce costs while maintaining or improving service quality and work outputs. The framework applies across Transmission, Distribution and shared functions and therefore serves as a common input into all System Plans.

The framework includes internal governance, initiative identification, implementation, ongoing tracking, reporting and auditing activities. Productivity savings are incorporated into business planning and help offset cost pressures while maintaining required service levels and performance outcomes. The framework has generated substantial productivity savings and remains a core component of Hydro One's planning and execution processes.

The Productivity Framework was previously reviewed by Concentric Energy Advisors (Concentric), an external independent consultant retained in Hydro One's previous

application. Concentric concluded that Hydro One's productivity approach was effective and robust relative to utility peers. Hydro One will continue to use the same framework to deliver productivity savings as the System Plans are carried out.

1.1.3.4 PERFORMANCE MEASUREMENT AND OUTCOMES (SPF SECTION 1.5)

Hydro One's planning process is directly linked to performance outcomes and OEB regulatory expectations. The Company has aligned its planning, execution and reporting functions with the OEB's RRF outcomes of Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

Performance outcomes are monitored through a structured governance framework that includes transmission, distribution and HOSSM regulatory scorecards, as well as internal corporate scorecards. Performance measures are monitored to ensure the System Plans produce outcomes valued by customers and the OEB.

The investment plans described in the TSP, DSP and GSP are intended to achieve these performance outcomes while balancing customer preferences, system needs, regulatory obligations and affordability considerations.

Further details on specific performance measures, performance history and targets are provided in TSP Section 2.5, HOSSM scorecards in TSP Section 2.10 Attachment 3, and DSP Section 3.5. For more information on Performance Reporting Governance, see SPF Section 1.5.

1.1.3.5 CUSTOMER, STAKEHOLDER AND INDIGENOUS COMMUNITIES ENGAGEMENT (SPF SECTION 1.6)

Customer engagement is a core input into the development of Hydro One’s and HOSSM’s investment plans and forms an integral component of the SPF. Customer engagement was integrated directly into investment planning and plan refinement. Hydro One retained an independent expert consultant, IRG, to design and execute a two-phase application-specific customer engagement process that first identified customer needs, priorities and outcome preferences and subsequently obtained feedback on draft investment plans and

associated investment trade-offs. More than 100,000 customers participated through focus groups, in-depth interviews and surveys. The engagement activities also included interviews with Indigenous leadership, municipalities and stakeholders.

The engagement process aligns with OEB expectations for customer-informed planning by using an independent expert consultant, broad and representative participation, multiple engagement methodologies and direct integration of customer feedback into investment decision-making. Phase I was undertaken before development of the draft plans and focused on identifying customer priorities, while Phase II was undertaken after preparation of draft investment plans and provided customers with an opportunity to provide feedback on the proposed investment levels, associated investment trade-offs and bill impacts. The results of both phases were provided directly to planners and informed development and finalization of the proposed plans.

Across all customer types, most customers support Hydro One spending at or above the level of investment included in the draft plans. Customers generally demonstrated support for replacing aging assets, improving resilience to severe weather, enabling economic growth and enhancing system visibility and performance. This feedback provided validation that the proposed plans appropriately balance reliability, affordability, customer service and growth objectives.

The engagement survey included dedicated engagement with Indigenous customers, First Nation leadership and the Métis Nation of Ontario. Hydro One also maintains ongoing engagement and partnerships with Indigenous communities through both project-specific consultations and broader Indigenous relations initiatives. These relationships provide an additional source of planning input and help ensure that investments reflect the evolving needs of Indigenous communities across the province.

Hydro One maintains ongoing customer engagement through customer contact centre interactions, customer satisfaction research, large customer account management functions, stakeholder oversight committees, Indigenous engagement programs, government and municipal relations activities and the Hydro One Ombudsman. These

ongoing engagement channels provide Hydro One with insight into customer needs, emerging issues and future investment requirements.

Further information regarding the customer engagement process, ongoing customer engagement, and how customer feedback informed investment planning is provided in SPF Section 1.6, SPF Section 1.7 and in TSP Section 2.7, TSP Section 2.10 (HOSSM), DSP Section 3.7 and GSP Section 4.7.

1.1.3.6 INVESTMENT PLANNING PROCESS (SPF SECTION 1.7)

The Investment Planning Process is the central integrating element of the SPF and the section explains how Hydro One and HOSSM translate customer needs, asset condition information, performance objectives, regional planning requirements, productivity expectations and risk assessments into coordinated investment plans. It describes the common planning methodology used across transmission, distribution and general plant planning. This structured, repeatable and evidence-based planning process is used to develop the proposed investment plans.

The investment planning process is outcome-focused and risk-based. Inputs from customer engagement, system performance analysis, regional planning activities, asset condition assessments, reliability requirements, regulatory obligations and operational experience are evaluated together to identify investment needs and develop candidate investment solutions. The planning process is designed to ensure that investments are aligned with customer priorities while maintaining safe, reliable and cost-effective service.

Common planning assumptions, customer engagement findings, performance objectives and risk management frameworks are applied across the organization. This provides a consistent decision-making framework for both Hydro One and HOSSM and ensures that investments are evaluated using comparable criteria regardless of the business area from which they originate.

The investment planning process is also aligned with OEB expectations for outcome-based and customer-focused planning. The planning framework links investment

decisions to measurable customer and system outcomes, incorporates feedback obtained through the customer engagement process and uses risk-informed prioritization techniques to assess competing investment needs. Further, proposed investments are subject to challenge and refinement throughout the planning process before final plans are established.

SPF Section 1.7 provides the framework and roadmap, while the detailed application of the planning process is presented in TSP Section 2.7, DSP Section 3.7 and GSP Section 4.7.

1.1.3.7 MANAGING MARKET COST PRESSURES (SPF SECTION 1.8)

Market cost pressures have been a significant common input into the Hydro One and HOSSM investment plans. Since 2021, the utility sector has experienced persistent and materially higher inflation that exceeded previous planning assumptions. These trends are supported by Handy-Whitman utility indices and Hydro One's procurement experience for critical utility equipment and materials.

Higher costs for major transmission and distribution equipment and materials have been driven by supply-chain disruptions, constrained manufacturing capacity, commodity price increases, tariffs and growing demand associated with electrification, economic growth, system renewal and grid modernization.

Hydro One actively manages these pressures through procurement and sourcing strategies designed to improve supply resilience and mitigate cost volatility, and pursues productivity and efficiency initiatives to partially offset external cost pressures.

Inflationary pressures, together with increasing volumes of mandatory and customer-driven work, required Hydro One to prioritize available funding during the 2023-2027 period, deferring work where timing flexibility existed. While these deferrals were necessary, the underlying deferred work remains prudent and required. Accordingly, this work has been incorporated into the investment plan.

Project cost estimates included in the System Plans have been updated to reflect current market prices for critical equipment, materials and services which have been impacted by the materially higher inflation that has occurred since 2021.

SECTION 1.2 – SPF – COORDINATION THROUGH REGIONAL PLANNING

1.2.1 INTRODUCTION

Regional infrastructure planning with key stakeholders supports transparency and the cost-effective development of electricity infrastructure in Ontario. This is consistent with one of the guiding principles in the OEB's Renewed Regulatory Framework (RRF), which states that infrastructure planning on a regional basis, between licensed transmitters, the Independent Electricity System Operator (IESO) and local distribution companies (LDCs), is to be undertaken to ensure that regional issues and requirements are integrated into a utility's planning processes.

To enable transparent, coordinated, and cost-effective planning of regional electricity infrastructure, the OEB convened a stakeholder working group (the Planning Process Working Group, or PPWG) in 2013 to prepare a Report to the OEB (the PPWG Report) that set out the details of an appropriate regional planning process. Upon release of the PPWG Report, the OEB endorsed the recommended process and established the regional planning process through amendments to the Transmission System Code (TSC) and Distribution System Code (DSC). In late 2020, the OEB initiated another consultation process to review and update the regional planning process to improve its efficiency and effectiveness (EB-2020-0176). This consultation resulted in a set of recommendations that build upon the foundational 2013 PPWG report and were formally approved by the OEB in April 2022.

As the largest transmitter and distributor in the province, Hydro One plays a key role in the regional planning process. Hydro One Transmission is the lead transmitter in 20 of the 21 regional planning regions and is responsible for leading the development of the Needs Assessments and Regional Infrastructure Plans (RIP) in those regions. Hydro One Distribution, as a LDC is one of the key stakeholders in 20 of the 21 regions that provides input, data and guidance regarding the regional and local distribution needs. One of the 20 regions, East Lake Superior, is led by Hydro One Sault Saint Marie (HOSSM), an affiliate of Hydro One Networks and a co-applicant in the 2028-2032 rate period.

This exhibit provides further details about the regional planning process. In accordance with the TSC and DSC, Hydro One Transmission, HOSSM and Hydro One Distribution, each have distinct roles in the process. As such, this exhibit discusses their respective roles and responsibilities and summarizes Hydro One Transmission's and Hydro One Distribution's capital investment needs that have been identified through the regional planning process in separate sections.

Attachment 1 provides additional context regarding the Ministry of Energy and Mines' Integrated Energy Plan and how provincial energy policy considerations inform Hydro One's regional planning activities.

1.2.2 REGIONAL PLANNING FRAMEWORK

Overview

As described in the *PPWG Report*, planning for the electricity system in Ontario is generally conducted at three levels:

1. Bulk system planning;
2. Regional system planning; and
3. Distribution system planning.

The IESO leads the bulk system planning process in close coordination with transmitters and individual LDCs undertake distribution system planning for their respective systems. While bulk and distribution system planning are being undertaken separately from the regional planning process, there can be an overlap between these processes that may trigger bulk or distribution planning investments to be considered as part of regional planning activities, as further described below.

Regional planning addresses supply and reliability issues at a regional and/or localized level, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Regional planning generally considers the 115kV and 230kV portions of the power system, that supply various parts of the province but can overlap with bulk system planning and/or distribution system planning at the interface points or

where there may be regional resource options or distribution solutions to address the broader local area for the specific region.

The regional planning process is typically initiated by the transmitter resulting from a planning trigger. Potential triggers may include but are not limited to the transmitter's regularly scheduled Needs Assessment, a Government directive, a significant change to the TSC, or an emergent need brought forward by the transmitter, distributors, customers, or IESO that must be addressed before the next scheduled review. Regional planning is intended to be undertaken for each of the planning regions identified in the PPWG Report on a five-year cycle beginning in 2013; though the process may occur more frequently depending upon the emergence of new needs.

Once the regional planning process is initiated by a planning trigger, the process unfolds through the following phases:

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

Needs Assessment

The Needs Assessment for a given region, is led by the lead transmitter in that region with participation from nominated subject matter experts (SMEs) from the transmitter, local LDC(s) and the IESO (collectively referred to as the "Technical Working Group (TWG)"[1]). As part of the Needs Assessment, the TWG collects a ten-year outlook of major high voltage equipment replacement candidates based on condition, analyzes and identifies emerging needs in the region by utilizing load forecast (reference, high, and low demand scenarios), CDM and DER penetration forecasts, and assesses alternatives to address the identified needs. The objective of the Needs Assessment is to ensure that the needs over the near to midterm are met in the most economical and efficient manner.

[1] The *Working Group* as described in the PPWG report is equivalent to *Study Team* as referred to by Hydro One and is the current terminology utilized in the RIP reports.

At the end of the Needs Assessment, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all of the regional needs. If no further regional coordination is required, recommendation to implement the preferred option and any resulting investments are planned directly by local LDC(s) (or customers) and the lead transmitter. The TWG can also recommend that a lead transmitter and local LDCs undertake a local planning process for further assessment when needs (a) are local in nature (b) require limited investments in "wires" (i.e. transmission or distribution) solutions, and (c) do not require upstream transmission investments.

Scoping Assessment

If during the Needs Assessment, the TWG identifies that further planning at the regional or sub-regional level is required, the IESO then takes the lead and initiates the Scoping Assessment phase. In this phase, the IESO, in collaboration with the lead transmitter and impacted LDCs, reviews the information collected during the Needs Assessment phase, along with the additional information on potential "non-wires" alternatives or resources and determines the most appropriate regional planning approach. If there is the potential to integrate a mix of different options, such as conservation, generation, distribution or new technologies, the IRRP is recommended. If needs can be met through focusing only on wires, meaning additions or improvements to transmission lines or infrastructure, a RIP led by the transmitter is recommended. A third option includes the local LDC and the transmitter working together to plan necessary local infrastructure investments.

Integrated Regional Resource Plan

If the Scoping Assessment concludes that an IRRP is required, a TWG, comprised of the IESO, lead transmitter, and local LDCs works together to develop a plan that integrates resource options to address the electricity needs of the region. The IRRP process involves identifying, evaluating and integrating potential wires and non-wires solutions at the regional or sub-regional level. The IRRP phase generally assesses "non-wires" resource (i.e., generation and/or conservation and demand management) versus "wires" infrastructure options at a higher level with sufficient details to allow for adequate comparison of options. If during this phase it is determined that "non-wires" resource

options are best suited to meet a need, then those options are further planned by the IESO. However, if the “wires” options are the more appropriate alternative, then those options are further assessed and/or planned by a lead transmitter as part of the RIP process.

Regional Infrastructure Plan

The RIP process is the final phase of the regional planning process and involves review and confirmation of previously identified needs, identification of any new needs that may have emerged since the start of the planning cycle (including transmission asset needs that may influence a solution to address broader regional needs), and development of a “wires” plan to address the identified needs. This phase is led and coordinated by a lead transmitter, and the deliverable from this phase is a comprehensive report setting out a “wires” plan from a regional planning perspective, known as a RIP Report. This report may include transmission and/or distribution investments needed to address the identified regional needs. A transmitter responsible for each region will implement the recommended transmission investments and local LDCs will undertake the recommended distribution investments in their respective service territories. Transmitters and LDCs include the recommended regional plan investments as part of their respective rate filings with the OEB.

Figure 1 below provides an overview of the various phases of the regional planning process described above. The flowchart also illustrates the relationship between the IESO-led IRRP process and Hydro One-led RIP process.

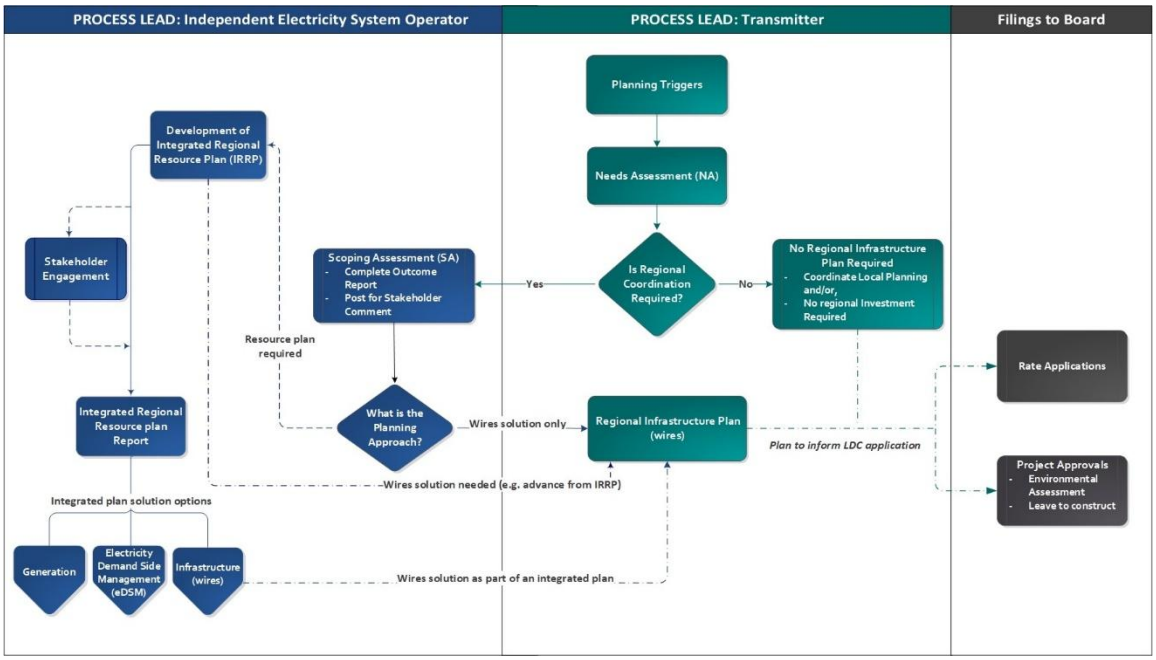


Figure 1: Regional Planning Process

1.2.3 REGIONAL PLANNING REGIONS

For the purpose of regional planning, Ontario has been divided into 21 electrical regions presented in Table 1 and illustrated in Figure 2 below. Hydro One Transmission (including HOSSM) is the lead transmitter in all regions, except North of Moosonee.[2] Hydro One Distribution is an LDC participating in 20 regions of the 21 regions.

[2] Five Nations Energy Inc. is the lead transmitter for this region.

Table 1 - Regional Planning Regions

Burlington to Nanticoke	Greater Bruce/Huron	Sudbury/Algoma
Windsor-Essex	East Lake Superior (Hydro One SSM)	Renfrew
GTA North	GTA East	North/East of Sudbury
Greater Ottawa	Peterborough to Kingston	St. Lawrence
Toronto	South Georgina Bay/Muskoka	Niagara
Kitchener-Waterloo-Cambridge-Guelph	Northwest Ontario	Chatham/Lambton/Sarnia
GTA West	London Area	North of Moosonee[3]

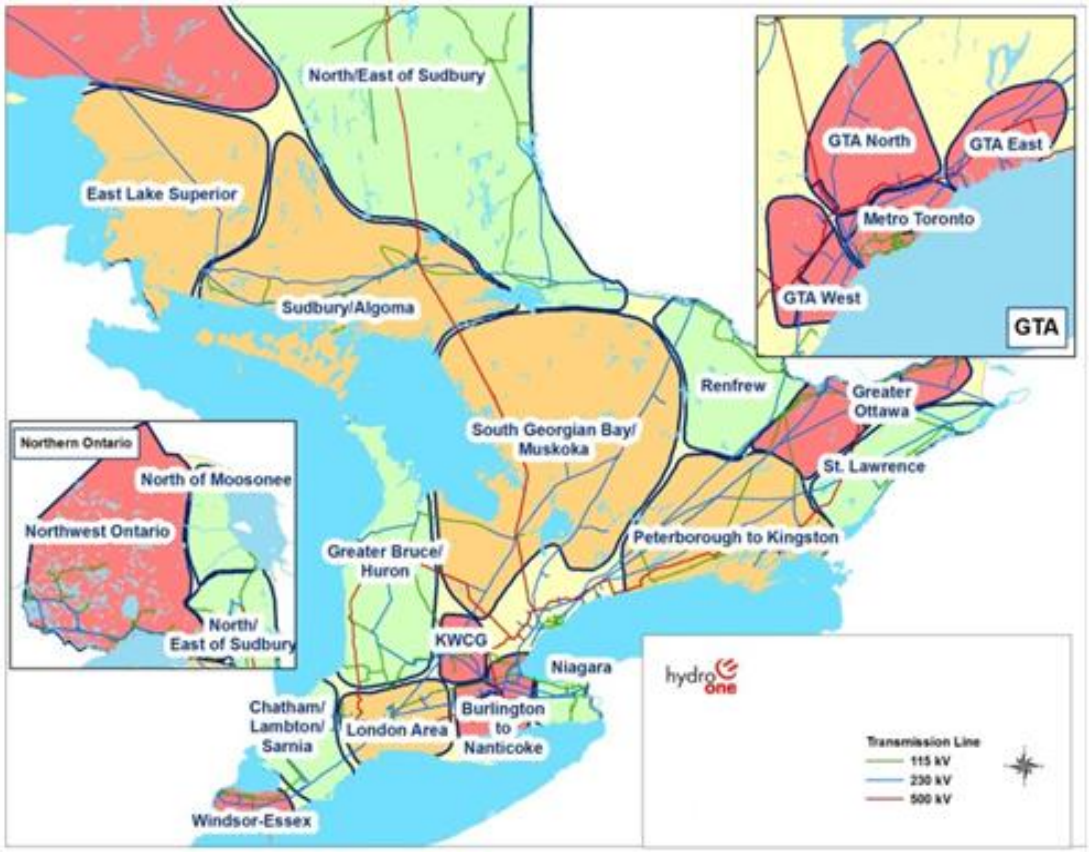


Figure 2: Regional Planning Regions

[3] Ibid

1.2.3.1 STATUS OF REGIONAL PLANNING ACTIVITIES

Regional planning is an inherently iterative process. Pursuant to the TSC, the Needs Assessment is undertaken at least once every five years or more frequently if required by reason of forecasted load or demand growth within a local LDC's licensed service area, requests for connection received by the transmitter or other events that the TWG believes may trigger the need for investment in transmission facilities, distribution facilities or both in a region. With energy transition accelerating, in the current third regional planning cycle to date, regional planning was accelerated for four regions: Greater Ottawa, London Area, Peterborough to Kingston and St Lawrence. Each region underwent a thorough study, resulting in timely recommendations to address the emerging new needs. We anticipate that additional regions in the fourth regional planning cycle will require advancing. The first cycle of regional planning activities was completed between 2013 and 2017, and the second cycle was completed in 2023 for all 21 regions, including the 20 regions for which Hydro One is designated the lead transmitter. Currently, the third cycle of regional planning activities is underway. Table 2 below summarizes the status of second and third cycles for each region, indicating the planning phases that are in progress/in future or have been completed. A letter from the IESO on the overall regional planning status is included in Attachment 3.

Table 2 - Regional Planning Status Summary

Region	Sub-region	2nd Cycle (2017-2023)				3rd Cycle (2022→)			
		NA (1)	**SA** (1)	**IRRP** (1)	**RIP** (1)	**NA** (1)(3)	**SA** (1)(3)	**IRRP** (1)(3)	**RIP** (1)(3)
Burlington to Nanticoke	Greater Hamilton	May. 2017	Aug. 2017	Feb. 2019	Oct. 2019	Sep. 2022	Dec. 2022	TBD	TBD
	Brant							Nov. 2024	Jun. 2025
	Bronte								
	Caledonia-Norfolk								
Greater Ottawa	Ottawa	Jun. 2018	Sep. 2018	Mar. 2020	Dec. 2020	Dec. 2022	Mar. 2023	Jul. 2025	Feb. 2026
	Outer Ottawa		*Not Required*	*Not Required*			*Not Required*	*Not Required*	
GTA East		Aug. 2019	*Not Required*	*Not Required*	Feb. 2020	Dec. 2024	Apr. 2025	Oct. 2026	TBD
GTA North		Mar. 2018	Aug. 2018	Feb. 2020	Oct. 2020	Jul. 2023	Oct. 2023	Oct. 2025	May. 2026

Region	Sub-region	2nd Cycle (2017-2023)				3rd Cycle (2022→)			
		NA (1)	**SA** (1)	**IRRP** (1)	**RIP** (1)	**NA** (1)(3)	**SA** (1)(3)	**IRRP** (1)(3)	**RIP** (1) (3)
GTA West		May. 2019	Aug. 2019	Jul. 2021	Feb. 2022	Aug. 2024	Nov. 2024	Nov. 2026	TBD
Kitchener-Waterloo-Cambridge-Guelph		Dec. 2018	May. 2019	May. 2021	Dec. 2021	Apr. 2024	Jul. 2024	Jul. 2026	Feb. 2027
Toronto		Oct. 2017	Feb. 2018	Aug. 2019	Mar. 2020	Dec. 2022	Mar. 2023	Oct. 2025	May-26
Northwest Ontario		Jul. 2020	Jan. 2021	Jan. 2023	Aug. 2023	Sep. 2025	Sep. 2025	Mar. 2027	TBD
Windsor-Essex		Oct. 2017	Mar. 2018	Sep. 2019	Mar. 2020	Feb. 2023	May. 2023	Apr. 2025	Oct. 2025
London Area		May. 2020	*Not Required*	*Not Required*	Aug. 2022	Nov. 2024	Apr. 2025	Oct. 2026	TBD
Peterborough to Kingston		Feb. 2020	May. 2020	Nov. 2021	May. 2022	Dec. 2024	Apr. 2025	Oct. 2026	TBD
South Georgian Bay/Muskoka	Barrie/Innisfil	Apr. 2020	Nov. 2020	May. 2022	Dec. 2022	Aug. 2025	Nov. 2025	May. 2027	TBD
	Parry Sound/ Muskoka			May. 2022					
Sudbury/Algoma		Jun. 2020	*Not Required*	*Not Required*	Dec. 2020	Oct. 2025	Jan. 2026	Jul. 2027	TBD
Chatham/Lambton/Sarnia		Sep. 2021	Dec. 2021	*Not Required*	Aug. 2022	Nov. 2026	TBD	TBD	TBD
Greater Bruce/Huron		May. 2019	Sep. 2019	Sep. 2021	Apr. 2022	Sep. 2024	*Not Required*	*Not Required*	Apr. 2025
Niagara		May. 2021	Aug. 2021	Dec. 2022	Jul. 2023	Jul. 2026	Oct. 2026	TBD	TBD
North/East of Sudbury(4)		May. 2021	Aug. 2021	Apr. 2023	Nov. 2023	Nov. 2026	TBD	TBD	TBD
Renfrew		May. 2021	Aug. 2021	Dec. 2022	Jul. 2023	Jul. 2026	TBD	TBD	TBD
St. Lawrence (2)		Sep. 2021	*Not Required*	*Not Required*	Mar. 2022	Mar. 2026	Apr. 2026	Oct. 2027	TBD
East Lake Superior		Jun. 2019	Oct. 2019	Apr. 2021	Oct. 2021	Oct. 2024	Jan. 2025	Jul. 2026	Feb. 2027
North of Moosonee									

Notes: (1): NA: Needs Assessment; SA: Scoping Assessment; IRRP: Integrated Regional Resource Plan; RIP: Regional Infrastructure Plan
(2): Note that St. Lawrence 2nd cycle NA was initiated two (2) months over the five (5) year period because of an error in oversight.
(3): All future completion dates are tentative based on Regional Planning Process timeline requirements.
(4):The IESO's recommended delaying the needs assessment for North/East of Sudbury until after the conclusion of the bulk plan. OEB agreed and granted extension to start NA in September 2026.

1.2.3.2 OEB REVIEWS AND PROCESS DEVELOPMENTS

In December 2020, the OEB initiated a consultation process to review the regional planning process that applies to Ontario's electricity sector. The primary purpose of this review was to improve the efficiency and effectiveness of the regional planning process at the time. The review was completed in December 2021 with recommendations to improve the process that were formally approved by the OEB in April 2022. The recommendations resulted in amendments to licenses and codes, which continue to inform regional planning today.

In December 2025, the OEB launched a review of the regional and bulk planning processes (EB-2025-0248) in response to the Ministry of Energy and Mines' Integrated Energy Plan (IEP) Directive. The OEB established a new Regional and Bulk Planning Process Advisory Group (RBPPAG) to assist the OEB in identifying opportunities for enhancing the regional and bulk planning processes. This review was completed in February 2026. The OEB provided an overview of proposed actions resulting from this review in their report back to Ministry on March 31, 2026.

1.2.4 HYDRO ONE TRANSMISSION

1.2.4.1 ROLES AND RESPONSIBILITIES OF HYDRO ONE TRANSMISSION

As the largest transmitter in Ontario, Hydro One Transmission plays a key role and is actively involved in the regional planning process. As the lead transmitter in 20 of the 21 regions, Hydro One Transmission takes the lead in triggering the regional planning cycle with the Needs Assessment and finally developing a wires plan for the region during the RIP phase of the process taking into consideration recommendations made during IRRP. In this role, Hydro One Transmission identifies the information or data required to carry out the necessary assessments; ensures that the appropriate LDCs have been informed of their requirement to participate in the process; ensures that all participants are treated in fair manner; conducts studies and shares findings with the TWG; and completes and publishes Needs Assessment and RIP reports. Where issues overlap with other regions, Hydro One Transmission may provide for inter-regional coordination and advise what LDCs are required to participate in each planning study.

Throughout the Needs Assessment and RIP phases, Hydro One Transmission undertakes extensive engagements and discussions with all stakeholders to identify needs and develop appropriate solutions to address the identified needs. Hydro One Transmission undertakes the following activities:

1. Data gathering: Hydro One Transmission collects information, such as, but not limited to historical load data, municipal communication and their input on electricity demand and emission reduction goals, future load forecast, DER and CDM forecasts, and a list of major equipment warranting replacement based on asset condition assessments. A clear and consistent approach is employed to ensure accurate information is collected. A methodical load forecast data gathering and development approach is used in accordance with OEB's Load Forecast Guideline and in coordination with the IESO and local LDCs taking into consideration CDM, DERs, municipal planning input, demand scenarios, and emerging technologies like electrical vehicles, battery energy storage, etc. A ten-year outlook of asset replacement needs based on asset condition assessment is identified for all major high voltage transmission assets.

   a) Every investment whose condition warrants replacement is considered for "right-sizing" opportunity. Where forecasted demand growth or decline is identified during the regional planning process and where a transmitter is making investments, considerations are made to right-size the transmission equipment, either by removing equipment in the case of demand decline or upgrading equipment in the case of demand growth.

2. Pre-meeting Conference Calls/Webinars: In advance of each phase of the regional planning process, local LDCs and the IESO are notified of upcoming regional planning activities and provided with an overview of the process. Hydro One Transmission also proactively notifies municipalities via annual emails (since 2023) of upcoming regional planning activities so they can begin preparing their input to share/discuss with their respective LDC(s). To facilitate this, Hydro One

provides municipalities with a template they can use to enter their electricity demand and emission reduction plans based on OEB's Municipal Information Guideline. Hydro One Transmission also reaches out to its large transmission-connected customers to obtain and update their electricity load forecasts.

3. Kick-off Meetings/Conference Calls/Webinars: Kick-off meetings with the TWG are organized to initiate each of the phases of the regional planning process and provide information on regional updates, schedules, and high-level deliverables for each phase. Follow-up meetings occur on a regular basis to discuss various planning matters such as assessment methodology, right sizing opportunities for deteriorated assets that require replacement, customer needs, and regional needs and timing before recommending a preferred plan.

4. Feedback from TWG: Hydro One Transmission regularly communicates with LDCs and IESO to seek feedback on prioritization and scheduling of regional planning for the regions, as well as seeking suggestions for enhancements in the upcoming cycles of regional planning.

Throughout the Scope Assessment and IRRP phases, the IESO also engages with local and regional communities to gather input that informs planning activities and supports the development of the IRRP. Hydro One Transmission, along with the other TWG members, also seeks further input as needed from stakeholders such as, local municipalities, Indigenous communities, business groups, citizen groups, consumers and environmental and conservation groups.

Outside of regional planning activities, Hydro One Transmission has the following requirements that pertain to the process:

- Submit an annual report to the OEB describing the status of the regional planning activities for all regions where it is a lead transmitter. The last report, 2025 Status Report, was filed on October 31, 2025.[4]
- Pursuant to section 2.4.3 of the OEB's Chapter 2 Filing Requirements for Electricity Transmission Applications, where regional planning is underway, but a RIP has not yet been completed for the applicable region, Hydro One Transmission is required to submit a letter from the IESO, identifying the status of the regional planning process, and the potential impacts on the Hydro One Transmission's investment plans. The letter is found at Attachment 3.
- To provide Planning Status Letters to all participating LDCs confirming the status of regional planning for a region, suitable for the purpose of supporting a rate application. In its 2025 Status Report, Hydro One Transmission identifies the LDCs to whom it has provided Planning Status Letters since November 2024. In addition to those LDCs, Hydro One Transmission has recently provided a Planning Status Letter to Milton Hydro, Enova Power Corporation, London Hydro, Canadian Niagara Power Inc. and Hydro One Distribution.

1.2.4.2 HYDRO ONE PROCESS IMPROVEMENTS

Over the three regional planning cycles to date, Hydro One has identified several lessons and opportunities for improvement related to the regional planning process and its deliverables. These improvements include recommendations from the OEB's Regional Planning Process Advisory Group (RPPAG), internal process and regional planning report updates, and feedback from regional TWG members. Hydro One has proactively implemented these improvements over the last three regional planning cycles which have led to a more effective and efficient process along with its deliverables.

Following the completion of the first cycle of regional planning activities, Hydro One Transmission undertook the initiative to enhance the regional planning process and to

[4] 2025 Regional Planning Process Annual Status Report to the Ontario Energy Board, October 31, 2025, https://www.oeb.ca/sites/default/files/HONI_OEB_RP_STATUS_REPORT_20251031.pdf.

identify areas for improvement. Hydro One Transmission sought feedback from various stakeholders and shared its own lessons learned with the IESO and OEB. Some of the key lessons learned during the first cycle included improving overall stakeholder engagement and data input with respect to asset conditions. Those improvements are further described below.

1.2.4.3 MUNICIPAL ENGAGEMENT FOR REGIONAL PLANNING

Hydro One created a new template that can be used by municipal planners to provide input to LDCs to inform the LDC's demand forecast. This template is aligned with OEB RPPAG's Municipal Information Guideline, "Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector." This template is intended to streamline the information exchange between LDCs and municipalities as it provides the format and specificity of the information required by municipalities. Following the distribution of this template to municipalities, and direct engagement with the Association of Municipalities Ontario, we observed a more positive engagement and a greater number of municipalities are now engaged and have begun completing and forwarding it to their respective LDCs. This marks another proactive measure by Hydro One to strengthen coordination with municipalities, offer support and improve load forecasting to help ensure their electricity and/or emission reduction plans are considered.

In addition, Hydro One has met with various municipalities and LDCs to support engagement and discuss any needs brought forward, including through attendance at the Association of Municipalities Ontario (AMO) 2025 Annual Conference, one-on-one meetings, and email outreach.

1.2.4.4 NATURAL GAS COORDINATION

Hydro One continues discussions with Enbridge Gas Inc. on how the two entities can further enhance coordination between Natural Gas and Electricity Regional Planning. Hydro One has developed a draft template to coordinate input from municipalities on gas and electricity needs. This is being further discussed as part of the ongoing OEB consultation on Gas-Electric Co-ordination and Information Sharing (EB-2025-0227).

1.2.4.5 EXPEDITING REGIONAL PLANNING PROCESS

Hydro One has consistently focused on improving efficiency in the regional planning process and enhancing responsiveness to benefit local priorities and broader system

requirements as the grid transformation accelerates. For example, although the Needs Assessment must be initiated every five years, emerging demands – such as sudden large connection requests – have necessitated earlier assessments in some regions. In the current third regional planning cycle to date, regional planning was accelerated for four regions: Greater Ottawa, London Area, Peterborough to Kingston and St Lawrence. Each region underwent a thorough study, resulting in timely recommendations to address the emerging new needs. We anticipate that additional regions in the fourth regional planning cycle will require advancing. In addition, Hydro One has initiated consultation and has been working proactively with the IESO and in parallel with the Regional Planning process, to evaluate system architecture, address and mitigate increased short circuit levels in some areas such as GTA East, Peterborough to Kingston, GTA West, Burlington to Nanticoke, Toronto, etc. to enable generation procurement.

1.2.4.6 STAKEHOLDER ENGAGEMENT

Hydro One Transmission has implemented an engagement phase prior to initiating the Needs Assessment and RIP processes by incorporating one-on-one pre-Regional Planning meetings with key stakeholders such as local LDCs to better understand their emerging needs and collect relevant information. These meetings have resulted in improved collaboration and efficiency during regional planning meetings with the Study Team members by having a head start in identifying emerging needs, discussing LDC-specific issues and concerns that may have an impact on regional planning.

1.2.4.7 TEN-YEAR OUTLOOK ON ASSET REPLACEMENT NEEDS

Managing aging infrastructure based on asset condition to determine its replacement or refurbishment is the primary accountability of asset owners for safe, secure and reliable operation. Each of the major assets, such as transformers, breakers and conductors require special technical expertise about the equipment and to develop a strategy for their replacement where warranted. Since the end of the first regional planning cycle, Hydro One Transmission enhanced its processes for data collection, analysis and supplying relevant information as part of regional planning studies. Given that sometimes the replacement of major equipment may also provide a broader planning opportunity, Hydro

One Transmission developed an internal process to collect and provide best available information for major high voltage transmission equipment for assessment and consideration during the regional planning process to ensure various planning alternatives are considered. For each of the regions, Hydro One Transmission provides a list of major equipment that is planned for replacement/refurbishment based on asset condition. Once it is determined that replacing the deteriorated equipment is the most appropriate approach, the TWG assesses, discusses planning alternatives and recommends the preferred approach, which may include:

- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
- Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
- Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all of the load to other existing facilities.

In 2022, the RPPAG formalized the process and recommended that going forward all transmission asset owners (TAO) provide a ten-year outlook related to their major transmission assets requiring replacement during the Needs Assessment phase. Hydro One successfully implemented this process and is documented in both the Needs Assessment and RIP reports for each region, thereby enhancing the quality of the planning deliverables.

1.2.4.8 SUMMARY OF HYDRO ONE TRANSMISSION NEEDS AND ASSOCIATED INVESTMENTS

This section provides further details regarding capital investment recommendations scheduled for each region and sub-region over the 2028 to 2032 period addressed in this Exhibit. While emerging system or customer needs may accelerate additions to the current regional plans, this Application includes transmission investments arising from regional planning recommendations. Additional long-term capital planning information filed in response to Hydro One's settlement commitment is provided in Attachment 2. The

investments arising from the recommendations of the TWG are summarized below by region, with further details provided in TSP Section 2.12 and in the corresponding Needs Assessment, IRRP and RIP reports included as attachments to this section at Attachments 4-46.

Burlington to Nanticoke

The Burlington to Nanticoke region is comprised of four sub-regions: Brant, Bronte, Greater Hamilton, and Caledonia-Norfolk. This region encompasses the municipalities of Burlington, Hamilton, Oakville, Brantford, and the Counties of Brant, Haldimand, and Norfolk. The participants in the region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation
- Burlington Hydro Inc.
- Grand Bridge Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Oakville Hydro Electricity Distribution Inc.

The third regional planning cycle for this region was concluded with the publication of the RIP Report in June 2025. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found in Attachment 4 and 5. However, the IESO will issue an IRRP addendum for the Hamilton sub-region and the Bronte TS supply area. The RIP, incorporating the final recommendations based on the TWG's assessment of the additional alternatives, will be re-released accordingly. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Beach TS: Auto-Transformer (T1/T7/T8) Replacement and DESN Switchgear (T-SR-01);
- Burlington TS: T12 Autotransformer and LV Switchgear (T-SR-01);
- Birmingham TS: MV Metalclad Switchgear Refurbishment (T-SR-03);
- Lake TS– T2, T3 and T4 transformers replacement. (T-SR-03)
- Nebo TS– T3 and T4 transformer replacement. (T-SR-03)
- Beach TS – T5 and T6 transformers replacement. (T-SR-03)
- Caledonia TS – T2 transformer replacement (T-SR-03)
- Gage TS – T8 and T9 transformer replacement. (T-SR-03)
- Jarvis TS – T3 and T4 transformers replacement. (T-SR-03)
- Dundas Area Capacity – Two new transformation facilities near Dundas TS. (T-SA-11)
- Brant Area Capacity – Two new transformation facilities near Brant TS. (T-SA-11)

Greater Ottawa

The Greater Ottawa Region is comprised of two sub-regions: Ottawa Area and Outer Ottawa. This region encompasses the municipalities bordering the Ottawa River from Stewartville in the West to Hawkesbury in the East and North of Highway 43. The participants in the region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro Ottawa Limited
- Ottawa River Power Corporation
- Hydro 2000 Inc.
- Renfrew Hydro Inc.

The third regional planning cycle for this region was concluded with the publication of the RIP Report in February 2026. The RIP is a comprehensive, region-wide detailed wires

plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 6 and 7. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Albion TS – T1 and T2 transformer replacement. (T-SR-03)
- Merivale TS – T22 and T23 transformer replacement and six 230 kV and four 115 kV breaker replacement. (T-SR-01)
- Nepean TS – T3 and T4 transformer replacement. (T-SR-03)
- 115 kV S7M – 6.5 km line refurbishment. (T-SR-13)
- South March TS – T1 and T2 transformer replacement. (T-SR-03)
- Lisgar TS – T2 transformer replacement (T-SR-03)
- Riverdale TS – Breaker replacement (T-SR-03)
- Build new 230 kV circuit Merivale TS X Greenbank MTS (T-SA-11)
- Merivale TS Supply Reliability – Split breaker position M1R and L2M (T-SS-12)
- Orleans TS – Provide second 230kV supply (T-SS-12)
- Kanata Area Transmission Reinforcement (T-SS-12)

GTA East

The GTA East Region is comprised of two sub-regions: Pickering-Ajax-Whitby and Oshawa-Clarington. This region encompasses the municipalities of Pickering, Ajax, Whitby, Oshawa, and parts of Clarington and other parts of Durham Region. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Oshawa PUC Networks Inc.
- Elexicon Energy Inc.

The second cycle RIP for this region was completed in February 2020 and is found at Attachment 8. The second cycle Needs Assessment suggested that no further regional coordination was required and so the TWG proceeded directly to the RIP phase. The third cycle Needs Assessment was completed in December 2024 (Attachment 9) and has identified needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of November 2026. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Cherrywood TS – ABCB Breaker Replacement (T-SR-02).
- Wilson TS – T3 and T4 Transformer replacement. (T-SR-03)
- Whitby TS Station Capacity - Connect new Whitby MTS (T-SA-11)

GTA North

The GTA North Region is comprised of two sub-regions: York and Western. This region encompasses the Regional Municipality of York, and includes parts of the Cities of Toronto, Brampton, and Mississauga. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited (THESL)

The third regional planning cycle for this region was concluded with the publication of the RIP Report in May 2026. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 10 and 11. The following material transmission investments have capital expenditures during the 2028–2032 rate

period; however, the in-service dates for these projects may extend beyond the rate period:

- Woodbridge TS – T5 transformer Replacement. (T-SR-03)
- Build new Markham TS #5 (T-SA-18)
- Build new Northern York TS 1 and 2 (T-SA-09)
- New DESN in Northern York Region (T-SA-09)
- New DESN #2 in Northern York Region (T-SA-11)
- Connect Vaughan MTS#5 (T-SA-11)
- Buttonville T3/T4 and component replacement (T-SR-03)
- Connect new Markham MTS#5 (T-SA-11)
- Buttonville Tap-Reconduct Parkway to Markham MTS#4 (T-SS-12)

GTA West

The GTA West Region is comprised of two sub-regions: Northwestern and Southern. This region encompasses the Regional Municipalities of Halton and Peel, and comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville, and parts of Burlington. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation
- Burlington Hydro Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The second regional planning cycle for this region was concluded with the publication of the RIP Report in February 2022. The RIP is a comprehensive, region wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The

IRRP and RIP reports for this region are found at Attachment 12 and 13. The third cycle Needs Assessment was completed in August 2024 (Attachment 14) and has identified needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of November 2026. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Bramalea TS – T3/T4 Transformer and Component Replacement (T-SR-03);
- Reconductor 230kV H29/H30 Transmission Line. (T-SA-08)
- Halton TS New DESN - Build new DESN (T-SA-03)
- Palermo TS - T3/T4 transformer replacement (T-SR-03)
- Pleasant TS – T5 and T6 transformer replacement (T-SR-03)
- Construct new 230kV double circuit from Hurontairo SS to Meadowvale TS (T-SS-12)
- Hurontario SS Reconfiguration (T-SS-12)

Kitchener-Waterloo-Cambridge-Guelph (KWCG)

The KWCG Region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and associated townships in the area. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Centre Wellington Hydro Ltd.
- Alectra Utilities Corporation
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Milton Hydro Distribution Inc.
- Wellington North Power Inc.
- Enova Power Corporation
- Grandbridge Energy

The second regional planning cycle for this region concluded with the publication of the RIP Report in December 2021. The RIP is a comprehensive, region wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The RIP report for this region is found at Attachment 15. The third cycle Needs Assessment was completed in April 2024 (Attachment 16) and has identified needs that require further regional coordination. The third cycle IRRP was also completed in July 2026 (Attachment 17), and the RIP is currently underway with a tentative completion date of February 2027. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Campbell TS: PCT and Component Replacement; (T-SR-03)
- Cedar TS: Transformer (T7/T8) Replacement; (T-SR-03)
- D6V/D7V - Upgrade circuits out of Detweiler TS (T-SS-12)
- Wellington TS: Build new 500kV/230kV Station (T-SS-12)
- 115kV Upgrades (B5/6C, D7/9F, F11/12C) (T-SS-12)

Toronto

The Toronto Region is comprised of two sub-regions: Central Downtown and Northern. This region comprises the area within the municipal boundary of the City of Toronto. The participants in this region's TWG include representatives from the following organizations:

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

The third regional planning cycle for this region was concluded with the publication of the RIP Report in May 2026. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also

incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 18 and 19. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Bermondsey TS – Transformer (T3/T4) Replacement (T-SR-03)
- Leslie TS – Transformer (T1) Replacement; (T-SR-03)
- 115kV H1L/H3L/H6LC/H8LC Transmission Lines – Refurbish line sections from Leaside Junction to Bloor St. Junction; (T-SR-13)
- HV UG Cable - Replace H1L/H3L & H2JK (T-SR-16)
- 115kV L9C/L12C Transmission Lines – Refurbish line sections from Leaside TS to Balfour Junction (T-SR-13)
- Strachan TS – T13, T14 and T15 transformer replacement. (T-SR-03)
- Duplex TS – T1, T2, T3 and T4 transformer replacement. (T-SR-03)
- Basin TS – T3 and T5 transformer replacement. (T-SR-03)
- Fairchild TS – T1, T3 and T4 transformer replacement. (T-SR-03)
- Bermondsey TS – T3 and t4 transformer replacement. (T-SR-03)
- Manby TS – T7, T9 & T12 transformer (T-SR-01) and T13 & T14 auto-transformer replacement (T-SR-03).
- Richview TS to Manby TS 230 kV Corridor Reinforcement: Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS. (T-SS-06)
- Manby X Riverside supply capacity - Increase transmission capacity by upgrading circuits from Manby TS to Riverside TS (T-SS-12)

Northwest Ontario

The Northwest Ontario Region is comprised of several sub-regions: North of Dryden, Greenstone-Marathon, City of Thunder Bay, and West of Thunder Bay. This region encompasses a large geographic area, stretching from the town of Marathon to the western and northern borders of the province and consists of the districts of Kenora, Rainy River, and Thunder Bay, which is roughly the area north of Lake Superior stretching from

the Wawa area in the east and the Manitoba border in the west. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Hydro One Networks Inc. (Distribution)
- Synergy North
- Sioux Lookout Hydro Inc.
- Wataynikaneyap Power LP
- NextBridge Infrastructure LP

The third regional planning cycle for this region was concluded with the publication of the RIP Report in August 2023. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 20 and 21. An addendum to the IRRP was also published in August 2025 for North of Dryden Sub-Region (Attachment 22). The third cycle Needs Assessment was completed in September 2025 (Attachment 23) and has identified needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of April 2027. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Wawa TS – T1 and T2 autotransformers replacement. (T-SR-01)
- Marathon TS – 230 kV,115 kV breakers and associated equipment replacement. (T-SR-01)
- Lakehead TS – 230 kV,115 kV breakers and associated equipment replacement. (T-SR-01)
- Lakehead TS – Condenser C8 will be replaced with a STATCOM. (T-SR-01)

- Fort Frances TS – 230 kV breakers and associated equipment's replacement. (T-SR-01)
- Kenora TS –T1 transformer replacement. (T-SR-01)
- North of Dryden Transmission Reinforcement or "Red Lake Transmission Project" – stations portion (T-SS-12)

Windsor-Essex

The Windsor-Essex Region is in the southernmost part of Ontario, extending from Chatham southwest to Windsor. This region encompasses the City of Windsor, the Municipality of Leamington, the Town of Amherstberg, the Town of Essex, the Town of Kingsville, the Town of Lakeshore, the Town of LaSalle, the Town of Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc. (Chatham-Kent)
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)

The third regional planning cycle for this region was concluded with the publication of the RIP Report in October 2025. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 24 and 25. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Lauzon TS – T7 and T8 transformer and Component Replacement (T-SR-03)
- Keith TS – Phase Angle Regulator PSR5 replacement. (T-SR-01)
- West Essex and Windsor sub-system supply capacity: Construction of new 22 km double circuit 230 kV from Lakeshore TS to supply the new Leamington DESN 5 and 6. (T-SA-10)
- Coatsworth Area supply capacity: Construction of new 230 kV double-circuit transmission line that taps the Chatham-by-Lakeshore circuits. (T-SA-11)
- Coatsworth Area Greenhouse Supply Station: Construction of new Coatsworth Area 75/125 MVA 230/27.6 -27.6 kV DESN1. (T-SA-11)
- Windsor Lakeshore Transmission Line Project – Station portion (T-SS-12)

London Area

The London Area Region is comprised of five sub-regions: Greater London, Aylmer-Tillsonburg, Strathroy, Woodstock, and St. Thomas. This region encompasses the Cities of Woodstock, London and St. Thomas as well as the Counties of Middlesex, Elgin, and Oxford. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Entegrus Powerlines Inc.
- ERTH Power Inc.
- Hydro One Networks Inc. (Distribution)
- London Hydro Inc.
- Tillsonburg Hydro Inc.

The second cycle RIP for this region was issued in August 2022 and is found at Attachment 26. The Needs Assessment suggested that no further regional coordination was required and the TWG proceeded directly to the RIP phase. The third cycle Needs Assessment was completed in November 2024 (Attachment 27) and has identified needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of November 2026. The following material transmission

investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Buchanan TS – T2, T3 transformer and Component Replacement (T-SR-01);
- Clarke TS: T3 and T4 transformer replacement (T-SR-03);
- Talbot TS – T3 and T4 transformer replacement (T-SR-03)

Peterborough to Kingston

The Peterborough to Kingston Region includes the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, Frontenac County on the East, and Lake Ontario on the South. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Kingston Hydro Corporation
- Peterborough Distribution Inc. (Recently acquired by Hydro One Distribution)
- Elexicon Energy Inc.
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

The second regional planning cycle for this region was concluded with the publication of the RIP Report in August 2022. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP report for this region is found at Attachment 28 and 29. The third cycle Needs Assessment was completed in December 2024 (Attachment 30) and has identified needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of November 2026. Additionally, IESO published Gatineau Corridor EOL study in December 2022, which recommended building a new 230kV double circuit line from Clarington TS to Dobbin TS (attachment 31). The following material transmission investments have capital expenditures during the 2028–

2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Port Hope TS – T3 and T4Transformer Replacement (T-SR-03);
- Dobbin TS – T1/T2 autotransformer replacement and T5 decommissioning(T-SR-03)
- Cataraqui TS – T1 and T2 autotransformer replacement(T-SR-01)

South Georgian Bay/Muskoka

The South Georgian Bay/Muskoka Region is comprised of two sub-regions: Barrie/Innisfil and Parry Sound/Muskoka. This region is the area roughly bordered by West Nippising on the North-West, the Algonquin Provincial Park on the Northeast, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation
- Hydro One Networks Inc. (Distribution)
- InnPower Corporation
- Orangeville Hydro Ltd.
- Elexicon Energy Inc.
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

The second regional planning cycle for this region was concluded with the publication of the RIP Report in December 2022. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 32 and 33. The third cycle Needs Assessment was completed in August 2025 (Attachment 34) and has identified

needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of June 2027. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Wallace TS – T3/T4 transformers replacement (T-SR-03)
- Midhurst TS – T4 transformer replacement (T-SR-03)
- Waubaushene TS – T5 and T6 transformer replacement (T-SR-03)
- Sections of E8V/E9V circuits line refurbishment (T-SR-13)
- Barrie TS station capacity – Extend E28B/E29B circuits to connect new 230/27.6kV DESN Innpower MTS. (T-SA-11)

Sudbury/Algoma

The Sudbury/Algoma Region includes the Greater Sudbury Area, Manitoulin Island, and Townships of Verner, Warren, Elliot Lake, Blind River, and Walden. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Greater Sudbury Hydro Inc.
- North Bay Hydro
- Hydro One Networks Inc. (Distribution)

The second cycle RIP for this region was issued in December 2020 and is found at Attachment 35. The Needs Assessment suggested that no further regional coordination was required and so the TWG proceeded directly to the RIP phase. The third cycle Needs Assessment was completed in October 2025 (Attachment 36) and has identified needs that require further regional coordination. The third cycle IRRP is currently underway with a tentative completion date of August 2027. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Martindale TS: T25 & T26 Transformer Replacement (T-SR-03);
- Clarabelle TS: T1 & T2 Transformer Replacement (T-SR-03);

Chatham/Lambton/Sarnia

The Chatham-Lambton-Sarnia Region includes the municipalities of Lambton Shores and Chatham-Kent, as well as associated townships in the area. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Bluewater Power Distribution Corporation
- Entegrus Powerlines Inc. (Chatham-Kent)
- Hydro One Networks Inc. (Distribution)

The second cycle RIP for this region was issued in August 2022 and is found at Attachment 37. The Needs Assessment and Scoping Assessment suggested that no further regional coordination was required and so the TWG proceeded directly to the RIP phase. The third cycle of Needs Assessment will be completed in November 2026. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Kent TS – T2 Transformer and switchyard replacement (T-SR-03)
- 115kV S2N – Line refurbishment between Scott TS and Adelaide Jct. (T-SR-13)

Greater Bruce / Huron

The Greater Bruce/Huron region includes the municipalities of Arran–Elderslie, Brockton, Kincardine, Northern Bruce Peninsula, and South Bruce. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Entegrus Powerlines Inc.
- ERTH Power corporation
- Festival Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Wellington North Power Inc.

- Westario Power Inc.

The third cycle RIP report for this region was published in April 2025 and is found at Attachment 38. The Needs Assessment suggested that no further regional coordination was required and so the TWG proceeded directly to the RIP phase. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Owen Sound TS – T5 autotransformer replacement (T-SR-01)

Niagara

The Niagara Region comprises the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation
- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Hydro One Networks Inc. (Distribution)
- Niagara-on-the-Lake Hydro Inc.
- Welland Hydro Electric System Corp.
- Niagara Peninsula Energy Inc.

The second regional planning cycle for this region was concluded with the publication of the RIP Report in July 2023. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 39 and 40. The third cycle Needs Assessment was completed in July 2026 (Attachment 41) and has identified needs

that require further regional coordination. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Glendale TS – T1 transformers replacement. (T-SR-03)
- Murray TS – T11/12 and T13/T14 transformers replacement. (T-SR-03)
- Allanburg TS – T3 autotransformer replacement (T-SR-03)
- 115 kV Q2AH – Conductor replacement Rosedene JCT X St. Anns JCT (T-SR-13)
- Crowland TS station capacity – Build new 230kV line into Welland and construct new Crowland TS. (T-SA-11)

North/East of Sudbury

The North/East of Sudbury Region is the area roughly bordered by Moosonee to the North, Hearst to the North-West, Ferris to the South, and Kirkland Lake to the East. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Hearst Power Distribution Company Ltd.
- Hydro One Networks Inc. (Distribution)
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.
- Greater Sudbury Hydro Inc.

The second regional planning cycle for this region was concluded with the publication of the RIP Report in November 2023. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 42 and 43. The IESO recommended delaying the third cycle Needs Assessment for North/East of Sudbury until after the conclusion of the bulk plan. OEB agreed and granted extension to start the Needs Assessment in September 2026. The following material transmission investments have

capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Otto Holden TS – T3/T4 autotransformers replacement. (T-SR-01)
- Timmins TS – T2 transformer replacement. (T-SR-03)
- Crystal Falls TS – T5/T6 transformer replacement. (T-SR-03)
- Trout Lake TS – T3/T4 transformers replacement. (T-SR-03)
- A4H/A5H – Overhead Conductor replacement and circuit refurbishment between Tunis Jct. x Fournier Jct. (T-SR-13)
- D2H/D3H – Overhead Conductor replacement and circuit refurbishment between Hunta SS x Abitibi Canyon SS. (T-SR-13)

Renfrew

The Renfrew Region includes all of Renfrew County that is made up of 17 municipalities and City of Pembroke. The rough boundaries of this Region are Ottawa River on the North-East, Algonquin Provincial Park on the West, and Route 508 on the South. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independant Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Ottawa River Power Corporation

The second regional planning cycle for this region was concluded with the publication of the RIP Report in July 2023. The RIP is a comprehensive, region-wide detailed wires plan that consolidates recommendations from all phases, including local plans and also incorporates any new needs and developments that have arisen since the IRRP. The IRRP and RIP reports for this region are found at Attachment 44 and 45. The third cycle Needs Assessment was completed in July 2026 (Attachment 46) and has identified needs that require further regional coordination. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- D6, Des Joachims TS X Petawawa DS, Tx Line Refurbishment (T-SR-13)

St. Lawrence

The St. Lawrence Region covers the southeastern part of Ontario bordering the St. Lawrence River. The region starts at Gananoque on the eastern end of Lake Ontario and extends to the inter-provincial boundary with Quebec. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Cooperative Hydro Embrun Inc.
- Rideau St. Lawrence Distribution Inc.

The second cycle RIP for this region was issued in March 2022 and is found at Attachment 47. The second cycle Needs Assessment suggested that no further regional coordination was required and so the TWG proceeded directly to the RIP phase. The third cycle Needs Assessment was completed in March 2026 (Attachment 48) and has identified needs that require further regional coordination. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Brockville TS: Installation of new LV Capacitor bank to mitigate the voltage issues. (T-SS-12)

East Lake Superior

The East Lake Superior Region includes all of Hydro One Sault Ste. Marie's 560km high-voltage transmission lines as well as ties to the rest of the provincial grid at Wawa TS in the northwest and Mississagi TS in the northeast. The participants in this region's TWG include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Algoma Power Inc.
- Chapleau Public Utilities Corporation (now Hydro One Networks Inc. Distribution)
- PUC Distribution Inc.

The first cycle of the Regional Planning process for the East Lake Superior region was initiated by the former Great Lakes Power Transmission ("GLPT"). The second cycle of regional planning was carried out by Hydro One Transmission on behalf of Hydro One Sault Ste. Marie . The RIP for this region was issued in October 2021 and is found at Attachment 49. The third cycle Needs Assessment was completed in October 2024 (Attachment 50) and has identified needs that require further regional coordination. The third cycle IRRP was also completed in July 2026 (Attachment 51), and RIP is currently underway with a tentative completion date of February 2027. The following material transmission investments have capital expenditures during the 2028–2032 rate period; however, the in-service dates for these projects may extend beyond the rate period:

- Patrick St. TS – 115 kV breakers replacement. (T-SR-03)
- Northern Ave TS – T1 transformers replacement. (T-SR-03)
- Clergue TS – Metal clad switchgear replacement. (T-SR-03)
- D.A Watson TS – Metal clad switchgear replacement. (T-SR-03)
- Goulais Component Replacement (T-SR-03)
- Hollingsworth TS Protection Upgrade (T-SR-03)

North of Moosonee

Five Nations Energy Inc. (FNEI) is the lead transmitter for this region and is therefore responsible for the RIP. The TSP does not contemplate any regional planning transmission infrastructure investments in this region.

1.2.5 HYDRO ONE DISTRIBUTION

1.2.5.1 ROLES AND RESPONSIBILITIES OF HYDRO ONE DISTRIBUTION

As a province-wide distributor, Hydro One Distribution actively participates in regional planning activities. Hydro One Distribution's assets are located in 20 of the 21 regions that have been identified for the purpose of regional planning. These regions correspond to the same 20 regions where Hydro One Transmission is the lead transmitter.

By participating as a TWG member in the regional planning process, Hydro One Distribution is actively engaged in various phases of the process. Hydro One Distribution's

role is to provide the lead transmitter with the information and data required to complete the RIP process, including information based on its embedded distributors' data. Hydro One Distribution assesses the impact of regional supply plans to its distribution systems and where appropriate, develops and reviews potential distribution options to address the identified regional needs. Hydro One Distribution is also expected to support regional planning by identifying to the lead transmitter, any activity/elements on a sub-regional level that may impact a review cycle in a region to the transmitter.

More particularly, throughout the Needs Assessment, Scoping Assessment, Stakeholder Engagement, IRRP and RIPs, Hydro One Distribution may be requested to provide the following input:

- Provide short-term and long-term load forecasts to the lead transmitter and the IESO. Hydro One Distribution provides "gross" and "net" peak demand forecasts for the short-term (five years) and medium-term (ten years), as well as the unbundled information used to show how they arrived at the "net" peak demand forecast.
- Provide background on the distribution system including information on past system performance;
- Identify local supply needs or constraints from the local LDC perspective;
- Participate in community engagement sessions such as LACs or with local municipalities and other stakeholders;
- Participate in local planning led by the lead transmitter to address local supply needs as determined through the Needs Assessment stage;
- Identify and evaluate potential distribution based wires solutions to meet regional or local infrastructure needs;
- Attend regularly scheduled IRRP and RIP Working Group meetings at the regional and sub-regional level as required;
- Provide input and comments to proposed wires and non-wires solutions to address identified system needs; and
- Review and provide comments on draft planning reports/documents prepared by the IESO and the lead transmitter.

- Provide ten-year outlook related to the end-of-life of major transmission voltage assets. For this, major transmission voltage assets include transformers; circuit breakers (where replacement includes the lesser of six breakers or more than 50% of station breakers); overhead lines (where replacement exceeds two kilometers and is over 50 kV); and underground cables (where replacement exceeds two kilometers and is over 50 kV)
- Provide prompt notice of any developments in that part of the region in which its licensed service area is located that may trigger the need for investments in transmission facilities, distribution facilities or both, as applicable, or that may otherwise reasonably be expected to affect the lead transmitter's conduct of a needs assessment for the region.

As further described in section above, to meet the requirements of its distribution rate application, Hydro One Distribution requested Hydro One Transmission to provide a letter confirming the status of regional planning for its regions. This letter also ensures the alignment between Hydro One Distribution, as a local LDC and Hydro One Transmission, as a lead transmitter in regards of the identified needs in each region. A copy of the Regional Planning Status Letter is provided at Attachment 52.

1.2.6 LIST OF ATTACHMENTS

Attachment 1 – Integrated Energy Plan (IEP)
Attachment 2 – Long Term Capital Plan Information
Attachment 3 – IESO Regional Planning Progress Update Letter to Hydro One Transmission
Attachment 4 – 3rd cycle IRRP Report: Burlington to Nanticoke
Attachment 5 – 3rd cycle RIP Report: Burlington to Nanticoke
Attachment 6 – 3rd cycle IRRP Report: Ottawa Area
Attachment 7 – 3rd cycle RIP Report: Greater Ottawa
Attachment 8 – 2nd cycle RIP Report: GTA East
Attachment 9 – 3rd cycle NA Report: GTA East
Attachment 10 – 3rd cycle IRRP Report: GTA North
Attachment 11 – 3rd cycle RIP Report: GTA North
Attachment 12 – 2nd cycle IRRP Report: GTA West
Attachment 13 – 2nd cycle RIP Report: GTA West
Attachment 14 – 3rd cycle NA Report: GTA West
Attachment 15 – 2nd cycle RIP Report: KWCG
Attachment 16 – 3rd cycle NA Report: KWCG
Attachment 17 – 3rd cycle IRRP Report: KWCG
Attachment 18 – 3rd cycle IRRP Report: Toronto
Attachment 19 – 3rd cycle RIP Report: Toronto
Attachment 20 – 2nd cycle IRRP Report: Northwest Ontario
Attachment 21 – 2nd cycle RIP Report: Northwest Ontario
Attachment 22 – IRRP Addendum Report: North of Dryden sub-region
Attachment 23 – 3rd cycle NA Report: Northwest Ontario
Attachment 24 – 3rd cycle IRRP Report: Windsor-Essex
Attachment 25 – 3rd cycle RIP Report: Windsor-Essex
Attachment 26 – 2nd cycle RIP Report: London Area
Attachment 27 – 3rd cycle NA Report: London Area
Attachment 28 – 2nd cycle IRRP Report: Peterborough to Kingston
Attachment 29 – 2nd cycle RIP Report: Peterborough to Kingston
Attachment 30 – 3rd cycle NA Report: Peterborough to Kingston
Attachment 31 - Gatineau Corridor EOL Study Report
Attachment 32 – 2nd cycle IRRP Report: South Georgian Bay / Muskoka
Attachment 33 – 2nd cycle RIP Report: South Georgian Bay / Muskoka

Attachment 34 – 3rd cycle NA Report: South Georgian Bay / Muskoka
Attachment 35 – 2nd cycle RIP Report: Sudbury / Algoma
Attachment 36 – 3rd cycle NA Report: Sudbury / Algoma
Attachment 37 – 2nd cycle RIP Report: Chatham / Lambton / Sarnia
Attachment 38 – 3rd cycle RIP Report: Greater Bruce / Huron
Attachment 39 – 2nd cycle IRRP Report: Niagara
Attachment 40 – 2nd cycle RIP Report: Niagara
Attachment 41 – 3rd cycle NA Report: Niagara
Attachment 42 – IRRP Report: North/East of Sudbury
Attachment 43 – RIP Report: North/East of Sudbury
Attachment 44 – 2nd cycle IRRP Report: Renfrew
Attachment 45 – 2nd cycle RIP Report: Renfrew
Attachment 46 – 3rd cycle NA Report: Renfrew
Attachment 47 – 2nd cycle RIP Report: St. Lawrence
Attachment 48 – 3rd cycle NA Report: St. Lawrence
Attachment 49 – 2nd cycle RIP Report: East Lake Superior
Attachment 50 – 3rd cycle NA Report: East Lake Superior
Attachment 51 – 3rd cycle IRRP Report East Lake Superior
Attachment 52 – Hydro One Transmission Regional Planning Status Letter to Hydro One Distribution

SECTION 1.2 – ATTACHMENT 1 – INTEGRATED ENERGY PLAN (IEP)

1.0 INTRODUCTION

Ontario's Energy for Generations: Ontario's Integrated Energy Plan (IEP) establishes a coordinated, whole-system planning framework to 2050 integrating electricity, natural gas, hydrogen, storage, and other energy sources to guide smarter, more coordinated investments in infrastructure, supply, and innovation. The IEP positions integrated planning as essential to delivering affordable, secure, reliable and clean energy for Ontarians. This Exhibit reinforces and builds upon the principles and outcomes described in SPF Section 1.2. Accordingly, this exhibit explains how the planning processes and considerations reflected in the IEP are incorporated into Hydro One's planning approach, including recent and ongoing planning process enhancements, the key transmission system expansion drivers arising from growth, and the alignment between transmission projects identified in the IEP and those proposed in Hydro One's 2028–2032 capital plan.

1.1 PRIORITIES FOR ONTARIO'S INTEGRATED ENERGY PLANNING

The government has established the following priorities to guide future energy planning:

- Develop a Single, Integrated Plan for All Energy Needs:
  Future planning must consider all fuels and technologies together - electricity, natural gas, hydrogen, biofuels, other fuels, and energy storage - to ensure Ontario has the affordable energy it needs to power a clean and growing economy.
- Plan on a Regular Cycle with Robust Indigenous and Stakeholder Engagement:
  Each five-year planning cycle will incorporate input from the public, Indigenous communities, energy stakeholders, and sector experts to ensure the plan reflects real-world needs and opportunities across Ontario.
- Coordinate Forecasting Across Energy Agencies and Utilities:
  The IESO, natural gas distributors, electricity utilities, and other market participants will be expected to work together toward using shared, evidence-based forecasts to ensure system-wide alignment across all types of energy use.

- Plan for High Growth:
  To ensure planning processes are better able to match the pace of growth, the IESO will be expected to coordinate frequent load growth forecasting with utilities and other stakeholders, and to identify transmission projects that would be needed to address capacity constraints that would arise under high growth forecasts.
- Ensure Regulatory Alignment and Implementation:
  The OEB will continue to play a central role in implementing the plan's direction through efficient regulation of and guidance to the sector.
- Incorporate Independent, Expert Advice:
  Integrated planning will be supported by independent, external advice on how best to align energy decisions with broader government priorities such as housing, economic development, and competitiveness.

The above priorities of the Province are expected to reduce system-wide costs, avoid overbuilding or underbuilding infrastructure, enable fuel-switching, focus on total customer energy bills, reduce shortages and economic risk, support energy export capacity, and improve stakeholder participation.

Implementing the government's priorities will shift Hydro One from being a primarily grid asset manager to a central system enabler of Ontario's economic and energy transition, with corresponding impacts such as the following:

- Expanded role in integrated, multi-fuel planning
- Expanded role in coordination and engagement
- More complex data analytics and integration
- Accelerated transmission development under high-growth scenarios

1.2 ALIGNMENT WITH HYDRO ONE'S PLANNING GOALS

Hydro One's current and planned practices align with the IEP's priorities in the following ways:

- Proactive growth planning, including advancing regional and bulk system plans in areas experiencing or expected to experience significant load growth
- Improved forecasting inputs, through enhanced coordination with municipalities, local distribution companies (LDCs), the IESO, and other stakeholders to inform load and timing assumptions
- Engagement, by maintaining ongoing, structured participation with municipalities, Indigenous groups, and expanding engagement to include Enbridge to support coordinated planning
- Active participation in OEB regulatory consultations aimed at improving planning processes, efficiency, transparency and alignment (e.g. Regional and Bulk Planning Process Advisory Group and Gas-Electric Coordination and Information Sharing Forum).

1.2.1 PROACTIVE GROWTH PLANNING

- Successful completion of two regional planning cycles, with a third currently underway, including advancing regional planning timelines ahead of their scheduled timeline, in high-growth regions in response to feedback from LDCs and municipalities (e.g., St. Lawrence, London Area, Peterborough to Kingston, and Greater Ottawa).

1.2.2 IMPROVED FORECASTING INPUTS

- Development of scenario-based regional demand forecasts informed by municipal input on electricity needs and emissions reduction goals, existing and new customer demand, CDM and DER assumptions, and electrification scenarios.
- Development of standardized input templates for municipalities, LDCs, and other transmission-connected customers to support consistent forecasting and effective, data sharing.

1.2.3 ENGAGEMENT

- Outreach to the Association of Municipalities Ontario and over 250 municipalities since 2023, including meetings with municipal representatives to enable better understanding of the electricity demand expectations and support coordinated planning toward affordable, secure, reliable, and clean energy outcomes.
- Coordination, both within the existing regional planning process, and directly between electric and gas utilities for high growth areas where new gas infrastructure investments are being explored.

1.2.4 REGULATORY AND PROCESS MODERNIZATION PARTICIPATION

- Active participation on the OEB's Regional and Bulk Planning Process Advisory Group (RBPP AG), supporting improvements to planning efficiency, alignment with growth timelines, and consistency in demand forecasting.
- Active participation in the OEB's Gas-Electric Coordination and Information Sharing consultation, building on prior coordination discussions with Enbridge regarding load forecasts and planning assumptions.

2.0 PLANNING FOR GROWTH: UPDATES TO REGIONAL AND BULK PLANNING PROCESSES

To respond to rapid growth:

- The OEB will continue to play a central role in implementing the plan's direction through efficient regulation of and guidance to the sector.
- The IESO will hold annual regional Technical Working Group meetings, including participation from Hydro One.
- Major Project Identification Committees (MPICs) will be established to detect new housing, industrial, mining, or transit projects early.
- The IESO, transmitters, and LDCs will identify bottlenecks proactively.
- Hydro One and the IESO working jointly to continue to support integration of new generation (nuclear, hydro, others) into regional and provincial systems.

Collectively, these changes improve planning responsiveness by enabling earlier identification of major projects, strengthening coordination across electricity and natural gas planning, enabling new generation resources and supporting more timely alignment of transmission development with emerging load growth and system constraints.

2.1 REVIEW OF PLANNING PROCESSES

The OEB launched a formal Regional and Bulk Planning Process Review in October 2025, which examined how to better align planning with actual load growth, improve flexibility and responsiveness, and reduce planning timelines.

The RBPPAG was composed of 21 members representing electricity and natural gas distributors, transmitters, large and small resource suppliers, municipalities, Indigenous communities, consumer groups, and non-government organizations. Its mandate was to provide expert input, advise on gaps and inefficiencies in the current framework, and support the OEB in developing recommendations that improve integration, transparency, and overall process performance. The group played a central role in helping the OEB ensure that planning processes are more adaptable to rapid load growth and better coordinated across sectors.

Hydro One Transmission, as a lead transmitter in 20 regions, worked closely with the OEB, IESO, local distribution companies (LDCs), natural gas distributors, municipalities, and other stakeholders to support OEB in developing recommendations to the Minister of Energy and Mines. Hydro One actively participated in these discussions and provided relevant information to the OEB. The recommendations from RBPPAG focused on improving forecasting methodologies, ensuring planning reflects emerging high-growth demand drivers, and pursuing procedural improvements that enable faster, more coordinated, and more cost-effective system planning across both regional and bulk levels. The RBPPAG provided its findings and proposed improvements in “Review of Ontario’s Regional and Bulk Planning Processes Report” to the Minister of Energy and Mines on March 31, 2026, and is waiting for feedback from the Ministry.

2.2 ELECTRICITY – NATURAL GAS COORDINATION IN REGIONAL PLANNING

A formal process will be established to engage gas distributors in regional planning and avoid misalignments such as heat pump electrification outpacing electricity system capacity or infrastructure investments being made without evaluating cross-fuel alternatives.

Coordination between fuels will move from ad hoc to formalized through:

- An ongoing OEB-led Information Sharing Forum (launched in Dec. 2025).
- Coordinated scenario modelling across electricity and gas utilities.
- Stronger utility participation in regional and bulk planning.
- Municipal and Indigenous engagement to improve alignment with local priorities.

3.0 IMPACT OF THE IEP ON HYDRO ONE'S TRANSMISSION CAPITAL PLAN

3.1 TRANSMISSION EXPANSION IN THE IEP: KEY DRIVERS

The IEP supports and indicates that Ontario will accelerate transmission development and add thousands of kilometers of new lines in the future. Key drivers for transmission expansion include:

- Increased electricity demand from population growth and electrification;
- New industrial development (e.g., EV and battery manufacturing, mining, greenhouse operations);
- Connection of new clean generation, including hydroelectric and nuclear facilities;
- Improved regional reliability and system flexibility; and
- Long-term planning to prevent future land-use conflicts and development delays.

3.2 IEP PRIORITY TRANSMISSION PROJECTS REFLECTED IN HYDRO ONE'S 2028–2032 CAPITAL PLAN

This section identifies the transmission projects included in Hydro One's proposed 2028–2032 capital plan that are also reflected in the Integrated Energy Plan (IEP), including those identified in the IEP as priority transmission projects or otherwise explicitly referenced for advancement. Where applicable, this section also identifies projects undertaken in compliance with the conditions of Hydro One's transmitter license arising from Ministerial directives to the OEB, as well as projects declared priority by the

Lieutenant Governor in Council. The projects listed below provide a clear linkage between the priorities and projects identified in the IEP and the corresponding investments included in this application.

In the 2028–2032 period, IEP aligned transmission investments are estimated at approximately $10 billion on a gross basis, reflecting the scale of transmission development required to support growth. A significant portion of this total (approximately $8.2 billion) is associated with Affiliate Transmission Partnerships and does not enter Hydro One Networks' regulated rate base. The investments focus on:

- Strengthening north–south transfer capability to move power from northern generation to southern demand centers
- Targeted regional investments in the GTA, Southwest, Eastern, and Northern Ontario to support growth and avoid bottlenecks
- Early planning and corridor protection to ensure future transmission can be delivered quickly, cost-effectively, and with minimized land impacts; and
- Early, ongoing Indigenous engagement and partnership, including equity participation and economic opportunities.

The major transmission investments recommended in the IEP that fall within the 2028-2032 application period are summarized below. These projects reflect provincial priorities to support economic growth, electrification, and system reliability, and are advanced to support timely delivery of critical energy infrastructure. Where applicable, these projects have been formally designated as priority transmission projects through an Order in Council (OIC). For the purposes of this section, priority transmission projects refers to such designations by the Lieutenant Governor in Council.

3.2.1 BUILDING A STRONGER NORTH-SOUTH ELECTRICITY BACKBONE

- **Barrie to Sudbury Transmission Line** (Essa TS to Hanmer TS, new single-circuit 500 kV line – target in service 2032) – T-SS-11
- **Orangeville to Barrie Reconductoring** (230 kV –target in service 2030) – T-SS-11

3.2.2 POWERING GROWTH IN THE GREATER TORONTO AREA (GTA)

- **Manby to Riverside Junction Reconductoring** (115 kV –target in service 2028)– T-SS-12
- **Bowmanville to GTA Transmission Line** (New double-circuit 500 kV is required to connect OPG's SMR units 2, 3 and 4 at Darlington to the grid and send additional electricity to the GTA and downtown core – target in service 2032) – T-SS-11
- **Downtown Toronto Third Major Transmission Line** (New Underwater cables; target in service mid-2030s) – T-SS-11

3.2.3 SUPPORTING ECONOMIC GROWTH IN SOUTHWEST ONTARIO

- **Longwood to Lakeshore Phase 1** (Single circuit 500 kV transmission line from Lakeshore TS to Longwood TS – target in service 2030) – T-SS-09
- **Windsor to Lakeshore Line** (230 kV transmission line from Lauzon Transformer Station to Lakeshore Transformer Station – target in service 2032) – T-SS-12

3.2.4 PLANNING FOR GROWTH IN EASTERN ONTARIO

- Durham-Kawartha Power Line (Dobbin TS to Clarington TS – target in service 2029) – T-SS-11

3.2.5 UNLOCKING NORTHERN OPPORTUNITIES

- **Wawa to Porcupine Transmission Line** (230 kV line between Wawa Transformer Station (south of Wawa) and Porcupine Transformer Station (Timmins) built to 500 kV standards – target in service 2030) – T-SS-11
- **North Shore Link Project** (Mississagi TS to Third Line TS – target in service 2029) – T-SS-11
- **Northeast Power Line** (Mississagi TS to Hanmer TS, 500 kV – target in service 2029) – T-SS-11

3.2.6 THE GREENSTONE AREA

- **Greenstone Transmission Line** (Longlac TS to Nipigon GS, connecting to East-West Tie – target in service 2032) – T-SS-10

3.2.7 ADVANCING TRANSMISSION IN THE RED LAKE AREA

- **North of Dryden Area Reinforcement**, as identified in the 2025 Northwest IRRP Addendum (230 kV transmission line from Dryden TS to Ear Falls TS, and another from Ear Falls TS to Red Lake SS, with autotransformers at Ear Falls TS and Red Lake SS) – T-SS-12

3.3 COMPLETED IEP PRIORITY TRANSMISSION PROJECTS

This section identifies the transmission projects identified as priority transmission projects in the Integrated Energy Plan (IEP) that Hydro One has completed or anticipates immaterial expenditures over the 2028 - 2032 period.

3.3.1 SUPPORTING ECONOMIC GROWTH IN SOUTHWEST ONTARIO

- **Chatham to Lakeshore Line** (230kV transmission line from Chatham Switching Station to Lakeshore Transformer Station) – completed January 2025
- **St. Clair Line** (230 kV transmission line from Lambton Transformer Station to Chatham Switching Station) – target completion in 2027

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SECTION 1.2 – ATTACHMENT 2 – LONG-TERM CAPITAL PLAN INFORMATION

1.0 INTRODUCTION

In EB-2021-0110, the Parties agreed that Hydro One would provide, with its next cost-based rate application, a summary of available long-term (10–20-year) forecast information for Transmission and Distribution from Regional Planning Reports and IESO Bulk planning, consistent with the framework being developed by the Regional Planning Process Advisory Group (RPPAG).

The information presented in the sections below provides directional, long-term capital planning context only. It does not represent a new Hydro One load forecast, does not reconcile to the load forecasts used elsewhere in this Application, and should not be interpreted as establishing the need, timing or scope of any individual investment.

1.1 HYDRO ONE'S RESPONSE TO THE SETTLEMENT COMMITMENT

Hydro One has prepared this summary in response to the EB-2021-0110 Settlement Agreement commitment related to long-term capital plan information. This section describes how Hydro One has addressed the commitment by consolidating available 10–20-year forecast information from regional planning materials and IESO planning inputs in a manner consistent with the intent of the Settlement Agreement.

The summary consolidates forecast data for the 20 regions where Hydro One is the lead transmitter, using the latest available second/third cycle Regional Infrastructure Plan (RIP) reports and third cycle Needs Assessment where 20-year RIP forecast was not available. Consolidating this information provided the basis for a 12-year forecast covering the 2026-2038 period.

The regional planning forecasts were prepared through separate regional planning processes completed at different points in time in accordance with the OEB's load forecast guidance document. As a result, the forecasts reflect assumptions and information from

different points in time that may have changed as regional circumstances evolved. Furthermore, the forecasts were not developed to establish Hydro One's revenue requirement or to support the need, timing, scope or cost of the individual investments proposed in this Application. This includes investments that may have emerged or evolved after the applicable regional planning forecast was prepared.

Accordingly, consolidating the regional planning forecasts into a common 12-year forecast provides directional, long-term capital planning context only. The forecasts reflect the sum of non-coincident peaks at the station level and therefore do not add up to Ontario's total peak demand. They also reflect load at the planning stage rather than the outcome of regional planning. For example, where station-level capacity issues are addressed through load transfers, the coincident peak across the affected stations, and therefore Ontario's peak demand, does not change, although the non-coincident peak at the stressed station is reduced. Similarly, where non-wires solutions are implemented to address capacity needs, actual load may be lower than the load forecast at the planning stage.

In contrast, the load forecast prepared for setting transmission rates in this Application forecasts future system load rather than load at the planning stage. These differences mean that the consolidated forecast is not directly comparable to the load forecast prepared for setting transmission rates in this Application. It therefore does not represent a new Hydro One load forecast, reconcile to the load forecasts used elsewhere in this Application, or provide a project-level investment forecast. For details regarding Hydro One's proposed transmission capital expenditures in this Application, refer to TSP Section 2.8.

Table 1 presents the consolidated 12-year regional load forecast for the 20 regions where Hydro One is the lead transmitter.

1 **Table 1 - Regional Load Forecast Summary for Hydro One Lead-Transmitter Regions (MW), 2026–2038**

Region	Regional Load Forecast (MW)													Average Annual Load Growth (%)	Total load Growth (2026-2038) (%)
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038		
Burlington to Nanticoke	2632	2717	3092	3210	3188	3223	3249	3285	3324	3362	3410	3461	3513	2.79%	33%
Toronto	4981	5005	5123	5186	5224	5272	5355	5445	5510	5583	5665	5765	5877	1.50%	18%
Windsor-Essex	1433	1507	1594	1668	1665	1683	1676	1670	1664	1709	1726	1740	1774	1.99%	24%
GTA North	1804	1906	2017	2086	2286	2391	2481	2580	2664	2738	2797	2872	2946	5.28%	63%
Greater Ottawa	2321	2395	2541	2589	2650	2726	2777	2822	2866	2901	2935	2963	2988	2.40%	29%
Kitchener-Waterloo-Cambridge-Guelph	1467	1482	1498	1517	1536	1560	1581	1607	1636	1662	1682	1702	1722	1.45%	17%
GTA West	3287	3348	3405	3474	3536	3601	3687	3760	3812	3857	3906	3943	3987	1.77%	21%
East Lake Superior (Hydro One SSM)	191	190	189	188	192	226	226	225	225	225	225	224	224	1.42%	17%
Greater Bruce/Huron	718	721	727	732	737	744	751	761	766	772	778	784	789	0.83%	10%
GTA East	1219	1235	1254	1271	1281	1291	1301	1310	1320	1330	1342	1353	1365	1.00%	12%
Northwest Ontario	561	565	566	564	568	576	581	585	600	604	609	614	619	0.87%	10%
Niagara	1275	1291	1308	1338	1356	1368	1377	1388	1403	1417	1429	1444	1457	1.19%	14%
Peterborough to Kingston	1220	1228	1237	1247	1256	1265	1274	1282	1292	1304	1317	1329	1342	0.83%	10%
South Georgian Bay/Muskoka	1596	1625	1641	1666	1698	1720	1753	1789	1834	1880	1916	1952	1985	2.03%	24%
Sudbury/Algoma	322	327	329	332	335	338	341	343	349	353	357	361	365	1.11%	13%
London Area	1514	1557	1619	1666	1706	1737	1777	1820	1866	1913	1962	2012	2064	3.03%	36%
Renfrew	141	141	143	143	145	145	146	146	149	150	152	155	156	0.87%	10%
North/East of Sudbury	398	399	401	403	408	410	411	416	418	420	423	426	429	0.66%	8%
St. Lawrence	360	362	364	367	369	375	379	397	415	425	471	474	477	2.71%	33%
Chatham/Lambton/ Sarnia	847	856	865	874	884	893	903	913	923	934	944	955	966	1.18%	14%
Total Province	**28287**	**28857**	**29913**	**30520**	**31020**	**31544**	**32026**	**32545**	**33037**	**33538**	**34045**	**34529**	**35046**	**1.99%**	**24%**

Witness: Mark Brodie

As shown in Table 1, the 2026–2038 regional load forecast provides a consolidated view of available long-term forecast information within the 10–20-year horizon contemplated by the EB-2021-0110 Settlement Agreement commitment. The RIP forecasts adopt the IESO's Integrated Regional Resource Plan (IRRP) load forecasts, subject to updates where material changes are identified through the technical working group process. The IRRP forecasts are prepared by the IESO using information and analytical foundations that also inform other long-term adequacy assessments, including bulk system planning. Accordingly, the RIP-based approach provides a practical mechanism for incorporating IESO planning context into Hydro One's regional forecast summary.

The forecast shows that growth is not uniform across the province. Regions in and around the Greater Toronto Area exhibit higher growth than outer and more rural areas of Ontario. The highest average annual growth is observed in GTA North at 5.28%, while the lowest is observed in North/East of Sudbury at 0.66%. Across all 20 regions, the compiled forecast reflects total load growth of approximately 24% over the 2026–2038 period, or approximately 2% average annual growth.

Taken together, this information responds to the EB-2021-0110 Settlement Agreement commitment by providing a consolidated summary of available long-term regional forecast information using the latest regional planning and IESO planning inputs.

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August 25, 2026

Ajay Garg
Director, Long-term Strategic Transmission System Planning
Hydro One Networks Inc.
483 Bay Street,
Toronto, ON, M5G 2P5

Dear Mr. Garg:

Re: Regional Planning Progress Update

The Independent Electricity System Operator (IESO) has been notified of Hydro One Networks Inc.'s (Hydro One Transmission) and Hydro One Sault Ste. Marie's (HOSSM) upcoming transmission revenue requirement applications with the Ontario Energy Board (OEB) and has been requested to provide a status update for regions where regional planning is currently underway, but a Regional Infrastructure Plan (RIP) has not yet been completed. This includes regions undergoing a Needs Assessment (NA), Scoping Assessment (SA), or Integrated Regional Resource Plan (IRRP).

This request is based on the requirements of Section 2.4.3 of the OEB's *Chapter 2 Filing Requirements for Electricity Transmission Applications*[1], which state:

> *2) Where regional planning is underway, but a Regional Infrastructure Plan has not yet been completed for the applicable region, the applicant shall submit a letter from the IESO, identifying the status of the regional planning process, and the potential impacts on the applicant's investment plans.*

Pursuant to the above-noted filing requirements, the IESO hereby provides the status of regional planning as follows:

Regional Planning Status Summary

Table 1 summarizes the status of regional planning activities undertaken by the IESO across all 20 regions where Hydro One Transmission is designated as the lead transmitter.

The table identifies completed, ongoing, and future planning phases for the third cycle of regional planning, including NAs, SAs, IRRPs, and RIPs, as applicable.

[1] OEB's *Chapter 2 Filing Requirements for Electricity Transmission Applications, October 30, 2025, p. 19.*

Needs Assessments are undertaken by the lead transmitter in a region, while subsequent SA and IRRP regional planning phases are coordinated by the IESO. For regions or sub-regions where certain planning phases were deemed not to be required, this determination reflects the conclusions of the applicable planning studies.

Region	Regional Planning Stage / Completion Date [2]			
	NA [1]	SA [1]	IRRP [1]	RIP [1]
Kitchener-Waterloo-Cambridge-Guelph	Apr. 2024	Jul. 2024	Jul. 2026	TBD
GTA West	Aug. 2024	Nov. 2024	Nov. 2026	TBD
East Lake Superior [3]	Oct. 2024	Jan. 2025	Jul. 2026	TBD
GTA East	Dec. 2024	Apr. 2025	Oct. 2026	TBD
Peterborough to Kingston	Dec. 2024	Apr. 2025	Oct. 2026	TBD
South Georgian Bay/Muskoka	Aug. 2025	Nov. 2025	May. 2027	TBD
London	Nov. 2024	Apr. 2025	Oct. 2026	TBD
Sudbury/Algoma	Oct. 2025	Jan. 2026	Jul. 2027	TBD
Northwest Ontario	Sep. 2025	Sep. 2025	Mar. 2027	TBD
GTA North	Jul. 2023	Oct. 2023	Oct. 2025	May 2026
Toronto	Dec. 2022	Mar. 2023	Oct. 2025	May 2026
Greater Bruce-Huron	Sep. 2024	N/A	N/A	Apr 2025
Chatham-Kent/Lambton/Sarnia	TBD	TBD	TBD	TBD
Windsor-Essex	Feb 2023	May 2023	Apr. 2025	Oct. 2025
Greater Ottawa	Dec. 2022	Mar 2023	Jul. 2025	Feb. 2026
Burlington to Nanticoke [4]	Sep. 2022	Dec. 2022	Nov. 2024	Jun. 2025
Niagara	Jul. 2026	Oct. 2026	TBD	TBD

Region	Regional Planning Stage / Completion Date [2]			
	NA [1]	SA [1]	IRRP [1]	RIP [1]
North/East of Sudbury [5]	TBD	TBD	TBD	TBD
Renfrew	Jul. 2026	TBD	TBD	TBD
St. Lawrence	Mar. 2026	Apr. 2026	Oct. 2027	TBD

Notes:

(1): NA: Needs Assessment; SA: Scoping Assessment; IRRP: Integrated Regional Resource Plan; RIP: Regional Infrastructure Plan

(2): Dates shown represent completion dates. Future dates are tentative and based on Regional Planning Process timeline requirements.

(3): HOSSM is the lead transmitter in the East Lake Superior region.

(4): An IRRP was issued for the Hamilton, Brant, and Caledonia-Norfolk sub-regions. An Addendum for the Hamilton sub-region is underway to address supply needs for the 230 kV subsystem and station capacity needs in the Hamilton sub-region.

(5): Hydro One is initiating the third cycle of Regional Planning for the Region approximately four months later than OEB mandated date, given the significant overlap with the North of Sudbury Bulk Plan currently being developed by the IESO which is set for publication in Q3 2026. Aligning the Regional and Bulk Planning processes supports efficient planning and minimizes duplication of effort.

Ongoing IRRPs, as well as any ongoing addendum studies, may result in changes to the recommendations made by Regional Planning Study teams. The IESO is currently completing an Addendum to the 2024 Burlington to Nanticoke IRRP focusing on the Hamilton sub-region.

In addition, while bulk system planning is distinct from the regional planning process summary described above, the IESO also notes that bulk system planning work remains ongoing at the time of Hydro One's filing. Through its bulk-planning engagements, the IESO continues to assess bulk system needs across the province. As this work is finalized and additional bulk plans are issued, relevant recommendations may have implications for Hydro One's transmission investment plans.

Should you have any questions regarding the regional planning status or require further clarification on specific regions or planning phases, please do not hesitate to contact us.

Sincerely,

Kennan Ip

Digitally signed by Kennan Ip
Date: 2026.08.26 11:42:42 -04'00'

Kennan Ip
Senior Manager, Transmission Integration North & East
Independent Electricity System Operator

cc: Carrie Aloussis, IESO
Gabriel Adam, IESO

Burlington to Nanticoke Integrated Regional Resource Plan

November 28, 2024

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Disclaimer

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

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Executive Summary

The Burlington to Nanticoke Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Burlington to Nanticoke Region over a 20-year period, from 2023 to 2042. The Burlington to Nanticoke Region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, County of Brant, the City of Brantford, Haldimand County, Norfolk County, the City of Burlington and the town of Oakville.

For the purposes of the IRRP, the region has been divided into four subregions: Brant, Bronte, Caledonia-Norfolk, and Hamilton. The Scoping Assessment Outcome Report completed in December 2022, identified no needs for coordinated regional planning in the Bronte subregion, and most needs in the Hamilton subregion will be addressed in an upcoming addendum to be started in early 2025 (see Section 2.5.1). As a result, this IRRP largely focuses on the needs and recommendations for the Brant and Caledonia-Norfolk subregions.

Need assessments for the 115 kV subsystem in the Brant subregion (the "Brant 115 kV Subsystem") could not be conducted in isolation from the 115 kV subsystem in the Hamilton subregion and the 115 kV subsystem in the City of Woodstock (outside of the Burlington to Nanticoke Region). This is because of interconnections within the 115 kV subsystem. Therefore, the combined 115 kV subsystem spanning from Karn TS in Woodstock through the Brant subregion and into the Hamilton subregion was studied as whole. This combined subsystem is referred to as the "Brant 115 kV Extended Area", and consists of the: "Hamilton 115 kV Subsystem", the Brant 115 kV Subsystem, and the "Woodstock 115 kV Subsystem".

Studies on the Brant 115 kV Extended Area were used to identify needs, assess options, and produce recommendations for supply and station capacity needs in the Brant subregion, and for supply needs for the Hamilton 115 kV Subsystem. Supply needs for the 230 kV subsystem and station capacity needs in the Hamilton subregion will be addressed in the Hamilton addendum. The Woodstock 115 kV Subsystem falls outside of the Burlington to Nanticoke Region and is instead part of the London Area Region. As a result, needs of the Woodstock 115 kV Subsystem will be assessed and addressed in the ongoing cycle of regional planning for the London Area, with the Needs Assessment expected to be published by Hydro One by the end of 2024.

The electricity demand forecast shows substantial growth for the Burlington to Nanticoke Region, with demand forecasted to grow by 50%, 180%, and 80% for the Brant, Caledonia-Norfolk, and Hamilton subregions, respectively, by 2042, relative to 2023 demand. Growth is driven by industrial expansion, housing growth, and decarbonization initiatives. To meet long-term needs, the Load Meeting Capability (LMC) for each of the 115 kV subsystems in the Region must approximately double from its existing value. These 115 kV subsystems are: the combined Brant and Hamilton 115 kV Subsystems, the Brant 115 kV Subsystem, and the Norfolk-Bloomsburg Area. In addition, each of these 115 kV subsystems, and several substations supplied by these subsystems, have immediate capacity needs.

To address needs, wires and non-wires options were considered, and ultimately a combination is recommended by the Technical Working Group. Wires solutions are recommended to address long-

term needs, as the most cost-effective and technically feasible solutions. Non-wires options are recommended to meet near-to-medium term needs, due to: their shorter lead times, the lower magnitude of needs in the near-to-medium term, and their system benefits.[1]

To address near-to-medium term needs, the Technical Working Group recommends the pre-contingency opening of bus-tie breakers, and load transfers between nearby stations at the distribution level, where viable and cost-effective. The opening of bus-tie breakers is needed to address near-to-medium term supply capacity needs for the combined Brant and Hamilton 115 kV subsystems, the Brant 115 kV Subsystem, and the Norfolk-Bloomsburg Area, and to address several station capacity needs where load transfers cannot resolve needs.

In the medium-term, the Technical Working Group recommends the procurement of a battery energy storage system, and the construction of a new substation[2] near Dundas TS. These recommendations will address supply capacity needs in the Norfolk-Bloomsburg Area, and on the Hamilton 115 kV Subsystem and at Dundas TS, respectively. The new substation will also address station capacity needs at Dundas TS.

In the long-term, the Technical Working Group recommends constructing two sets of new 230 kV transmission lines and associated substations, separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem:

- New 230 kV transmission lines from Nanticoke TS into the Simcoe community, and a new station[2] to entirely offload Norfolk and Bloomsburg 115 kV stations.
- A new double-circuit transmission line constructed as an extension from the existing Middleport-Detweiler corridor (in the Kitchener/Waterloo/Cambridge/Guelph region) into County of Brant, and two new stations[2] to entirely offload Brant and Powerline 115 kV stations.

Cost-effective CDM at Brantford TS and Caledonia TS is also recommended to defer station capacity needs. Once the Brant 115 kV Subsystem has been offloaded by the above recommendation, the Technical Working Group recommends separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem when the total net load in the Woodstock 115 kV Subsystem exceeds the limit.

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, market participants, municipalities, stakeholders, communities, Indigenous communities, and customers to be considered in the development of the plan. Furthermore, engagement helps lay the foundation for successful implementation.

The Technical Working Group will continue to monitor growth at Brantford TS and Caledonia TS, as well as across the region. This includes any future community energy planning, electrification trends, datacentres, or industrial load. The Technical Working Group will meet at regular intervals to complete the recommended Hamilton addendum, monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through

[1] Non-wires options, such as conservation and demand management (CDM), storage procurement, or generation procurement, help meet the CDM and procurement needs of the provincial grid, thereby providing benefits to the system while addressing local needs.

[2] Converting the existing 115 kV DESNs to 230 kV is equivalent to constructing new stations when addressing supply capacity needs. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective solution and develop a detailed plan for implementation.

an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

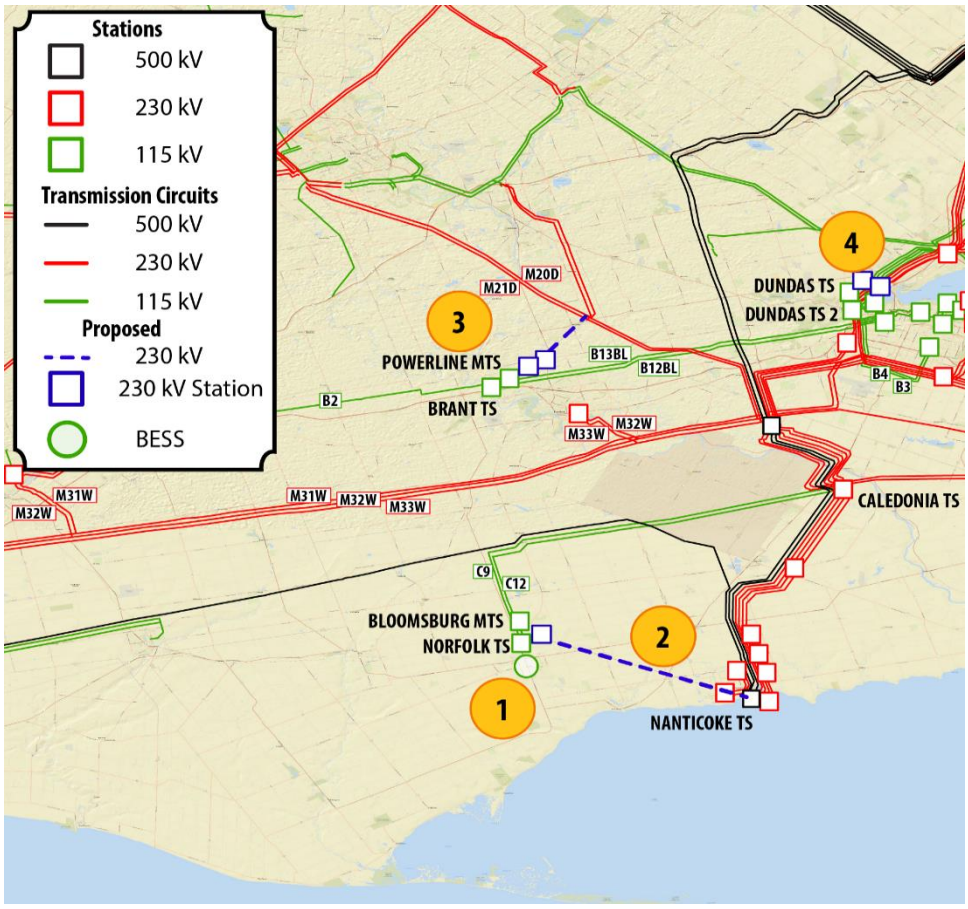
Summary of Recommendations

The medium and long-term recommendations for the Burlington to Nanticoke region are shown in the figure below and include:

1. Build a transmission-connected battery energy storage system (BESS) facility capable of continuously providing voltage support near Norfolk TS.
2. Build new transmission lines from Nanticoke TS into the Simcoe community, and a new station[2] to entirely offload Norfolk and Bloomsburg 115 kV stations.
3. Build a new double-circuit transmission line as an extension from the existing Middleport-Detweiler corridor (in the Kitchener/Waterloo/Cambridge/Guelph region) into County of Brant, and two new stations[2] to entirely offload Brant and Powerline 115 kV stations.
4. Build new 230kV stations[2] at Dundas TS connecting to the adjacent Middleport-Burlington circuits to entirely offload the Dundas load from the 115 kV stations to 230 kV.

In the interim, operational measures such as opening station bus-tie breakers combined with feasible and cost-effective load transfer between stations on a permanent or temporary basis are recommended to resolve supply and station capacity needs.

Medium/Long-Term Recommendations in the Burlington Nanticoke Region



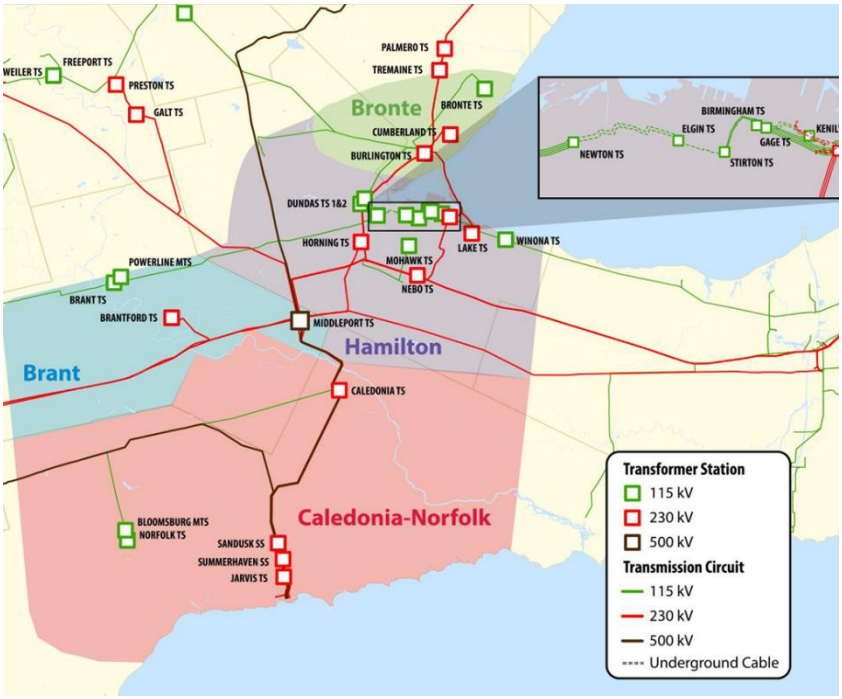
1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Burlington to Nanticoke Region (the "Region") over a 20-year period, from 2023 to 2042. The Burlington to Nanticoke Region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, County of Brant, the City of Brantford, Haldimand County, Norfolk County, the City of Burlington and the town of Oakville. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Several Indigenous communities are located in or near the Region including: Mississaugas of the Credit First Nation, Six Nations of the Grand River, and a number of Métis Nation of Ontario (MNO) councils including MNO Clear Waters Métis Council and MNO Grand River Métis Council.

For the purposes of regional planning, the Burlington to Nanticoke region has historically been sub-divided into four subregions: Brant, Bronte, Caledonia-Norfolk, and Hamilton. The electricity infrastructure supplying the Burlington to Nanticoke region and the subregions are shown in Figure 1. The Burlington Nanticoke Region is summer-peaking, and over 2019 to 2023, normal weather peak electrical demand has remained steady at approximately 1,825 MW.

Figure 1 | Overview of the Burlington Nanticoke Region[3]



The Bronte subregion includes Burlington TS and the 230 kV and 115 kV supply northeast of the station which services Cumberland TS and Bronte TS, respectively. The 115 kV supply southwest from Burlington TS and the 230 kV supply from Beach TS service the 115 kV network in the Hamilton subregion, while 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS,

[3] IRRP regions are defined by electricity infrastructure; geographical boundaries are approximate.

and Middleport TS and Burlington TS supply the Hamilton subregion's 230 kV connected load supply stations. The 230 kV supply south from Middleport TS supplies the 230 kV connected stations in the Caledonia-Norfolk subregion, including Caledonia TS. The 115 kV supply from Caledonia TS then supplies Bloomsburg DS and Norfolk TS. The Brant subregion is supplied from the 230 kV supply west from Middleport TS and a 115 kV supply from Burlington TS. Because of tight connection between i) the Brant 115 kV supply, ii) part of the Hamilton 115 kV supply and iii) the 115 kV supply to the City of Woodstock, the regional plan considered the capability of the broader Brant 115 kV Extended Area which includes theses three subsystems comprising the entire 115 kV network between Burlington TS and Karn TS.

The region's electricity is delivered by five local distribution companies (LDCs): Alectra Utilities Corporation, Burlington Hydro Inc. (BHI), GrandBridge Energy Inc., Hydro One Networks Inc. (Distribution), and Oakville Hydro Inc. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Burlington Nanticoke IRRP was initiated in December 2022, following the publication of the Needs Assessment report in September 2022 by Hydro One and the Scoping Assessment Outcome Report in December 2022 by the IESO. The Scoping Assessment identified the area's needs should be further assessed through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Burlington to Nanticoke Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Burlington to Nanticoke electricity demand forecast, provided by the LDCs, anticipates sustained growth driven by industrial expansion, housing growth, and decarbonization initiatives. These drivers are present across all municipalities in the Region.

In the Brant subregion, residential housing is a primary driving factor in the forecast along with industrial customers which have shown interest and purchased property both within City of Brantford and County of Brant. One customer has already scheduled an expansion project with a significant quantity of new load. With the annexation of 2,720 hectares of land from County of Brant to the City of Brantford, there is an expectation of intense development in the north of Brantford. Beyond 2030, 4 per cent growth is expected for electrification.

In the Caledonia-Norfolk subregion, the forecast is mainly driven by economic factors, e.g. housing and GDP, and community/municipal energy and decarbonization plans. Industrial and residential development in Courtland has a large effect in the Norfolk forecast. New residential and employment growth is forecasted to be 1% per annum into the future.

In the Hamilton subregion, the forecast is driven primarily by economic factors, and supplemented by electric vehicle growth. Economic factors include: population and employment growth, housing activities, and commercial and industrial development.

Following a review on the status of the plans recommended in the last cycles of IRRP, the recommendations in this cycle of IRRP are organized under interim and permanent plans. This distinction reflects the different levels of lead time for development and planning commitment required. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while initiating projects with long lead times that are ultimately needed.

2.1 Status of Plans from Previous IRRP Cycles

Following the previous cycle of region planning, and concluding with the 2nd Cycle RIP report, several projects were recommended which have now been completed or are presently underway. The projects consisted largely of replacements, in addition to two capacitor bank installations, and two sets of distribution-level load transfers. The status of these projects is summarized in Table 1 below.

Table 1 | Summary of Ongoing and Recently Completed Plans

Station/Line Section	Need	Expected In-Service
Cumberland TS	Power factor correction: capacitor bank installed at customer level	2019 (Completed)
115 kV B3/B4	Line section Horning Mountain Jct. X Glanford Jct. replacement	2020 (Completed)
Elgin TS	Transformer and switchgear replacement	2022 (Completed)
Gage TS	Transformer and switchgear replacement	2024 (Completed)
Newton TS	Transformer replacement	2020 (Completed)
Norfolk-Bloomsburg Area Supply Capacity	Load transfers to Jarvis TS: 3 MW	2026
Kenilworth TS	Transformer and switchgear replacement	2023 (Completed)
Kenilworth TS	Power factor correction: capacitor bank installation	2025 (Completed)
115 kV B7/B8	Line section Burlington TS X Nelson Jct. replacement	2024
Dundas TS	Load transfers to Dundas 2 TS: 20 MW	2025
Newton TS	115 kV breaker refurbishment	2022 (Completed)

2.2 Interim Plans

For the interim, until permanent solutions are placed in service, the Technical Working Group recommends operational measures to address near-/medium-term supply and station capacity needs. This includes the pre-contingency opening of bus-tie breakers, as needed, to secure the system and resolve the needs.

The recommended operational measures also include load transfers between nearby stations at the distribution level. The Technical Working Group recommends that LDCs assess the feasibility and cost-effectiveness of transferring loads on a temporary or permanent basis with consideration to the recommended long-term solutions which resolve supply or station capacity needs. Moreover, coordination between load transfer and opening station bus-tie breakers is necessary since opening

bus-tie breakers may still be required either to make the system secure or because the amount of load transferred is not sufficient to resolve the needs. Where viable and cost-effective, the Technical Working Group prefers transferring loads since opening station bus-tie breakers may interrupt electricity service to a higher number of customers following a network outage.

Note that the Technical Working Group makes these interim recommendations strictly on a provisional basis, until solutions with longer lead times are in place.

Table 2 | Interim Plans for Station and Supply Capacity Needs

Need	Recommendation	Lead Responsibility
Various station and supply capacity	As required, open bus-tie breakers at Bloomsburg DS, Norfolk TS, Brant TS, Powerline MTS, Dundas 1 and 2 TS, Newton TS, Mohawk TS, Nebo, Woodstock TS and Commerce Way TS	Hydro One, GrandBridge Energy, Alectra
Various station and supply capacity	If feasible and cost-effective, permanently/temporarily transfer load from Bloomsburg DS, Norfolk TS, Brant TS, Powerline MTS, Dundas 1 and 2 TS, Newton TS, Mohawk TS, and Nebo to nearby stations	Hydro One, GrandBridge Energy, Alectra

2.3 Medium-Term Plans

The Technical Working Group recommends the medium-term plans summarized in Table 3 to bridge the gap between the interim and long-term solutions. Multiple needs are grouped together when they will be resolved by the same solution. The following sections discuss these medium-term plans.

2.3.1 Battery Energy Storage System in the Norfolk-Bloomsburg Area

To address the Norfolk-Bloomsburg Area supply capacity in the medium term ahead of a long-term wires solution, the Technical Working Group recommends a battery energy storage system (BESS). The BESS should be connected to both 115 kV supply circuits (C9 and C12) between the Bloomsburg junctions and Norfolk TS, preferably at Norfolk TS.

To be a viable solution, the BESS must always remain connected to the transmission system and provide reactive power (Mvar) support for extended periods of time, irrespective of its active power output. The continuous reactive power capability would determine the minimum requirements of rated capacity and storage (MW/MWh) for a viable BESS solution. Because of the timing, specific location and combination of active and reactive power requirements, the IESO will investigate the most appropriate implementation mechanism to procure the BESS.

The operational measures described in the previous section may be necessary to secure the system under outages on the BESS solution.

2.3.2 Two New 230 kV DESNs at Dundas Station

As part of the long-term solution, discussed in the next section, and to address the supply capacity needs for the Hamilton 115 kV Subsystem within the Brant 115 kV Extended Area, the Technical

Working Group recommends transferring the loads of both Dundas TS DESNs from the 115 kV subsystem to the 230 kV subsystem. This may be achieved by either: constructing two new 230 kV Dual Element Spot Network (DESN) at the Dundas switchyard, or converting the existing DESNs from 115 kV to 230 kV supply. In either case, the 230 kV supply will be the existing 230 kV Middleport to Burlington circuits, M27B and M28B, which pass next to the station.

If the new DESNs are pursued, each should have an approximate LTR of 200 MVA, and the LDCs (Hydro One Distribution and Alectra Utilities Corporation) should entirely transfer the loads from the existing Dundas TS DESNs onto the new 230 kV DESNs.

The choice between constructing new DESNs or converting existing DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter. However, constructing new DESNs will also resolve the Dundas station capacity needs, whereas converting the existing DESNs will not resolve these needs.

Table 3 | Medium-Term Plans for Supply and Station Capacity Needs

Need	Recommendation	Lead Responsibility	Expected In-Service
Norfolk-Bloomsburg Area Supply Capacity	Procure BESSs[*] capable of always providing reactive power support[**] connecting to C9 and C12 between the Bloomsburg junctions and Norfolk TS	IESO	2029 or earlier[***]
Hamilton 115 kV Subsystem Supply Capacity and Dundas 1 and 2 Station Capacity	Construct two new 230 kV DESNs[****] each with an LTR of ~200 MVA at the Dundas switchyard connecting to the nearby Middleport to Burlington circuits (M27B and M28B)	Hydro One	2032 or earlier[***]
	Entirely transfer the Dundas loads from the existing 115 kV DESNs to the new 230 kV DESNs	Hydro One and Alectra	

[*] Under BESS outage conditions, operational measures discussed in Section 2.2 for the Norfolk-Bloomsburg Area may be required to secure the system.

[**] Depending on the amount of reactive power (Mvar) support the BESSs can constantly provide, minimum requirements on the rated capacity and storage (MW/MWh) of the BESSs are specified and the BESSs may potentially be combined with other NWAs, e.g., renewables, CDM or load transfer, to make this option viable and cost-effective.

[***] Provided years are estimated maximum timelines to bring solution in-service; however, implementation should be expedited to bring in-service as soon as possible.

[****] Rather than building a new DESN, the existing DESNs may be converted from a 115 kV supply to a 230 kV supply by replacing all 115 kV station equipment. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective approach that addresses the needs and develop a detailed plan for implementation.

2.4 Long-Term Plans

The long-term plans comprise several recommendations to resolve needs and to support long-term load growth. These recommendations are summarized in Table 3 and further discussed below. The recommended wires solutions will need to be initiated as soon as possible, starting with the upcoming Regional Infrastructure Planning (RIP) led by the transmitter.

The operational procedures which were recommended as the interim solutions will no longer be required after the needs are addressed with the long-term plans.

Table 4 | Long-Term Plans for Supply and Station Capacity Needs

Need	Recommendation	Lead Responsibility	Expected In-Service
Norfolk-Bloomsburg Area Supply and Station Capacity	Construct one new 230 kV DESN* with an LTR of ~200 MVA within or in the vicinity of Simcoe connecting to the Nanticoke TS with a new 230 kV double-circuit line*	Hydro One	2035
	Entirely transfer the Norfolk and Bloomsburg loads to the new 230 kV DESN	Hydro One	
Brant 115 kV Subsystem Supply Capacity and Brant and Powerline Station Capacity	Construct two new 230 kV DESNs* each with an LTR of ~200 MVA within or in the vicinity of County of Brant connecting to the Middleport to Detweiler corridor with new 230 kV extensions**	Hydro One	2035
	Entirely transfer the Brant and Powerline loads to the new 230 kV DESNs	GrandBridge Energy	
Woodstock 115 kV Subsystem	If the Woodstock Subsystem total net load exceeds 113 MW, separate it from Brant Subsystem by pre-contingency opening the Brant DB2 breaker	IESO and Hydro One	***
Caledonia Station Capacity	Implement targeted and cost-effective CDM to defer the need from 2034 and monitor the demand growth for advancing the need	IESO	****
Brantford Station Capacity	Implement targeted and cost-effective CDM to defer the need from 2035 and monitor the demand growth for advancing the need	IESO	****

* Rather than building a new DESN, the existing DESNs may be converted from a 115 kV supply to a 230 kV supply by replacing all 115 kV station equipment. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective solution and develop a detailed plan for implementation.

** Since new DESNs are connected to the lines in the Kitchener/Waterloo/Cambridge/Guelph (KWCG) region, the ongoing KWCG IRRP will finalize the connection arrangement and details of this option.

*** The timing of this option is after the load transfers of Dundas 1 and 2, Brant and Powerline Stations from the existing 115 kV to new 230 kV DESNs are complete.

**** CDM program design and implementation start after the IRRP is finished and continue over the planning horizon.

2.4.1 One New 230 kV DESN and Transmission Line into Simcoe

To address the supply capacity need to the Norfolk-Bloomsburg Area and to address station capacity needs at Bloomsburg DS and Norfolk TS, the Technical Working Group recommends constructing a new 230 kV double-circuit transmission line from Nanticoke TS into the vicinity of Simcoe, and either:

constructing one new 230 kV DESN, or converting Bloomsburg DS and Norfolk TS from 115 kV to 230 kV supply.

If the new DESN is pursued, it should have an approximate LTR of 200 MVA, and Hydro One Distribution should entirely transfer the loads from Bloomsburg DS and Norfolk TS onto the new 230 kV DESN.

The line routing and choice between constructing a new DESN or converting existing DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter. However, constructing new DESNs will also resolve the Bloomsburg DS and Norfolk TS station capacity needs, whereas converting the existing DESNs will not resolve these needs.

2.4.2 Two New 230 kV DESNs and Transmission Line into County of Brant

To address supply capacity needs to the Brant 115 kV Subsystem and to address station capacity needs at Brant TS and Powerline MTS, the Technical Working Group recommends constructing a new 230 kV double circuit extension of the Middleport to Detweiler corridor into the vicinity of County of Brant, and either: constructing two new 230 kV DESNs, or converting Brant TS and Powerline MTS from 115 kV to 230 kV supply. However, constructing new DESNs will also resolve the Brant TS and Powerline MTS station capacity needs, whereas converting the existing DESNs will not resolve these needs.

If the new DESNs are pursued, each should have an approximate LTR of 200 MVA, and GrandBridge Energy Inc. should entirely transfer the loads from Brant TS and Powerline MTS onto the new 230 kV DESNs.

Since the DESNs (new or converted) are connected to the lines in the KWCG region, the ongoing KWCG IRRP will finalize the connection arrangement and details of this option.

Please note that this plan in combination with the new Dundas 230 kV DESNs (see Section 2.3.2) will address the supply capacity need in the Hamilton 115 kV Subsystem up to the sum of the capacities of the remaining stations, namely, Elgin, Mohawk and Newton TS and CTS3.

2.4.3 Separate Woodstock 115 kV Subsystem from Brant 115 kV Subsystem

To address the supply capacity need to the Woodstock 115 kV Subsystem after transferring the loads to new 230 kV DESNs as explained in Section 2.3.2 and 2.4.2, the Technical Working Group recommends that the Brant DB2 115 kV circuit breaker be opened pre-contingency for a total net load in the Woodstock Subsystem above 113 MW. This will separate the Woodstock from Brant 115 kV Subsystem and increase the LMC of the Woodstock 115 kV Subsystem to 210 MW.

2.5 Ongoing Initiatives

In addition to the plans above, four ongoing actions were identified to manage long-term needs for the Burlington to Nanticoke Region in general and for the Hamilton subregion, in particular.

2.5.1 Undertake a Comprehensive Study of the Hamilton Subregion

Following Public Webinar #1 for the Burlington to Nanticoke IRRP in September 2023, electrification and decarbonization plans were identified which will have a significant impact on the Hamilton area.

In response, a new forecast for Hamilton was produced in June 2024, which resulted in a 230 MW or 11 per cent increase relative to the previous forecast.

Based on the new Hamilton demand forecast, several station capacity needs were identified. To the extent possible, some of these needs were assessed as part of this IRRP. Specifically, assessment of the Hamilton 115 kV Subsystem within the Brant 115 kV Extended Area and subsequent long-term recommendation will help address some of these supply and station capacity needs, namely at Dundas TS. The remaining needs warrant a more fulsome assessment of needs, which were too significant to fully assess and address within the IRRP timelines. Given the rapid growth in the Area, collecting more information on supply options and conducting integrated planning for the revised needs is critical to ensuring the continued reliability of this subregion. Thus, the Technical Working Group recommends that a Hamilton Addendum be undertaken, to fully assess and address the needs of the Hamilton subregion. Please see Appendix J for an initial scope of the Addendum.

The Addendum will kick-off in 2025 and finish within 12 months of formal kick-off. In early 2025, the terms of reference will be published by the TWG and will build upon the scope outlined in Appendix J, by confirming the objectives and establishing timelines. An engagement plan will also be created, which will outline expectations for webinars and targeted outreach with key stakeholders over the 12-month addendum process.

2.5.2 Monitor Load Growth and Continue to Explore Opportunities for Targeted CDM

The Technical Working Group recommends that the LDCs and IESO continue to monitor long-term growth at Brantford TS and Caledonia TS between regional planning cycles to determine when decisions on the long-term plan are required and inform the next cycle of regional planning for the region, as required.

In addition, the Technical Working Group recommends continuing to consider opportunities for targeted CDM, identifying the benefits and potential of incremental, cost-effective CDM particularly if targeted to help manage near-term needs until transmission reinforcements are in-service or to defer long-term needs. The Technical Working Group should continue to support and monitor CDM uptake and bring these insights into the next cycle of regional planning for the Burlington to Nanticoke Region.

2.5.3 Data Centre and Industrial Load Growth

The IESO has been made aware of a growing number of large data centre connection requests (100-1000 MW each) throughout the province, as well as an increase in requests for industrial load growth (see Section 6.2.4). At the time of this IRRP publication, the Technical Working Group is aware of significant interest from multiple potential customers throughout the region at various commitment levels, with interest from 700-1,700 MW of data centre connections within the Caledonia-Norfolk Subregion alone, which have not been captured in this IRRP forecast. Given the magnitude of such load growth, wires solutions are commonly the only technically feasible solution but require a lead time of 7-10 years.

To help mitigate the risks posed by these large but uncertain connection requests, the IESO will continue to monitor data centre and industrial growth patterns within the Burlington to Nanticoke Region and the province at large. The IESO is also undertaking a South and Central Bulk Plan to review the capability of the bulk system to support future generation connections and demand

growth in key areas throughout southern and central Ontario to enable a decarbonized power system in the future. This study will continue the assessment of the bulk transmission system between the Hamilton and Windsor areas to understand future transmission needs that could result from further economic development. In addition, when developing solutions to address needs, the IESO will evaluate different scenarios, to support more complex considerations, to ensure that recommendations are optimal under a range of future scenarios.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report is posted on the IESO's website.

3.2 Burlington to Nanticoke IRRP Development

The process to develop the Burlington to Nanticoke IRRP was initiated in December 2022, following the publications of the Needs Assessment Report in September 2022 by Hydro One and the Scoping Assessment Outcome Report in December 2022 by the IESO. The Scoping Assessment recommended that the needs identified for the Burlington to Nanticoke Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4 Background and Study Scope

This is the third cycle of regional planning for the Burlington to Nanticoke Region. This Region is located in southwestern Ontario and includes all or part of the following Counties and Districts:

City of Hamilton	City of Brantford	Norfolk County	Town of Oakville
County of Brant	Haldimand County	City of Burlington	

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

This Region also includes several Indigenous communities, located within or near the Region:

Mississaugas of the Credit First Nation	Métis Nation of Ontario:
Six Nations of the Grand River	Clear Waters Métis Council
Haudenosaunee Confederacy Chiefs Council	Grand River Métis Council

Following a Needs Assessment and Scoping Assessment in 2017, an IRRP and subsequent RIP were initiated and published in 2019, concluding the second planning cycle for the Region.

This IRRP develops and recommends options to meet the electricity needs of the Burlington to Nanticoke Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The following transmission facilities were included in the scope of this study:

Transformer stations:

Beach TS	Bronte TS	Dundas 2 TS	Kenilworth TS	Norfolk TS
Birmingham TS	Burlington TS	Elgin TS	Lake TS	Powerline MTS
Bloomsburg DS	Caledonia TS	Gage TS	Mohawk TS	Stirton TS
Brant TS	Cumberland TS	Horning TS	Nebo TS	Winona TS
Brantford TS	Dundas TS	Jarvis TS	Newton TS	CTS1 to CTS6

115 kV transmission circuits:

B3	B6G	B10	B13BL	HL3	H6K	K2G
B4	B7	B11	C9	HL4	H9W	Q2AH
B5G	B8	B12BL	C12	H5K	K1G	

230 kV transmission circuits:

B18H	M34H	M20D	M31W	N6M	N20K	Q30M
B20H	H35D	M21D	M32W	N21J	Q24HM	Q29HM
B40C	H36D	M27B	M33W	N22J	Q23BM	S39M
B41C	K40M	M28B	N5M	N37S	Q25BM	

The Burlington to Nanticoke Region covers a large portion of the transmission system in southwest Ontario, and for this reason it has been broken up into four subregions:

- Brant Subregion
- Bronte Subregion
- Caledonia-Norfolk Subregion
- Hamilton Subregion

Based on the Needs Assessment led by Hydro One in the beginning of the planning process, regional planning was required for the Burlington to Nanticoke Region except for the Bronte Subregion. Figure 2 to Figure 4 show single line diagrams of the subregions and subsystems for which the regional plan was conducted.

The Brant subregion consists of the following stations:

Brant TS	Brantford TS	Powerline MTS.

The Caledonia-Norfolk subregion consists of the following stations:

Bloomsburg DS	Jarvis TS	Caledonia TS
Norfolk TS	CTS1	CTS2

The Hamilton subregion consists of the following stations:

Beach TS	Dundas 2 TS	Horning TS	Mohawk TS	Stirton TS
Birmingham TS	Elgin TS	Kenilworth TS	Nebo TS	Winona TS
Dundas TS	Gage TS	Lake TS	Newton TS	CTS3 to CTS5

Note need assessments for the Brant 115 kV Subsystem, that includes Brant TS and Powerline MTS, could not be conducted in isolation and the area of study was extended to the entire 115 kV system enclosed between the Burlington and Karn 115 kV stations. Therefore, in addition to the Woodstock 115 kV Subsystem in the London Area, CTS3, Dundas, Dundas 2, Mohawk, Newton and Elgin stations in the Hamilton 115 kV Subsystem were also included in the studies. This is referred to as the Brant 115 kV Extended Area and is shown in Figure 2.

The Woodstock 115 kV Subsystem is not part of the Burlington to Nanticoke Region and was considered in the analysis of this IRRP because of its impact on the 115 kV Subsystems in the Brant and Hamilton subregions (please see "Brant 115kV Extended Area" in Section 6.3). The Woodstock subregion is part of the London Area Region, and consists of Commerce Way TS, Woodstock TS and CTS6.

Note that the bulk system transfer capabilities on the Buchanan Longwood Input (BLIP) and Queenston Flow West (QFW) interfaces through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

Figure 2 | Single Line Diagram of Brant 115 kV Extended Area, the Brant 115 kV Subsystem, the Hamilton 115 kV Subsystem, and the Woodstock 115 kV Subsystem

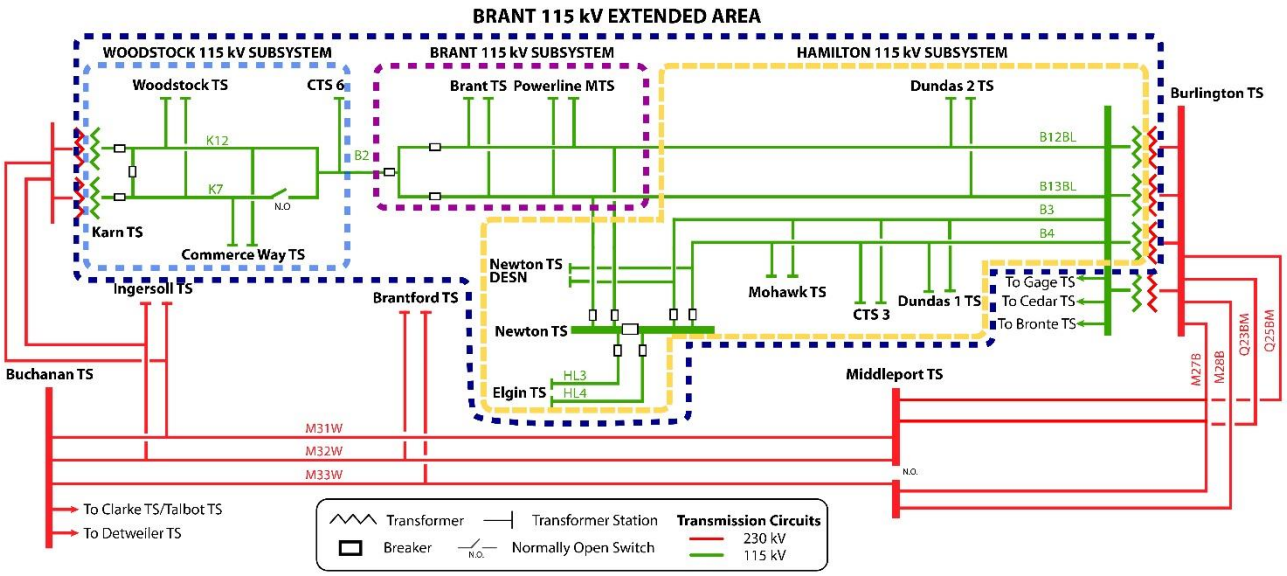


Figure 3 | Single Line Diagram of the Caledonia-Norfolk Subregion and Norfolk-Bloomsburg Area

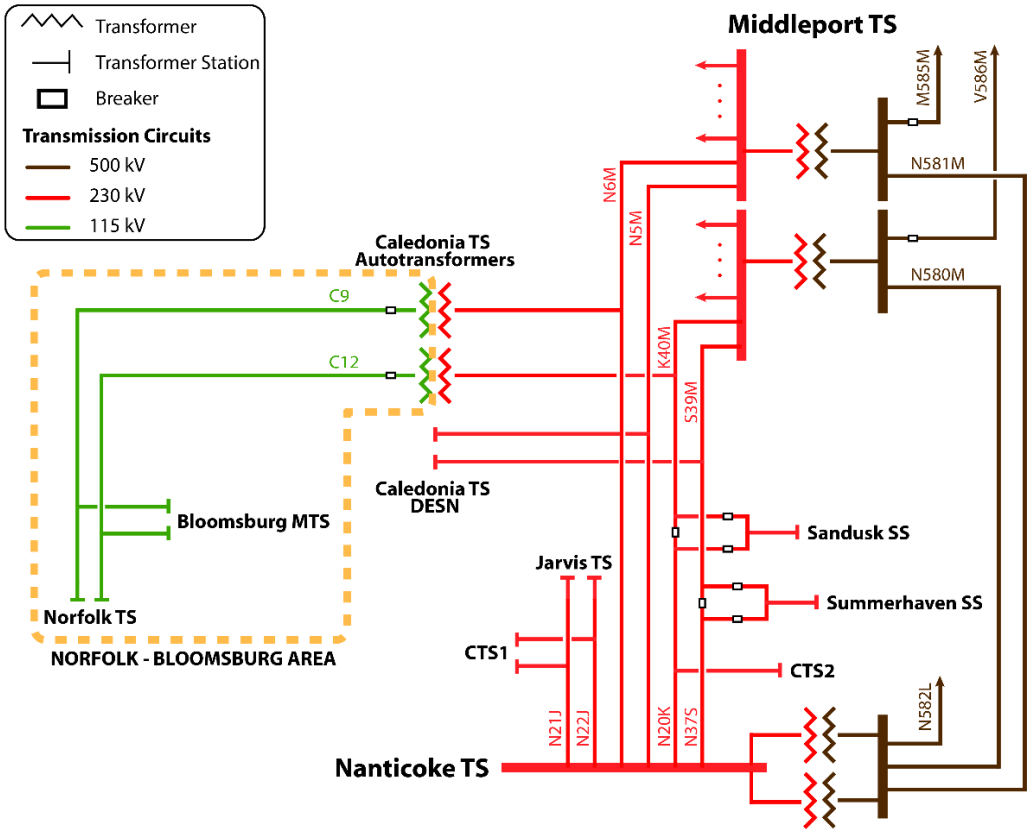
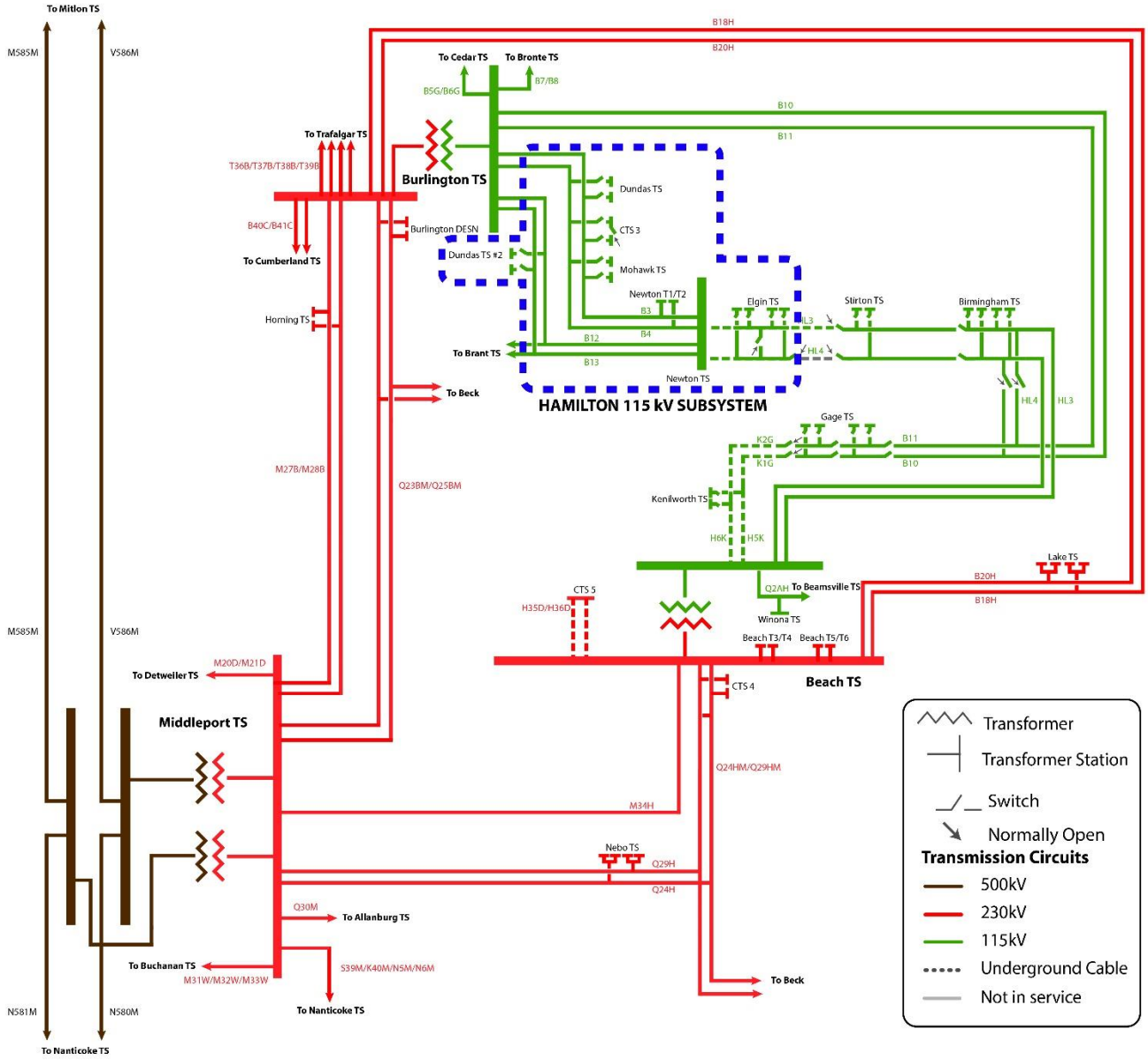


Figure 4 | Single Line Diagram of the Hamilton Subregion and Hamilton 115 kV Subsystem



The Burlington to Nanticoke IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria.
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
- Confirming identified asset replacement needs and timing with the transmitter and LDCs.

- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wire alternatives including CDM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near- to long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Burlington to Nanticoke Region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of CDM and DG. Both a reference and high growth scenario were provided by Hydro Onde Distribution for their service territory, while the other LDCs only provided a reference scenario. Compared with their reference scenario, Hydro One Distribution's high growth scenario additionally considered potential upcoming load connections with a lower degree of commitment (e.g., capacity inquiries, long-term assumptions from municipal plans, etc.). The high growth scenario from Hydro One Distribution was used for the "planning" forecast, since the difference with the reference scenario they provided was only marginal.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. In the case of this IRRP, three study areas were developed corresponding to the three subregions: Brant, Caledonia-Norfolk, and Hamilton.

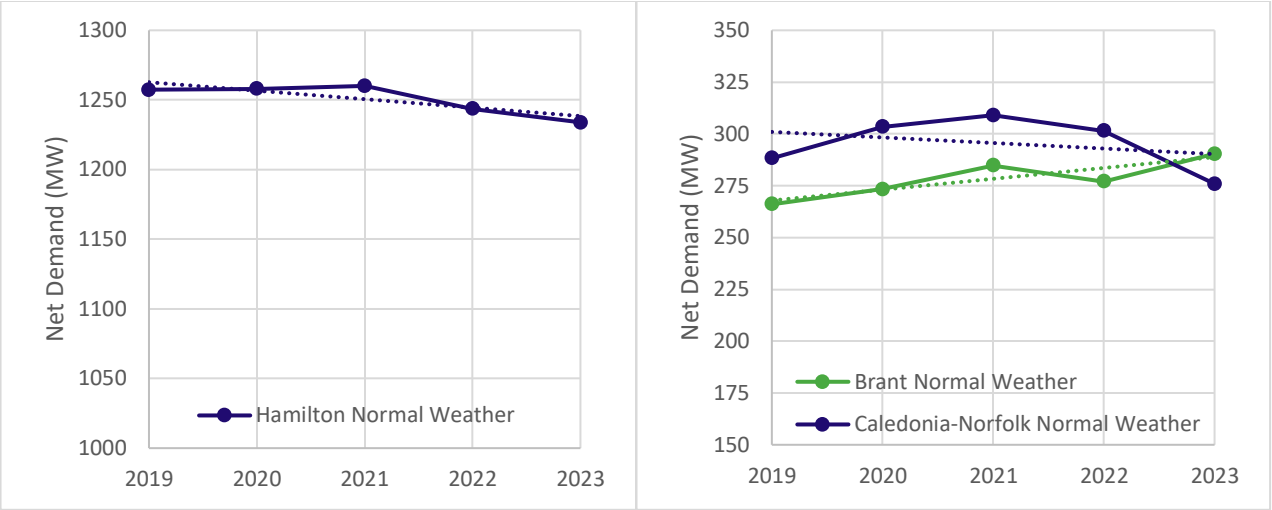
The coincident peak differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Each subregion of the Burlington to Nanticoke Region is summer peaking.

5.1 Historical Demand

Peak electricity demand within the Burlington to Nanticoke Region has been on average steady over 2019 to 2023. Figure 5 below shows the coincident net normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for each subregion, which have unique trends. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand. Weather-corrected demand is more appropriate for evaluating growth trends. The peak demand hour for each year occurred consistently in the summer between approximately 2 PM to 7 PM.

The net weather-corrected demand for the Brant, Caledonia-Norfolk, and Hamilton subregions has averaged 278 MW, 296 MW, and 1251 MW, respectively, over the last five years with negligible upward or downward trends. Demand has slightly been increasing for the Brant subregion while slightly declining for the Caledonia-Norfolk and Hamilton subregions.

Figure 5 | Historical Subregion Normal-Weather Demands

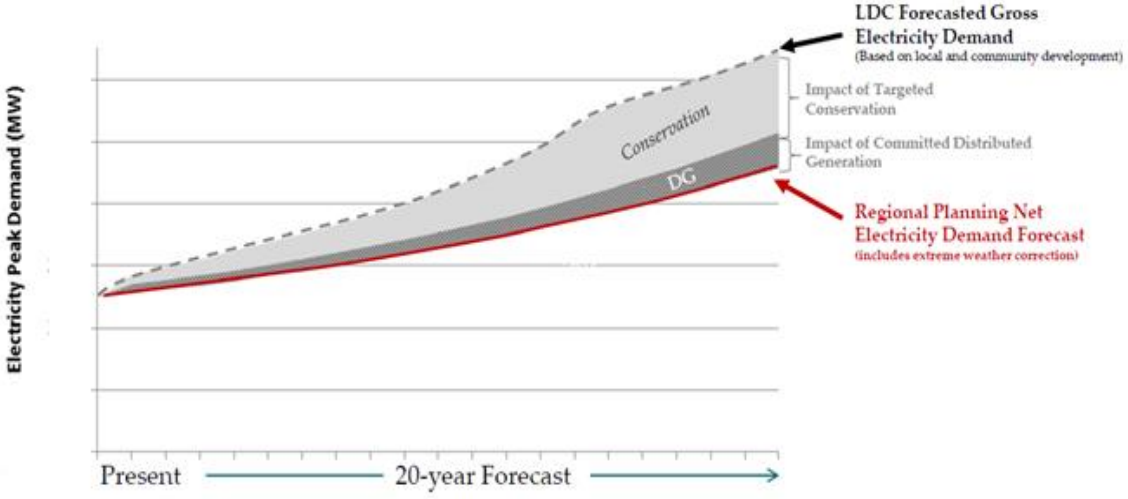


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast starting from LDC forecasts is illustrated in Figure 6. Gross demand forecasts, which assume the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

Each participating LDC in the Burlington to Nanticoke Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. In addition, when producing these gross demand forecasts, the impact of existing DG was removed, as DG impacts are accounted for later (see Section 5.5). Therefore, gross demand forecasts show the demand expected without any DG contributions, new or existing. Please see Section B.1 of Appendix B for more detail.

The LDCs cited alignment with municipal and regional plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices (natural conservation), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes normal weather conditions (e.g. median weather, expected 1 in 2 years), and peak station loading which may be non-coincident to the regional peak.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.

5.4 Contribution of Conservation to the Forecast

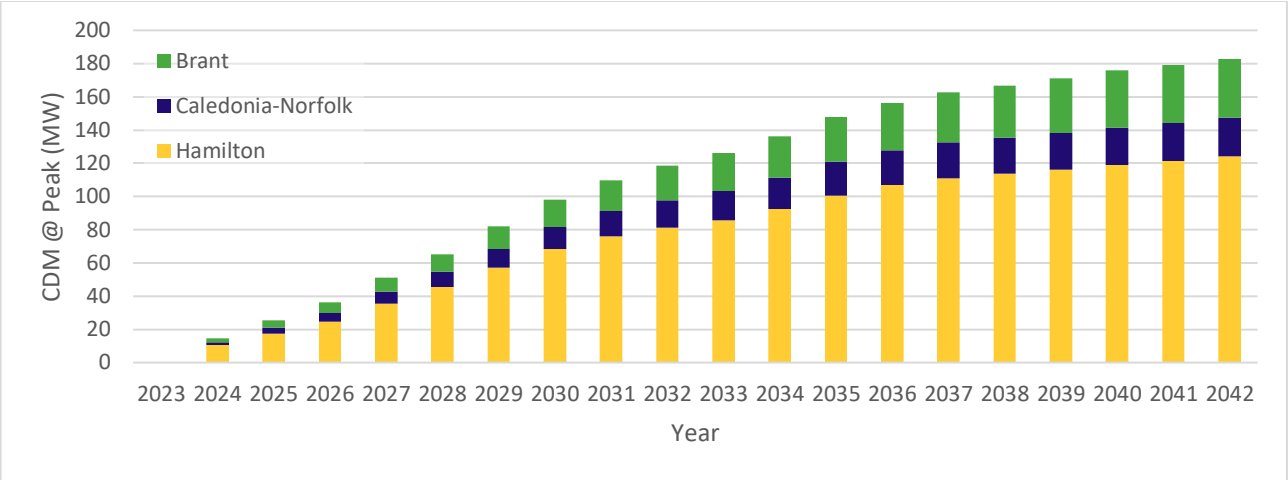
Conservation and demand management is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak-demand, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

The estimated demand reduction from codes and standards is based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities is based on the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs assumed to be consistent with current framework savings levels. Through the ongoing 2021-2024 CDM Framework the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities. At the time of forecast development and IRRP publication, actual energy and peak demand savings targets for the new 2025-2036 framework are not confirmed. Should the new savings targets be higher, it may push out the timing or reduced the magnitude of identified needs.

Figure 7 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each subregion. Additional details are provided in Appendix B.

Figure 7 | Peak Demand Reduction Due to Conservation and Demand Management



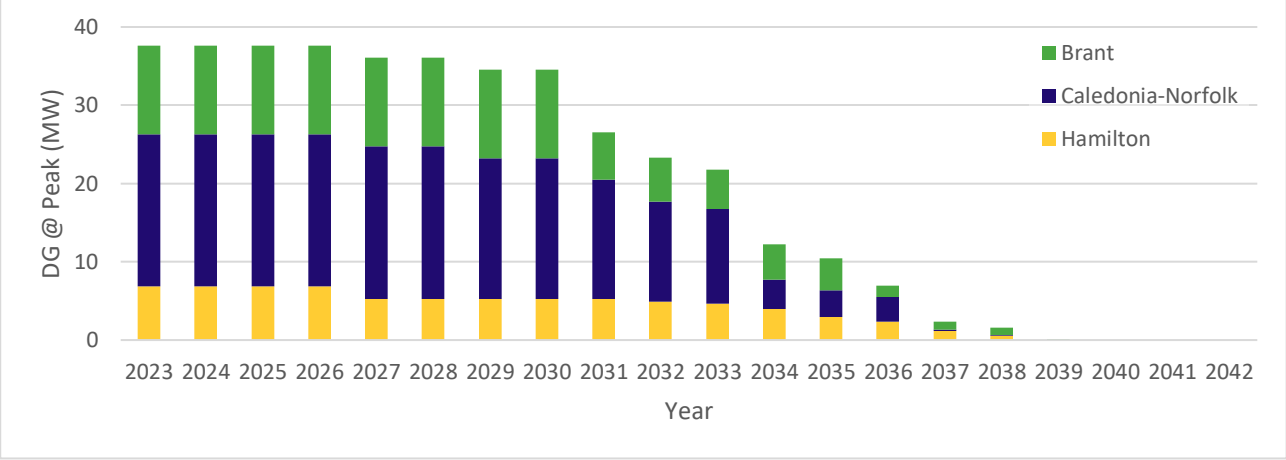
5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG is also forecasted to offset peak-demand requirements. The introduction of Ontario's FIT and microFIT Programs increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and the associated contribution factor assumptions can be found in Appendix B. Most of the total contracted installed DG capacity in the Burlington to Nanticoke Region is solar generation, but there is a comparable quantity of non-renewable generation. In the Brant and Hamilton subregions, the split is approximately equal, but in the Caledonia-Norfolk region there is only renewable generation, which is almost entirely solar.

Figure 8 shows the estimated impact of DG on the Burlington to Nanticoke Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 38 MW of peak contribution is identified for the Burlington to Nanticoke Region in 2023, reducing to zero by 2039 throughout the 2030s. This reduction is reflected in the Planning forecast as discussed in the next section.

Figure 8 | Peak Demand Reduction Due to Distributed Generation



5.6 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is traditionally a region-wide coincident forecast, meaning that each station forecast reflects its expected contribution to the regional peak demand. This supports the identification of need dates for regional needs that are driven by more than one station.

Due to the specific needs of the three subregions within the Burlington to Nanticoke Region (the Brant, Caledonia-Norfolk, and Hamilton subregions), and due to the small or lack of excess capacity remaining on these subregions, the "planning" forecast was produced as a subregion coincident forecast. This means that each station forecast reflects its expected contribution to its subregion 's peak demand rather than the regional peak demand. This puts a greater focus on identifying subregion needs, which was required due to the high level of loading in these subregions.

The planning forecast is produced from three main steps: converting to a coincident forecast, adjusting for extreme weather, and converting to a net forecast.

As discussed in Section 5.3, LDCs provide gross forecasts assuming normal weather conditions, and peak station loading that is non-coincident to the region or subregion. Therefore, the first step is to convert this non-coincident forecast to a coincident forecast, by applying a coincidence factor to each station. The factor is based on the station's historical contribution to the subregion peak demand compared to the station's non-coincident peaks over the past five years (2018-2022 in this case). This results in a subregion coincident gross forecast which assumes normal weather.

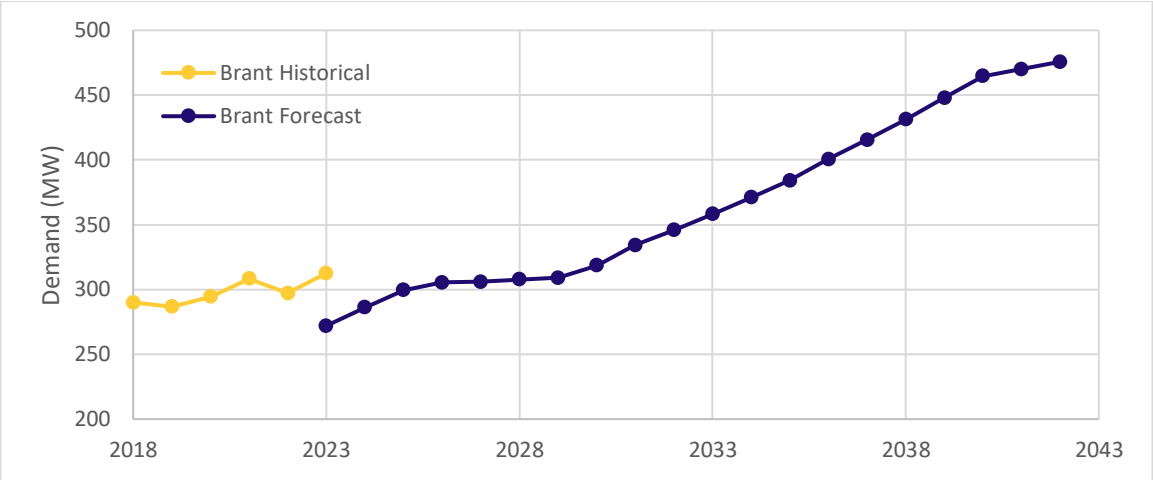
The second step is to adjust the resulting coincident gross normal weather forecast for extreme weather conditions. The weather correction methodology is described in Appendix B. This results in a coincident gross forecast which assumes extreme weather.

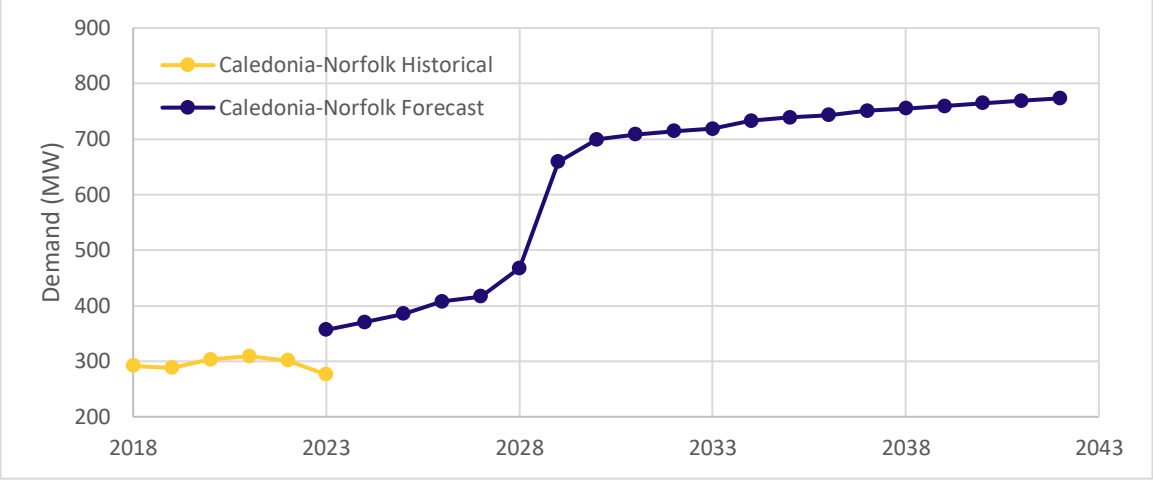
The last step is to adjust the resulting coincident gross extreme weather forecast for DG and conservation impacts. This is done by subtracting the forecasted DG and conservation impacts (as described in the above Sections) from the coincident gross extreme weather forecast. Finally, this results in a (subregional) coincident net extreme weather forecast, which is the "planning" forecast used to identify needs.

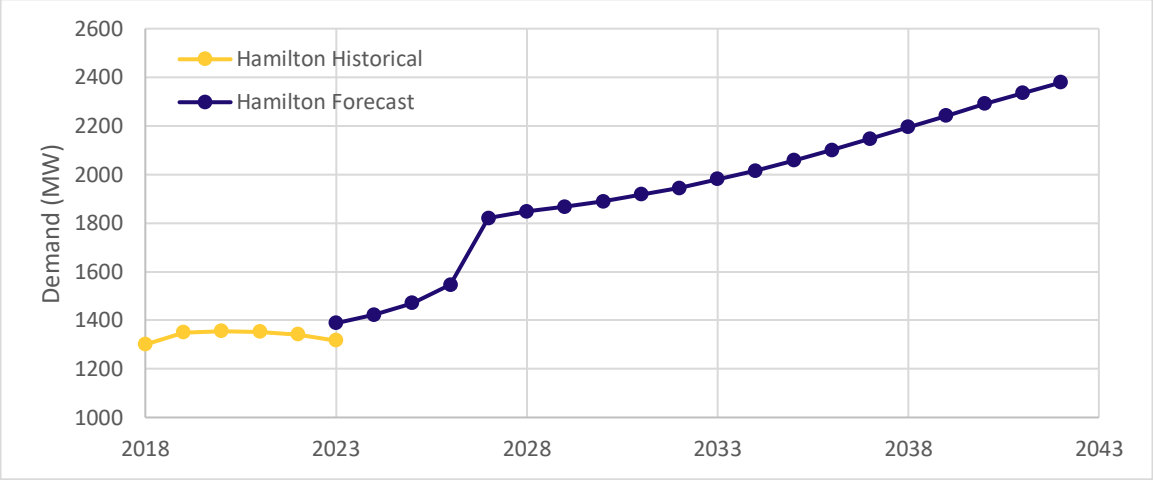
For station-specific needs, a non-coincident net extreme weather forecast used instead. The process for producing this forecast is similar as described above, except the first step is skipped.

The subregion coincident net extreme weather forecast ("planning" forecast) for each subregion in the Burlington to Nanticoke Region is shown in Figure 9 below. Historical net extreme weather demands have also been added for reference. The large increases in demand between 2026 to 2030 in the Caledonia-Norfolk and Hamilton subregions are caused by demand increases from a small number of existing industrial customers supplied by the 230 kV subsystems. These demand increases are unrelated to the needs and recommendations discussed in the following sections, which concern the 115 kV subsystems.

Figure 9 | Historical Demand and Planning Forecast for the Subregions







5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles (8,760 hours per year over the 20-year forecast horizon) for the Bloomsburg DS and Norfolk TS stations were developed to better assess non-wire alternatives to address needs at these stations. In particular, these profiles were used to quantify the magnitude, frequency, and duration of needs, as described later in Section

7. The profiles were based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

Station Capacity Needs describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by the thermal ratings of downstream or upstream equipment, i.e., breakers, disconnect switches, medium-voltage bus or high voltage circuits; or, by voltage drop limitations, which are independent of thermal ratings.

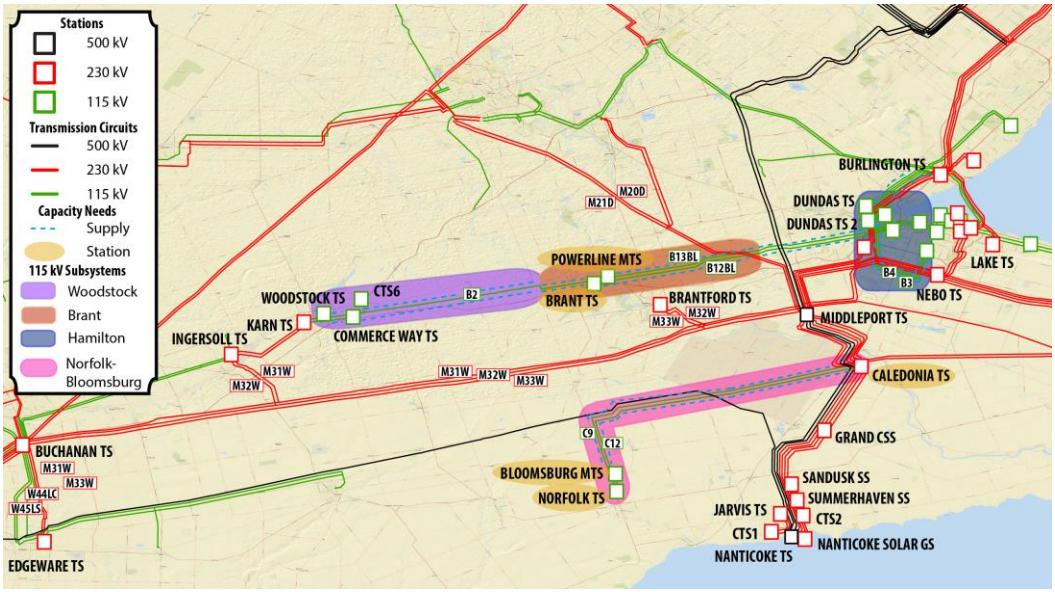
Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.

Asset Replacement Needs are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

Load Security and Restoration Needs describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the Burlington to Nanticoke IRRP can be found in Appendices G and H. The needs identified are discussed in the following sections, and are shown in Figure 10 below.

Figure 10 | Needs Identified in the Burlington to Nanticoke Region



6.2 Station Capacity Needs

Many station capacity needs emerge in the Burlington to Nanticoke region as shown in Table 5 with the majority in the near-/medium-term. Please see Appendix I, Figures of Station and Supply Capacity Needs, for graphical representation of these needs.

Table 5 | Station Capacity Needs

Time Horizon	Station	Subregion	Emerging Year	2042 Need (MW)
Near-term	Bloomsburg DS	Caledonia-Norfolk	2023	16
	Dundas 2 TS	Hamilton	2023	40
	Nebo TS (T1/T2)*	Hamilton	2023	142
	Nebo TS (T3/T4) *	Hamilton	2023	50
	Dundas TS	Hamilton	2025	59
	Powerline MTS	Brant	2026	68
	Mohawk TS	Hamilton	2026	46
	Brant TS	Brant	2027	41
Medium-term	Norfolk TS	Caledonia-Norfolk	2031	16
	Newton TS	Hamilton	2031	31

Time Horizon	Station	Subregion	Emerging Year	2042 Need (MW)
Long-term	Caledonia TS	Caledonia-Norfolk	2034	20
	Brantford TS	Brant	2035	54
	Lake TS (T1/T2) *	Hamilton	2035	19
	Elgin TS	Hamilton	2037	23
	Horning TS*	Hamilton	2038	14
	Beach TS (T5/T6) *	Hamilton	2042	2

*The station capacity needs were identified using the station load meeting capabilities (LMC) calculated by the IESO from load flow studies, or, if the LMC calculations were deferred to the addendum, using the station limited time ratings (LTR) provided in the transmitter-led Needs Assessment report.

6.2.1 Brant Subregion Station Capacity Needs

The three stations supplying the Brant subregion, Powerline MTS, Brant TS and Brantford TS, are forecasted to exceed their station capacity within the next decade. For a time, overloading at Brant TS and Powerline MTS can be addressed through distribution-level load transfers to Brantford TS until Brantford TS exceeds its capacity. However, by 2031 Brantford TS would no longer have capacity to provide relief, and new capacity is needed in the subregion. Additionally, the technical requirements and cost of upgrading the distribution system may limit the feasibility or viability of load transfer to Brantford TS.

6.2.2 Caledonia-Norfolk Subregion Station Capacity Needs

Half of the stations supplying the Caledonia-Norfolk subregion, Bloomsburg DS, Norfolk TS and Caledonia TS, are forecasted to exceed their station capacity within the next decade. For a time, overloading at these stations can be lessened through distribution-level load transfers to Jarvis TS. However, by 2035 Jarvis TS would no longer have capacity to provide relief, and new station capacity is needed in the subregion. Additionally, feasibility and economic reasons may restrict the amount of the load transfers.

6.2.3 Hamilton Subregion Station Capacity Needs

In the Hamilton subregion, ten out of 19 DESNs are forecasted to exceed their station capacity within the planning horizon. Notably six of these DESNs, i.e., Dundas TS, Dundas 2 TS, Mohawk TS, Nebo TS (T1/T2) and (T3/T4) and Newton TS, are identified with station capacity needs with a near- or medium-term timeframe.

The majority of needs for the Hamilton subregion will be addressed in the Hamilton Addendum as discussed in Section 2.5.1. However, the needs of the Dundas stations will be addressed by the Technical Working Group recommendations as part of the Brant 115 kV Extended Area as described in Section 6.3.

6.2.4 Customer-Owned Transformer Stations

Two customer-owned transformer stations (CTS) within the Burlington to Nanticoke Region are forecasted to exceed their station capacity. Since these stations are privately owned, the private owners will need to coordinate their solution with the IESO and transmitter (Hydro One) via the Connection Assessment and Approval (CAA) process.

6.3 Supply Capacity Needs

Supply capacity needs for the majority of the Hamilton subregion will be assessed and addressed in the addendum as discussed in Section 2.5.1. However, a portion of the Hamilton 115 kV system was included in the need assessments for the Brant subregion because of their impact on one another. This larger area is referred to as the Brant 115 kV Extended Area which, similarly, was further extended on the opposite side to include the Woodstock 115 kV Subsystem. In summary, the Brant 115 kV Extended Area consists of:

- **Brant 115 kV Subsystem:** the Powerline and Brant stations in the Brant subregion supplied via B12BL, B13BL, and B2
- **Hamilton 115 kV Subsystem:** the Dundas, Dundas 2, Mohawk, Newton, Elgin and CTS3 stations in the Hamilton subregion supplied via B12BL, B13BL, B3, and B4
- **Woodstock 115 kV Subsystem:** the Woodstock, Commerce Way and CTS6 stations in the Woodstock subregion of the London Area supplied via K7, K12 and B2

Table 6 shows the supply capacity needs identified for the Norfolk-Bloomsburg Area in the Caledonia-Norfolk subregion and various Subsystems in the Brant 115 kV Extended Area. Please see Appendix I, Figures of Station and Supply Capacity Needs, for graphical representation of these needs.

The LMC of the Norfolk-Bloomsburg Area, which is radially supplied via circuits C9 and C12, is limited by voltage constraints to 80 MW, well below the thermal limitation of the circuits at 150 MW. This Area has an immediate need of 33 MW in 2023 which increases to 78 MW in 2042.

Supply capacity needs for the Brant 115 kV Extended Area were identified based on its Subsystems: the Brant, Hamilton and Woodstock 115 kV Subsystems.

- The Brant 115 kV Subsystem has an immediate need of 3 MW in 2023 and a long-term need of 129 MW in 2042. The LMC of the Brant 115 kV Subsystem is presently limited by thermal limitations on circuits B12BL and B13BL to 134 MW, but following that, voltage constraints limit the LMC to nearly the same limit of 137 MW.
- The combined Brant and Hamilton 115 kV Subsystems has an immediate need of 66 MW in 2023 which increases to 483 MW in 2042. The LMC of the combined Subsystems is presently limited by thermal limitations on circuits B12BL and B13BL to 500 MW, but following that, voltage constraints limit the LMC to nearly the same limit of 535 MW.
- The Woodstock 115 kV Subsystem has an immediate need of 20 MW in 2023 which increases to 47 MW in 2042. The LMC of the Woodstock 115 kV Subsystem is presently limited by voltage constraints to 85 MW.

The magnitudes of the needs shown in Table 6 can reach approximately 100 per cent of the LMC. This indicates that significant reinforcements that are required for the 115 kV Subsystems listed in this table.

Table 6 | Supply Capacity Needs

			Need Magnitude (MW)	
Subregion	**Subsystem**	**LMC (MW)**	**2023**	**2042**
Caledonia-Norfolk Subregion	Norfolk-Bloomsburg Area	80	33	78
Brant 115 kV Extended Area	Brant 115 kV Subsystem	134	3	129
	Combined Brant and Hamilton 115 kV Subsystems	500	66	483
	Woodstock 115 kV Subsystem	85	20	47

6.4 Asset Replacement Needs

At the time of the Burlington to Nanticoke Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. These needs and recommendations from the Technical Working Group have been included in Table 7.

Table 7 | Asset Replacement Needs

Timeframe	Station	Asset	Recommendation
Medium-term	Beach TS	230/115 kV autotransformers DESN transformers	Proceed with like-for-like replacement
	Birmingham TS	DESN transformers and switchgear	Proceed with like-for-like replacement
	Caledonia TS	DESN transformer (T1)	Station capacity need identified; replace with maximum-rated unit
	Gage TS (T8/T9)	DESN transformers and switchgear	Proceed with replacement with nearest standard units
	Jarvis TS	DESN transformers	Proceed with like-for-like replacement; assess if current-limiting reactors can be removed*
	Lake TS	DESN transformers and switchgear	Station capacity need identified; replace with maximum-rated unit

Timeframe	Station	Asset	Recommendation
	Nebo TS (T3/T4)	DESN transformers	Station capacity need identified; replace with maximum-rated unit
	Norfolk TS	DESN switchgear	Defer replacement if possible, New 230 kV DESNs recommended (Section 7.3.2.3)
Long-term	Dundas TS	DESN switchgear	Defer replacement if possible, New 230 kV DESNs recommended (Section 7.3.2.3)

* The current-limiting reactors reduce the station LMC by 25 MW from ~125 MW to ~100 MW.

6.5 Load Security and Load Restoration Needs

The recommended interim solutions to open station bus-tie breakers can be violations to the load security criteria. However, the LDCs and transmitter can apply for exemptions until the medium-/long-term plans to address the needs are placed in service after which opening bus-tie breakers would not be needed.

The Technical Working Group did not identify any restoration needs.

7 Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Burlington to Nanticoke Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included feasibility, cost, lead time, system benefits, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new transmission or distribution infrastructure. These are commonly referred to as "wire" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wire" options and can include things like local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wire option. Subsequently, Section 7.3 to Section 7.4 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wire options are always considered in regional planning and while they are always viable options for regional needs, non-wire option may be more suitable for specific need types and characteristics. Hence, to select and appropriately size non-wire option such as generation or battery storage, additional work is required – including creation of an hourly load profile, as described in Section 5.7. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile, which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Burlington to Nanticoke Region needs.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. In contrast, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and decarbonization efforts, new natural gas-fired generation was not considered as a generation option for local needs identified by the regional plan. Battery energy storage, solar generation, and wind generation were considered for generation options.

New CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors (previously "CDM Guidelines) to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wire and non-wire options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wire option (typically 70 years for transmission infrastructure). The net present value (in 2024 CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around cost estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The transmitter-led RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, pilot or demonstration projects can be explored in cases where other barriers (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options following the completion of the IRRP.

The list of assumptions made in the economic analysis can be found in Appendix F.

7.2 Screening Options

As explained in the previous section, an array of options is developed to meet local needs during an IRRP and then each option is evaluated to recommend the option which is the most cost effective or the option which best balances cost and risk mitigation when substantial additional risks not captured by the Planning forecast are present. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 11 and further discussed in the next sections for the needs identified in the Burlington to Nanticoke region.

Station capacity needs identified for the Hamilton subregion in Section 6.2.3 are not included here, as the needs for the Hamilton subregion will be addressed in the addendum (see Section 2.5.1). More details on the steps and inputs used in the screening mechanism can be found in Appendix C, and a

summary of the options screening results for Burlington to Nanticoke Region is provided in Table 8 for station capacity needs, and in Table 9 for supply capacity needs.

Figure 11 | IRRP NWAs Screening Mechanism

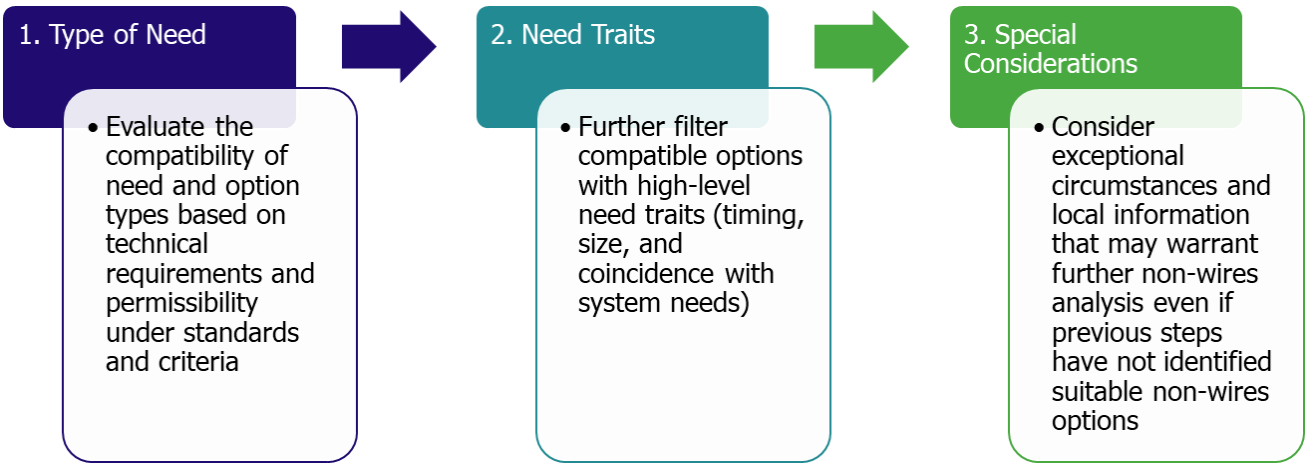


Table 8 | Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity: Bloomsburg DS, Norfolk TS, Caledonia TS, Brant TS, Powerline MTS	• Operational measures • CDM • Distributed generation[4] • Wires options	• Demand response – due to magnitude and timing of need

Table 9 | Options Screening Results for Supply Capacity Needs

Need	Screened In	Screened Out
Supply Capacity: Line C9 and C12, Brant 115 kV Subsystem, Hamilton 115 kV Subsystem, Woodstock 115 kV Subsystem	• Operational measures • CDM • Distributed generation[4] • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of need

7.2.1 Non-Wires Options for the Station Capacity Needs

[4] Later found to be technically infeasible due to short circuit limitations

Non-wires options cannot typically resolve the station capacity needs for the Burlington to Nanticoke region. The magnitude of the needs is too great to be addressed via CDM and DR and significantly exceeds the amount of DG that is technically feasible to connect at the distribution level due to short circuit and thermal constraints. Transmission-connected generation was also excluded because resources must be connected downstream of the limiting step-down transformer to have an impact on the station capacity needs.

Nevertheless, CDM has been considered for deferring long-term station capacity needs.

7.2.2 Non-Wires Options for the Supply Capacity Needs

Non-wires options, except transmission-connected resources, cannot resolve the supply capacity needs for the Burlington to Nanticoke Region since these needs are large in magnitude. Nevertheless, non-wire options can be explored in combination with wire options.

Only non-emitting resources such as battery storage and renewables were included in the option assessments.

7.3 Options and Recommendations for the Brant Subregion

7.3.1 Station Capacity Needs

The three stations supplying the Brant subregion, Powerline MTS, Brant TS and Brantford TS, are forecasted to exceed their station capacity, in the same order, within the next decade.

The needs at Powerline MTS and Brant TS are too large to be addressed by CDM or DR and DG is not viable because of short-circuit and thermal limitations at the stations. For a time, overloading at Powerline MTS and Brant TS can be addressed through distribution-level load transfers to Brantford TS until Brantford TS exceeds its capacity. The technical requirements and cost of upgrading the distribution system may limit the feasibility or viability of this load transfer.

Normally, the wire option, that is to upgrade the Powerline and Brant transformers, is recommended at this point. However, since there is also a supply capacity need for these stations, it would be more efficient and cost-effective to recommend a solution that resolves all supply and station capacity needs in the area, as discussed in the next section.

Therefore, as an interim solution, it is recommended to open bus-tie breakers at Powerline MTS and Brant TS, as required, to resolve their station capacity needs.

Load transfer to Brantford TS on a permanent or temporary basis may be used to reduce or resolve the station capacity needs but should be coordinated with the recommended interim option for resolving the supply capacity needs for the area explained in Section 7.3.2.1.

Since the Brantford station capacity need is in the long term, no immediate action is required. The Technical Working Group will monitor the load growth at the station for any change that can advance the need to take an appropriate action.

7.3.2 Supply Capacity Needs

No supply capacity need was identified for Brantford TS which is supplied from M32W and M33W, the 230 kV double-circuit line between Middleport and Buchanan.

Needs for the Brant 115 kV Subsystem, 115 kV circuits B12BL, B13BL and B2 supplying Powerline MTS and Brant TS, could not be identified and addressed in isolation due to its tight connectivity with the neighboring subregions. As such, the area of study was extended to the entire 115 kV system enclosed between the Burlington and Karn 115 kV stations. This study area is referred to as the Brant 115 kV Extended Area which, in addition to the Brant 115 kV Subsystem, consists of the Hamilton 115 kV Subsystem plus Woodstock 115 kV Subsystem, which are the Dundas, Dundas 2, Mohawk, Newton, Elgin and CTS3 stations in the Hamilton subregion supplied via B12BL, B13BL, B3 and B4 plus the Woodstock, Commerce Way and CTS6 stations in the Woodstock subregion of the London Area supplied via K7, K12 and B2.

7.3.2.1 Interim Solution – Operational Measures

As presented in Section 6.3, there are immediate supply capacity needs in the Brant 115 kV Extended Area.

Therefore, as an interim solution, it is recommended to take some operational measures to maintain system security by opening station bus-tie breakers within each Subsystem to maintain the post-contingency total load within the applicable load meeting capability. Effort should be taken to minimize the overall number of bus-tie breakers that must be open based on system conditions.

7.3.2.2 Non-Wire Options

Due to the large magnitude of the supply capacity needs in the Brant 115 kV Extended Area, CDM, DR and DG were not found to be adequate to resolve the needs. Transmission-connected resources, such as battery storage, are the only non-wire options with the potential to address these needs.

Due to the large area spanned when evaluating the resource option, a minimum of two facilities were needed, one at Brant TS and one at Newton TS with a total capacity of 450-600 MW. To be viable, the battery storage at both places should be paired with wind and solar generation because there are extended periods of time when the batteries cannot be charged from the grid due to extremely limited supply capacities. This implies having 600-1,500 MW wind and solar farms within the densely populated urban areas of Hamilton, which is not practical. As a result, transmission-connected resources were not considered feasible to meet this need and are not recommended.

7.3.2.3 Wire Options

Wire options listed in Table 10 were considered for resolving supply capacity needs in the Brant 115 kV Extended Area with additional information provided in the following sections.

Option 1: Reinforcing 115 kV and Dynamic Voltage Support

Based on load flow studies, almost all the 115 kV lines – 30 km of a single-circuit lines and 80 km of double/quadruple-circuit lines – must be reinforced with higher capacity wires by a factor ranging

from 1.35 to 3 in various sections. Additionally, dynamic voltage support devices, e.g. STATCOM, SVC or synchronous condenser, with a total post-contingency capacity of 500 Mvar at the Karn, Brant and Powerline stations are required to stabilize the voltage. It can take up to $790 M and 10 years to implement this option and still the long-term needs are not resolved let alone enabling future load growth.

Option 2: Upgrading 115 kV to 230 kV

This option entails replacing towers and wires on 85 km of double/quadruple-circuit lines and 2x8 stepdown transformers serving loads at eight stations. In addition to being prohibitively costly and lengthy, implementing this option is not practical since the lines pass through dense urban areas or along busy roads with a tight right of way.

Option 3: Adding New Supply Point Via 230/115 kV Autotransformers

None of the three alternatives considered for this option showed better load meeting capabilities than Option 1 although similar 115 kV reinforcements and dynamic voltage support were necessary and reinforcing 230 kV system might also be required. This implies this option has a higher cost and longer implementation time than Option 1 with no additional benefits.

Option 4a: Offloading 115 kV System to MxD and MxB 230 kV Circuits

Option 4a is the recommended solution since it can resolve both supply and station capacity needs for the Brant and Powerline and Dundas and Dundas 2 stations within an acceptable cost and timeframe without any negative impact on major bulk interfaces. Furthermore, the 115 kV system can supply the remaining Hamilton stations, CTS3, Mohawk, Newton and Elgin TS, up to their capacities without any additional reinforcement. Supply and station capacity needs, which would still limit the expected load growth for these remaining Hamilton stations, will be further assessed and addressed in the addendum discussed in Section 2.5.1.

To address supply capacity needs, rather than constructing new DESNs, it is possible to convert the existing DESNs at Brant TS and Powerline MTS from 115 kV to 230 kV supply. However, this will not resolve station capacity needs, and additional measures will be needed.

The choice between constructing new DESNs or converting existing DESNs, and the siting of potential new DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter. The point of connections to Middleport-Detweiler corridor will be finalized via the ongoing KWCG IRRP since these circuits are in the KWCG region.

Option 4b: Offloading 115 kV System to MxW and QxBM 230 kV Circuits

Option 4b is an alternative to Option 4a with similar benefits. However, the circuits to which load is transferred are part of major interfaces. Addition of load to these circuits negatively affect power transfer across the province and should be avoided. Otherwise, reinforcements are required to compensate for the negative impact.

Table 10 | Wire Options for Brant 115 kV Extended Area*

#	Description	Cost ($M)	Note
1	Reinforce 115 kV lines and add dynamic voltage support at Karn, Brant and Powerline	750-800	Does not resolve the long-term needs or enable future growth
2	Upgrade 115 kV lines and stations to 230 kV	1,000-1,500	Impractical and prohibitively costly and lengthy
3	Add new supply point via 230/115 kV autotransformers using either of the following alternative connections: - from Brantford TS to Brant TS on B12BL and B13BL - from Brantford TS to Alford Junctions on B12BL and B13BL - from Horning Mountain Junctions on M27B and M28B to Newton TS	850-1,000	Worse than Option 1; does not resolve the long-term needs or enable future growth; requires similar 115 kV reinforcements and dynamic voltage support as Option 1; may require 230 kV reinforcements
4a	Offloading 115 kV system to 230 kV: - Transfer Brant and Powerline loads to new 230 kV DESNs supplied from new taps on The Middleport-Detweiler corridor** - Transfer Dundas and Dundas 2 loads to new 230 kV DESNs at Dundas switchyard supplied from M27B and M28B***	200-300	**Recommended option.** Resolve supply and station capacity needs for Brant and Powerline and Dundas and Dundas 2; 115 kV system can supply the remaining Hamilton stations up to their capacities with no additional reinforcement****
4b	Offloading 115 kV system to 230 kV: - Transfer Brant and Powerline loads to new 230 kV DESNs supplied from Brantford TS or new taps on M32W and M33W - Transfer Dundas 1 and 2 loads to new 230 kV DESNs at Dundas switchyard supplied from Q23BM and Q25BM	300-400	Same benefits as Option 4a but not recommended due to negative impact on power transfer across the province as the circuits are part of major interfaces

* Line notations:
B12BL and B13BL: 115 kV circuits between Burlington, Brant and Newton, supplying Brant and Powerline loads
M27B and M28B: 230 kV circuits between Middleport and Burlington
M20D and M21D: 230 kV circuits between Middleport and Detweiler
M32W and M33W: 230 kV circuits between Middleport and Buchanan, part of a major interface transferring power across Ontario
Q23BM and Q25BM: 230 kV circuits between Beck 2, Burlington and Middleport, part of a major interface transferring power across Ontario

** DESN placements and point of connection to the Middleport-Detweiler corridor will be finalized via ongoing KWCG IRRP.

*** Transmitter-led Regional Infrastructure Plan (RIP) assesses and develops a detailed plan for implementation.

**** Woodstock 115 kV System LMC increases to 113 MW after which operational measures should be used to secure the system. Opening Brant DB2 115 kV breaker is recommended.

7.4 Options and Recommendations for the Caledonia-Norfolk Subregion

7.4.1 Station Capacity Needs

Three out of six stations supplying the Caledonia-Norfolk subregion, Bloomsburg DS, Norfolk TS and Caledonia TS, are forecasted to exceed their station capacity, in the same order, within the next decade.

The needs at Bloomsburg DS and Norfolk TS are too large to be addressed by CDM or DR and DG is not viable because of short-circuit and thermal limitations at the stations. For a time, overloading at Bloomsburg DS can be addressed through distribution-level load transfers to Norfolk TS until Norfolk TS exceeds its capacity after which Bloomsburg and Norfolk loads may be transferred to Jarvis TS. However, Hydro One Distribution has indicated limited ability to cost-effectively transfer load to Jarvis TS, and estimates that more than 20 km of new distribution line is needed meet long term needs.

Normally, the wire option, that is to upgrade the Bloomsburg and Norfolk transformers, is recommended at this point. However, since there is also a supply capacity need for these stations, it would be more efficient and cost-effective to recommend a solution that resolves all supply and station capacity needs in the area, as discussed in the next section.

Therefore, as an interim solution, it is recommended to open bus-tie breakers at Bloomsburg DS and Norfolk TS, as required, to resolve their station capacity needs.

Load transfer from Bloomsburg DS to Norfolk TS and additional load transfer from any of these stations to Jarvis TS on a permanent or temporary basis may be used to reduce or resolve the station capacity needs but should be coordinated with the recommended interim solution for resolving the supply capacity needs for the area explained in Section 7.4.2.1.

Since the Caledonia station capacity need is in the long term, no immediate action is required. The Technical Working Group will monitor the load growth at the station for any change that can advance the need, and consider the use of CDM closer towards the needs date to defer needs.

7.4.2 Supply Capacity Needs

As presented in Section 6.3, there is a supply capacity need in the Norfolk-Bloomsburg Area. No supply capacity need was identified for Caledonia TS or Jarvis TS.

7.4.2.1 Interim Solution – Operational Measures

To address the immediate supply capacity need in the Norfolk-Bloomsburg Area, an immediate interim solution is needed until permanent solutions can be put in place.

Therefore, as an interim solution, it is recommended to take some operational measures and open station bus-tie breakers at Bloomsburg DS or Norfolk TS, as required, to ensure the

security of the system by maintaining the post-contingency total load within the applicable load meeting capability.

Permanent or temporary load transfer to Jarvis TS may be used to reduce reliance on opening bus-tie breakers.

7.4.2.2 Non-Wire Options

Due to the large magnitude of the supply capacity needs in the Norfolk-Bloomsburg Area, CDM, DR and DG were not found to be adequate to resolve the needs. Transmission-connected resources, such as battery storage, are the only non-wire options with the potential to address these needs. However, due to the sizeable capacity required to meet needs, this non-wire option is only economically viable when considering the system benefit that resources provide to the provincial system.

Load flow analyses showed battery energy storage systems (BESS) are viable if they:

- constantly control the voltage of the points of interconnection (POI) to the grid by providing enough reactive power (Mvar) support to the system.
- connect on both 115 kV lines, C9 and C12, between Bloomsburg Junctions and Norfolk TS, preferably at Norfolk TS.
- have enough redundancy in components and connections not to lose active/reactive power support and voltage control under any outage conditions; otherwise, the operational measures recommended as the interim solution in the previous section must be taken.

Minimum requirements for the rated capacity (MW) and energy (MWh) of a viable BESS are dependent on the minimum reactive power (Mvar) support that the BESS can constantly provide. Higher constant reactive power support results in lower rated capacity and energy requirements which may imply the BESS reactive power support exceeds the reactive power requirement from Market Rules Appended 4.2 – Category 5.

If the BESS option is found unviable because of low reactive power support, it may be possible to make it viable by pairing with renewables. Further analyses are needed to determine the capacity of wind and solar generation needed for this, and the associated feasibility of building sufficient wind and solar farms in the area.

As discussed in the next section, the recommended long-term solution for the Norfolk-Bloomsburg Area is a 230 kV wire option. However, since the needs are immediate and the implementation of the wire option can take up to 10 years, to bridge the gap until the Norfolk-Bloomsburg long-term wire solution is placed in service, a medium-term solution is also recommended.

Therefore, as a medium-term solution, a BESS capable of continually providing reactive support to control the voltage at the points of interconnection is recommended. The BESS may potentially be combined with other NWAs such as renewables.

7.4.2.3 Wire Options

The transmission-connected resources recommended in the previous section would not enable future long-term growth in the Area. In addition, a heavily loaded Norfolk-Bloomsburg 115 kV system would significantly restrict the load meeting capabilities of the upstream 230 kV system. Connecting new large loads, such as industrial projects or AI/data centres, with a magnitude of 1,000-2,000 MW to the Nanticoke-Middleport corridor or Nanticoke 230 kV TS may not be feasible unless the Norfolk-Bloomsburg Area is offloaded. As such, wire options listed in Table 10 were explored. Additional information is provided in the following sections.

Option 1: Dynamic Voltage Support and CDM

Based on load flow studies, dynamic voltage support devices, e.g. STATCOM, SVC or synchronous condenser, with a total post-contingency capacity of 100 Mvar are required to stabilize the voltage and increase the load meeting capability of the Norfolk-Bloomsburg Area to its thermal limit of 150 MW. Combined with new CDM programs, this option can meet the supply capacity need for the 20-year forecast without enabling any further growth. However, it does not resolve the station capacity needs at Bloomsburg DS and Norfolk TS. In addition, a limitation on the upstream 230 kV system is also present.

Option 2: Upgrading 115 kV System to 230 kV

This option entails replacing 115 kV wires along 45 km of double-circuit lines and adding two sets of stepdown transformers serving loads at the two stations. Implementing this upgrade would require frequent outages to the system including the 500 kV circuit that shares towers with the 115 kV circuits. The cost and lead time of this option are the largest among the wire options without providing any additional benefits comparing to Options 3a and 3b.

Option 3a and 3b: Transferring Load to a New 230 kV DESN Supplied Via New Lines Connecting to the Nanticoke-Middleport 230 kV Corridor or Nanticoke TS

Option 3 has two alternatives, a and b, with similar cost, timeline, and benefits.

Option 3b, constructing a new DESN and connecting to Nanticoke TS, is recommended because it addresses the long-term supply and station capacity needs and enables future growth for the Norfolk-Bloomsburg Area. Option 3b is preferred over 3a, since it can address the needs for multiple areas, including possible growth due to industrial projects or AI/data centers in the vicinity of Nanticoke TS.

To address supply capacity needs, rather than constructing a new DESN, it is possible to convert the existing DESNs at Bloomsburg DS and Norfolk TS from 115 kV to 230 kV supply. However, this will not resolve station capacity needs, and additional measures will be needed.

The choice between constructing a new DESN or converting existing DESNs, the siting of new transmission lines, and the siting of potential new DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter.

Depending on the implementation of the medium-term recommendation for a BESS in the Norfolk area, and the pace of load growth and distributed generation connections in the area over the near and medium term, there may be an opportunity to further defer the need for the long-term solution. However, given the interest from large loads in the Nanticoke area and the long lead time of the solution, it is recommended that as the work proceeds on the long-term solution, the TWG continues to monitor interest from load connections in the area. In the next planning cycle, the TWG will review the proposed in-service date and determine if any changes are needed.

Table 11 | Wire Options for Norfolk-Bloomsburg Area

#	Description	Cost ($M)	Note
1	Add dynamic voltage support + new CDM at Norfolk and Bloomsburg	100-200	Barely meets the 20-year supply capacity need; does not resolve station capacity needs; does not enable future growth; limits upstream 230 kV system
2	Upgrade 115 kV lines and stations to 230 kV	250-350	Resolves supply and station capacity needs and enable future growth at highest cost
3a	Transfer Norfolk and Bloomsburg loads to a new 230 kV DESN supplied via new lines connecting to the Nanticoke-Middleport 230 kV corridor	150-200	Resolves supply and station capacity needs; enable future growth
3b	Transfer Norfolk and Bloomsburg loads to a new 230 kV DESN supplied via new lines connecting to Nanticoke TS*	150-200	**Recommended long-term option.** Same benefits as Option 3; additionally, can address needs in multiple areas

* Transmitter-led Regional Infrastructure Plan (RIP) assesses and develops a detailed plan for implementation.

For a summary of recommendations with timing and lead responsibility, please refer Table 2, Table 3, and Table 4 in Sections 2.2 to 2.4.

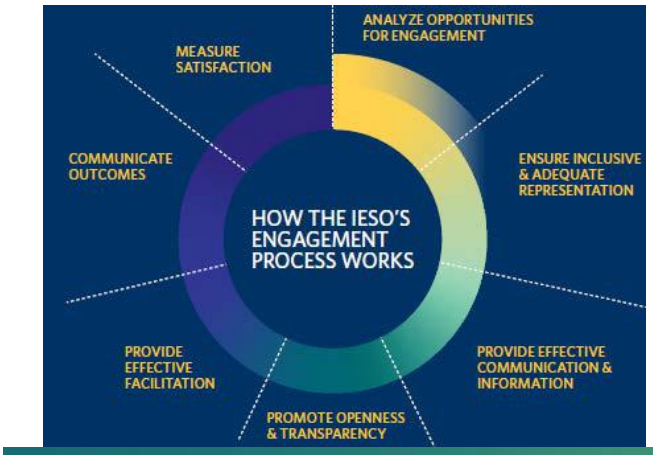
8 Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the Burlington to Nanticoke IRRP.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 12 | The IESO's Engagement Principles



The IESO applies these principles to every engagement, ensuring that we honour our commitment to partners:

Purposeful
Initiate meaningful conversations that move the sector forward

Accessible
Ensure we meet people where they are on their energy journey

Inclusive
Invite many voices and diverse perspectives to the table

Traceable
Allow everyone to follow the path that is being taken

Timely
Seek input and insight when it can have the most impact

Transparent
Show how engagement has shaped final outcomes

8.2 Engagement Approach

To ensure that the Plan reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement involved:

- Leveraging the Burlington to Nanticoke engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback.
- Timely and targeted discussions with transmission-connected loads and municipalities to help inform the engagement approach for this planning cycle;
- Hosted a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Burlington to Nanticoke Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Burlington to Nanticoke Region Scoping Assessment Report finalization. A public webinar was held in November 2022 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in December 2022, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, several targeted outreach meetings then began to involve large customers and municipalities in the region to ensure growth and development plans have been accurately captured in the Technical Working Group's draft demand forecast and solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Burlington to Nanticoke Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an

opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement primarily focused on:

- Organic growth and economic development projects across the region;
- Interest in leveraging existing and local generation; and
- Interest in ensuring electricity infrastructure can accommodate economic development.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Burlington to Nanticoke's Region subscribers, municipalities, and Indigenous communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion as shared by Norfolk County, residential growth as shared by Haldimand County, and capacity concerns as shared by Hamilton). These insights have been valuable to the IESO – as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

Additionally, participants would like to be engaged when there is additional information to share regarding Hamilton's needs, options and draft recommendations as well as progress in-between planning cycles. To that end, ongoing discussions will continue through the Hamilton Addendum to keep interested parties engaged in a two-way dialogue. Additionally, municipalities are encouraged to ensure their local distribution company is aware of any changes and updates to their growth and development plans.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Burlington to Nanticoke IRRP engagement webpage.

8.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region and community preferences around solutions:

- Over the next 20 years, significant residential growth in Caledonia with 4,000 to 5,000 residential dwellings, Hagersville with 3,000 to 3,500 residential dwellings and Jarvis and Dunnville with 500.
- There is a potential urban boundary expansion in Norfolk County and a new employment area in Delhi.
- Significant growth is anticipated for St. George (when wastewater treatment plant expansion is completed), Burford (servicing master plan is underway) and Oakland/Scotland areas in the County of Brant.
- Electrification initiatives within City of Brantford are underway such as the construction of a transit hub.
- Capacity concerns for Dundas and Dundas 2 were raised by the City of Hamilton prompting those station capacity needs to be explored in this study rather than the Hamilton Addendum.
- Several municipalities are exploring local energy projects to support their energy needs and would like to have these, or other non-wire alternatives, considered as solutions for the IRRP.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Region throughout the development of the plan. This includes the Mississaugas of the Credit First Nation, Six Nations of the Grand River, and a number of MNO councils located within or near the Region including MNO Clear Waters Métis Council and MNO Grand River Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9 Conclusions

The Burlington to Nanticoke IRRP identifies electricity needs in the region over the 20-year period from 2023 to 2042, and recommends a plan to address needs from the immediate to long-term. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near-to-medium term, the Technical Working Group recommends the pre-contingency opening of bus-tie breakers, and load transfers between nearby stations at the distribution level, where viable and cost-effective. These recommendations are needed at several stations supplied by the 115 kV transmission system and one by the 230 kV transmission system.

In the medium-term, the Technical Working Group recommends the procurement of a BESS in the Norfolk-Bloomsburg Area, and the construction of a new substation[5] near Dundas TS. These recommendations will respectively address needs in the Norfolk-Bloomsburg Area, and on the Hamilton 115 kV Subsystem and at the Dundas and Dundas 2 stations.

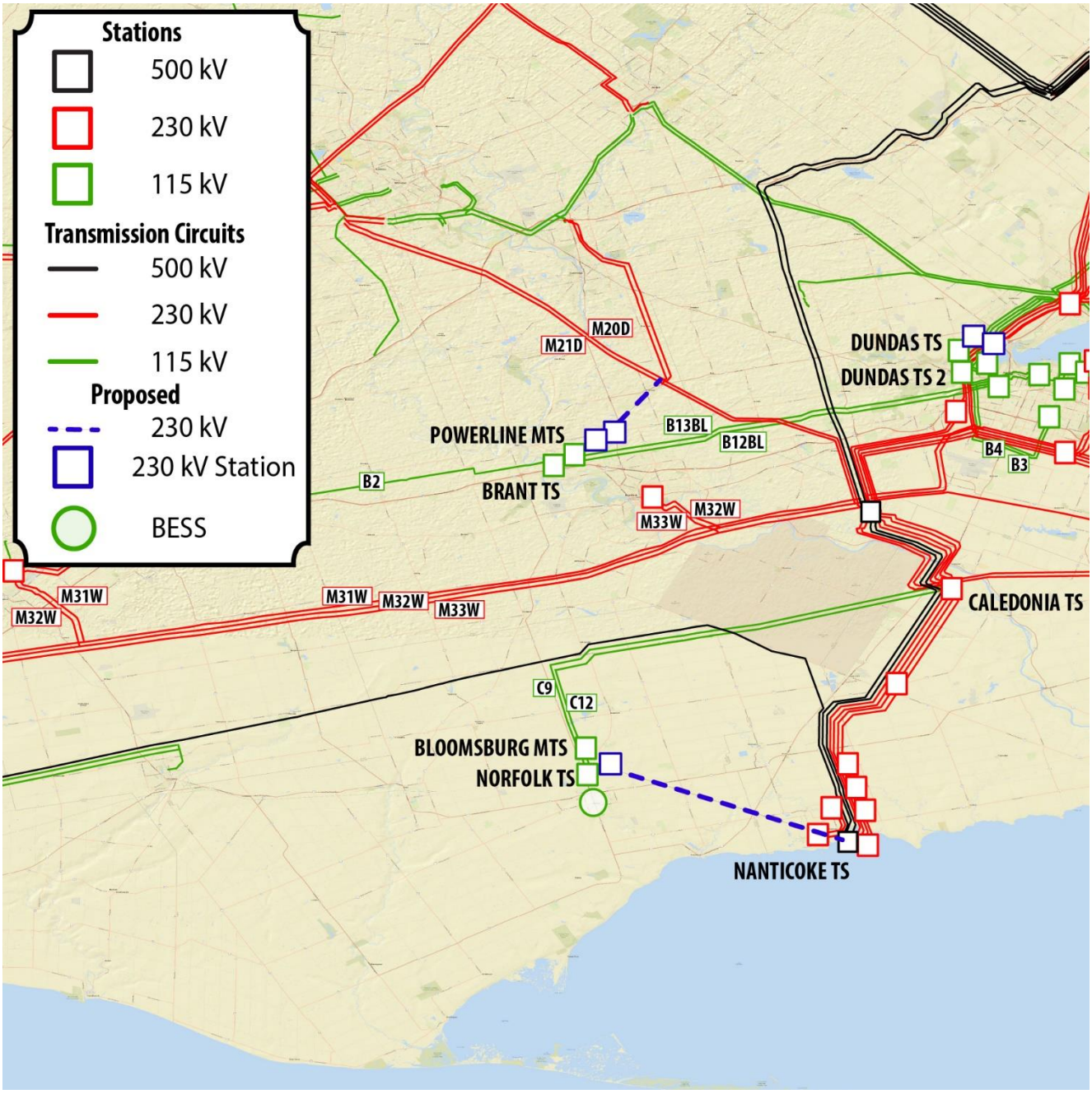
Finally, in the long term, the Technical Working Group recommends constructing two new double-circuit transmission lines and associated substations[5], separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem, and considering cost-effective CDM at Brantford TS and Caledonia TS closer to needs dates to defer capacity needs at these stations. A map outlining the medium- and long-term recommendations is provided in Figure 13.

The first transmission line is recommended from Nanticoke TS into the Norfolk-Bloomsburg Area, and a new station with an LTR of approximately 200 MVA is recommended at the end of the line. The Technical Working Group then recommends that Norfolk TS and Bloomsburg TS be entirely offloaded onto the new substation[5]. The second transmission line is recommended as an extension from the existing Middleport-Detweiler corridor in the Kitchener/Waterloo/Cambridge/Guelph region into County of Brant, and a new station with an LTR of approximately 400 MVA is recommended at the end of this line. The Technical Working Group then recommends that Brant TS and Powerline MTS be entirely offloaded onto the new substation[5]. Last, the Woodstock 115 kV Subsystem is recommended to be separated from the Brant 115 kV Subsystem by opening the Brant DB2 breaker.

The Technical Working Group will continue to monitor growth at Brantford TS and Caledonia TS and across the region. This includes any future community energy planning, electrification trends, datacentres, or industrial load. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region. The Technical Working Group will meet at regular intervals to complete the Hamilton addendum, monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

[5] Rather than building a new station, the existing DESNs may be converted from a 115 kV supply to a 230 kV supply by replacing all 115 kV station equipment. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective solution and develop a detailed plan for implementation.

Figure 13 | Medium/Long-Term Recommendations in the Burlington to Nanticoke Region



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REGIONAL INFRASTRUCTURE PLAN REPORT

Burlington to Nanticoke

Regional Infrastructure Plan Report

Burlington to Nanticoke

June 16, 2025

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Burlington to Nanticoke Technical working group

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Disclaimer

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

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

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

Executive Summary

REGION	**Burlington to Nanticoke** (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: December 18, 2024	**END DATE:** June 16, 2025

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Burlington to Nanticoke region, preceded by, the publication of Needs Assessment (NA) report in September 2022 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in December 2022 and in November 2024 respectively, by the Independent Electricity System Operator (IESO). The assessment for Hamilton sub-region was not completed in the November 2024 IRRP and re-assessment of the Bronte TS supply area due to upcoming load forecast revision will be completed as an addendum to the IRRP.

Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes an RIP report. The RIP report includes a common discussion of all the options and recommended plans, and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs. The RIP load forecast was refreshed for the next 10 years following the completion of IRRP based on input from WG members and developed an additional alternative for one of the 115kV supply capacity needs in Brant Area as well as an alternative location for one of the Dundas DESNs recommended in the IRRP south of Hamilton near Hydro One's existing Middleport TS. In addition, Hydro One will issue an addendum to this RIP with a final recommendation based on the findings of the Technical Working Group for the additional alternatives within 90 days of the IESO Hamilton area addendum IRRP kickoff.

Objectives:

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

Scope:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2025 - 2035 identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, or Integrated Regional Resource Plan).

- Identification of any new needs over the 2025-2035 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified by the TWG.

2. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Integrated Regional Resource Plan and finally details the Regional Infrastructure plan Methodology.

3. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the Burlington to Nanticoke region though a regional planning area map and a Single Line diagram.

The Burlington to Nanticoke region covers the City of Brantford, Municipality of Hamilton, counties of Brant, Haldimand and Norfolk. The portions of Cities of Burlington and Oakville south of Dundas Street are included in the Burlington to Nanticoke region up to Third Line Road in the east.

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

This section provides a summary and brief description of all the projects completed in the past ten years or are currently underway.

i. The following major projects were completed during the last ten years:

i. Burlington TS (2016) – Installed an additional 230 kV circuit breaker to reduce probability of the simultaneous loss of two autotransformers to improve supply reliability of the stations supplied from 115 kV bus.

ii. Transformer replacement at stations: Dundas TS (T1&T2 -2015), Brant TS (T1&T2 -2016), Beach TS (T3 &T4 -2018), Mohawk TS (T1&T2 -2018) and Newton TS (T1&T2 - 2020).

iii. B7/B8 115 kV Transmission line capacity (2018) – addressed supply capacity constraint to Bronte TS through distribution load transfers.

iv. Horning TS (2018) – replaced 230/ 13.8 kV transformers (T1 &T2) & LV switchgear.

v. Bronte TS (2019) – replaced 115/ 27.6 kV transformers (T5 &T6) & associated LV switchgear.

vi. Brant Switching Station (2019) – installed three (3) 115 kV breakers at Brant TS integrating 115 kV B12BL/B13BL circuits with 115 kV B2 circuit from Karn TS, to provide additional supply capacity for Brant TS and Powerline MTS.

vii. Cumberland TS (2019): Power factor correction – Capacitors installed at customer level.

viii. 115 kV B3/B4 (2020): Refurbished line section from Horning Mountain Jct. to Glanford Jct. based on asset condition assessment.

ix. Elgin TS (2022): Transformers & switchgear replacement based on asset condition assessment and reconfiguring from two (2) DESNs to a single DESN.

x. Kenilworth TS (2023): Transformer & switchgear replacement based on asset condition assessment and reconfiguration from two (2) DESNs to single DESN.

xi. Gage TS (2024): Transformers & switchgear replacement based on asset condition assessment, reconfiguring station from a three (3) DESNs station to a two (2) DESNs station replacing equipment.

ii. The following major projects are underway:

i. Kenilworth TS: Power factor correction (2025)

ii. Dundas TS: Load Balancing between DESNs (2025)

iii. Norfolk area supply capacity – Load transfer and additional reactive support (2026)

iv. 115 kV B7/B8: Refurbish of line section from Burlington TS to Nelson Jct. (2025)

v. Beach TS: Autotransformer (T1/ T7/T8) Replacement (2028)

vi. Lake TS: Transformer (T2) Replacement (2028)

Note: The planned in-service year for the above projects are tentative and are subject to change.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the Burlington to Nanticoke region is expected to grow at an average annual rate of approximately 3.1% in summer from 2025 to 2035. The Region is summer peaking, so this assessment is based on summer peak loads.

The following actions and assumptions are made in this report.

- The study period for the RIP assessments is 2025-2035.
- LDCs are requested to confirmed load forecasts up to 2035 in the area.
- The CDM values were updated based on the 2025 APO to incorporate the expanded eDSM programs.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or based on historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations uses non-coincident peak loads.
- Adequacy assessment is conducted as per required regulations.

6. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying Burlington to Nanticoke region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

Needs identified in the region:

a. Asset Renewal for Major HV Transmission Equipment

i. Nebo TS: Transformer (T3/ T4) refurbishment
ii. Lake TS: DESN (T3/T4) refurbishment
iii. Beach TS: DESN (T5/T6) refurbishment
iv. Caledonia TS: Transformer (T2) refurbishment
v. Birmingham TS: Transformer (T1) and MV Metalclad Switchgear refurbishment
vi. Gage TS: DESN (T8/T9) refurbishment
vii. Jarvis TS: Transformer (T3/T4) refurbishment

The refurbishment needs that currently fall beyond the study period of this report are not included in this report and will be reassessed, as needed, during the next planning cycle. The Hamilton 115 kV cable refurbishment needs will be studied as part of the upcoming Hamilton IRRP report, led by the IESO.

b. Area Supply Needs

i. Brant Area
ii. Norfolk Area
iii. Dundas Area
iv. Bonte Area

c. Station Capacity

i. Nebo TS (T3/T4) 13.8 kV DESN
ii. Mohawk TS
iii. Newton TS
iv. Nebo TS (T1/T2) 27.6 kV DESN

The station capacity needs beyond the study period of this report are not included in this report and will be reassessed, as needed, during the next planning cycle.

d. Transmission Line Supply Capacity

The TWG identified overloading of 115 kV B2 intertie line between Brant and Woodstock area which is studied as part of the Brant area supply needs and supply capacity of C9/C12 will be studied as part of Norfolk area supply need.

e. System Reliability, Operation and Load restoration

The Technical Working Group did not identify any other reliability, operation and load restoration needs for this region during this regional planning cycle.

7. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Burlington to Nanticoke Region. The needs include those previously identified in the NA and IRRP for the Burlington to Nanticoke Region as well as any new needs identified during the RIP phase.

8. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the Burlington to Nanticoke region are given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Section No.
Asset Renewal Needs				
Nebo TS	Transformer (T3/ T4) refurbishment	Hydro One	2030-2035	8.1.1
Lake TS	DESN (T3/T4) Refurbishment	Hydro One	2030-2035	8.1.2
Beach TS	DESN (T5/T6) Refurbishment	Hydro One	2030-2035	8.1.3
Caledonia TS	Transformer (T2) refurbishment	Hydro One	2030-2035	8.1.4
Birmingham TS	Transformer (T1) and MV Metalclad Switchgear Refurbishment	Hydro One	2030-2035	8.1.5
Gage TS	DESN (T8/T9) Refurbishment	Hydro One	2030-2035	8.1.6
Jarvis TS	Transformer (T3/T4) refurbishment	Hydro One	2030-2035	8.1.7
Area Supply Needs				
Brant Area*	Two (2) new 230kV/ 27.6 kV 200 MVA transformation facilities near the existing Brant TS.	Hydro One	2029	8.2.1
Norfolk Area	Load transfers, additional reactive support and large Battery Storage.	Hydro One	2025	8.2.2

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Section No.
Dundas Area*	Two (2) new 230kV/ 27.6 kV 200 MVA transformation facilities near existing Dundas TS.	Hydro One	2035	8.2.3
Bronte Area	To be assessed as part of the upcoming Hamilton IRRP	Hydro One	TBD	8.2.4
Station Capacity Needs				
Nebo TS (T3/T4) 13.8 kV DESN	Transformers are to be replaced based on their asset condition assessment with Hydro One standard units	Hydro One	2025	8.3.1
Mohawk TS	Load monitoring, load transfers to neighboring stations and operational measures as required. This need to be reassessed during the next regional planning cycle	Hydro One	2035	8.3.2
Newton TS	Load monitoring, load transfers to neighboring stations and operational measures. This need to be reassessed during the next regional planning cycle	Hydro One	2035	8.3.4
Nebo TS (T1/T2) 27.6 kV DESN	Load monitoring, load transfers to neighboring stations and operational measures. Additional transformation required in the forecasted timeframe south of Hamilton.	Hydro One/ Alectra	2031	8.3.5
Transmission Line Capacity Needs				
The overloading of 115 kV B2 intertie line between Brant area and Woodstock area is included as part of the Brant area and supply capacity of C9/C12 115 kV circuits as part of the Norfolk area supply needs.				
System Reliability, Operation and Load restoration Needs				
No other system reliability, operation and load restoration needs have been identified for this region				

**- New options identified during RIP phase for these needs and will be assessed as an addendum to this report.*

Note: The planned in-service dates are tentative and subject to change.

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of the Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The third cycle of the Regional Planning process for the Burlington to Nanticoke region initiated with the publication of Needs Assessment (NA) and the report published in September 2022 by Hydro One. This followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in December 2022 and November 2024 respectively, by the Independent Electricity System Operator (IESO). Typically, an IRRP takes 18 months to complete. However, due to the complex nature of the needs in the region, the IESO requested a six-month extension from the OEB to finalize the plan. The 3rd cycle IRRP did not include the assessment for Hamilton sub-region which is planned for completion in 2026 and will be an addendum to this IRRP. The LDCs supplied by Bronte TS are currently updating their load forecast. The assessment of Bronte area supply will be completed in the Hamilton IRRP addendum.

The RIP report includes a common discussion of all the options and recommended plans, and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by Burlington to Nanticoke TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDC"), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1.

Table 1: Burlington to Nanticoke Region TWG Participants

Sr. no.	Name of TWG Participants
1	Alectra Utilities Corporation
2	Burlington Hydro Inc.
3	Grand Bridge Energy Inc.
4	Hydro One Networks Inc. (Distribution)
5	Independent Electricity System Operator (IESO)
6	Oakville Hydro
7	Hydro One Networks Inc. (Lead Transmitter)

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Burlington to Nanticoke region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near- and medium- term needs (2025-2035) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2025-2035 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in Burlington to Nanticoke IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and require longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most

essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides an outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all regional needs. If no further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs are:

a) local in nature;
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

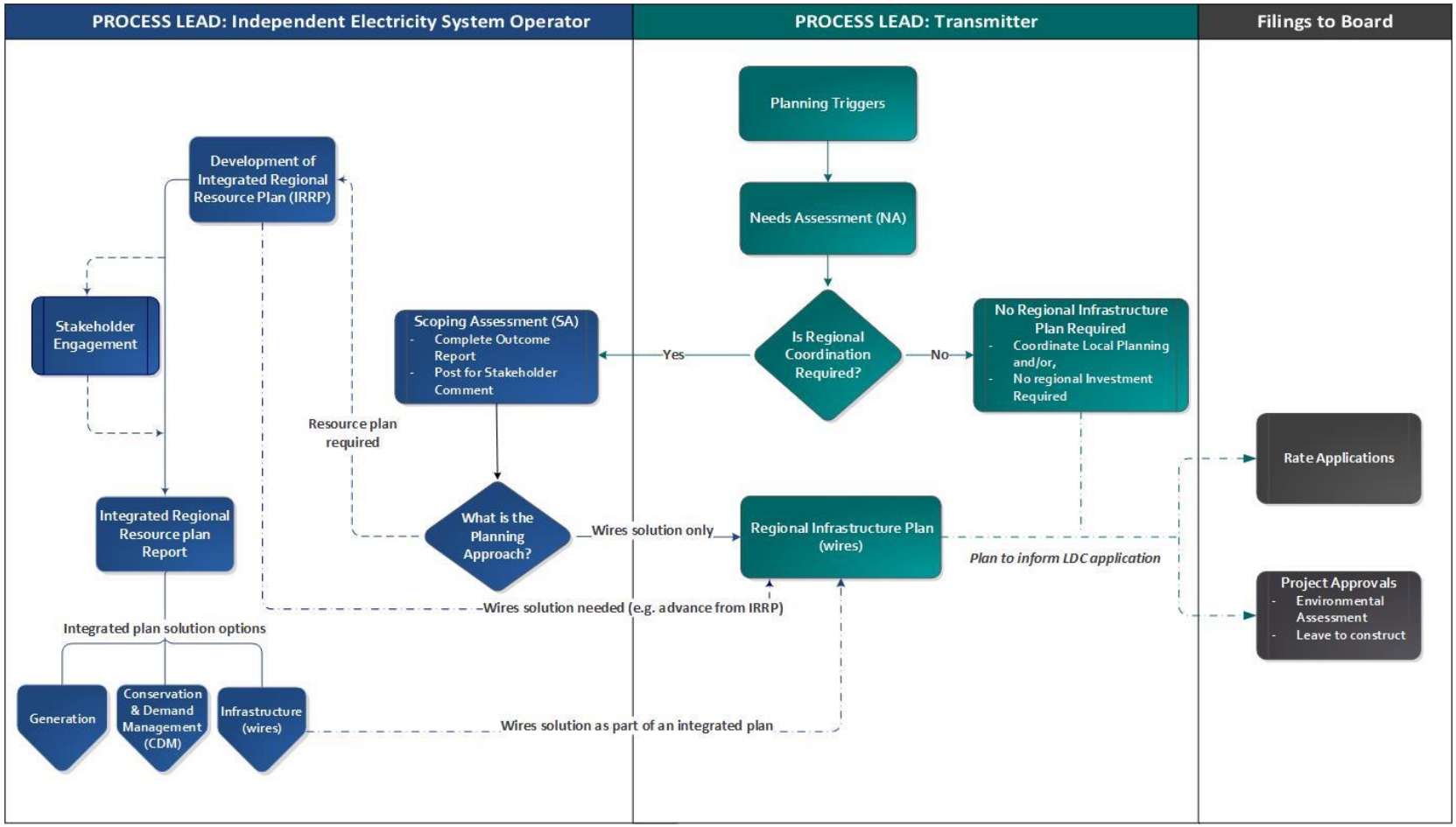
If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter, and the deliverable is a comprehensive and consolidated report of a wires plan for the

region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

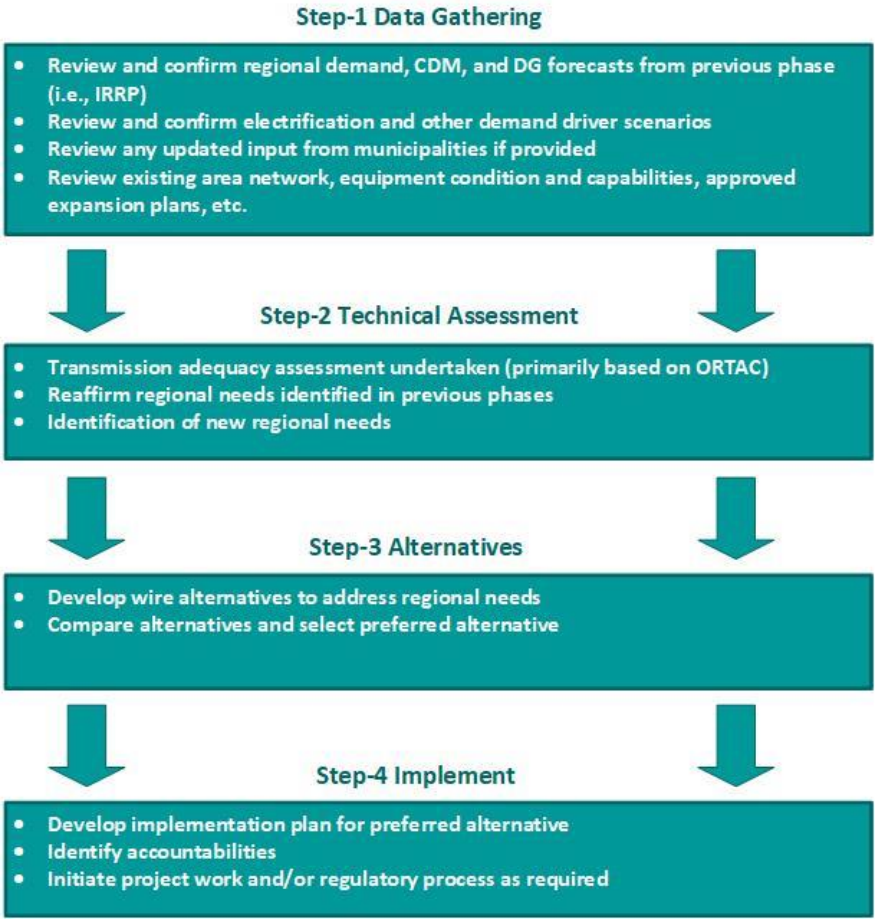
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in figure-1.

Figure-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight on the future load growth and was translated into the load forecast through inputs provided by their respective

LDCs. As agreed by TWG members, the load forecast from the IRRP to be used for this RIP unless material changes in the load forecast are envisaged.

- Review and confirm electrification and other growth scenarios which affect the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

The third step is the development of wires options to address needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

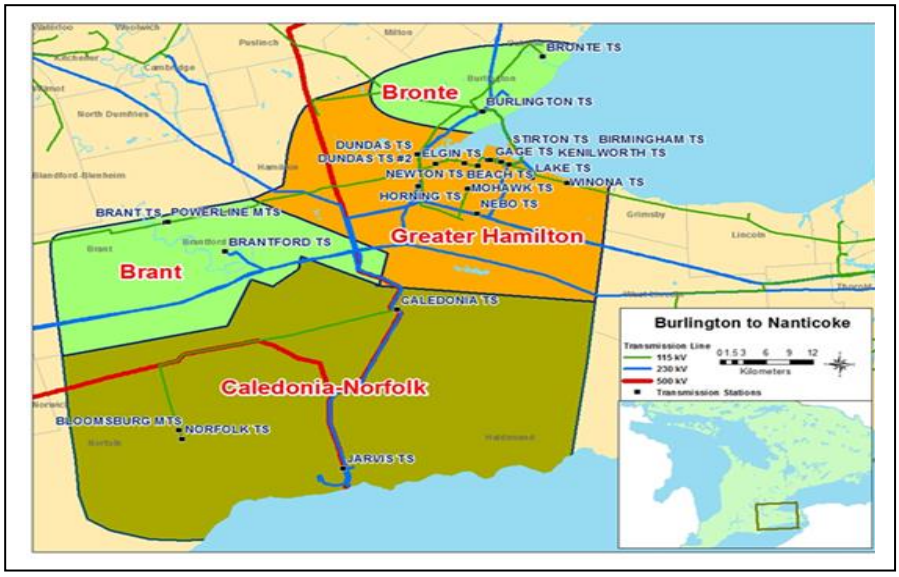
The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiating project work or obtaining permission from the Regulatory Commission, if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Burlington to Nanticoke region covers the city of Brantford, municipality of Hamilton, and counties of Brant, Haldimand and Norfolk. Portions of Burlington and Oakville south of Dundas Street are included in the Burlington to Nanticoke region up to Third Line Road in the east.

The geographical boundaries of the Burlington to Nanticoke Region are shown in Figure 3 below.

Figure 3: Map of Burlington to Nanticoke Regional Planning Area



Bulk electrical supply to the Burlington to Nanticoke Region is provided through the 500/230 kV autotransformers at Nanticoke TS and Middleport TS and 230 kV circuits from Middleport TS, Nanticoke TS and Beck TS. The 115 kV network is supplied by 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS. The area loads are supplied by a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into four sub-regions as shown in Figure 3 and described below:

The **Brant sub-region** encompasses the County of Brant, City of Brantford, and surrounding areas. Electricity supply to the sub-region is provided by:

- Brant TS and Powerline MTS are supplied by 115 kV double circuit B12BL/B13BL line and B2 single circuit line.
- Brantford TS supplied by the 230 kV double circuit transmission line M32W/M33W.

The Brant Sub-region transmission facilities are shown in Figure 3-1.

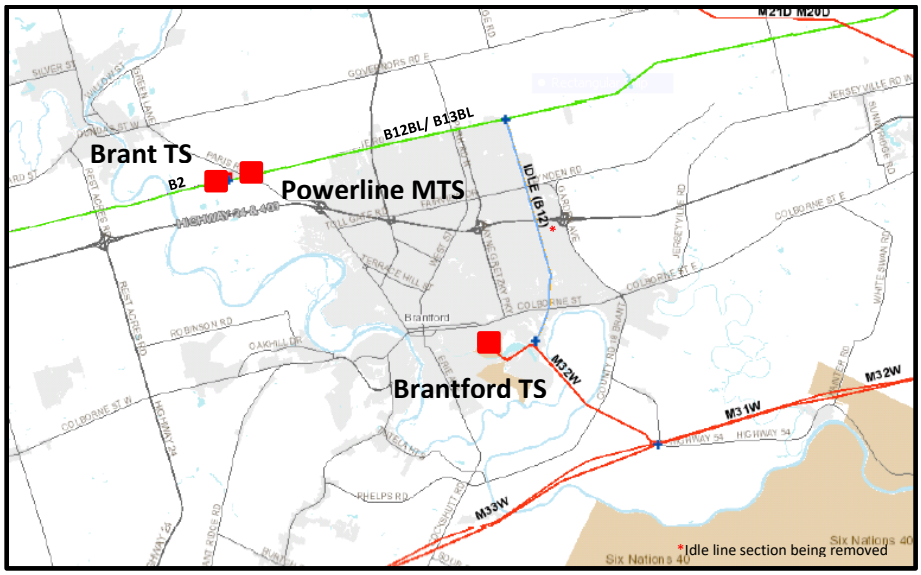


Figure 3-1 Brant sub-region

The total 2024 non-coincident peak demand for the three stations was 278 MW. GrandBridge Energy Inc. is the main LDCs that serves the electricity demand for the City of Brantford. Hydro One Distribution supplies load in the outlying areas of the sub-region. The electricity demand is comprised of residential, commercial, and industrial customers.

The **Bronte sub-region** covers the City of Burlington and the western part of the City of Oakville up to Third Line Road. Electricity supply to the sub-region is provided by:

- Bronte TS is supplied by 115 kV double circuit line B7/B8.
- Burlington TS is supplied by 230 kV double circuit line Q23BM/ Q25BM.
- Cumberland TS supplied by 230 kV double circuit transmission line B40C/ B41C.

The Bronte sub-region transmission facilities are shown in Figure 3-2.

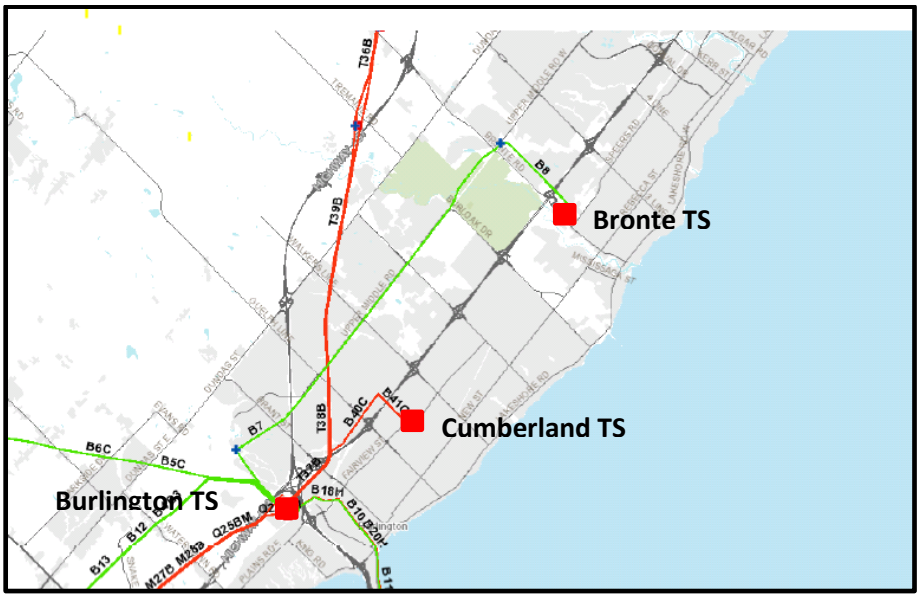


Figure 3-2 Bronte sub-region

This area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial, and industrial customers. The total 2024 non-coincident peak station demand for the three stations was 361 MW.

The **Greater Hamilton sub-region** encompasses the City of Hamilton that includes the Townships of Flamborough and Glanbrook and towns of Dundas and Stoney Creek. The electricity supply to the sub-region is as follows:

- Beach TS 115 kV area which includes four 115 kV step down stations Birmingham TS, Kenilworth TS, Stirton TS and Winona TS supplied from the 230/115 kV autotransformers at Beach TS.
- Burlington TS 115kV area which includes Dundas TS, Dundas #2, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer owned transformer station (CTS) supplied from the 230/115 kV autotransformers at Burlington TS.
- 230 kV area which includes Beach TS (T3/T4 & T5/T6 DESNs), Horning TS, Nebo TS, Lake TS and two customer owned stations supplied from 230 kV circuits connecting into Beach TS and Burlington TS.

The Greater Hamilton sub-region transmission facilities are shown in Figure 3-3.

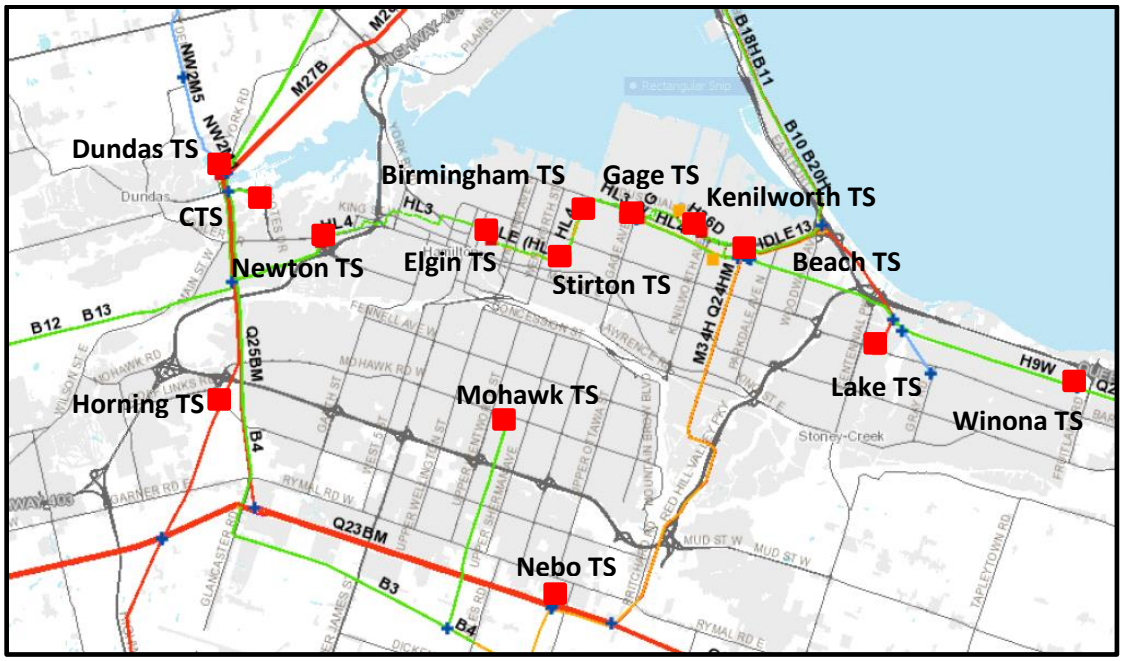


Figure 3-3 Greater Hamilton sub-region

The total 2024 non-coincident peak demand for the Greater Hamilton sub-region was 1330 MW. The area is served by Alectra Utilities, Hydro One Distribution, and CTSs comprise a significant number of large industrial customers along with commercial and residential customers.

The **Caledonia Norfolk sub-region** covers the eastern part of Norfolk County and the western part of Haldimand County. Electricity supply to the Sub-region is provided by:

- Caledonia TS supplied by 230 kV double circuit line N5M/S39M.
- Jarvis TS, a large Battery Energy Storage System (BESS) and two CTSs supplied from the 230 kV double circuit line N21J/N22J.
- One CTS is supplied from the 230 kV single circuit N20K.
- Bloomsburg DS and Norfolk TS are supplied from 115 kV double circuit transmission line C9/C12.

The Caledonia Norfolk sub-region transmission facilities are shown in Figure 3-4.

The area is served by Hydro One Distribution. The electricity demand mix is comprised of residential, commercial and industrial uses. The 2024 non-coincident peak demand for this sub-region was 429 MW.

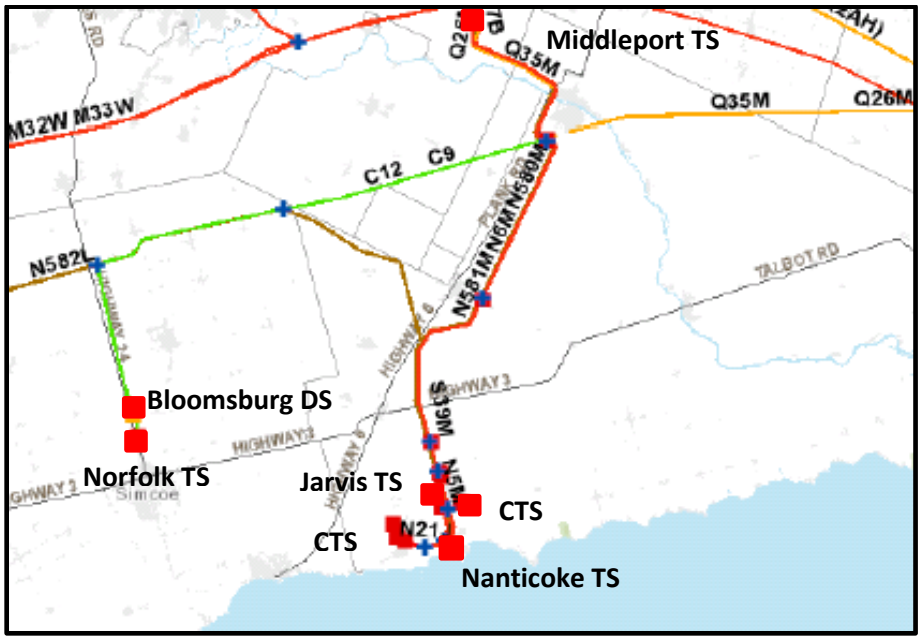


Figure 3-4 Caledonia Norfolk sub-region

The circuits and stations of the area are summarized in Table 2 below:

Table 2: Transmission Station and Circuits in the Burlington to Nanticoke region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
B10, B11, H5K, H6K, HL3, HL4, Q2AH, H9W, B12BL, B13BL, B7, B8, B5G, B6G, B3, B4, C9, C12, K1G, K2G	H35D, H36D, B18H, B20H, M34H, Q24HM, Q29HM, B40C, B41C, M27B, M28B, Q23BM, Q25BM, Q30M, M31W, M32W, M33W, M20D, M21D, N5M, N6M, S39M, K40M, N21J, N22J, N37S, N20K	Beach TS*, Birmingham TS, Bloomsburg DS, Brant TS, Brantford TS, Bronte TS, Burlington TS*, Caledonia TS*, Cumberland TS, Dundas TS, Dundas TS #2, Elgin TS, Gage TS, Horning TS, Jarvis TS, Kenilworth TS, Lake TS, Mohawk TS, Nebo TS, Newton TS, Norfolk TS, Powerline MTS, Stirton TS, Winona TS, CTS#1, CTS#2, CTS#3, CTS#4, CTS#5, CTS#6	CGS#1, CGS#2, CGS#3, CGS#4, CGS#5, BESS#1, BESS#2

*Stations with 230kV/ 115kV Autotransformers installed

The single line diagram of the Transmission Network of Burlington to Nanticoke region is shown in Figure 4 below.

Figure 4: Burlington to Nanticoke Region Transmission Single Line Diagram

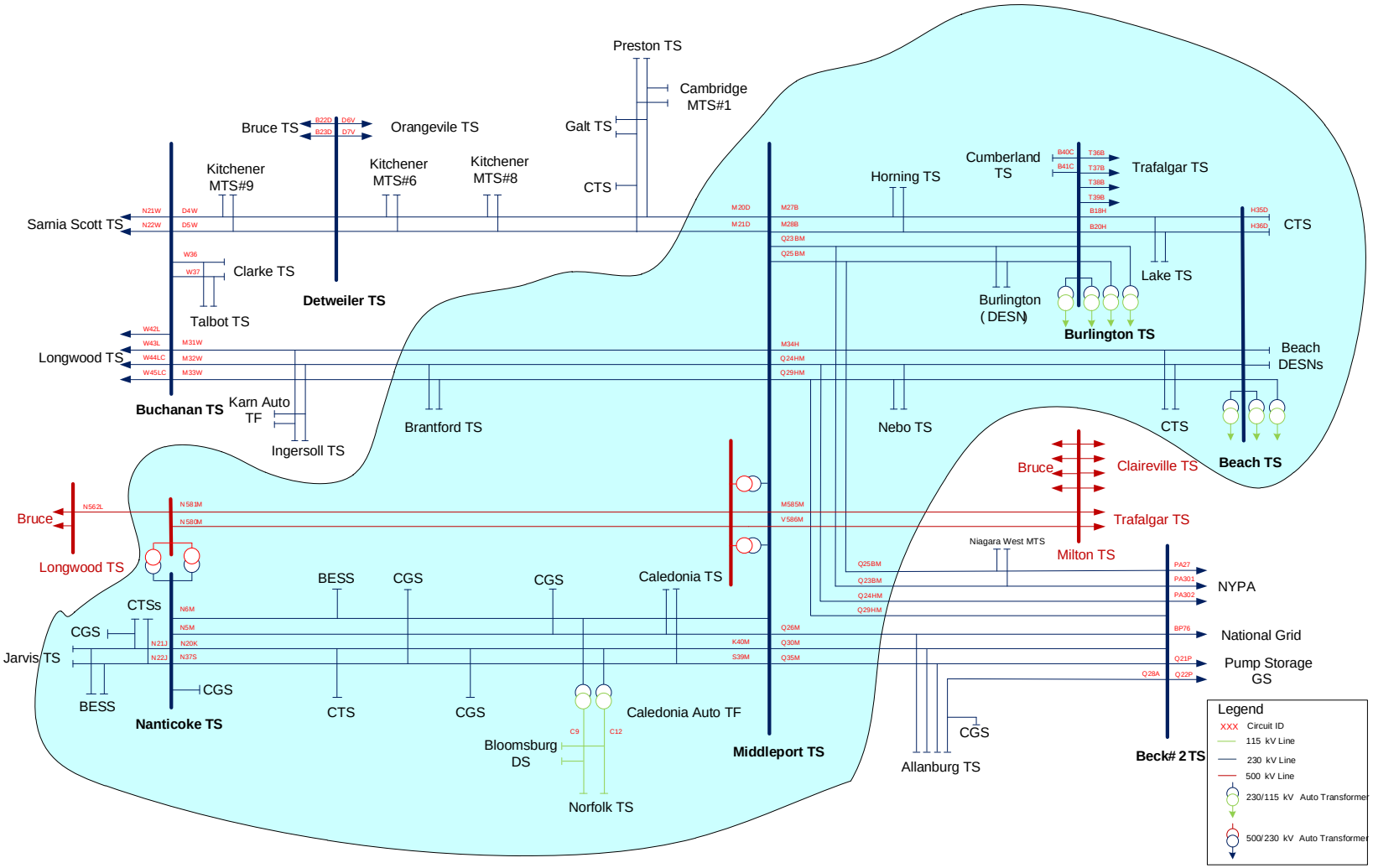
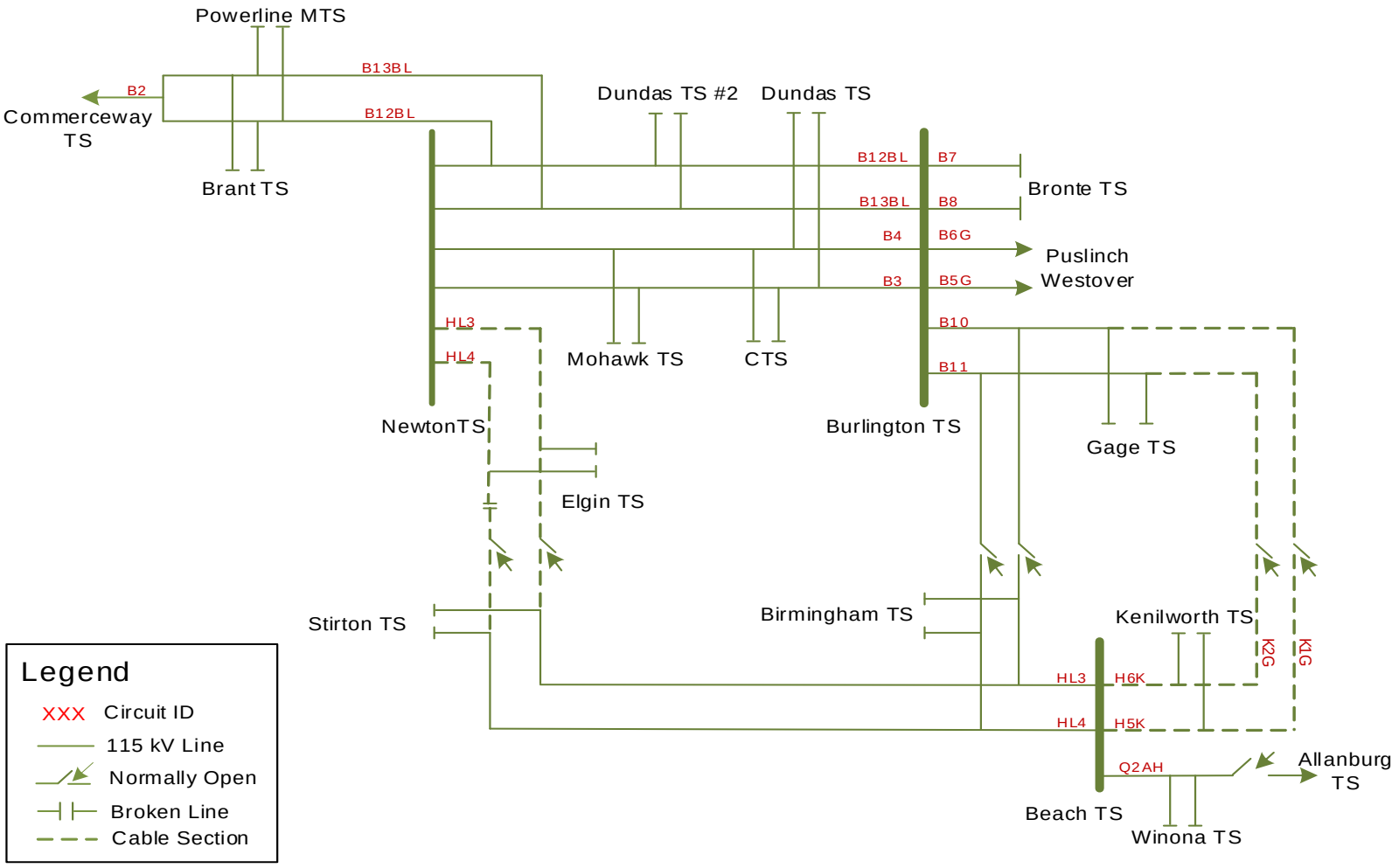


Figure 5: Burlington to Nanticoke Region Transmission Hamilton- Brant Area Single Line Diagram



5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that have been completed in the past ten years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Burlington to Nanticoke region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner (TAO) in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. The following major projects were completed during the last ten years:

i. Burlington TS (2016) – installed an additional 230 kV circuit breaker to reduce probability of the simultaneous loss of two autotransformers to improve supply reliability of the stations supplied from 115 kV bus.

ii. Transformer replacement at stations: Dundas TS T1&T2 (2015), Brant TS T1&T2 (2016), Beach TS T3&T4 (2018), Mohawk TS T1&T2 (2018) and Newton TS T1&T2 (2020).

iii. B7/B8 115 kV Transmission line capacity (2018) – addressed supply capacity constraint to Bronte TS through distribution load transfers (Ongoing)

iv. Horning TS (2018) – replaced 230/ 13.8 kV transformers (T1/T2) & LV switchgears.

v. Bronte TS (2019) – replaced 115/ 27.6 kV transformers (T5/T6) & associated LV switchgear.

vi. Brant Switching Station (2019) – installed three (3) 115 kV breakers at Brant TS integrating 115 kV B12BL/B13BL circuits with 115 kV B2 circuit from Karn TS, to provide additional supply capacity for Brant TS and Powerline MTS.

vii. Cumberland TS (2019): Power factor correction – Capacitors installed at customer level.

viii. 115 kV B3/B4 (2020): Based on asset condition assessment refurbish line section from Horning Mountain Jct. to Glanford Jct.

ix. Elgin TS (2022): Transformers & switchgear replacement based on asset condition assessment and reconfiguring from two (2) DESNs to a single DESN.

x. Kenilworth TS (2023): Transformer & switchgear replacement based on asset condition assessment and reconfiguration from two (2) DESNs to single DESN.

xi. Gage TS (2024): Transformers & switchgear replacement based on asset condition assessment, reconfiguring station from a three (3) DESNs station to a two (2) DESNs station replacing equipment based on their asset condition assessment.

II. Following Major projects are underway:

i. Kenilworth TS: Power factor correction (2025)
ii. Dundas TS: Load Balancing between DESNs (2025)
iii. Norfolk area supply capacity – Load transfer and reactive support (2026)
iv. 115 kV B7/B8: Refurbish line section from Burlington TS to Nelson Jct. (2025)
v. Beach TS: Autotransformer (T1/ T7/T8) replacement (2028)
vi. Lake TS: Transformer (T2) Replacement (2028)

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

The loading pattern for the years prior to 2024 (2019 – 2023) were impacted by COVID 19 and may not provide a good base load for future load forecasting. A new load forecast has been developed with participation of the TWG using 2024 station loads as base year, updated CDM from the IESO and revised load forecast from GrandBridge Energy. This results in a 3.2% lower load forecast than IRRP. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight into the future load growth and was translated into the load forecast through inputs provided by their respective LDCs. TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for this new Load forecast that will be used in this report.

During the study period, the load in the Burlington to Nanticoke region is expected to grow at an average annual rate of approximately 3.1% in summer from 2025 to 2035. The Region is summer peaking, so this assessment is based on summer peak loads.

Figure 5 & 6 shows the Burlington to Nanticoke region extreme summer weather net coincident and non-coincident load forecast from 2025 to 2035. The load forecasts from the Burlington to Nanticoke region were adopted as agreed by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident and coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

Figure 6: Burlington to Nanticoke region summer coincident Net Peak Load Forecast

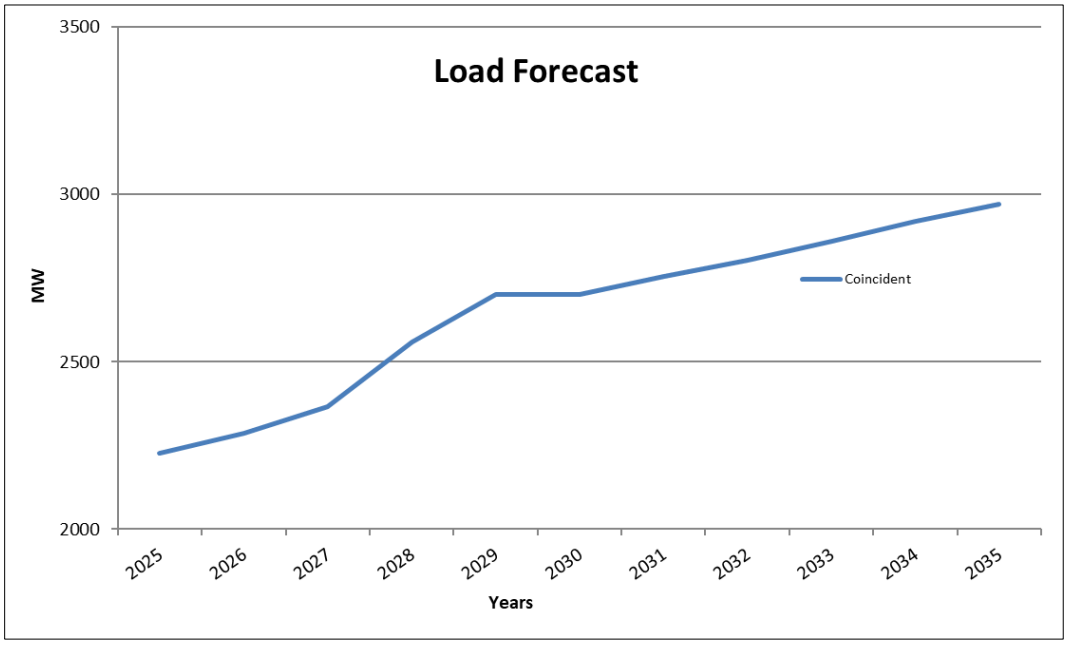
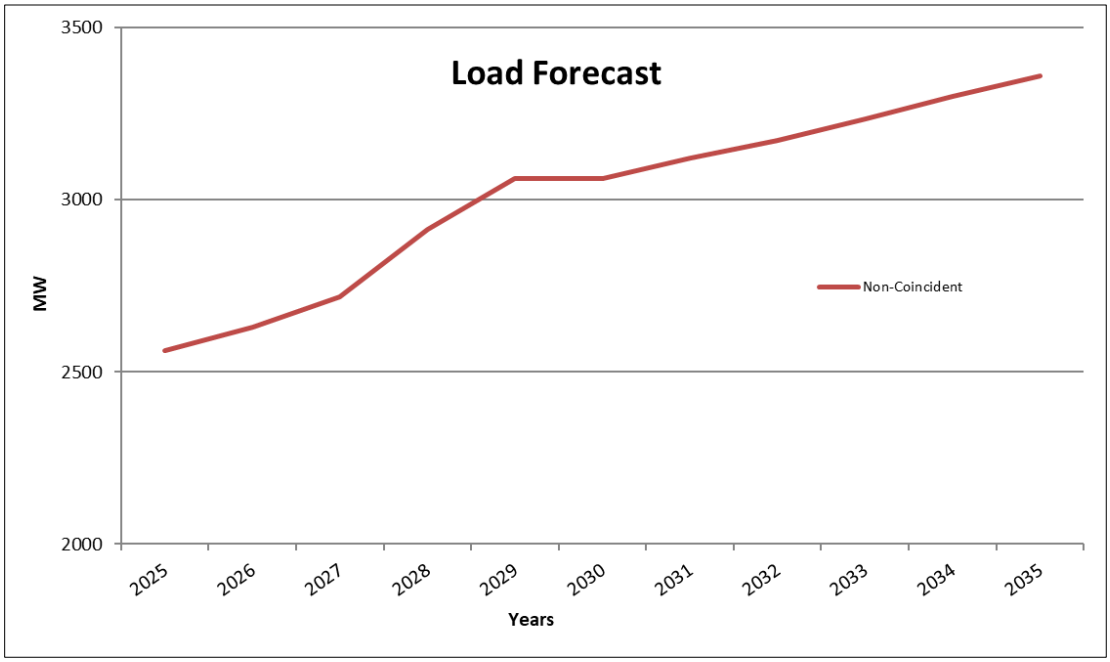


Figure 7: Burlington to Nanticoke region summer Non-coincident Net Peak Load Forecast



6.2. Other Study Assumptions

The following other actions and assumptions are made in this report.

- The study period for the RIP assessments is 2025-2035.
- Most LDCs reconfirmed and GrandBridge Energy updated the load forecast up to 2035 in the area.
- All planned facilities for which work has been initiated and are listed in section 5 are assumed to be in-service.
- The Region is peaking in summer, so this assessment is based on 2024 summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks or based on historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations uses non-coincident peak loads.
- All Battery storage projects are assumed to only charge during off-peak hours. Any future charging of these battery storage projects may impact LMC (Load Meeting Capability) of some circuits.
- Adequacy assessment is conducted as per required regulations.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying Burlington to Nanticoke region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"**, are completed.

In the current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Burlington to Nanticoke region Third cycle Needs Assessment Report, Completed in September 2022 by Hydro One
- Burlington to Nanticoke region Third cycle Scoping Assessment Report, Completed in December 2022 by the IESO

- Burlington to Nanticoke region Third cycle Integrated Regional Resource Plan Report, Completed in November 2024 by the IESO

The Technical Working Group identified several regional needs based on the forecasted demand over the near-to-mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG have also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Burlington to Nanticoke region. The complete list of major HV transmission equipment requiring replacement in the Burlington to Nanticoke region is provided in table 3 in this sub-section. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Table 3: Major HV Transmission Asset assessed for Replacement in the Region

Station/Circuit	Need Description	Planned ISD
Nebo TS	Transformer (T3/ T4) refurbishment	2030 - 2035
Lake TS	T3/T4 DESN refurbishment	2030 – 2035
Beach TS	T5/T6 DESN refurbishment	2030 – 2035
Caledonia TS	Transformer (T2) refurbishment	2030 – 2035
Birmingham TS	Transformer (T1) and MV Metalclad Switchgear refurbishment	2030 – 2035
Gage TS	T8/T9 DESN refurbishment	2030 – 2035
Jarvis TS	Transformer (T3/T4) refurbishment	2030 - 2035

The above refurbishment needs are currently planned but may be adjusted or reconsidered based on a variety of evolving factors. The refurbishment needs T12 autotransformer at Burlington TS and MV switchgear refurbishment needs at Burlington TS, Dundas TS and Norfolk TS included in the earlier phases of Regional Planning cycle fall outside the study period of this report and will be reassessed during the next planning cycle. Any refurbishment needs for 115 kV cables in the Hamilton area will be assessed as part of the upcoming Hamilton IRRP report.

Note: The planned in-service timeframe for the above projects is tentative and is subject to change.

7.2. Area Supply Needs

Over the study period 2025-2035, RIP reviewed the area supply capacity needs that include combination of both the line and station supply capacity adequacy for isolated areas with limited available transfer capacities. During the earlier phases of this regional planning cycle two such areas, i.e. Norfolk and Brant areas, were identified requiring reinforcement/s. The future station supply capacity need at Dundas TS and Dundas TS#2 are combined as a single 27.6 kV Dundas area need. After the completion of the IRRP in late 2024, Burlington Hydro and Oakville Hydro approached TWG to revise the load forecast to accommodate additional supply capacity need in the area supplied by Bronte TS.

Sr. No.	Name of Area	Need	Maximum capacity	Current loading	Need Year
1	Brant Area	Supply Capacity	134 MW	148 MW	Current and 2029[1]
2	Norfolk Area	Line supply Capacity	80 MW	101 MW	Current
3	Dundas Area	Station Capacity	188MW	151 MW	2035[2]
4	Bonte Area	TBD*	135 MW	122 MW	TBD[3]

1- LDC will transfer loads to Brantford TS to adhere to 134 MW limit. Brantford TS will reach its supply capacity by 2029, assuming no transfer constraints. Need may be sooner as load balancing between the stations may be limited due to physical constraints.

2- Need may be sooner due to load transfer constraints between the stations

3- Burlington Hydro and Oakville Hydro, the local LDCs are in the process of developing a revised load forecast

7.3. Station Capacity Needs

Over the study period 2025-2035, RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the Burlington to Nanticoke region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 4 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time ratings.

Table 4: Burlington to Nanticoke region Station Capacity Needs in the study period

Sr. No.	Station Name	Station LTR(MW) (Summer)	2024 Loading (MW) (Summer)	Need Date
1	Nebo TS (T3/T4) 13.8 kV DESN	51	52	Current*
2	Mohawk TS	90	72	2035
3	Newton TS	75	48	2035
4	Nebo TS (T3/T4) 27.6 kV DESN	178	145	2031

*- The LDC has historically maintained the load power factor closed to unity that provides a little more supply capacity, and the loading has remained around its supply capacity.

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. Transmission Line Supply Capacity Needs

Over the study period 2025-2035 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Burlington to Nanticoke region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 5 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time ratings.

Table 5: Burlington to Nanticoke region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Maximum capacity	Current loading	Need Date
The overloading of 115 kV B2 intertie line between Brant area and Woodstock area is included in Brant area supply need and the supply capacity of 115 kV C9/C12 line is included in the Norfolk area need.					

7.5. System Reliability, Operation and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The RIP further confirms that there are no violations identified in the region with regards to System Reliability, Operation and Load restoration requirements.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Burlington to Nanticoke Region. These needs include those previously identified in the NA and IRRP for the Burlington to Nanticoke Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 6 below:

Table 6: Near/ Mid-term Needs Identified in the Region

Area/ Station/Circuit	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs*			
Nebo TS	Replace T3/ T4 transformers	2030 - 2035	8.1.1
Lake TS	Replace T3/T4 transformers and switchgear	2030 - 2035	8.1.2
Beach TS	Replace T5/T6 transformers and switchgear	2030 - 2035	8.1.3
Caledonia TS	Replace T2 transformer	2030 - 2035	8.1.4
Birmingham TS	Replace T1 Transformer and MV Switchgears	2030 - 2035	8.1.5
Gage TS	Replace T8/T9 transformers and switchgear	2030 - 2035	8.1.6
Jarvis TS	Replace T3/ T4 transformers	2030 - 2035	8.1.7
Area Supply Needs			
Brant Area	Supply capacity	Current and 2029**	8.2.1
Norfolk Area	Transmission line supply capacity	Current	8.2.2
Dundas Area	Station supply capacity constraint	2035	8.2.3
Bonte Area	LDC developing load forecast to identify additional needs above current supply capacity	TBD	8.2.4
Station Capacity Needs			
Nebo TS (T3/T4) DESN	Nebo T3/T4 is a 230kV / 13.8kV DESN operating around its supply capacity for a long time	Current	8.3.1
Mohawk TS	Mohawk TS will be approaching its supply capacity by the end of study period.	2035	8.3.2
Newton TS	Newton TS is a 115kV/ 13.8 kV single DESN station supply loads in western part of city of Hamilton	2035	8.3.3

Nebo TS (T1/T2) DESN	Nebo T1/T2 is a 230kV / 27.6 kV DESN requiring additional transformation capacity in the need timeframe.	2031	8.3.4
Transmission Line Capacity Needs			
The overloading of 115 kV B2 intertie line between Brant area and Woodstock area is included in Brant area supply need and the supply capacity of C9/C12 line is included in the Norfolk area need.			
System Reliability, Operation and Load restoration Needs			
The Technical Working Group did not identify any other reliability, operation and load restoration needs for this region.			

*- The above refurbishment needs are currently planned but may be adjusted or reconsidered based on a variety of evolving factors.

**- LDC will transfer loads to Brantford TS to adhere to 134 MW limit. Need may be sooner due to physical load transfer constraints.

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

8.1.1 Nebo TS - Replace T3/ T4 Transformers

Nebo TS is located south of the city of Hamilton, having two DESNs units T1/T2 and T3/T4 supplying loads in the city of Hamilton and surrounding areas. The loads at T3/T4 13.8 kV DESN at Nebo TS has been historically around its supply capacity and is currently marginally overloaded, supplying loads of 52 MW against its supply capacity of 51 MW. The loads at this DESN are currently forecasted to grow above and beyond its supply capacity.

At this time both T3/T4 230 kV / 13.8 kV 75 MVA transformers are planned for replacement based on their asset condition assessment in the next 10 years.

Alternatives and Recommended Plan

The following alternatives are considered to address Nebo TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset conditions and would result in increased maintenance costs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T3/T4 DESN at Nebo TS. This alternative was considered but is not feasible.
- Replacement of the assets: Replace existing nonstandard 75 MVA T3/ T4 transformers with 100 MVA Hydro One standard units.

The TWG recommended that Hydro One and Alectra monitor the loading at Nebo TS T3/T4 DESN and take remedial measures, if required, until replacement of these transformers is completed. The TWG recommends that Hydro One replace T3/T4 transformers at Nebo TS with Hydro One standard 100 MVA units.

8.1.2 Lake TS - T3/ T4 DESN Refurbishment

Lake TS is located south-east of the city of Hamilton, having two DESNs units T1/T2 and T3/T4 supplying loads in the city of Hamilton and surrounding areas. T1/T2 is a 27.6 kV DESN with a current load of 49 MW having a sufficient supply capacity of 94 MW over the study period. The T3/T4 13.8 kV DESN is currently supplying 45 MW of loads having a sufficient supply capacity of 113 MW over the study period.

At this time both 230kV/13.8kV 75 MVA T3/ T4 transformers at Lake TS are planned for future replacement based on their asset condition assessment.

Alternatives and Recommended Plan

The following alternatives are considered to address Lake TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset conditions and would result in increased maintenance costs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T3/T4 DESN at Lake TS. This alternative was considered but is not feasible.
- Replacement of the assets: Replace existing nonstandard 75 MVA T3/ T4 transformers with 100 MVA Hydro One standard units.

The TWG recommends that Hydro One replace T3/T4 transformers at Lake TS with Hydro One standard 100 MVA units.

8.1.3 Beach TS - T5/T6 DESN Refurbishment

Beach TS is located inside the city of Hamilton, having two DESNs units T3/T4 and T5/T6 having supply capacities of 135 MW and 96 MW and supplying loads of 16 MW and 64 MW respectively. The supply capacities of both T3/ T4 and T5/ T6 DESNs are sufficient over the study period.

At this time both 230 kV/ 13.8 kV T5/ T6 DESN transformers have been identified by Hydro One for future replacement based on their asset condition assessment.

Alternatives and Recommended Plan

The following alternatives are considered to address Beach TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset conditions and would result in increased maintenance costs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T5/T6 DESN at Beach TS. This alternative was considered but is not feasible due to customer requirements.
- Replacement of the assets: Replace T5/T6 DESN replacing existing nonstandard 75 MVA T5/ T6 transformers with 100 MVA Hydro One standard units.

The TWG recommends that Hydro One replace T5/T6 transformers at Beach TS with Hydro One standard 100 MVA units.

8.1.4 Caledonia TS-Replace T2 Transformer

Caledonia TS is located in the Haldimand area supplying area loads. Caledonia TS is a single T1/T2 DESN station having 83 MVA transformers supplying loads of 53 MW and having a sufficient supply capacity of 99 MW over the study period.

At this time the T2 83 MVA 230 kV/ 27.6 kV transformer has been identified by Hydro One for replacement based on asset condition assessment.

Alternatives and Recommended Plan

The following alternatives are considered to address Caledonia TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance cost.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T1/T2 DESN at Caledonia TS. This alternative was considered but is not feasible as there are no nearby stations to transfer existing DESN loads.
- Replacement of the assets: Replace T2 transformer replacing existing 83 MVA transformer with a similar Hydro One standard unit.

The TWG recommends that Hydro One replace the T2 transformer at Caledonia TS with a similar sized Hydro One standard unit.

8.1.5 Birmingham TS - Replace T1 Transformer and MV Switchgears

Birmingham TS is located in the city of Hamilton, having two DESN units T1/T2 and T3/T4 of 75MVA each with supply capacities of 76 MW and 91 MW respectively which is sufficient over the study period. Birmingham TS mainly supplies a large industrial customer with unique connection requirements.

At this time, one 115 kV/ 13.8 kV transformer and three 13.8 kV MV Metalclad switchgears have been identified by Hydro One for future replacement based on asset condition assessment of these assets.

Alternatives and Recommended Plan

The following alternatives are considered to address Birmingham TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset conditions and would result in increased maintenance costs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Birmingham TS. This alternative was considered but is not feasible due to the customer's unique needs.
- Replacement of the assets: Replace the T1 transformer with a similar unit and replace three (3) Metalclad switchgears.

The TWG recommends replacing the T1 transformer and three 13.8 kV LV Metalclad switchgears at Birmingham TS to meet the unique connection needs of the customer at this station with similar equipment.

8.1.6 Gage TS - T8/T9 DESN Refurbishment

Gage TS is located inside the city of Hamilton, having two DESNs units T8/ T9 and T11/ T12 having supply capacities of 123 MW and 132 MW and supplying loads of 18 MW and 34 MW respectively. The supply capacities of both T8/ T9 and T11/ T12 DESNs are sufficient over the study period.

At this time both 115 kV/ 13.8 kV T8/T9 DESN having 120 MVA transformers have been identified by Hydro One for refurbishment.

Alternatives and Recommended Plan

The following alternatives are considered to address Gage TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset conditions and would result in increased maintenance costs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T8/T9 DESN at Gage TS. This alternative was considered but is not feasible due to customer requirements.
- Replacement of the assets: Replace T8/T9 DESN, nonstandard 120 MVA T8/ T9 transformers with 100 MVA Hydro One standard units.

TWG recommends that Hydro One replace T8/T9 DESN at Gage TS. Replacing the existing 120 MVA nonstandard transformers with Hydro One standard 100 MVA units.

8.1.7 Jarvis TS - Replace T3/ T4 Transformers

Jarvis TS is in Haldimand County, having a single T3/T4 DESN of 83 MVA 230 kV / 27.6 kV transformers supplying local area loads. Jarvis TS has a sufficient supply capacity of 99 MW over the study period.

Both 230kV/ 27.6kV 83 MVA T3/T4 transformers have been identified by Hydro One for future replacement based on asset condition assessment.

Alternatives and Recommended Plan

The following alternatives are considered to address Jarvis TS asset replacement needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset conditions and would result in increased maintenance costs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T3/T4 DESN at Jarvis TS. This alternative was considered but it is not feasible.
- Replacement of the assets: Replace existing 83 MVA T3/ T4 transformers with similar Hydro One standard units.

TWG recommends that Hydro One continue with the replacement of the T3/T4 transformers replacing existing 83 MVA transformers with similar standard Hydro One units.

8.2 Area Supply Needs

An area supply capacity assessment was performed over the study period 2025-2035 for the 115kV Brant and Norfolk areas. This included both transmission line supply capacity as well as station supply capacity needs using the summer peak load forecast developed based on the information from TWG. The local distribution companies supplying the Bronte area are working on the revised long-term load forecasts and this area will be reassessed as part of the upcoming IRRP for Hamilton sub-region.

8.2.1 Brant Area Supply

The 115 kV Brant area is supplied by two stations, Brant TS and Powerline MTS. They currently supply 69 MW and 79 MW loads and have supply capacities of 101 MW and 114 MW respectively. The area supply is limited by the capacity of its transmission system.

In the IRRP completed by the IESO, it was indicated that with the current system conditions the Brant area's supply capacity is limited to 134 MW, which is a reduction from 165 MW that was previously identified. The current total coincident peak load in the Brant area already exceeds this supply capacity of 134 MW. The supply capacity in the Brant area depends on overall system flows, loading in the Woodstock

and Hamilton areas and higher loading in Brant area may be possible depending on system conditions and loading in the Woodstock and Hamilton areas. The only nearby station where the Brant area loads can be transferred to is Brantford TS.

The combined supply capacity and loading in the Brant area and Brantford TS is as follows:

Supply Capacity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
322*	283	296	313	320	331	338	350	358	366	374	383

*- Brant TS and Powerline MTS together limited to 134 MW

The loads in the Brant area and Brantford TS are forecasted to exceed the supply capacity by 2029 if managed through load transfers. The need may arise sooner due to physical constraints in load transfers.

Alternatives, Recommended Plan and Current Status

- Maintain status quo: This alternative was considered and rejected as it does not address the Brant area's load supply needs.
- Transfer excess Brant area loads to Brantford TS: Moving loads in excess to the Brant area supply capacity to Brantford TS as much available through load transfers, keeping the Brant area loads below supply capacity. This option will require reconfiguring distribution assets by the LDCs.
- Operational Measures: Increasing Brant area's supply capacity through operational measures including but not limited to opening DB2 115 kV breaker at Brant TS on 115 kV B2 circuit and opening the LV bus-tie breakers at Brant TS and Powerline MTS
- New 230kV area supply: A new 230 kV double circuit supply is being considered North of Brant area tapping 230 kV M20D/ M21D circuits and supplying loads through two (2) new 230 kV stations in the area offloading 115 kV system.
- These following new interim options have emerged after the completion of the IRRP.
    - New 115 kV Area Supply: The Commerce Way TS to Brant TS 115 kV is a single circuit built on a double circuit tower line. An additional circuit can easily be added to the existing towers:
        i. A new approximately 30km 115kV circuit from Commerce Way TS to Brant TS connected to existing B2 115 kV circuit increasing the capacity of the B2 circuit, a super circuit option.
        ii. A new approximately 30km 115kV circuit from Commerce Way TS to Brant TS parallel to existing B2 115 kV circuit along with an additional 115 kV breaker at Brant TS creating two (2) separate circuits. This will effectively extend 115kV circuit K7 parallel to the existing B2 / K12 circuit to Brant TS. This will increase transmission supply capacity to Brant area.

      These two different options for configuring additional circuit parallel to B2, may provide sufficient capacity for the Brant area over the study period.

TWG recommends transfer of load in excess of the supply capacity from Brant area to Brantford TS along operational measures as required within the near term. TWG recommends Hydro One and GrandBridge Energy to work together for the implementation of the above recommendations. Since the capacity need is in 2029 timeframe and a 230 kV solution takes at least 5-7 years to implement. A 230kV solution alone may not be a viable alternative to meet need timelines of 2029. Since a new interim alternative has emerged the TWG further recommends assessing the new 115 kV options that may provide sufficient time for the implementation of the 230 kV solution recommended in the IRRP. The assessment of this interim solution will be published in addendum to this RIP. The TWG recommends continuing with the IRRP solution of a new 230 kV double circuit supply tapping 230 kV M20D/ M21D circuits and supplying loads through two (2) new 230 kV stations in the area offloading 115 kV system.

8.2.2 Norfolk Area Supply

The Norfolk area loads are supplied through Norfolk TS and Bloomsburg DS supplied through two 115 kV circuits from Caledonia autotransformers. The current supply capacity of the Norfolk area is limited by the two (2) 115kV circuits supplying this area, which is approximately 80 MW. Norfolk TS and Bloomsburg DS are currently supplying loads of 61MW and 41MW and have supply capacities of 97MW and 49MW respectively. The total supply capacity of Norfolk TS and Bloomsburg DS are sufficient over the study period, however load balancing between the two stations through distribution load transfers will be required. These loads already exceed the Norfolk area supply capacity of 80 MW. An earlier IESO assessment has recommended load transfers out of the Norfolk area and additional reactive support at Norfolk TS to provide local area voltage support.

Alternatives, Recommended Plan and Current Status

- Maintain status quo: This alternative was considered and rejected as it does not address the Norfolk area's load supply needs.
- Opening LV bus-tie breakers at Norfolk TS and Bloomsburg DS
- Additional Reactive Support and Load Transfers: Installing additional reactive support (capacitor bank) at Norfolk TS and moving Norfolk area loads to Jarvis TS as much is available through load transfers. This work is already in progress.
- Battery Storage in Norfolk Area: Install a new battery energy storage system close to Norfolk TS capable of providing dynamic reactive power support connecting to both 115 kV C9 and C12 circuits and offsetting area loads. Reactive support should be able to provide sufficient support to maintain adequate voltages in the Norfolk area for the loss of one of the C9/ C12 circuits under peak load conditions over the study period and beyond. Load balancing between Norfolk TS and Bloomsburg DS will be required. A sufficient sized Battery Storage System (BES) close to Norfolk TS meeting MW and MVAR requirements to allow the area load meeting capability to increase to about 150 MW. This is expected to defer the need for area transmission reinforcement well beyond the study period.
- New 230kV area supply: A new 230 kV double circuit supply extending 230 kV N21J/N22J circuits to Norfolk area supplying a new 230 kV supply station in Norfolk area.

TWG recommends continuing with the load transfers out of the Norfolk area and providing new additional reactive support at Norfolk TS, and opening the LV bus-tie breakers at Norfolk TS and Bloomsburg DS as required until a new battery energy storage system is procured capable of providing the required dynamic reactive support and providing peak load reducing function. This recommendation is in line with the IRRP completed for the Burlington to Nanticoke region led by IESO. The arrangement to install BESS to provide the above-mentioned functions will be sufficient to meet the load supply needs over the study period and beyond. The ultimate supply solution will be a new 230 kV/ station in the Norfolk area, but the need is currently beyond the foreseeable future.

8.2.3 Dundas Area Supply

The Area west of Hamilton are supplied through a 27.6 kV distribution system. Dundas TS (T1/T2) and Dundas TS #2 (T5/T6) are supplying a total peak load of 151 MW at the west end of the city of Hamilton. The total supply capacity of both stations is 188 MW with loads forecasted to reach this supply capacity by the end of the study period.

Alternatives and Recommended Plan

The following alternatives are considered to address supply for supply capacity need at these three stations:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's supply capacity needs.
- Load Transfers or Station/load consolidation: Moving excess loads to the neighboring station/s or moving all loads to neighboring station/s and retiring assets at Dundas TS or Dundas TS #2 and opening the LV bus-tie breakers at these stations.
- Two (2) New 200 MVA 230/ 27.6 kV DESNs near Dundas: The recently completed IRRP proposed two (2) new 200 MVA 230/27.6 kV stations near Dundas TS transferring all existing Dundas TS and Dundas TS#2 load to the 230 kV system to address 115 kV system future needs.
- Build New Middleport DESN south of Hamilton: This new option emerged after the completion of the IRRP. Due to forecasted load growth in the south of Dundas area a new supply station of 200 MVA in the area close to Hydro One's existing 500 kV Middleport TS may be preferrable.

TWG recommended Hydro One and Alectra to continue with load balancing between the two Dundas transformer stations and monitor the loading levels at these stations. If required, to proceed with load transfers and opening LV bus-tie breakers. TWG recommends continuing with the IRRP recommendation of building two (2) new 200 MVA transformations near Dundas TS. The alternate 200 MVA transformation location close to Middleport TS assessment will be published as an addendum to this RIP.

8.2.4 Bronte TS Area Supply

An IRRP was completed in 2016 to address the supply capacity issues for the loads supplied by Bronte TS. Bronte TS has a supply capacity of 208 MVA and is radially supplied from the double-circuit 115 kV transmission line B7/B8 originating from Burlington TS. The supply capacity from Bronte TS is limited to 135 MW as recommended by the IRRP mainly due to thermal limitations of 115kV B7/B8 supply circuits.

Recently Oakville Hydro and Burlington Hydro, the local distribution companies serving area loads, informed TWG of future additional supply capacity needs from Bronte TS.

Alternatives, Recommended Plan and Current Status

- Maintain status quo: This alternative was considered and rejected as it does not address the Bronte TS supply area's needs.
- Transfer customer load to Neighboring Stations: Moving loads in excess to the Bronte TS area supply capacity to neighboring stations.
- Upgrade 115 kV B7/B8 circuits: Upgrade the 115 kV B7/B8 3 km long line section with larger conductor.
- Additional Reactive Support: Additional reactive support at Bronte TS to maintain pre and post contingency voltages at this station.
- New 230kV area supply: A new 230 kV double circuit supply from Burlington TS, replacing the existing 115 kV circuits and transformers or a new additional 230 kV supply and station to supply additional loads.

Oakville Hydro and Burlington Hydro, the LDCs supplied by this station are working to develop a long-term load forecast for Bronte TS area to determine timeframe and amount of additional supply capacity needs. A decision can't be made until Oakville Hydro and Burlington Hydro finalize their load forecast.

TWG recommends that the additional supply capacity need of more than 135 MW at Bronte TS be assessed as part of the upcoming IRRP for Hamilton sub-region to be completed by the IESO.

8.3 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2025-2035 for the 230kV and 115kV Transforming stations in the Burlington to Nanticoke region using the summer peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified during the study period:

8.3.1 Nebo TS (T3/T4) DESN

Nebo TS is located south of the city of Hamilton, having two DESNs units T1/T2 and T3/T4 supplying loads in the city of Hamilton and surrounding areas. The current loads at T3/T4 13.8 kV DESN is 52 MW and have been historically around the same level against its supply capacity of 51MW. The loads at this DESN are currently forecasted to grow well above its supply capacity.

At this time both T3/T4 230 kV / 13.8 kV 75 MVA Hydro One nonstandard transformers have been identified by Hydro One for future replacement based on their asset condition assessment.

Alternatives and Recommended Plan

The following alternatives are considered to address Nebo TS supply capacity needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance cost.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T3/T4 DESN at Nebo TS. This alternative was considered but is not feasible.
- Opening LV bus-tie breakers at Nebo T3/T4 DESN and transferring excess loads to neighboring stations
- Replacement of the assets: Replace existing nonstandard 75 MVA T3/ T4 transformers with 100 MVA Hydro One standard units.

The TWG recommends that Hydro One and Alectra monitor the loading at Nebo TS T3/T4 DESN and take remedial measures like transferring excess loads and opening the LV bus-tie breaker, if required, until replacement of these transformers is completed. Hydro One would replace the existing 75 MVA nonstandard transformers with Hydro One standard 100 MVA units providing sufficient supply capacity over the foreseeable future.

8.3.2 Mohawk TS

Mohawk TS is a single DESN 115kV / 13.8 kV station located in the city of Hamilton. This station has a supply capacity of 90 MW and currently supplying about 72MW of loads. The station is forecasted to approach its supply capacity by the end of the study period.

Alternatives and Recommended Plan

The following alternatives are considered to address Mohawk TS supply capacity needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's supply capacity needs at this station.
- Load Transfers or Station/load consolidation: Moving excess loads to the neighboring station/s or moving all loads to neighboring station/s and retiring Mohawk TS. This alternative was considered but is not feasible as there are no nearby station/s having sufficient surplus capacity to accommodate these loads.
- Opening LV bus-tie breakers at Mohawk TS
- Additional Station Supply: Replace existing 75 MVA transformers with 100 MVA Hydro One standard units.

TWG recommends that Hydro One and Alectra monitor the loading at Mohawk TS as the supply capacity need is close to the end of the study period and open the LV bus-tie breaker at this station, if required. This need will be again reassessed during the next regional planning cycle.

8.3.3 Newton TS

Newton TS is a single DESN 115kV / 13.8 kV station located in the city of Hamilton. This station has a supply capacity of 75 MW and currently supplying about 48MW of loads. The station is forecasted to be approaching its supply capacity by the end of the study period.

Alternatives and Recommended Plan

The following alternatives are considered to address Newton TS supply capacity needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's supply capacity needs at this station.
- Load Transfers or Station/load consolidation: Moving excess loads to the neighboring station/s or moving all loads to neighboring station/s and retiring Newton TS. This alternative was considered but is not feasible as there are no nearby station/s having sufficient surplus capacity to accommodate these loads.
- Opening LV bus-tie breakers at Newton TS
- Additional Station Supply: Replace existing 75 MVA transformers with 100 MVA Hydro One standard units.

TWG recommends that Hydro One and Alectra monitor the loading at Newton TS as the need is close to the end of the study period and open the LV bus-tie breaker, if required. This need will be again reassessed during the next regional planning cycle.

8.3.4 Nebo TS (T1/T2) DESN

Nebo TS is located south of the city of Hamilton, having two DESNs units T1/T2 and T3/T4 supplying loads in the city of Hamilton and surrounding areas. The current loading at T1/T2 27.6 kV DESN is 145 MW having a supply capacity of 178MW. The loads at this 27.6 kV DESN are forecasted to reach its supply capacity by 2031.

Alternatives and Recommended Plan

The following alternatives are considered to address Nebo TS supply capacity needs:

- Maintain status quo: This alternative was considered and rejected as it does not meet customer needs.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring T1/T2 DESN at Nebo TS. This alternative was considered but is not feasible.
- Transferring loads to neighboring stations and opening LV bus-tie breakers at Nebo T1/T2 DESN

The TWG recommends that Hydro One and Alectra monitor the loading at Nebo TS T1/T2 DESN and take remedial measures like transferring loads to neighboring stations and opening the LV bus-tie breaker, if required.

8.4 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2025-2035 for the 115kV Transmission line circuits in the Burlington to Nanticoke region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater for this need. The TWG identified overloading of 115 kV B2 intertie line between Brant and Woodstock area which is studied as part of the Brant area supply needs and the supply capacity need of 115 kV C9/C12 circuits as part of the Norfolk area study.

8.5 System Reliability, Operation and Restoration Needs

The Technical Working Group did not identify any restoration needs during this regional planning cycle.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for Burlington to Nanticoke region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon [2025-2035] are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 7: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD
Asset Renewal Needs			
Nebo TS	Replace T3/ T4 transformers	Hydro One	2030-2035
Lake TS	Replace T3/T4 transformers and switchgear	Hydro One	2030-2035
Beach TS	Replace T5/T6 transformers and switchgear	Hydro One	2030-2035
Caledonia TS	Replace T2 transformer	Hydro One	2030-2035
Birmingham TS	Replace T1 Transformer and MV Switchgears	Hydro One	2030-2035
Gage TS	Replace T8/T9 transformers and switchgear	Hydro One	2030-2035
Jarvis TS	Replace T3/ T4 transformers	Hydro One	2030-2035
Area Supply Needs			
Brant Area	Two (2) new 230kV/ 27.6 kV 200 MVA transformation facilities near the existing Brant TS.	Hydro One/ GBE	2029
Norfolk Area	Battery Storage along with load transfers, additional reactive support and operational measures.	Hydro One	2025
Dundas Area	Two (2) new 230kV/ 27.6 kV 200 MVA transformation facilities near existing Dundas TS.	Hydro One/ Alectra	2035
Bonte Area	LDC developing load forecast to identify additional need above current supply capacity	Hydro One/ Oakville Hydro/ Burlington Hydro	TBD
Station Capacity Needs			
Nebo TS (T3/T4) DESN	Nebo T3/T4 is a 230kV / 13.8kV DESN transformers to be replaced with Hydro One standard 100 MVA units. In the meantime, operational measures, if required	Hydro One/ Alectra	Current
Mohawk TS	The loading at this station to be monitored and as required excess load transferred to neighboring station/s along with operational measures, if required	Hydro One/ Alectra	2035
Newton TS	The loading at this station to be monitored and as required excess load transferred to neighboring station/s along with operational measures, if required	Hydro One/ Alectra	2035
Nebo TS (T1/T2) DESN	Nebo T1/T2 is a 230kV / 27.6kV DESN. The loading at this station to be monitored and as required excess	Hydro One	2031

Station/Circuit Name	Recommended Plan	Lead	Planned ISD
	load transferred to neighboring station/s along with operational measures, if required		
Transmission Line Capacity Needs			
The Technical Working Group did not identify any other line capacity needs. The overloading of 115 kV B2 intertie line between Brant area and Woodstock area is included in Brant area supply need.			
System Reliability, Operation and Load restoration Needs			
The Technical Working Group did not identify any reliability, operation and load restoration needs for this region.			

Note: The planned in-service dates are tentative and subject to change.

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Burlington to Nanticoke 3rd Cycle Needs Assessment (NA) Report

[6] Burlington to Nanticoke region Integrated Regional Resource Planning (IRRP) Report

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: Burlington to Nanticoke region – Summer Coincident- Net Load Forecast

Area	Station	LTR	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Brant 115 kV	Brant TS (T1 / T2)*	101	64	64	57	57	56	56	55	54	54	53	53
	Powerline MTS (T1 / T2)*	114	46	51	56	55	57	56	55	53	52	51	50
Brant 230 kV	Brantford TS (T3 / T4)*	188	146	151	168	176	185	193	206	215	223	232	242
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	193	107	106	104	103	102	101	100	99	98	97	97
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	116	116	116	117	118	120	121	123	124	127	130
	Cumberland TS (T3 / T4)	174	81	81	81	81	81	82	83	84	84	86	88
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	12	12	12	13	13	14	14	14	15	16	16
	Birmingham TS (T3 / T4)	91	59	59	59	60	60	61	61	61	62	63	64
	Dundas TS (T1 / T2)	99	94	93	92	92	92	92	92	92	93	93	95
	Dundas TS #2 (T5 / T6)	89	49	69	68	67	67	67	67	67	68	69	70
	Elgin TS (T1 / T2)	134	78	82	84	88	88	90	91	92	93	95	98
	Gage TS (T8/ T9)	123	12	12	12	12	13	13	13	13	13	13	13
	Gage TS (T11/ T12)	132	22	23	24	24	25	26	26	27	27	27	28
	Kenilworth TS (T2 / T3)	124	26	26	26	26	26	26	26	26	26	26	27
	Mohawk TS (T1 / T2)	90	65	66	67	68	69	70	71	71	73	74	77
	Newton TS (T1 / T2)	75	49	54	57	58	60	60	61	62	64	65	67
	Stirton TS (T3 / T4)	112	52	52	52	53	54	55	55	56	57	58	60
	Winona TS (T1 / T2)	89	49	49	48	47	47	48	48	49	50	51	52
	CTS		32	32	32	32	32	32	32	32	32	32	32
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	10	11	11	11	11	11	12	12	12	12	13
	Beach TS (T5 / T6)	91	41	41	43	43	44	44	45	45	46	47	48
	Horning TS (T3 / T4)	107	58	59	59	60	61	62	62	63	64	66	68
	Lake TS (T1 / T2)	94	42	42	43	43	44	44	45	45	46	47	49
	Lake TS (T3 / T4)	113	38	41	43	44	45	46	46	47	48	49	51
	Nebo TS (T1/T2)	178	126	133	137	141	144	148	152	155	159	161	163
	Nebo TS (T3 / T4)	51	45	46	46	47	48	48	49	50	51	52	53
	CTS		321	321	321	471	561	510	510	510	510	510	495
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)**	97	54	54	54	53	55	55	59	59	59	59	60
	Bloomsburg DS (T1/T2)**	49	36	36	35	35	35	35	35	35	37	37	38
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	50	59	61	61	63	65	66	67	68	74	75
	Jarvis TS (T3/T4)**	99	36	37	37	37	37	37	38	38	38	39	39
	CTS		210	211	261	286	311	336	361	386	411	436	461

**- Temporary load transfers from Brant TS and Power line MTS keeping loads below Brant area supply capacity.*

***- Load transfers from Norfolk TS and Bloomsburg DS to Jarvis TS as one of the measures to reduce loads in Norfolk area.*

Table A.2: Burlington to Nanticoke region – Summer non-Coincident – Net Load Forecast

Area	Station	LTR	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Brant 115 kV	Brant TS (T1 / T2)	101	69	69	62	61	60	60	59	58	58	57	57
	Powerline MTS (T1 / T2)	114	52	58	64	63	65	64	63	61	60	58	57
Brant 230 kV	Brantford TS (T3 / T4)	188	162	168	187	196	205	215	229	239	248	259	270
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	193	125	124	122	121	119	118	117	116	115	114	114
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	128	128	129	129	130	132	134	136	137	140	144
	Cumberland TS (T3 / T4)	174	122	122	122	122	123	124	125	126	127	129	132
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	12	13	13	14	14	14	15	15	16	16	17
	Birmingham TS (T3 / T4)	91	62	63	63	63	64	64	65	65	66	67	68
	Dundas TS (T1 / T2)	99	105	107	106	106	106	106	106	106	107	107	109
	Dundas TS #2 (T5 / T6)	89	56	76	75	74	74	74	74	74	75	76	77
	Elgin TS (T1 / T2)	134	81	85	88	91	92	93	94	95	97	99	102
	Gage TS (T8/ T9)	123	19	20	20	20	21	21	22	22	22	22	22
	Gage TS (T11/ T12)	132	37	38	39	40	41	42	44	44	45	45	46
	Kenilworth TS (T2 / T3)	124	50	50	50	51	51	52	52	53	53	54	55
	Mohawk TS (T1 / T2)	90	76	77	78	79	80	81	82	83	85	87	89
	Newton TS (T1 / T2)	75	55	60	64	65	66	67	68	69	71	72	75
	Stirton TS (T3 / T4)	112	52	52	52	53	54	55	55	56	57	58	60
	Winona TS (T1 / T2)	89	53	52	51	51	50	51	51	52	53	54	56
	CTS		32	32	32	32	32	32	32	32	32	32	32
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	17	17	17	18	18	18	19	19	20	20	21
	Beach TS (T5 / T6)	91	66	67	69	70	71	71	72	73	74	76	78
	Horning TS (T3 / T4)	107	71	72	73	74	75	76	77	78	80	81	84
	Lake TS (T1 / T2)	94	52	53	53	54	54	55	56	56	57	59	60
	Lake TS (T3 / T4)	113	47	51	53	55	56	57	57	58	60	61	63
	Nebo TS (T1/T2)	178	153	161	166	170	174	178	181	185	188	191	193
	Nebo TS (T3 / T4)	51	55	56	56	57	58	59	59	60	61	62	64
	CTS		321	321	321	471	561	510	510	510	510	510	495
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	60	59	59	58	60	60	65	65	65	65	67
	Bloomsburg DS (T1/T2)	49	39	39	39	39	39	39	39	39	41	41	41
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	53	62	63	64	66	68	69	71	72	78	79
	Jarvis TS (T3/T4)	99	69	69	70	70	70	71	71	72	72	73	74
	CTS		210	211	261	286	311	336	361	386	411	436	461

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Beach TS	230	Beach TS 230 kV Bus[1]
2	Birmingham TS	115	HL3, HL4
3	Bloomsburg DS	115	C9, C12
4	Brant TS	115	B12BL, B13BL
5	Brantford TS	230	M32W, M33W
6	Bronte TS	115	B7, B8
7	Burlington TS DESN	230	Q23BM, Q25BM
8	Caledonia TS	230	N5M, S39M
9	Cumberland TS	230	B40C, B41C
10	CTS#1	230	Q24HM, Q29HM
11	CTS#2	230	H35D, H36D
12	CTS#3	230	N20K
13	CTS#4	230	N21J, N22J
14	CTS#5	230	N21J, N22J
15	CTS#6	115	B3, B4
16	Dundas TS	115	B3, B4
17	Dundas TS #2	115	B12BL, B13BL
18	Elgin TS	115	HL3, HL4
19	Gage TS	115	B10, B11
20	Horning TS	230	M27B, M28B
21	Jarvis TS	230	N21J, N22J
22	Kenilworth TS	115	H5K, H6K
23	Lake TS	230	B18H, B20H
24	Mohawk TS	115	B3, B4
25	Nebo TS	230	Q24HM, Q29HM
26	Newton TS	115	Newton TS 115 kV Bus[2]
27	Norfolk TS	115	C9, C12
28	Powerline MTS	115	B12BL, B13BL
29	Stirton TS	115	HL3, HL4
30	Winona TS	115	Q2AH

(1) Beach TS 230 kV bus is supplied by five 230 kV B18H, B20H, Q24HM, Q29HM and M34H circuits
(2) Newton TS 115 kV bus is supplied by four 115 kV B3, B4, B12BL and B13BL circuits

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Beach TS - CTS	H35D, H36D	230
2	Beach TS - Burlington TS	B18H, B20H	230
3	Beach TS - Middleport TS	M34H	230
4	Beach TS - Middleport TS - Beck #2 TS	Q24HM, Q29HM	230
5	Burlington TS - Cumberland TS	B40C, B41C	230
6	Burlington TS - Middleport TS	M27B, M28B	230
7	Burlington TS - Middleport TS - Beck #2 TS	Q23BM, Q25BM	230
8	Middleport TS - Beck #2 TS	Q30M	230
9	Middleport TS - Buchanan TS	M31W, M32W, M33W	230
10	Middleport TS - Detweiler TS	M20D, M21D	230
11	Middleport TS - Nanticoke TS	N5M, N6M	230
12	Middleport TS - Summerhaven SS	S39M	230
13	Middleport TS - Sandusk SS	K40M	230
14	Nanticoke TS - Jarvis TS	N21J, N22J	230
15	Summerhaven SS - Nanticoke TS	N37S	230
16	Sandusk SS - Nanticoke TS	N20K	230
17	Beach TS - Gage TS	B10, B11	115
18	Beach TS - Kenilworth TS	H5K, H6K	115
19	Beach TS - Newton TS	HL3, HL4	115
20	Beach TS - Winona TS	Q2AH	115
21	Beach TS - CSS	H9W	115
22	Burlington TS - Brant TS	B12BL, B13BL	115
23	Burlington TS - Bronte TS	B7, B8	115
24	Burlington TS - Cedar TS	B5G, B6G	115
25	Burlington TS - Newton TS	B3, B4	115
26	Caledonia TS - Norfolk TS	C9, C12	115
27	Kenilworth TS - Gage TS (Idle)	K1G, K2G	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Alectra Utilities Corporation
2	Burlington Hydro Inc.
3	Grand Bridge Energy Inc.
4	Hydro One Networks Inc. (Distribution)
5	Oakville Hydro

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	City of Brantford
2	City of Hamilton
3	Brant County
4	Haldimand County
5	Norfolk County
6	City of Burlington
7	City of Oakville (partial)

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor

Acronym	Description
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station
TWG	Technical Working Group

Ottawa Area Integrated Regional Resource Plan

July 31, 2025

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List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
BESS	Battery Energy Storage System
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
eDSM	Electricity Demand Side Management
EV	Electric Vehicle
FIT	Feed-in-Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
ISD	In-Service Date
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAPS	Local Achievable Potential Study
LDC	Local Distribution Company
LDV	Light-Duty Vehicles
LMC	Load Meeting Capability
LTR	Limited Time Rating

Acronym	Definition
MTS	Municipal Transformer Station
MVA	Megavolt Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SCADA	Supervisory Control and Data Acquisition
TS	Transformer Station
ULO	Ultra-Low Overnight

Executive Summary

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Ottawa Area Sub-Region over a 20-year horizon. Developed by the Independent Electricity System Operator (IESO) in collaboration with Hydro Ottawa Limited (Hydro Ottawa), Hydro One Networks Inc. (Distribution), and Hydro One Networks Inc. (Transmission), the plan outlines recommendations to ensure a reliable and cost-effective electricity supply that can support continued economic development and the City of Ottawa's decarbonization objectives.

The Ottawa Area Sub-Region includes the City of Ottawa and the Village of Casselman, and falls within the traditional territory of the Algonquins of Ontario, Kitigan Zibi Anishinabeg, Pikwakanagan First Nation, and Métis Nation of Ontario Region 5. This plan is part of Ontario's broader regional planning framework, now in its third cycle, and reflects the coordinated input of local distribution companies, transmission asset owners, and regional stakeholders.

The need for this IRRP was confirmed through the Scoping Assessment, which identified the Ottawa Area Sub-Region as requiring regional coordination and consideration of non-wires alternatives. The plan is shaped by the City's electrification and decarbonization targets, customer connection requests, and ongoing engagement with groups such as Invest Ottawa. These drivers signal a broader shift toward city-wide energy transformation, with particularly strong momentum in areas like Kanata-Stittsville.

This IRRP marks a notable evolution in planning by integrating electrification as a core assumption from the outset. Load forecasting was developed in collaboration with Hydro Ottawa and Hydro One Distribution, incorporating multiple scenarios with varying degrees of electrification. The selected reference forecast balances feasibility and risk, and reflects a likely trajectory of sustained load growth, winter-peaking demand, and increased system complexity.

In response, the plan provides a flexible sequence of near-, medium-, and long-term actions designed to manage uncertainty while ensuring the system remains prepared to accommodate growth. It reflects established planning best practices, including ongoing adaptation to evolving conditions. Key near-term investments include new transformer stations, line upgrades, and system reinforcements to address station and system capacity needs, asset replacement, and load security and restoration concerns.

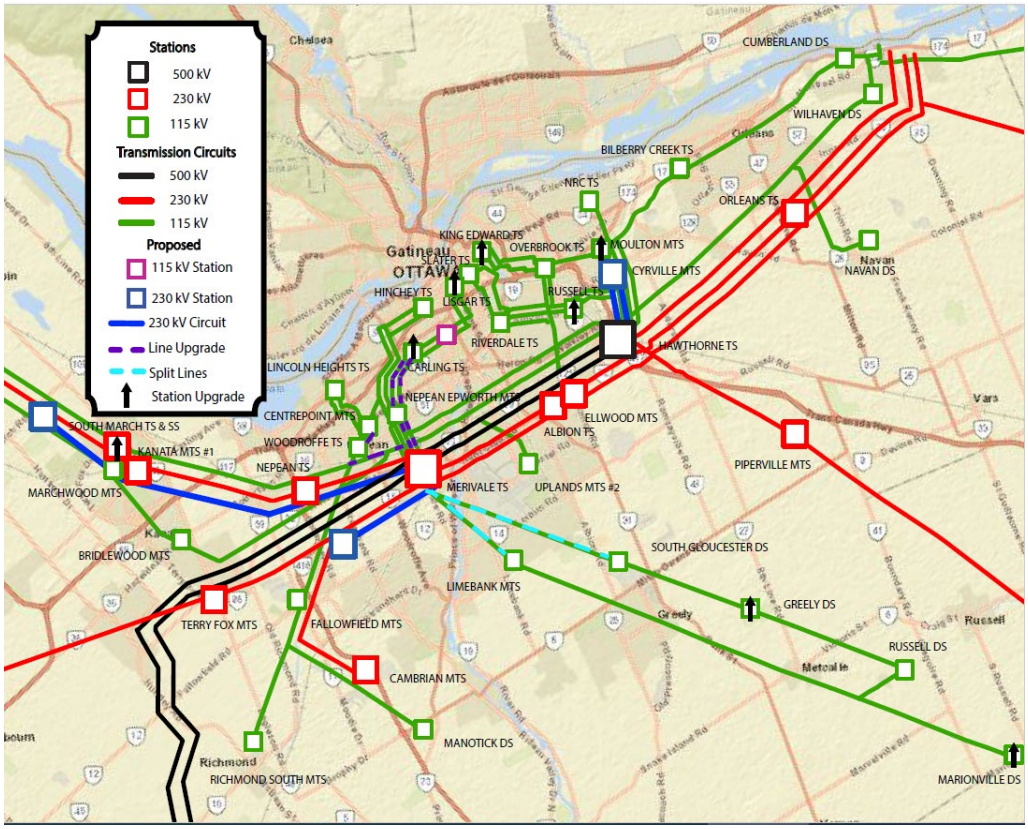
Non-wires solutions play an increasingly important role in the plan. Several large-scale Battery Energy Storage System (BESS) projects identified through the IESO's Long-Term Procurement I (LT1) will enhance reliability, voltage performance, and system resilience. In parallel, the Local Achievable Potential Study (LAPS) will inform targeted demand-side measures that may defer or reduce the need for major infrastructure upgrades, especially in the downtown core.

The recommendations outlined in this IRRP represent a balanced, cost-effective path forward that supports Ottawa's growth while maintaining reliability and customer value. Annual monitoring of load growth and system conditions will inform future updates and help determine when to initiate the next regional planning cycle. A summary of the recommendations can be seen in **Figure 1.**

In summary, the plan proposes to:

- Build new or upgrade Transformation Stations to increase station capacity:
    - Three new 230 kV stations: Kanata North area, Core West area and Cyrville MTS (converted from 115 kV)
    - One new 115 kV station: Core East area (a new MTS by converting from existing distribution station)
    - Station upgrades: Carling TS, Lisgar TS, King Edward TS, Moulton MTS, Russell TS, Greely DS, South March TS and Marionville DS
- Build new or upgrade transmission lines to connect new stations and increase System Capacity:
    - Two new 230 kV transmission lines to connect new stations (Kanata North and Core West areas) from Merivale TS
    - A new 230 kV switching station in Kanata North area
    - 115 kV transmission line uprating: portions of M4G and M5G
- Modify connection configuration to improve load security:
    - Install new circuit breaker at Merivale TS and separate L2M and M1R
    - Provide second supply to Nepean TS via new transmission circuit from Merivale TS.
- Transfer load between stations through the distribution system to balance and optimize the utilization of station capacity
- Integrate the eDSM program opportunities identified as part of LAPS
- Formalize adaptive pathways for each subsystem

Figure 1 | Map of Recommendations for Ottawa Area Sub-Region



1. Introduction

This IRRP documents the recommendations required to address the electricity needs for the Ottawa Area Sub-Region over the next 20 years. It was prepared by the IESO on behalf of a technical working group (Working Group) composed of the IESO, Hydro Ottawa, Hydro One Distribution, and Hydro One Transmission. Hydro Ottawa, a municipally owned utility that operates in the City of Ottawa (City) and in the Village of Casselman, and Hydro One Distribution are local distribution companies (LDCs) that serve customers in the sub-region. Hydro One is the transmission asset owner in the sub-region.

This sub-region also includes the following First Nations and Métis Nation of Ontario councils:

- Algonquins of Ontario
- Kitigan Zibi Anishinabeg
- Pikwakanagan First Nation
- Métis Nation of Ontario Region 5

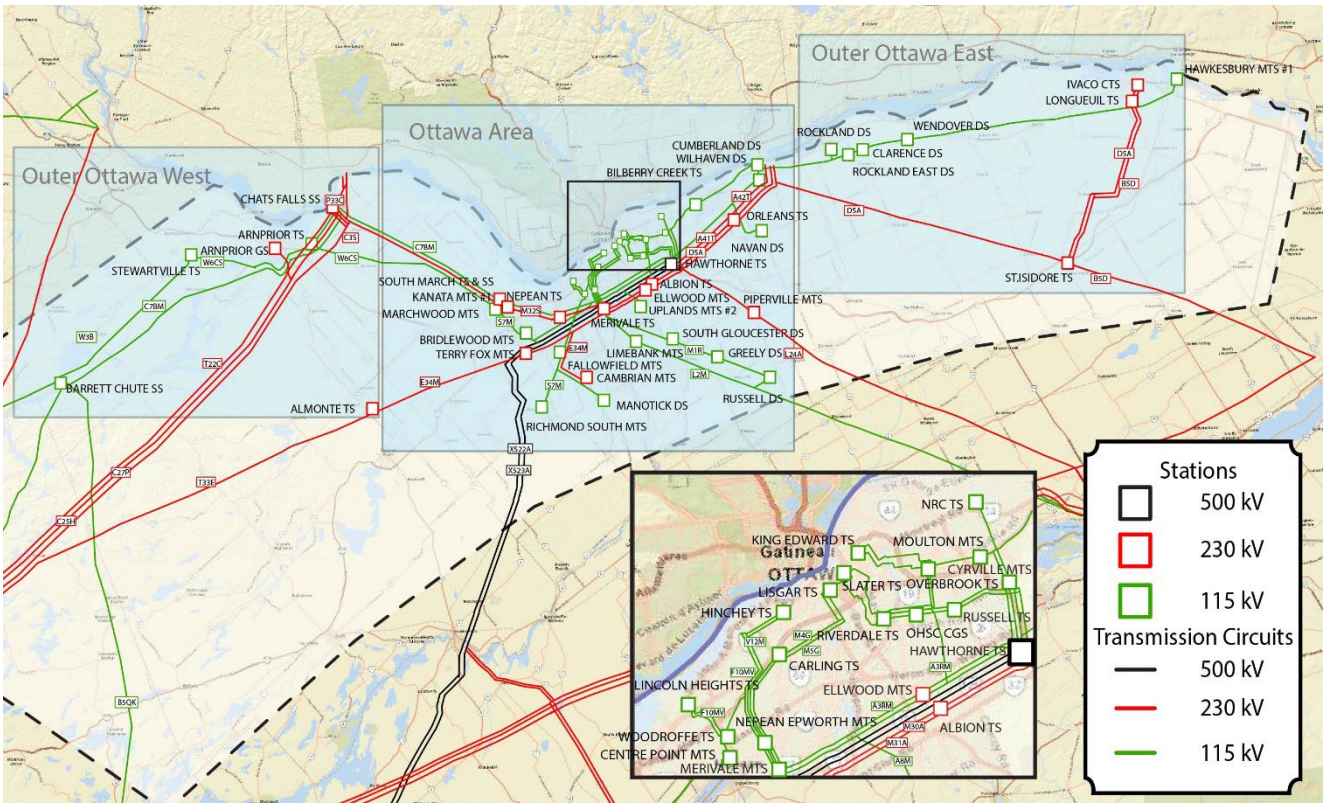
In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributers, and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. This is the third cycle of regional electricity planning, which resulted in the third IRRP for the Ottawa region.

For the purposes of regional planning, the Ottawa region has historically been subdivided into three major sub-regions, as shown in **Figure 2**. One of the main purposes of an IRRP is to foster collaboration where coordination between multiple stakeholders in a region is required. Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the surrounding areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations (TS) and distribute it to end users, including industrial, commercial, and residential customers.

The Scoping Assessment confirmed the need for regional coordination and the importance of evaluating non-wires alternatives to address emerging electricity needs. As a result, the Working Group determined that this IRRP will focus on the Ottawa Area Sub-Region, while the remaining sub-regions will be addressed through the Regional Infrastructure Plan (RIP) led by Hydro One Transmission as those sub-regions are predominantly served by Hydro One Distribution.

The Ottawa Area Sub-Region encompasses the City, including the Kanata, Nepean, and Orléans communities. To further simplify the organization and analysis, the Working Group further divided the sub-region into four subsystems based on their geographic and electrical characteristics. The four subsystems can be seen in **Figure 3** and this report will address each subsystem separately throughout. A more thorough description of each of the subsystems can be found in Section 4 (background) and Section 6 (needs).

Figure 2 |Overview of the Greater Ottawa Sub-Regions

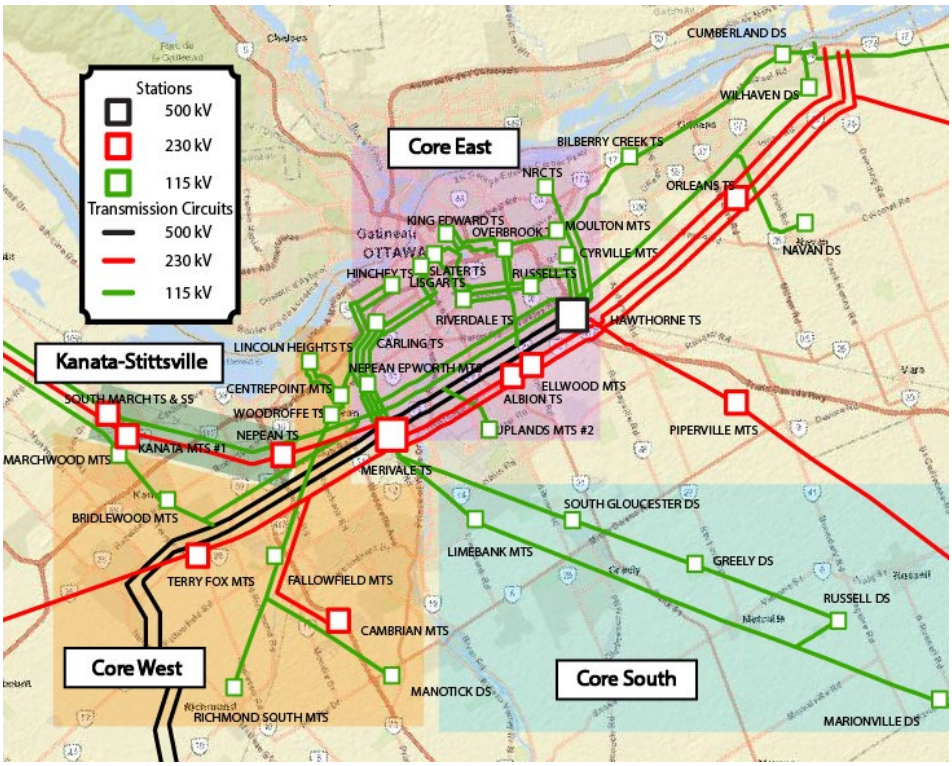


Every plan faces its own unique challenges, and this third cycle of regional planning for the Ottawa area is no exception. The City of Ottawa and the federal government have set ambitious decarbonization and electrification goals, which serve as a foundational input to this IRRP. These goals, supported by customer connection requests, projected growth trends, and consultations with economic sector participants such as Invest Ottawa, reflect a broader shift toward city-wide economic transformation — with particular momentum in areas like Kanata-Stittsville. While previous regional plans included electrification among several scenarios, this IRRP distinguishes itself by embedding electrification as a core planning assumption from the outset, recognizing both the uncertainty it introduces and the opportunity to plan proactively to meet emerging system demands.

The Working Group convened a series of discussions with the City and various energy stakeholders during the development of the plan, aiming to collaboratively shape the demand forecast and align on anticipated decarbonization trends. These conversations helped inform the demand forecasts developed by Hydro Ottawa and Hydro One Distribution. Several scenarios were developed with varying degrees of electrification. By balancing risk and feasibility, one of these scenarios was selected as the reference demand forecast that drove the needs, options, and recommendations found in this report. A high-growth scenario was also identified for sensitivity analysis.

The forecasted economic development, decarbonization, and electrification would result in a substantial increase in peak electricity demand over the next 20 years. Furthermore, the forecast indicates that the region will soon become winter-peaking, due in large part to the effects of transitioning heating from natural gas to electric or hybrid. This ultimately led to the identification of numerous needs in the sub-region that span the near-, medium-, and long -terms which refer to outlooks in the 5-, 10-, and 20-year horizons respectively.

Figure 3 | Overview of the Four Ottawa Area Subsystems



Anticipated electricity demand growth in Ottawa presents a planning challenge: ensuring the system is positioned to support organic growth and economic development, while avoiding the premature construction of assets that may not be needed in the near term. Missed opportunities to enable new connections or achieve the City's decarbonization targets could have lasting impacts. At the same time, overbuilding infrastructure too far in advance could result in unnecessary costs to electricity customers.

To manage these risks, this plan takes a flexible and phased approach — one that reflects good planning practice and builds on how the electricity sector in Ontario has adapted to uncertainty over time. This IRRP outlines a sequence of actions that can evolve as conditions change, providing a framework to respond to growth while managing uncertainty responsibly.

Multiple BESS projects in the sub-region have been recommended through the IESO's LT1 initiative. Once developed, these large-scale batteries will help improve voltage performance, enhance reliability, and provide added flexibility and resilience to the grid.

In addition, a LAPS is expected to inform targeted conservation and demand management opportunities. These measures may help defer large, costly upgrades — particularly in the downtown core — by reducing strain on existing infrastructure.

The firm recommendations in this IRRP are designed to address near-term system and station capacity needs, asset replacement requirements, and load security and restoration needs, while laying the groundwork for longer-term improvements. Annual monitoring of potential issues will provide additional input on when the next regional planning cycle should be initiated.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are presented in Section 3;
- The context for electricity planning in the region and the study scope are described in Section 4;
- Demand forecast scenarios, and electricity Demand Side Management (eDSM) and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Ottawa Area Sub-Region over the next 20 years. The identified needs are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider reliability, cost, technical feasibility, and maximizing the use of the existing electricity system (where economically feasible). The plan also reflects feedback from stakeholders and seeks to balance the need to ensure the system is poised to enable growth — including economic development — with the risk of building investments too early.

The Ottawa Area Sub-Region electricity demand forecast, provided by the LDCs, projects sustained growth driven by municipal growth, commercial development, and the effects of electrification and decarbonization. The planned phase-out of gas heating in the region is also a major driver of the demand forecast and electricity supply needs in the sub-region, especially in later years of the demand forecast.

The IRRP recommendations are organized into a near-term plan and a set of ongoing or medium- to long-term initiatives. This structure reflects the varying degrees of forecast certainty, development lead times, and planning commitments required over different timeframes. By doing so, the IRRP offers clear guidance on immediate investment needs while maintaining flexibility to adapt over the medium and long term as electrification, energy efficiency, and development plans continue to evolve.

2.1 Near-Term Plan

The near-term plan consists of several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Many of these needs are driven by the strong growth in the winter demand forecast. The major recommendations are summarized in **Table 1**.

Table 1 | Summary of Recommendations

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[1]
System Capacity (Transformation, Voltage Stability)	Kanata-Stittsville	Build new 230kV Transformer Station north of existing stations. Connect to C3S and new transmission line from Merivale TS. Interim station name: Kanata North Municipal Transformer Station (MTS).	$45M
		Build new 230kV transmission line from Merivale TS by rebuilding C7BM corridor, connecting Nepean TS and new Kanata North MTS	$185M
		Build a switching station that connects existing and new 230kV stations to improve resiliency and flexibility	$65M
System Capacity (Transformation)	Core East	Build new 115kV Transformer Station by converting existing distribution station. Connect to M4G and M5G. Interim station name: Bronson MTS.	$65M
System Capacity (Thermal Overload)	Core East	Upgrade portions of existing 115kV circuits M5G and M4G.	$35M
System Capacity (Transformation)	Core East	Convert Cyrville MTS (115kV) to 230kV thereby preserving capacity on autotransformers for growth on the 115kV downtown system	$75M
		Pursue eDSM program opportunities identified as part of LAPS to reduce demand and delay large scale infrastructure upgrades.	N/A

[1] All cost estimates are capital cost values

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[1]
System Capacity (Transformation)	Core West	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS. Interim station name: Greenbank MTS.	$40M
		Build new 230kV transmission line from Merivale TS to supply new Greenbank MTS.	$50M
Load Security	Core South	Install new circuit breaker at Merivale TS and separate L2M and M1R	$30M
Planning	N/A	Working Group to produce Adaptive Pathways documents for each subsystem following the publishing of the IRRP. Utilize Annual Working Group meeting to refine and communicate the pathways to relevant stakeholders.	

A complete list of recommendations can be found in Section 7.8.

A high-level planning estimate based on 2025 capital costs for the proposed suite of solutions is approximately $900 million, with a recommended In-Service Date (ISD) ranging between 2029-2032, based on the growth forecast. The identified needs have been grouped to align with integrated solution sets, as outlined in Section 6 of this report. The recommendations from this report will be further prioritized during the RIP. The near-term recommendations represent critical first steps in expanding the electricity grid's capabilities to support the region's goals in a timely manner.

2.2 Medium-, to Long-Term Plan

While most of the recommended actions from the Ottawa Area Sub-Region IRRP are planned for the near-term (within the next five years), the sections below outline potential medium- to long-term recommendations beyond that horizon. The actions described below illustrate the adaptive pathways identified through this regional planning process. These pathways are subject to change and will be continuously re-evaluated as planning progresses, based on new information and actual load growth. Awareness of these plans is important to enable timely decision-making. Further details on the adaptive pathways, including the subway-style maps, are provided in Section 7. It is recommended that the Working Group finalize the long-term adaptive pathway plan for each subsystem following the completion of this cycle of regional planning.

Kanata-Stittsville Subsystem

To address the significant capacity needs at Kanata MTS, South March TS and, eventually, Nepean TS a new switching station is planned to interconnect these key sites. This switching station will provide critical resiliency, operational flexibility, and expandability for future load growth. Additionally, the station will serve as a hub for a new transmission line extending north to Chats Falls TS, pending upgrades at Chats Falls to support the connection. This project will not only diversify supply paths and increase the Load Meeting Capability (LMC) for the area, but also improve Ottawa's overall system strength.

The East Bulk Study, currently underway, is exploring potential reinforcements to strengthen the supply path into Ottawa. As part of this, the proposed switching station is being evaluated for its potential to support the expansion of the 230 kV network. In addition to enhancing regional integration, this connection would diversify supply sources and improve the overall resilience of the electricity system in the Ottawa area.

Core East Subsystem

Core East faces the most acute and widespread capacity challenges, particularly in the 115 kV downtown network. Due to physical constraints on system expansion, eDSM program opportunities identified in the LAPS could play a crucial role in regulating and managing downtown load growth. Long-term planning includes expanding Hawthorne TS, extending a mix of 115 kV and 230 kV circuits into the downtown core, and constructing additional supply stations to relieve pressure on aging infrastructure. A fourth autotransformer at Merivale TS is also under consideration, which would enhance transfer capability and reduce strain on nearby stations. To further alleviate pressure on the 115 kV system, a planned conversion of S7M will allow additional load to be shifted off the constrained network.

Core West Subsystem

With station overloads emerging across Marchwood, Fallowfield, Manordale, and others, the long-term strategy for Core West centres on the conversion of circuit S7M to 230 kV. This will relieve the 115 kV system, preserving capacity for downtown load growth while supporting suburban development. The new circuit can be extended to provide a second supply path to Terry Fox MTS and Cambrian MTS, enhancing reliability and operational flexibility. This conversion will also unlock the full potential of a large-scale BESS identified in the LT1 framework. Additional transmission work, including uprating portions of C7BM and F10MV, is planned to mitigate thermal overloads and enhance backbone performance.

Core South Subsystem

Future planning in Core South hinges on the findings of the East Bulk Study, with a possible 230 kV transmission line from the St. Lawrence area offering the potential to fully convert the pocket to 230 kV operation. Limebank MTS, forecast to exceed capacity in the medium term, will require a second supply path as load grows; monitoring and proactive circuit upgrades will be key. A new autotransformer station in western Ottawa is also under consideration, and its implementation will influence future planning and routing decisions for Core South.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the inter-related needs of a region—defined by common electricity supply infrastructure—over the near-, medium-, and long -term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A **Needs Assessment**, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A **Scoping Assessment**, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An **IRRP**, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. An **RIP**, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

3.2 Ottawa Area Sub-Region IRRP Development

The process to develop the Ottawa Area Sub-Region IRRP started in March 2023, following the publication of the **Needs Assessment Report** in December 2022 by Hydro One and the **Scoping Assessment Outcome Report** in February 2023 by the IESO. The Scoping Assessment recommended that the needs identified for the Ottawa Area Sub-Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

Given the significant uncertainty surrounding the impacts of electrification and decarbonization, the Working Group has taken several important steps to manage this risk. Recognizing Ottawa's unique combination of rapid urban growth, economic development opportunities, and decarbonization initiatives, it was clear that a flexible and forward-looking approach was necessary. As a first step, the LDC engaged a third-party consultant to develop a series of load forecast scenarios that

incorporated full decarbonization by 2050. This process ensured that the forecasts accounted for electrification in a meaningful way and were developed with a high degree of objectivity and technical rigour. The resulting scenarios highlighted the challenge of managing substantial load growth over a relatively short period of time, which further reinforced the need for a more flexible planning approach.

The Working Group remains committed to ongoing monitoring of actual load growth, technological developments, and policy changes, ensuring the plan continues to reflect real-world conditions. This approach reflects a foundational aspect of electricity planning in Ontario — the recognition that flexibility and regular updates are essential in the face of evolving system needs. The adaptive approach outlined in this IRRP provides a structured yet flexible roadmap that enables the electricity system to grow in step with Ottawa's evolving demand, while maintaining reliability, cost-effectiveness, and resilience. It also aligns with the City of Ottawa's direction on electrification and supports local aspirations related to the energy transition.

4. Background and Study Scope

4.1 Previous Regional Planning Cycle

This is the third cycle of regional planning for the Ottawa Area Sub-Region. The previous cycle of regional planning for the Ottawa Area Sub-Region was carried out from 2018 to 2020 and resulted in the publishing of an IRRP and an RIP. Furthermore, between-cycle planning occurred in 2022 to revisit a previous recommendation for the Orléans area. The Working Group reconvened and decided not to refurbish Billberry Creek as previously recommended and will instead decommission the station and focus on new infrastructure in the Orleans area. The recommendations are described within the report.

The previous Ottawa Area Sub-Region IRRP was published in March 2020. The IRRP used a 20-year demand forecast and made recommendations to monitor long-term needs in the region, while providing clear direction on actions required in the near-term. This included several distribution load transfers and asset replacements as described below. Furthermore, the plan recognized the need for a long-term solution for the Kanata-Stittsville area but decided that interim measures in the forms of enhanced IESO led energy efficiency programs were more prudent at that stage. This plan picks up where the previous plan left off and provides the next steps for expanding the electricity system to meet growing demand.

The plan also identified two supply deficiencies in the southwest and southeast areas of the Ottawa Area Sub-Region. In the southwest, referred to as the Core West subsystem in this report, the Cambrian MTS station was brought into service in 2022. Originally identified in 2008 and approved by the IESO in 2016, this new station addresses growing demand in the area. In the southeast, a new station, Piperville MTS, is currently under construction. This station will relieve neighbouring stations and provide additional capacity to support emerging load growth in the region.

Additionally, to accommodate both load growth and the end-of-life considerations in the Orléans area, it is recommended that the Billberry Creek station be decommissioned. In its place, a new station—tentatively named Mer-Bleue MTS—will be required to serve the existing load, with an expected in-service date of 2027. Finally, the introduction of a new electrified municipal bus fleet will necessitate the construction of a bus charging station near Hawthorne TS, referred to as Hydro Road MTS in the current plan

2020 Ottawa Integrated Regional Resource Plan Recommendations

- Hydro Ottawa is to implement the North Kanata Retrofit Top-Up Program and the North Kanata Smart Thermostat Program, which are targeted commercial and residential energy efficiency programs. Hydro Ottawa is also planning distribution system transfers to reduce demand at heavily loaded stations.
- Hydro One is to replace Merivale TS Transformer T22 with one that is equivalent to T21.
- Hydro One is to proceed with the like-for-like refurbishment of Bilberry Creek TS, which is approaching its end-of-life, and expand the station to accommodate two additional breaker positions to supply Hydro Ottawa customers.

- Hydro One is to replace Slater TS T2 and T3, which are approaching their end-of-life, with larger transformers, approximately 100 megavolt amperes (MVA), as was done for the recent replacement of T1.
- Hydro One is to replace the two 75 MVA transformers at Albion TS, which are approaching their end-of-life, with similar size transformers.
- Hydro One is to replace the two 75 MVA transformers at Lincoln Heights TS, which are approaching their end-of-life, with similar size transformers.
- Hydro Ottawa is to plan and seek approval for a new 230 kV connected supply station in southeast Ottawa.

2020 Ottawa Regional Infrastructure Plan Recommendations

- Replace end-of-life transformers T1/T2 at Lincoln Heights TS: complete in 2024, 2023 respectively (45/60/75 MVA).
- Replace end-of-life transformers T3/T4 at Longueuil TS: in-service date of 2025.
- Replace end-of-life 115 kV breakers at Riverdale TS: In-service date of 2028.
- Increase transformation capacity in southeast Ottawa, with Hydro Ottawa building a transformer station: station named Piperville TS, expected in-service date 2026.
- Replace end-of-life transformers T1/T2 and circuit breakers at Albion TS.
- Replace end-of-life transformers at Russel TS.
- Determine limitation of low voltage-cables, upgrade cables at Overbrook TS: station Limited Time Rating (LTR) increased between cycles, which reflects this change.
- Upgrade Hawkesbury MTS station capacity.
- Refurbish Bilberry Creek TS end-of-life: the Working Group recommends decommissioning Billberry Creek in favour of new DESN, as described within the report.
- Replace T22 at Merivale TS: this project is ongoing and is part of the Merivale project, which is in service in 2029
- Voltage performance of 79M1 evaluated as part of next IRRP: moving to 2025 RIP

4.2 Bulk Planning and Other Developments

Beyond historical regional planning efforts, the Ottawa Area Sub-Region has also been the focus of bulk planning initiatives and other key developments.

2022 Gatineau Corridor Study

- Refurbish all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing end-of-life.
- Build a new double-circuit 230 kV transmission line into Dobbin TS (in Peterborough) from Clarington TS (in Oshawa), with a planned in-service date of 2029.

- Pursue up to 230 megawatts (MW) of additional system cost-effective energy efficiency in the Ottawa area over the 20-year planning horizon, while monitoring demand growth and resource acquisition activities in the Ottawa zone.
- Update and expand the use of remedial action schemes (RASs) in the Peterborough and Ottawa areas to meet planning standards and further improve the load meeting capabilities of both areas.
- Implementation of recommendations is ongoing.

2023 Orléans Area Study

To manage forecast risks from high electrification growth, maintain reliability, and defer major upgrades to Ottawa's 115 kV system beyond the third autotransformer at Merivale TS, an integrated solution package is recommended. This includes decommissioning Bilberry Creek TS, building a new 230 kV circuit from Hawthorne TS to Orléans TS, and upgrading Orléans TS to a 230 kV DESN.

IESO Long-Term 1 Procurement

During the IRRP process, the IESO launched its Long-Term 1 Procurement, which has led to competitive pricing for new resources, municipal support, and significant Indigenous participation and equity ownership in projects. The IESO entered into contracts with 13 selected proponents, securing approximately 2,200 MW of new capacity, set to come online between 2026 and 2028. Among these procurements are two large-scale BESS located in the Kanata-Stittsville and Core West subsystems to the west of Ottawa.

Although the IRRP evaluated batteries as part of the non-wires solutions process and found that they could not fully address the identified needs on their own, they offer valuable benefits, including improvements in voltage stability, peak demand management, and enhanced system reliability. This plan supports the technical advantages of these projects and acknowledges that a diversified system will be crucial for realizing the long-term vision of the electricity landscape.

Eastern Ontario Bulk Plan

- The IESO is carrying out an Eastern Ontario Bulk Study to assess the sufficiency of the bulk transmission system to reliably supply the demand growth expected in Greater Ottawa areas. The bulk plan will be coordinating with this IRRP regarding demand forecast and regional assumptions to ensure alignment and efficiency.
- The targeted completion of this bulk plan is Q1 2026.

4.3 Current Cycle of Regional Planning

The current cycle of regional planning began in 2023 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2023 Ottawa Scoping Assessment recommended an IRRP for the Ottawa Area Sub-Region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2024.

This IRRP develops and recommends options to meet the electricity needs of the Ottawa Area Sub-Region in the near-, medium-, and long-term. The plan was prepared by the IESO on behalf of the

Working Group, and considers forecast electricity demand growth, eDSM, distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The transmission facilities included in the scope of this study are shown in **Table 2**, **Table 3**, and **Table 4**:

Table 2 | Transformer Stations

Albion TS	Bridlewood MTS	Cambrian MTS	Carling TS
Centrepoint MTS	Cumberland DS	Cyrville MTS	Ellwood MTS
Fallowfield MTS	Greely DS	Hawthorne TS	Hinchey TS
Kanata MTS	King Edward TS	Limebank MTS	Lincoln Heights TS
Lisgar TS	Manordale MTS	Manotick DS	Marchwood MTS
Marionville DS	Merivale MTS	Moulton MTS	National Aeronautical CTS
National Research Council CTS	Navan DS	Nepean Epworth MTS	Nepean TS
Piperville MTS	Orléans TS	Overbrook TS	Richmond South MTS
Riverdale TS	Russell DS	Russell TS	Slater TS
South Gloucester DS	South March TS	Terry Fox MTS	Uplands MTS
Wilhaven DS	Woodroffe TS	Hydro Road MTS	

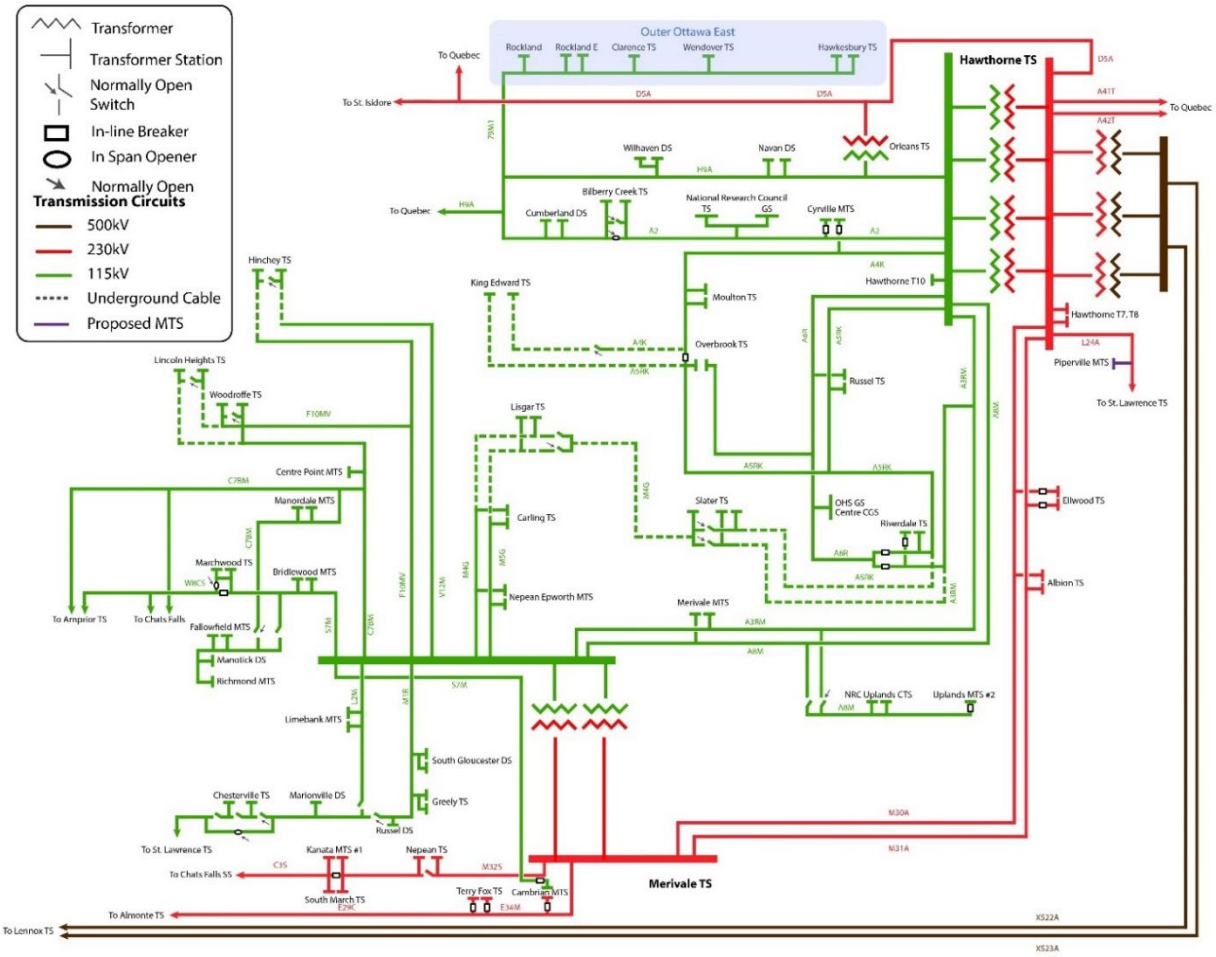
Table 3 | 115 kV Transmission Circuits

C7BM	F10MV	V12M	S7M	W6CS	A5RK
A4K	A6R	A8M	A3RM	A2	H9A
M1R	L2M	M4G	M5G		

Table 4 | 230 kV Transmission Circuits

E34M	D5A	L24A	B5D	M30A	M31A
M32S	C3S	L24A			

Figure 4 | Single Line Diagram of the Ottawa Area Sub-Region



The single line diagram of the Ottawa Area Sub-Region is shown in **Figure 4**. Note that the bulk system transfer capabilities on the Flow-into-Ottawa (FIO) interface into the region is not within the scope of this IRRP and was separately studied in the East bulk transmission plan. The schedule of bulk planning activities is identified through the IESO's **Annual Planning Outlook**.

Ottawa is a major load centre in eastern Ontario, which is primarily supplied by:

- two 500 kV circuits from Lennox TS in Lennox and Addington County
- two 230 kV circuits from St. Lawrence TS in Cornwall
- one 230 kV circuit from Chats Falls SS
- one 115 kV circuit from Barrett Chute GS
- one 115 kV circuit from Stewartville GS
- an inter-connection with Quebec's transmission system at Hawthorne TS, located in the east side of Ottawa

The transmission system serving Ottawa has several interfaces that can limit the ability to meet demand within the city and efficiently transfer power from generation and imports in eastern Ontario across the provincial grid. Ottawa's electricity needs are primarily met by a series of 230 kV and 115 kV transmission circuits that emanate from the Merivale TS and Hawthorne TS stations, which serve as the central hubs for the city's power supply.

Historically, Ottawa experiences peak demand during the summer, with loads reaching approximately 1,600–1,700 MW. However, over the next 20 years, demand is expected to grow significantly, and the region is forecast to transition into a winter-peaking area as early as 2030. There is minimal internal generation capacity in Ottawa, with only one transmission-connected generator—a 70 MW combined-cycle gas plant. In addition, there are several distribution-connected generators within the city, with the most notable being the Chaudière Falls hydroelectric plants, which collectively contribute around 90 MW of capacity

The Ottawa IRRP was developed by completing the following steps:

1. Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
    a. Examining the LMC and reliability of the existing transmission system, considering facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria.
    b. Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
    c. Confirming identified asset replacement needs and timing with the transmitter and LDCs.
2. Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches, such as non-wires alternatives including eDSM.
3. Engaging with the community on needs and possible alternatives.
    a. Evaluating alternatives to address near- and long-term needs.
    b. Considering the impact of the high forecast as a sensitivity of the flexibility and optionality of the potential alternatives.
4. Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in a region. This section describes the development of the demand forecast for the Ottawa Area Sub-Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of eDSM and DG, and the development of a high-growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.6.2.

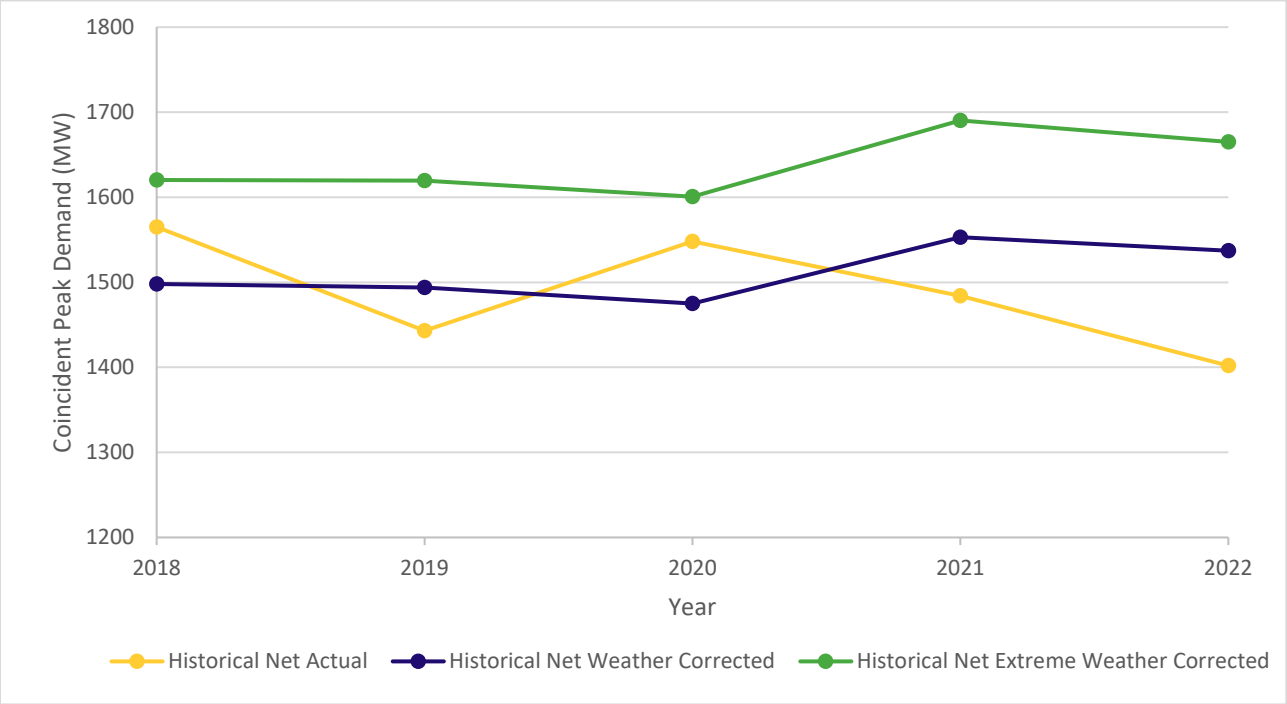
To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Ottawa Area Sub-Region, the peak loading hour for each year has historically occurred in the summer. However, with the recent and projected growth of electric heating, the region is projected to become winter-peaking.

5.1 Historical Demand

Summer peak electricity demand within the Ottawa Area Sub-Region has remained stable in the five years prior to this planning cycle. **Figure 5** shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and net extreme weather-corrected (adjusted to reflect extreme weather conditions) historical demand. The summer net median weather-corrected demand has averaged 1,500 MW over the past five years, with the peak demand hour for each year occurring between approximately 3 PM to 5 PM.

Since the forecast was developed in 2023, only the 2022 values were available to create gross starting points. The starting points used the median weather corrected 2022 values, adding the effect of DG to make it a gross weather-corrected starting point.

Figure 5 | Historical Peak Demand in the Ottawa Area Sub-Region

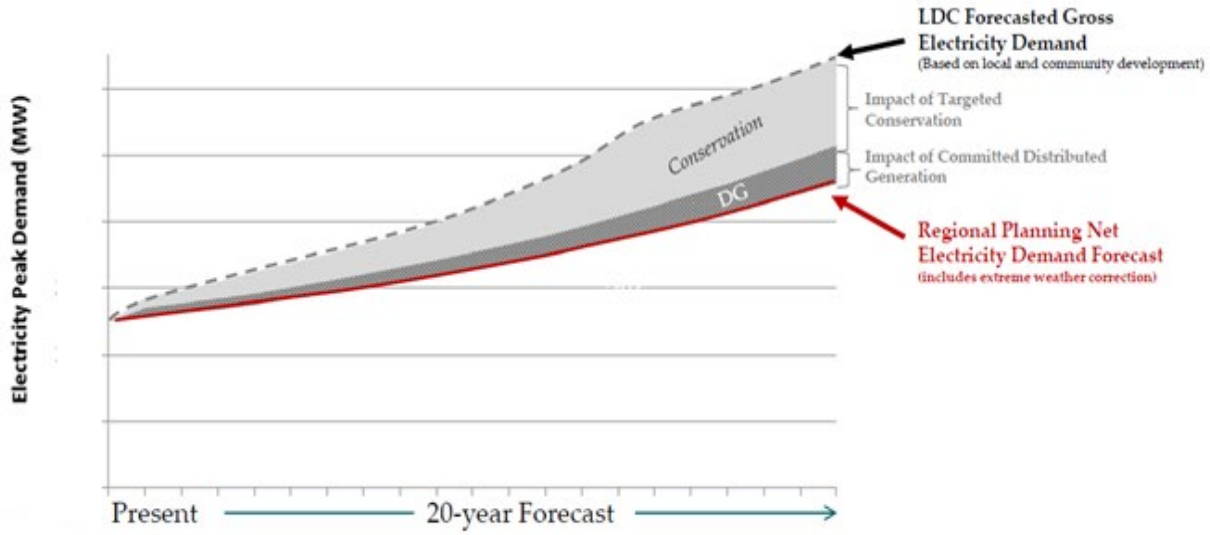


5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in **Figure 6**. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial eDSM targets and DG contracted through previous provincial programs such as Feed-In Tariff (FIT) and microFIT and adjusted to reflect extreme weather conditions to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The Ontario Energy Board has also published a **Load Forecast Guideline** for regional planning, through the **Regional Planning Process Advisory Group**.

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecasts

Each participating LDC in the Ottawa Area Sub-Region prepared gross demand forecasts at the station level. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.45).

The gross LDC forecasts assume median on-peak weather conditions and loading that is coincident to each station. A coincident demand forecast was used instead of a non-coincident forecast because it better reflects the system-level peak, which is critical for planning shared infrastructure. While some individual stations may experience higher non-coincident peaks, these are typically captured in the winter forecast, which drives most station capacity needs. However, this approach can introduce some uncertainty, particularly for the winter period, and may understate summer needs in some areas—potentially shifting the summer need date slightly later.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with the customers, connection applicants, and municipalities and communities that they serve. The IESO typically carries out demand forecasting at the provincial level. More details on LDC load forecast assumptions can be found in Appendix B.2 to B.6. **Figure 7** and **Figure 8** show the total reference and high-growth gross coincident demand forecasts provided by the LDCs for the Ottawa Area Sub-Region.

Hydro Ottawa worked closely with Enbridge Inc. to develop electrification scenarios dealing with the transition from natural gas to heat-pump based electrical heating. A full breakdown of each LDC's methodology can be found in the Appendix B and on the IESO's Ottawa engagement webpage.

Figure 7 | Total Summer Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)

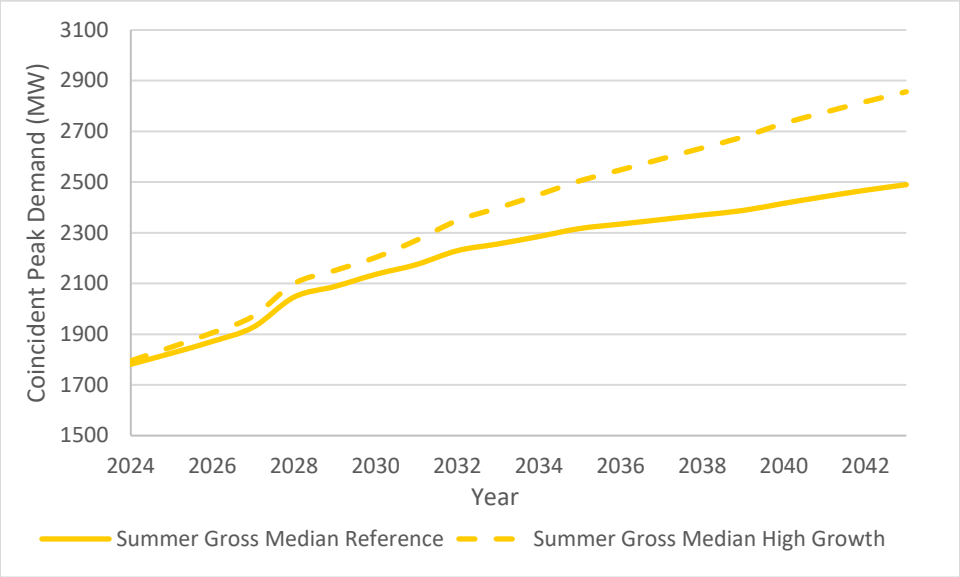
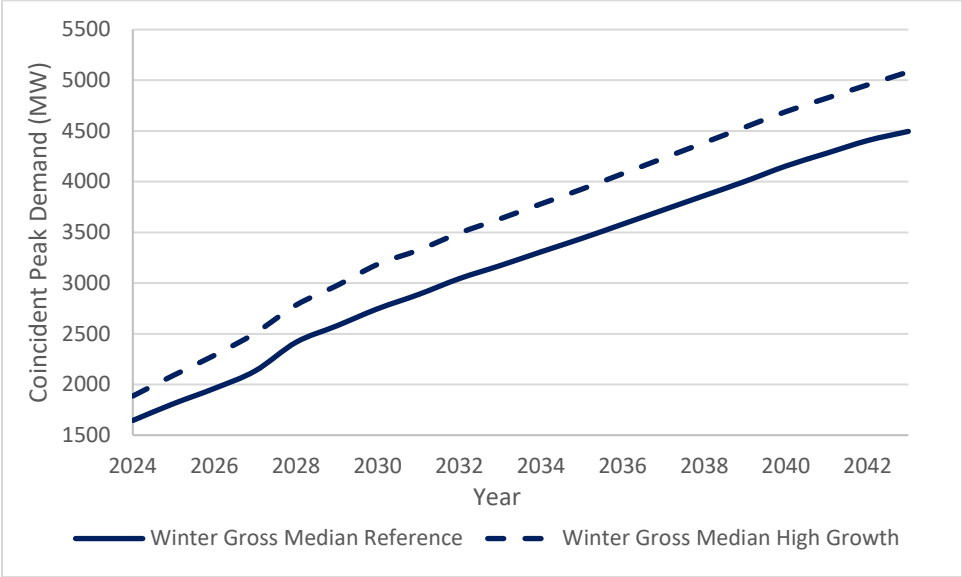


Figure 8 | Total Winter Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)



5.4 Contribution of eDSM to the Forecast

Electricity Demand Side Management is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. eDSM is achieved through both codes and standards amendments, as well as eDSM incentive program-related activities. These approaches complement each other to maximize results.

In alignment with the language of the November 7, 2024, directive to the IESO regarding a new energy efficiency framework for 2025–2036, this IRRP uses the term "electricity demand-side

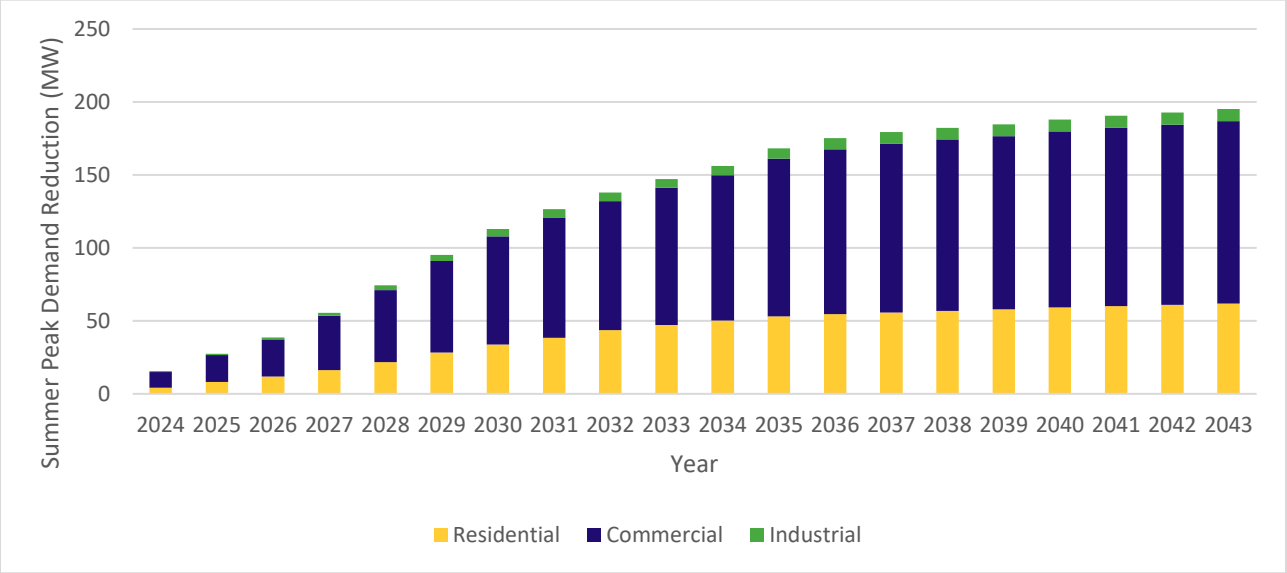
management" replacing "conservation and demand management (CDM)" used in previous IRRPs and other IESO planning reports.

The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the IESO's 2021-2024 eDSM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. At time of forecast development, the 2021 – 2024 eDSM framework was the main piece, in which the IESO centrally delivered programs to serve business and residential customers, including Indigenous communities, across the province.[2]

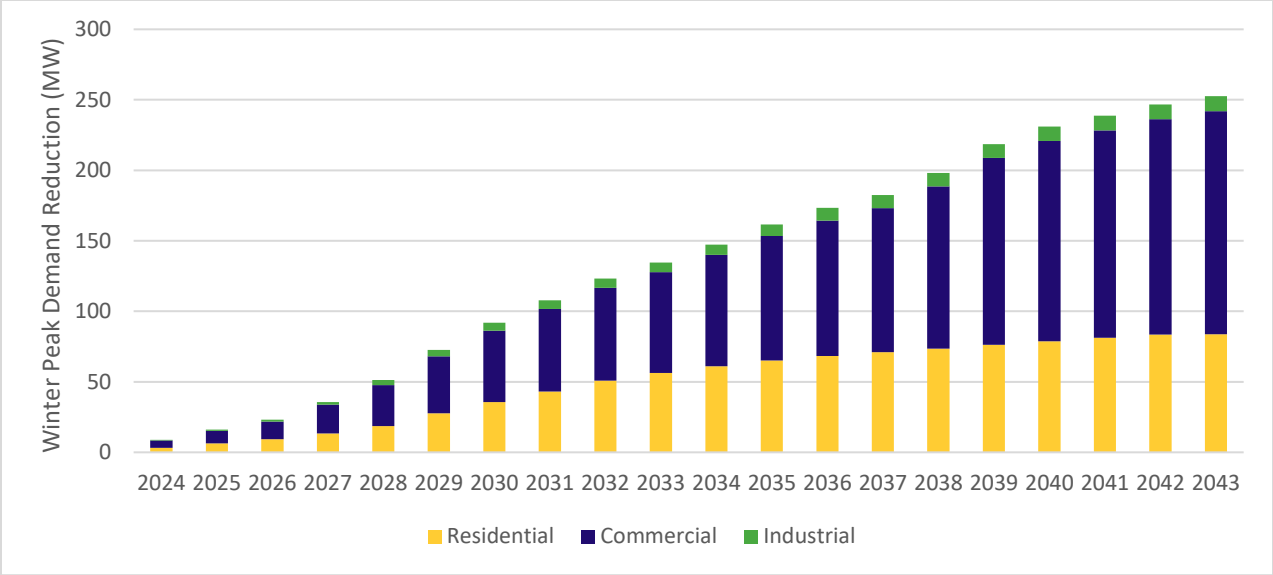
Figure 9 and **Figure 10** show the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and eDSM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.4.

Figure 9 | Total Summer Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)



[2] The IESO has received a directive to continue delivering eDSM programs for 2025-2036.

Figure 10 | Total Winter Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)



5.5 Contribution of Distributed Generation to the Forecast

In addition to eDSM, DG in the Ottawa Area Sub-Region is also forecast to offset peak demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation that, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B. Most of the total contracted installed DG capacity in the Ottawa Area Sub-Region is solar and hydro, with the remainder being gas or wind facilities.

After reducing the demand forecast due to eDSM, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG, except for DG facility information provided directly by the LDCs. **Figure 11** and **Figure 12** show the impact of DG on reducing the Ottawa Area Sub-Region demand forecasts. Note that facilities without a contract with the IESO were not included in the DG peak demand reduction forecast, except for DG facility information provided directly by the LDCs.

Figure 11 | Summer Peak Demand Reduction Due to DG

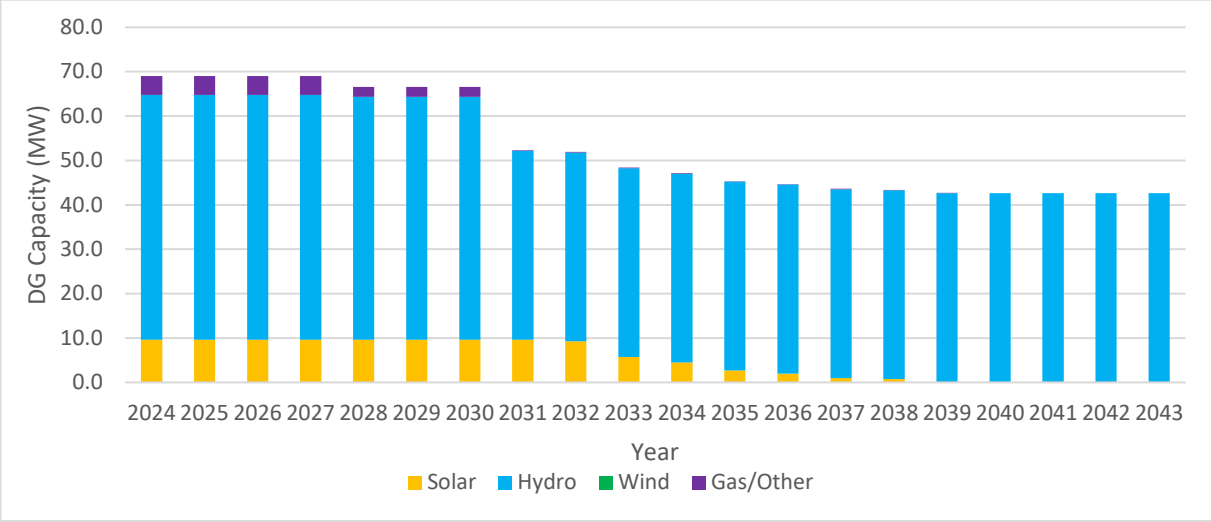
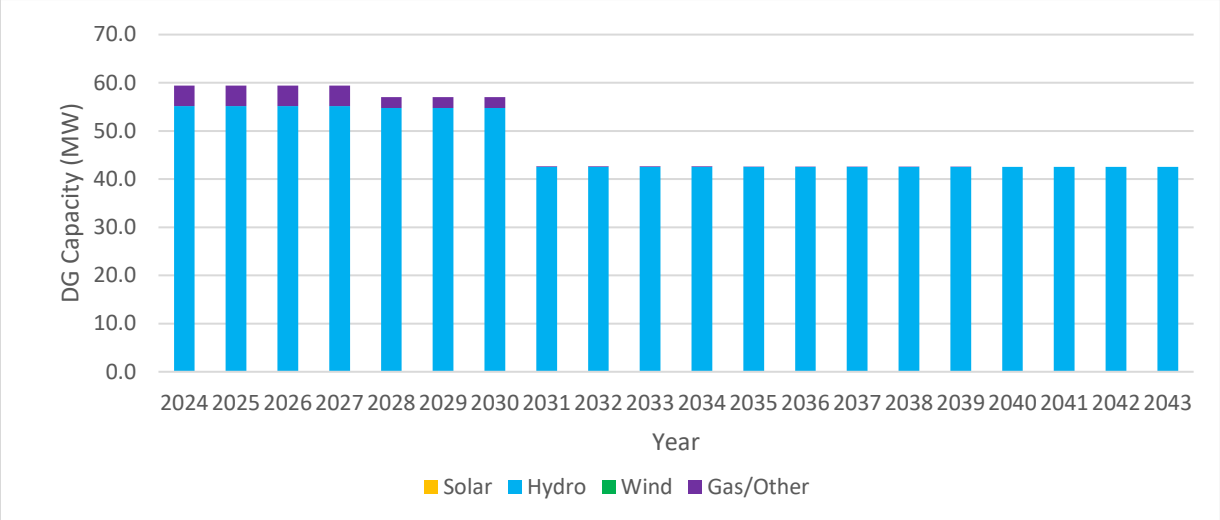


Figure 12 | Winter Peak Demand Reduction Due to DG



A decision was made within the Working Group to consider the expected lifespan of each distributed generation facility based on resource type, rather than assuming that facilities will not be re-contracted past their current contract end date. In alignment with the IESO 2024 Annual Planning Outlook, the assumption for resource expected lifespans was 25 years for solar, and 30 years for wind, natural gas and biogas.

A total of 115 MW of DG summer peak contribution and is identified for the Ottawa Area Sub-Region in 2024, reducing throughout the 2030s to 43 MW by 2043. In the winter, the DG peak contribution decreases from 70 MW in 2024 to 43 MW by 2043.

5.6 Planning Forecasts

After taking into consideration the combined impacts of eDSM and DG, a 20-year planning Reference and High forecast was produced for the Ottawa Area Sub-Region.

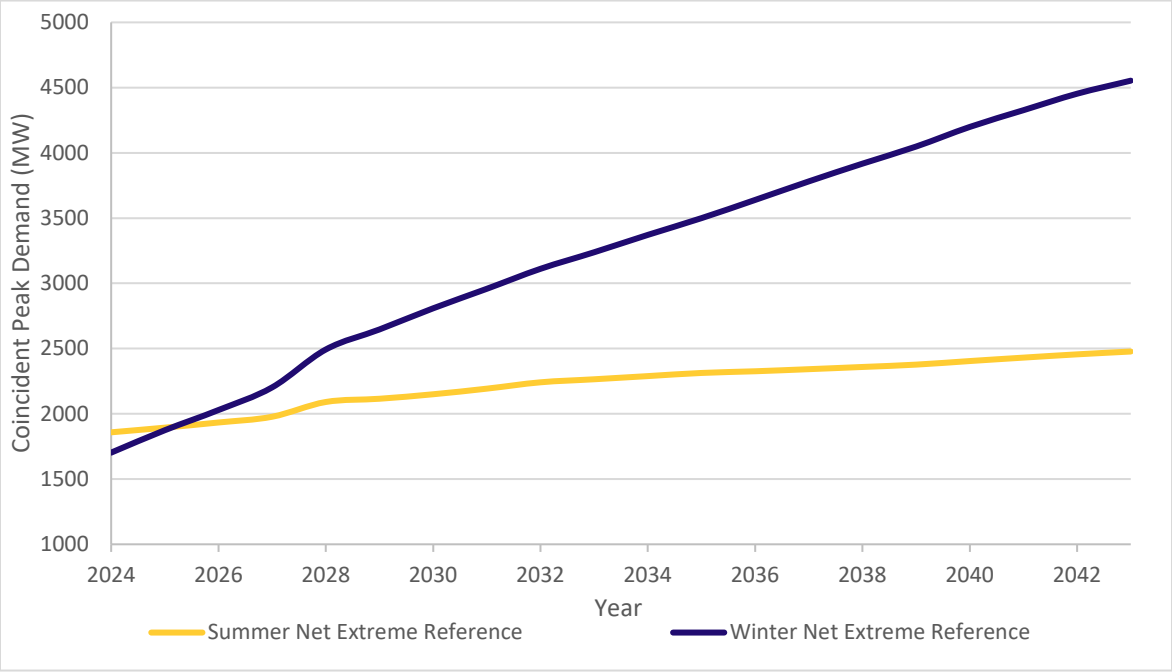
5.6.1 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and eDSM impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station.

The coincident net extreme weather forecast for the Ottawa Area Sub-Region is shown in **Figure 13**.

Figure 13 | Net Extreme Weather (Planning) Forecast for the Ottawa Area Sub-Region

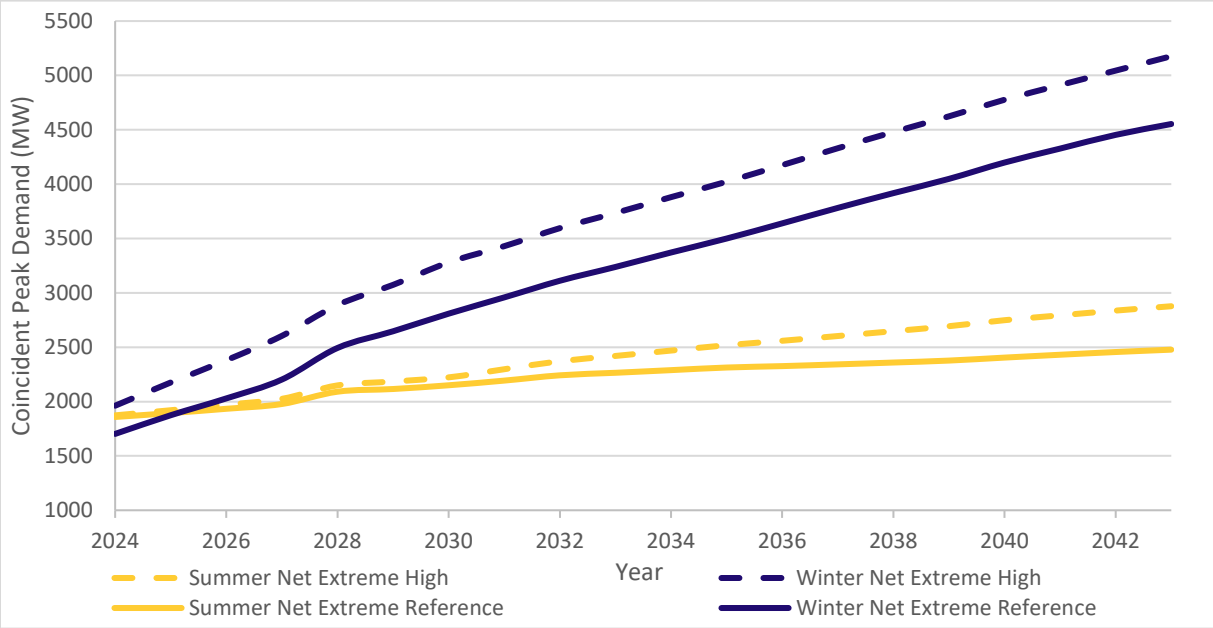


5.6.2 High Forecast Scenario

The Working Group chose to develop a high-growth sensitivity scenario for the Ottawa Area Sub-Region. This scenario modifies assumptions around the adoption of electrification technologies and assumes a faster pace of decarbonization. While both the reference and high-growth scenarios aim for a net-zero future by 2050, they differ in the speed at which that transition occurs. The higher demand scenario was not used to drive firm recommendations in this IRRP; however, it served as a tool for the Working Group to identify potential future pinch points and the timelines in which they might emerge. This information is also valuable for communities working on Community Energy Plans for the Working Group as it determines areas to monitor in future planning cycles and for local

stakeholders considering various regional projects. Additionally, during the course of this IRRP, the Working Group assessed the flexibility of the evaluated options to accommodate long-term growth.

Figure 14 | High Forecast Scenario for the Ottawa Area Sub-Region



The higher demand scenario, as seen in **Figure 14**, was not used to drive any firm recommendations for this IRRP; however, it was used to help the Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth.

5.7 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for station(s) included in identified needs were developed to characterize the needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand, such as calendar day (i.e., holidays and weekends) and weather as well as future electrification. They were also based off of hourly load forecasts provided by the LDCs. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details, including hourly heat maps for each need, can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors, like actual weather, customer operation

strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Working Group will continue to monitor forecast changes as part of the implementation of the plan.

6. Needs

This section summarizes the needs identified through the IRRP process. The projected impacts of economic growth, decarbonization, and electrification—particularly the transition from natural gas to electric or hybrid heating—are expected to place increasing pressure on the electricity system, especially during winter months. In response, a range of electricity needs have been identified across near-, medium-, and long-term horizons.

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards, the Working Group identified electricity needs that generally fall into the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment (i.e., breakers, disconnect switches, low-voltage bus or high-voltage circuits).
- **System Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter using an asset condition assessment, which is based on a range of considerations, such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early medium-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of

both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

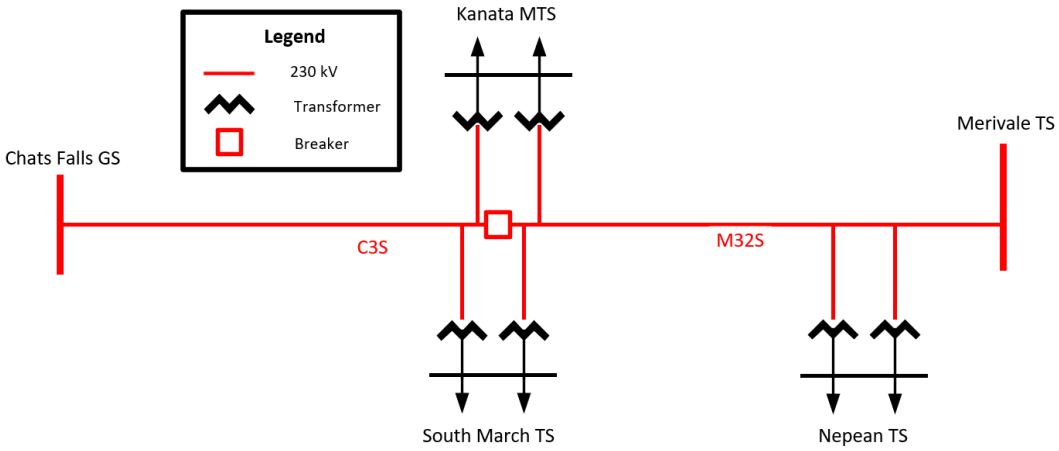
Technical study results for the Ottawa IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 to 6.5, below, for each of the four subsystems.

6.2 Ottawa Subsystems

To support detailed technical analysis, the Ottawa Area Sub-Region has been further subdivided into four major subsystems: Kanata-Stittsville, Core East, Core West, and Core South. These subdivisions reflect the electrical connectivity of the transmission network and group together stations, supply circuits, and infrastructure that operate as electrically cohesive units. This approach allows for more accurate modelling of system performance, localized planning for station and System Capacity needs, and alignment with regional infrastructure development. Within each subsystem, further division into pockets is used where necessary to better reflect local electrical boundaries and simplify LMC assessments, as illustrated in **Figures 15–18**.

Located west of Merivale TS, the Kanata-Stittsville subsystem is supplied by two 230 kV circuits—one from Merivale TS and another from Chats Falls TS, which is approximately 25 km to the north and includes a hydroelectric generation component. These lines supply Kanata MTS and South March TS, both of which are projected to reach capacity in the near term and are identified as key station needs. As shown in **Figure 15** this subsystem's layout enables focused planning to address rising demand and operational risk. While Marchwood MTS and Bridlewood MTS are located geographically within this area, they are supplied via the 115 kV system and are therefore included in the Core West subsystem.

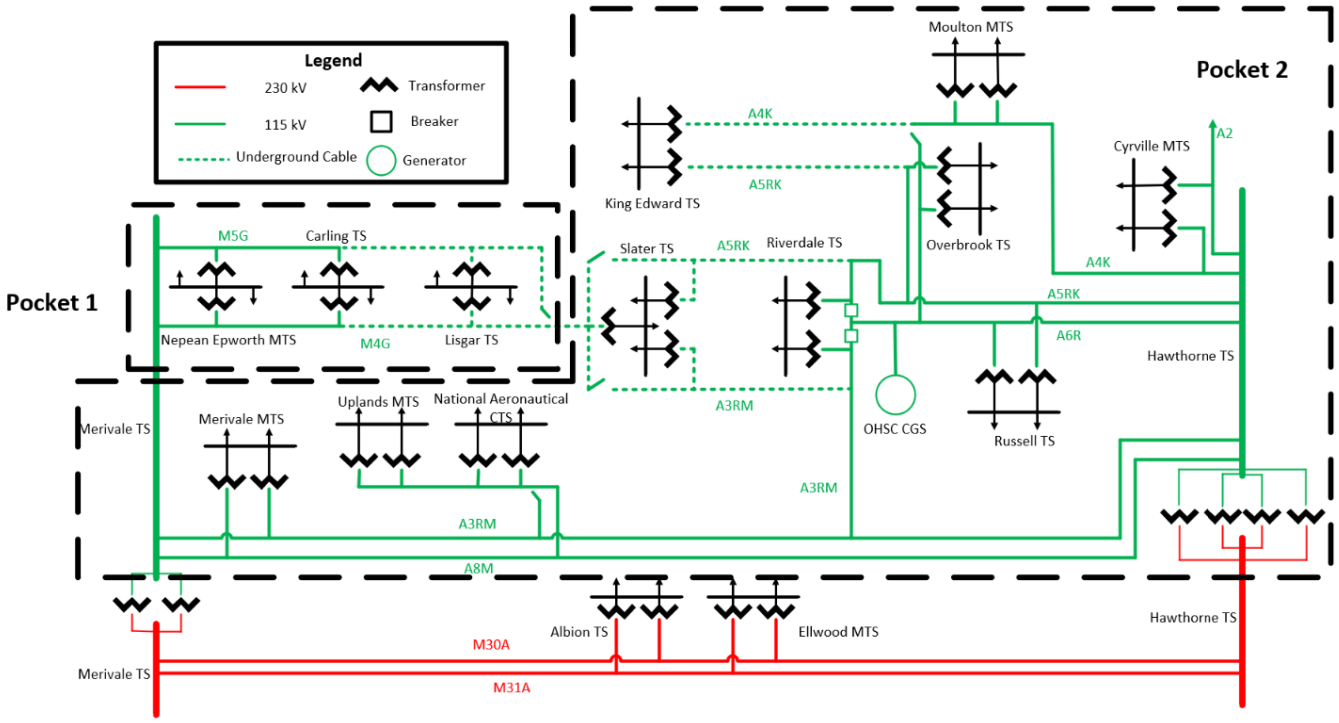
Figure 15 | Overview of the Ottawa Kanata-Stittsville area



The Core East subsystem represents Ottawa's urban downtown core and is characterized by a large, interconnected 115 kV system. For the purposes of the technical studies and to support more

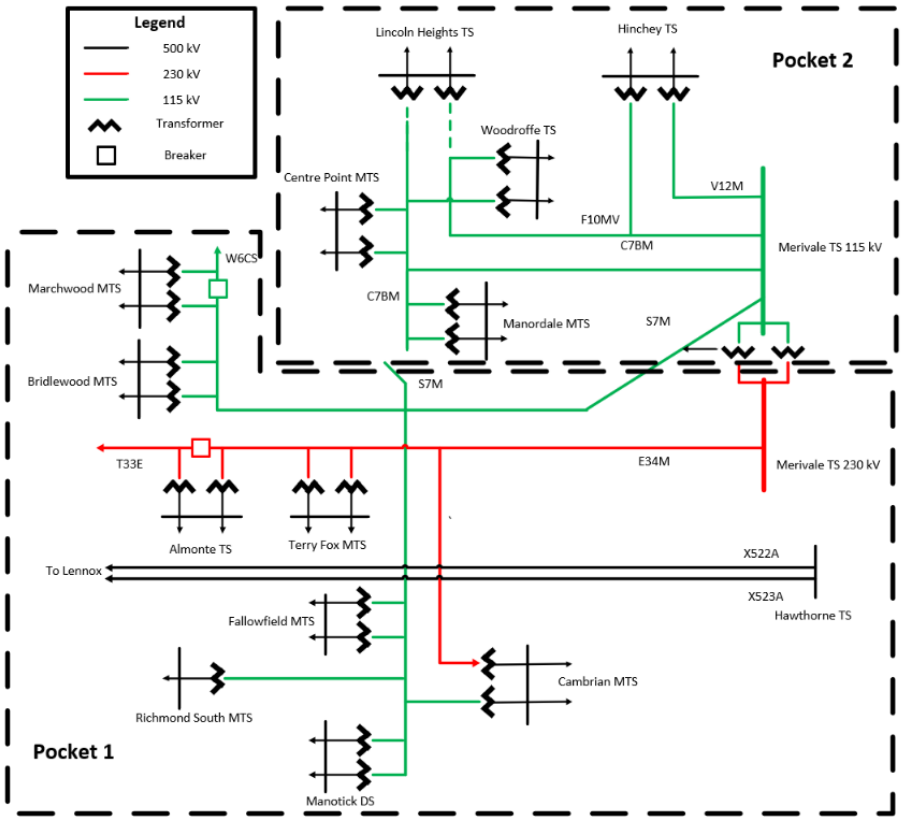
manageable modelling, Core East is divided into two pockets. Pocket 1 consists of circuits M4G and M5G, which supply Nepean Epworth MTS, Carling TS, and Lisgar TS. Notably, M4G also provides one of three supplies to Slater TS. The remaining 115 kV circuits form Pocket 2, supplying the remaining downtown stations predominantly east of the Rideau River. **Figure 16** illustrates this breakdown, allowing for better assessment of local supply adequacy and reinforcement needs.

Figure 16 | Overview of the Ottawa Core East Area



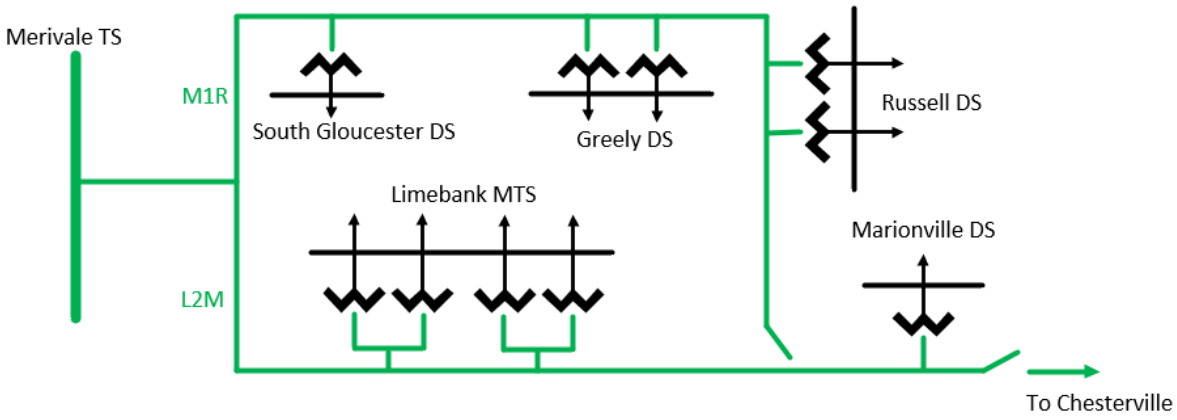
Core West has also been divided into two pockets to reflect the operational and electrical characteristics of the area. Pocket 1 includes stations supplied by 115 kV circuits S7M and W6CS, as well as 230 kV circuit E34M. All three connect at Cambrian TS, where a Fast Transfer Scheme (a RAS) is used to quickly restore load in the event of a circuit loss, avoiding the need for more expensive dual 230 kV supply infrastructure. This pocket includes several stations experiencing or approaching capacity limits. **Figure 17** depicts the full subsystem and pocket breakdown, supporting the identification of local needs and future conversion opportunities.

Figure 17 | Overview of the Ottawa Core West Area



The Core South subsystem comprises the area south of Ottawa's urban core and includes five supply stations served radially by two 115 kV circuits. The stations are relatively remote and less interconnected compared to those in other subsystems. **Figure 18** shows the simplified layout of this subsystem. The 2020 Ottawa IRRP identified the need for a new 230 kV station—Piperville MTS—to support rapid growth in the southeastern portion of the city. Connected to circuit L24A, Piperville MTS is expected to be energized in 2026 and will play a key role in alleviating station capacity constraints in the area and supporting long-term system reliability.

Figure 18 | Overview of the Ottawa Core South Area



6.3 Station Capacity Needs

Many station capacity needs emerge in the Ottawa Area Sub-Region, as shown in **Table 5** with the majority in the near/medium term.

Table 5 | Summary of Station Capacity Needs in the Ottawa Area Sub-Region

Time Horizon	Station	Subsystem	Emerging Year Summer	Emerging Year Winter	2043 Need Summer (MW)	2043 Need Winter (MW)
Near Term	Carling TS	Core East – Pocket 1	2028	2029	40	130
	Lisgar TS	Core East – Pocket 1	2025	2027	30	120
	Nepean Epworth MTS	Core East – Pocket 1	2031	2028	1	10
	Cyrville MTS	Core East – Pocket 2	-	2029	0	40
	King Edward TS	Core East – Pocket 2	2037	2026	10	160
	Moulton MTS	Core East – Pocket 2	2028	2028	3	30
	Riverdale TS	Core East – Pocket 2	2038	2028	8	110
	Ellwood MTS	Core East – Pocket 2	2024	2027	60	5
	Bridlewood MTS	Core West – Pocket 1	2032	2029	1	20

Time Horizon	Station	Subsystem	Emerging Year Summer	Emerging Year Winter	2043 Need Summer (MW)	2043 Need Winter (MW)
	Fallowfield MTS	Core West – Pocket 1	2024	2030	7	40
	Marchwood MTS	Core West – Pocket 1	2025	2025	8	40
	Centrepoint MTS	Core West – Pocket 2	2024	2026	2	20
	Manordale MTS	Core West – Pocket 2	2024	2025	3	20
	Greely DS	Core South	2024	2024	10	10
	Limebank MTS	Core South	-	2030	0	50
	Marionville DS	Core South	2026	2026	10	10
	Kanata MTS	Kanata-Stittsville	2024	2026	20	40
	South March TS	Kanata-Stittsville	2027	2027	20	100
Medium Term	Overbrook TS	Core East – Pocket 2	-	2032	0	90
	Hawthorne TS	Core East – Pocket 2	-	2031	0	60
	Hinchey TS	Core West – Pocket 2	-	2033	0	60
	Nepean TS	Kanata-Stittsville	-	2031	0	100
Long Term	Merivale MTS	Core East – Pocket 2	-	2039	0	7
	Uplands MTS	Core East – Pocket 2	-	2041	0	5
	Albion TS	Core East – Pocket 2	-	2035	0	40
	Cambrian MTS	Core West – Pocket 1	-	2038	0	20
	Richmond South MTS	Core West – Pocket 1	-	2037	0	10
	Terry Fox MTS	Core West – Pocket 1	-	2037	0	30
	Lincoln Heights TS	Core West – Pocket 2	-	2040	0	10
	Woodroffe TS	Core West – Pocket 2	-	2040	0	10

6.3.1 Station Capacity Needs Kanata-Stittsville Subsystem

Kanata MTS has an LTR of 54 MW and is forecast to exceed capacity by 2024 in summer and 2026 in winter. By 2030, the projected winter overload is 15 MW, indicating continued and significant growth in demand. This early emerging need reflects increasing development across the Kanata area, necessitating reinforcements or capacity upgrades within the near term.

South March TS, with a winter LTR of 120 MW and summer LTR of 105 MW, is forecast to reach capacity by 2027 in both seasons. By 2030 the winter overload is projected to reach 23 MW. The station's two 230/44 kV transformers, in service since 1971, are due for replacement between 2030–2032, and the Working Group is evaluating whether to replace them with larger 75/100/125 MVA units.

Nepean TS has a winter LTR of 170 MW and is expected to exceed this rating by 2031. Although there is no summer need forecasted, the station is facing a load security issue: winter peak demand is projected to exceed 150 MW by 2029, and with M32S as the sole supply, an outage would violate ORTAC criteria by resulting in a full load loss. Addressing this concern will require both capacity and contingency planning for secure operation in the Kanata-Stittsville area.

6.3.2 Station Capacity Needs Core East Subsystem

Carling TS has a summer LTR of 100 MW and a winter LTR of 132 MW. It is projected to exceed capacity in 2028 (summer) and 2029 (winter). By 2030, the winter overload is expected to reach 17 MW, driven by ongoing electrification in Ottawa's downtown core. It is important to note that both Carling TS and Lisgar TS have hydroelectric generation supplying each station which has been accounted for in the forecast but contributes to the variability of the station capacity need.

Lisgar TS has an LTR of 77 MW (summer) and 86 MW (winter), with capacity needs emerging as early as 2025 (summer) and 2027 (winter). By 2030, the projected winter overload reaches 40 MW, one of the highest in the region driven by winter heating load as well as large customer connections.

Nepean Epworth MTS has an LTR of 13 MW for both summer and winter. It is forecast to reach capacity in 2031 (summer) and 2028 (winter), with a 2 MW winter overload expected by 2030. This modest but significant overload reflects continued urban infill in the surrounding residential area, requiring minor station upgrades or targeted load transfers.

Cyrville MTS, rated at 45 MW, is forecast to exceed capacity in 2029 (winter). The projected winter overload by 2030 is 3 MW. While no summer need is currently identified, load growth in the adjacent industrial and commercial areas is expected to continue contributing to the station's winter peak constraint.

King Edward TS has LTRs of 92 MW (summer) and 96 MW (winter). The winter capacity need is projected to emerge by 2026, with the overload reaching 40 MW by 2030. Though the summer need emerges much later (2037), the station will require substantial reinforcement to manage escalating winter demand, especially from institutional and high-density residential growth downtown.

Moulton MTS is rated at 33 MW in both seasons. It is expected to exceed capacity by 2028 (both summer and winter), with an 8 MW winter overload forecasted for 2030. Located in a growing mixed-use area, the station will require capacity upgrades or operational measures to accommodate new developments.

Riverdale TS has a summer LTR of 118 MW and a winter LTR of 124 MW. While its summer need arises in 2038, winter constraints begin much sooner, with a need emerging in 2028 and a 20 MW overload projected by 2030. The area includes a mix of mature neighbourhoods and new high-rise developments, putting increasing strain on winter capacity.

6.3.3 Station Capacity Needs Core West Subsystem

Bridlewood MTS has an LTR of 23 MW in both summer and winter. Winter need is expected by 2029, with a 2 MW overload projected by 2030. The summer need follows in 2032. This modest overload is driven by steady residential development and densification in the surrounding suburbs.

Centrepoint MTS has an LTR of 13 MW for both seasons and is expected to exceed capacity by 2024 (summer) and 2026 (winter). By 2030, the winter overload is forecast at 5 MW, indicating a strong and persistent local demand requiring targeted capacity relief in the near term.

Fallowfield MTS is rated at 25 MW and is projected to reach its summer capacity by 2024, followed by winter needs emerging in 2030. An 11 MW summer overload is forecast for 2030. Situated near key growth corridors, this station will need reinforcement to manage short- and medium-term demand increases.

Manordale MTS has an LTR of 9 MW and is expected to exceed capacity by 2024 (summer) and 2025 (winter). The projected winter overload reaches 5 MW by 2030. The small size of the station and its location in a maturing neighborhood mean that even moderate demand growth results in capacity pressure.

Marchwood MTS is rated at 30 MW and is expected to exceed capacity in both 2024 (summer) and 2025 (winter). By 2030, the winter overload is projected to reach 17 MW, making it one of the most constrained stations in the Core West subsystem. Rapid suburban expansion and limited load transfer capability intensify the need for reinforcement.

6.3.4 Station Capacity Needs Core South Subsystem

Limebank MTS has an LTR of 89 MW and is forecast to reach capacity in 2030 (winter), the LTR is limited by a load security constraint, once this is remedied the LTR of the station increases significantly. By 2030, the projected winter overload is modest at 1 MW, but demand is expected to intensify as development continues along the expanding Limebank corridor. Early planning for reinforcement may help pre-empt longer-term constraints. Greely DS is expected to reach its LTR in 2024 and Marionville DS in 2026.

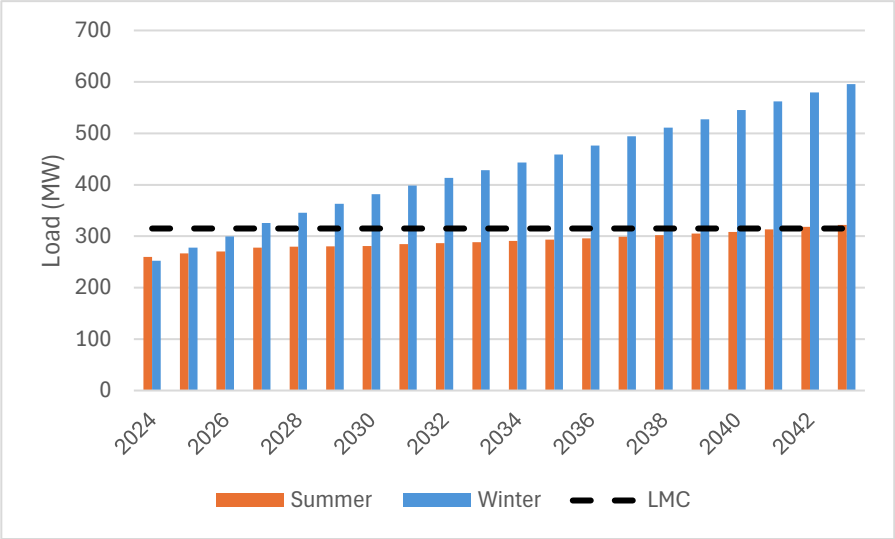
6.4 System Capacity Needs

6.4.1 System Capacity Needs Kanata-Stittsville Subsystem

This subsystem is supplied by two transmission circuits, one from Chats Falls (C3S) and one from Merivale TS (M32S). The loss of both of these circuits would mean all stations in the area (Kanata MTS, South March TS, and Nepean TS) would be out of power. This would be a load security consideration, the maximum allowable load lost by configuration for two elements is 600 MW and as their combined LTR is 312 MW in the summer and 345 MW in the winter. The subsystem only reaches 600 MW in the winter in 2043 which assumes a fully electrified heating load.

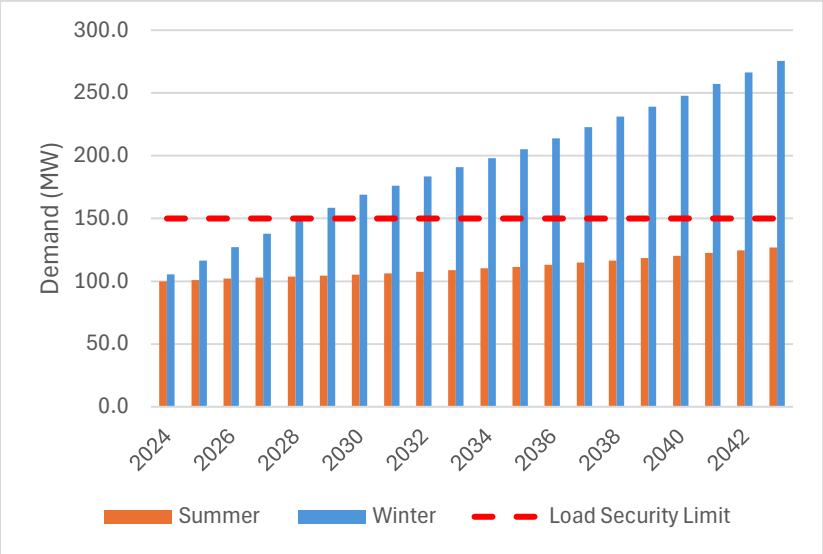
Losing either of the circuits supplying the area leads to voltage instability at varying load levels and it was found that the most limiting configuration is having M32S on outage followed by a contingency on C27P. This occurs at roughly 310 MW which is near the summer LTR for the subsystem as seen in **Figure 19**. There are no System Capacity needs for the summer forecast.

Figure 19 | Reference Forecast vs LMC for Kanata-Stittsville



There is also an additional load security issue in this subsystem as well. For an M32S contingency, beyond losing one of the two supply circuits for this subsystem, the entire load at Nepean TS is lost by configuration as well. Load security requires that no more than 150 MW can be lost for a single element contingency. **Figure 20** shows the Nepean TS forecast compared to this limit. This limit is not reached in the summer forecast, but is reached in 2029 in the winter forecast.

Figure 20 | Nepean Load Forecast vs Load Security Limit



6.4.2 System Capacity Needs Core East

Core East Pocket 1 is supplied by circuits M5G and M4G. The limiting phenomenon is a thermal overload on each circuit when the companion circuit is lost, as both Lisgar TS and Carling TS would be fully supplied by the remaining circuit. It was found that a contingency to M5G was more limiting, leading to an LMC of 223 MW, as seen in **Figure 21**.

Core East Pocket 2 consists of many more circuits and stations. The combined LTR of all the stations is about 600 MW, or just above 750 MW, including Slater TS. This is important because the summer forecast does not reach this figure, while the winter forecast exceeds it by over 600 MW as seen in **Figure 22**. The studies evaluating the system today find that voltage instability issues occur at a loading above the combined station LTR.

Figure 21 | Reference Forecast vs LMC for Pocket 1

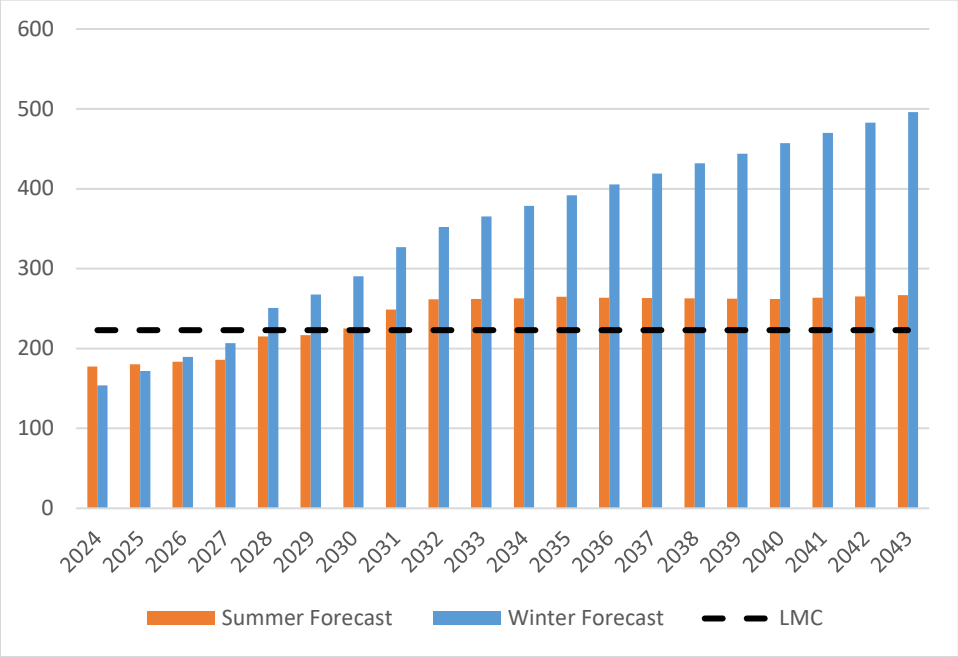
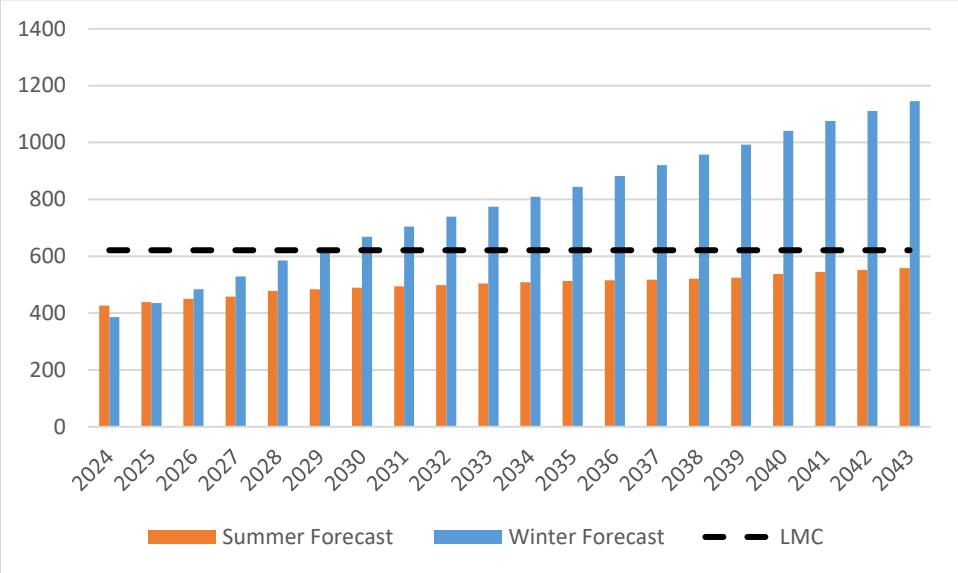


Figure 22 | Reference Forecast vs LMC for Pocket 2



6.4.3 System Capacity Needs Core West Subsystem

The Core West subsystem was found to have healthy voltages, and no voltage violations were found as part of the technical studies. The LMC of the two pockets was found to be limited by thermal overloads. For Pocket 1, which is made up of loads supplied by S7M, as seen in **Figure 17**, the most limiting contingency is a loss of E34M, which transfers Cambrian MTS onto S7M, leading to a thermal

overload on the branch of circuit emanating from Merivale TS to the junction right before the circuit continues south, which is approximately 5km long. **Figure 23** shows that the forecast will not exceed the identified limit of approximately 250 MW in the summer but will do so in the winter in the medium-term.

As for pocket 2, the thermal overload identified as the most limiting occurs during a contingency to F10MV which places both Woodroffe TS and Lincoln Heights TS solely on C7BM, where thermal overloads begin to occur at around 230 MW of combined station load. The loss of C7BM also causes an overload on certain sections of F10MV, but is not more limiting. **Figure 23** and **Figure 24** illustrate the limits versus the expected forecast. In both cases, these needs occur only in the winter.

Figure 23 | Reference Forecast vs LMC for Core West Pocket 1

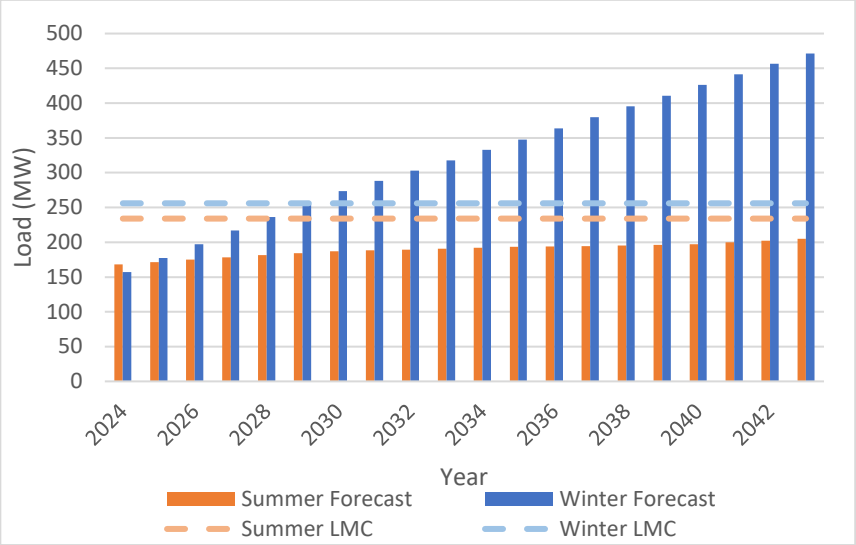
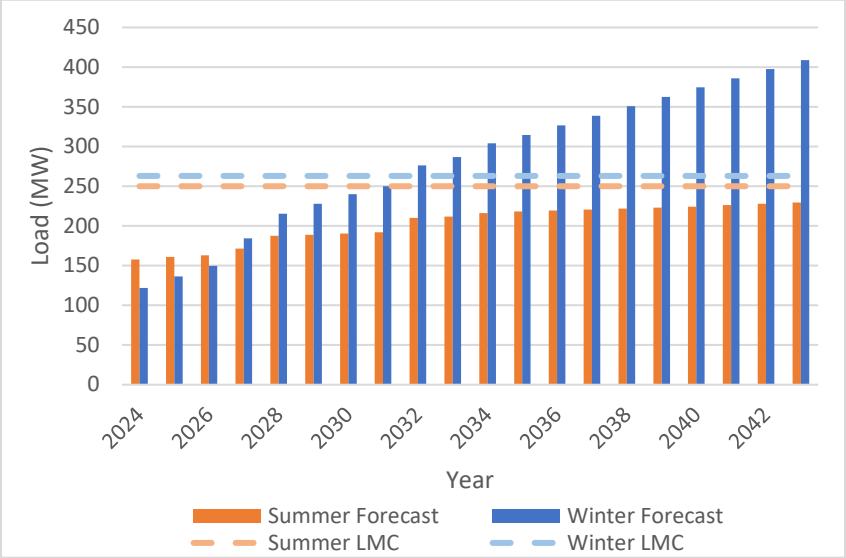


Figure 24 | Reference Forecast vs LMC for Core West Pocket 2

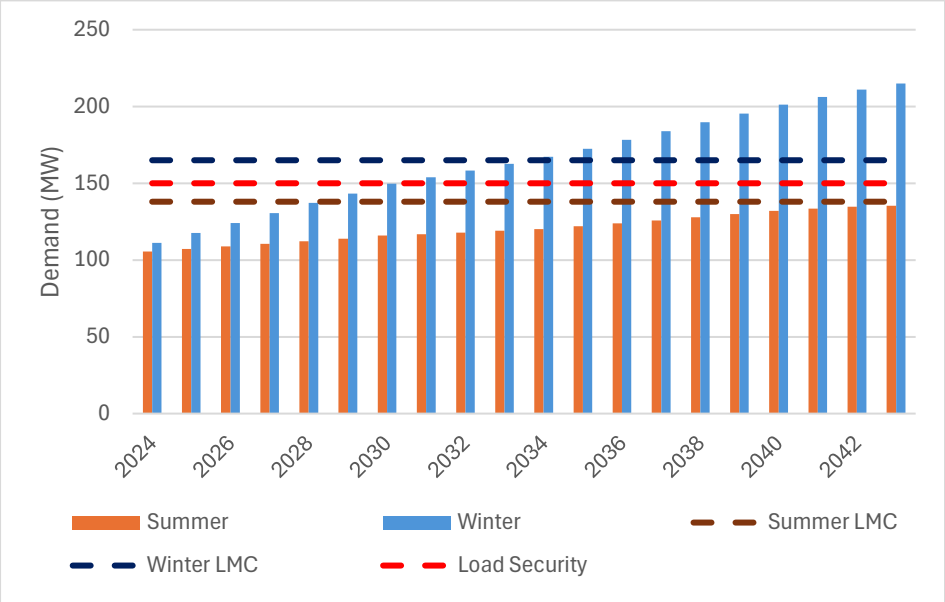


6.4.4 System Capacity Needs Core South Subsystem

There are no relevant contingencies to study in this area, since the loss of either circuit results in both circuits being tripped. This is due to L2M and M1R sharing a breaker position at Merivale TS. The limiting phenomenon in Core South is a thermal overload on the portion of L2M between Merivale TS and Limebank MTS, which occurs around the end of the medium term (2034). By scaling the stations how they are expected to grow in the next 20 years, this thermal overload happens at a load of 140 MW in the summer and 165 MW in the winter among the five stations in the subsystem. This overload is almost entirely caused by the loading on Limebank MTS. The second most limiting phenomenon in this subsystem would be voltage instability, but this limit is not approached in the 20-year forecast. The combined LTR of the stations in Core South is 160 MW in both summer and winter, meaning the limit of this subsystem is reached around the same time the station capacities would be reached.

Core South also has a limit on its total load growth of 150 MW, due to load security as seen in **Figure 25**. By design, the system must limit load loss to no more than 150 MW if a single element fails. In Core South, however, the two lines share a breaker position, so a contingency (fault) on one line causes both to be out of service. This effectively makes the two circuits a single element. As a result, this configuration becomes the most limiting factor in the winter.

Figure 25 | Reference Forecast vs LMC for Core South



6.5 End-of-Life/Asset Replacement Needs

6.5.1 Asset Replacement Needs Core East Subsystem

Lisgar TS has an LTR that is expected to be exceeded in 2026, based on the coincident forecast. Transformer T1 was in-serviced in 1974 and needs replacement. This replacement to a 45/60/75MVA transformer was planned to be in-serviced 2031–2033.

The Working Group determined that the transformer should be upgraded to a 60/80/100 MVA unit, instead of a 45/60/75MVA unit.

6.5.2 Asset Replacement Needs Core West Subsystem

Sections of circuit S7M have asset renewal needs. Decisions on the preferred option to address the asset renewal need should consider prefer supply configuration for the area. Two sections that need to be refurbished are Manotick JCT x Richmond MTS (5.2km) and STR 673N JCT x Manordale MTS (1.4km). The Working Group recommends the need be further reviewed to determine the preferred supply option for the area.

6.5.3 Asset Replacement Needs Core South Subsystem

No asset replacement needs were identified for Core South.

6.5.4 Asset Replacement Needs Kanata-Stittsville Subsystem

South March TS has an LTR that is expected to be exceeded in 2027 based on the coincident forecast.

South March has two 230kV/44kV, 50/67/83 MVA transformers in-serviced in 1971 which need replacement. The Working Group recommends to upgrade the transformers to 75/125 MVA units. This project is planned to have an in-service date of 2030–2032.

7. Plan Options and Recommendations

This section outlines the options considered and presents recommendations to address the electricity needs in the Ottawa Area Sub-Region. In developing the plan, the Working Group considered a range of integrated solutions, taking into account factors such as feasibility, cost, implementation timelines, system benefits, and consistency with the region's long-term electricity needs.

To meet the growing regional electricity demand, there are generally two types of approaches:

- Transmission/Distribution Infrastructure Expansion ("Wires" Options): These involve building new facilities or upgrading existing assets to increase the area's LMC. Examples include new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or enhancements to existing infrastructure. Wires solutions may also encompass operational measures such as control actions or protection schemes that optimize system performance and mitigate reliability concerns.
- Demand Reduction, Management, or Local Generation ("Non-Wires" Solutions): These aim to reduce peak electricity demand so that it remains within the system's existing LMC. Examples include local utility-scale generation or energy storage, distributed energy resources (such as distribution-connected generation and demand response), demand-side management programs, and distribution-level load transfers.

Section 7.1 provides a detailed overview of the various types of options typically considered in Integrated Regional Resource Plans. Section 7.2 outlines the screening methodology used to identify which needs were most appropriate for further assessment of non-wires solutions. Sections 7.3 through Section 7.6 present the specific options that were developed and evaluated, leading to the Working Group's final recommendation.

7.1 Options Considered in IRRPs

Wires solutions are a core part of regional planning and are developed by identifying transmission upgrades or control measures tailored to address the specific technical limitations—such as voltage, thermal, or stability concerns—associated with each need. These solutions are shaped through collaboration with the Working Group.

While traditional wires infrastructure remains a reliable solution for addressing regional electricity needs, certain non-wires options may be better suited to specific types of needs and system characteristics. Selecting and sizing these alternatives—such as local generation or storage—requires additional analysis, including the development of an hourly load profile, as outlined in Section 5.7. The most appropriate technology and capacity are determined by examining the "unserved energy" profile, which highlights the portion of demand that exceeds the area's existing LMC. This profile provides key insights into the duration, frequency, magnitude, and total energy shortfall for each identified need. Visual representations of these characteristics for the Ottawa Area Sub-Region are provided in Appendix D.

High-level cost estimates for wires options are provided by the transmitter. For non-wires alternatives—such as generation or storage—cost estimates are based on industry benchmarks for capital and operating cost characteristics for each resource type and size. The costs for wires options presented are in terms of capital costs and represent a high level planning estimate while non-wires costs are net present value. In line with current policy direction and decarbonization goals, new natural gas-fired generation was not considered. Instead, battery energy storage, solar, and wind generation were evaluated as potential non-wires solutions.

Additional eDSM programming can also help decrease the net electricity demand. Expected peak demand savings from the 2021-2024 eDSM framework and subsequent frameworks (under the **Save on Energy brand**) are already included in the load forecast, as discussed in the Section 5.4. As part of this framework and the new 2025-2036 framework, the IESO was enabled to deliver a new program to address regional and/or local system needs. The **Local Initiative Program** is now one tool that is available to target the delivery of additional eDSM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[3] Generally, incremental eDSM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating costs are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The net present value (in 2024 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It's important to note that planning-level cost estimates carry a significant margin of uncertainty, as they are developed without detailed engineering design or field assessments. These estimates are intended to support high-level comparisons between options during the IRRP process, rather than provide precise project costs. The RIP, which follows the IRRP and/or supports specific projects, includes more detailed analysis and provides an opportunity to refine cost estimates for wires solutions. The IESO remains actively involved in the Working Group during the RIP and engages with the transmitter if significant differences in cost estimates arise. In cases where downstream barriers—such as regulatory challenges around cost-sharing or the need to address local reliability constraints—limit the implementation of otherwise cost-effective solutions, pilot or demonstration projects may be pursued to explore their feasibility.[4]

The list of assumptions made in the economic analysis can be found in Appendix F.

[3] More information about the eDSM Guidelines is available on the Ontario Energy Board's **website**

[4] Barriers to non-wires alternatives and recommendations to address them were a part of the **Regional Planning Process Review**

7.2 Screening Options

As explained in Section 7, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the option that is most cost effective, or the option that best balances cost and risk mitigation when substantial additional risks not captured by the Planning forecast are present. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) toward the most promising options. The three-step, high-level approach is shown in **Figure 26**, and the results of its application to the Ottawa Area Sub-Region IRRP needs are summarized in **Table 6** and then further described in **Table 7** and in the sections below.

More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 26 | IRRP Screening Mechanism

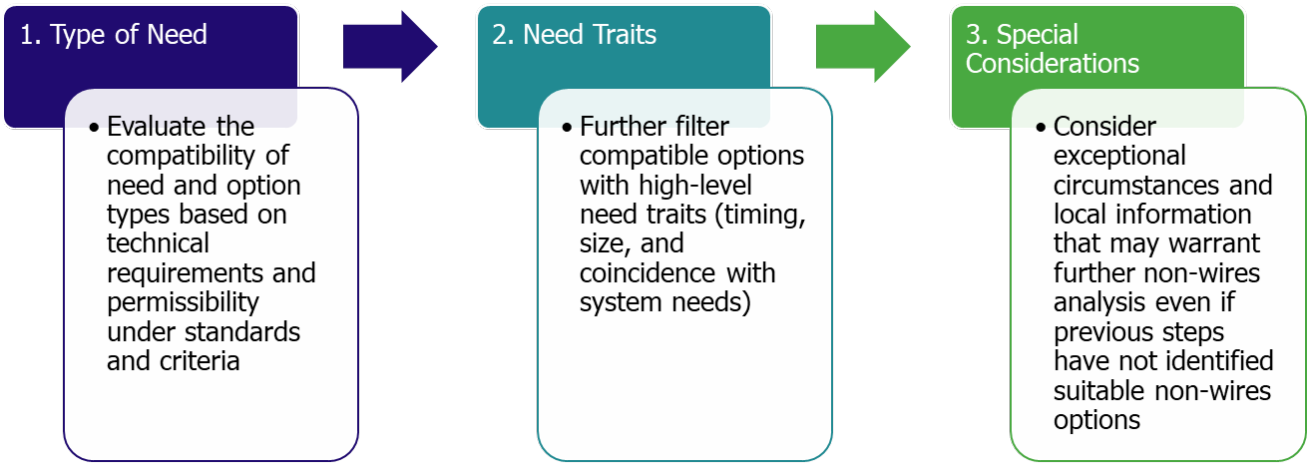


Table 6 | Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity	• eDSM • Distributed generation • Wires options	• Demand response – due to magnitude and timing of needs, and limited DR capacity historically offered in this area • Operational measures

Table 7 | Options Screening Results for System Capacity Needs

Need	Screened In	Screened Out
System Capacity: Thermal, Voltage, Load Security	• eDSM • Distributed generation • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of needs, and limited DR capacity historically offered in this area • Operational measures due to complexity of Ottawa system

7.2.1 Non-Wires Options for the Station Capacity Needs

A range of non-wires solutions—including transmission-connected generation, BESS, demand response, and hybrid approaches—were considered as part of the planning process. Given the significant forecasted load growth and the resulting number of station capacity needs, a practical screening approach was necessary to focus on the most feasible and impactful options. While eDSM programs alone are unlikely to significantly defer most of the identified needs, they remain important for slowing the pace of demand growth—supporting the timely development of long-term infrastructure solutions.

Due to the time and resources required for in-depth evaluation, it was not practical to assess non-wires options at every individual station. Instead, needs were grouped and prioritized based on where non-wires solutions—such as wind, solar, and battery storage—were most likely to be viable. This focused analysis was conducted for station groups within the Kanata-Stittsville, Core East Pocket 1, and Core East Pocket 2 subsystems.

7.2.2 Non-Wires Options for the System Capacity Needs

Among the System Capacity needs identified, four circuits were found to be limited by thermal constraints. Based on the current range of non-wires solutions, none were considered feasible for addressing these specific limitations. In contrast, the voltage stability concern identified in the Kanata-Stittsville subsystem was well suited for non-wires options and was therefore examined in greater detail. Additionally, two major battery storage projects—each exceeding 100 MW—have been proposed in the Ottawa area. Their potential impact on the regional electricity system has been assessed, with findings and observations outlined below.

7.3 Options and Recommendations for the Kanata-Stittsville Subsystem

The Kanata-Stittsville subsystem, while relatively straightforward in design, is facing rapid load growth and is expected to reach its LMC in the near term. Technical studies show that the loss of either of the two existing supply circuits—particularly from Merivale TS—would cause voltage stability issues under peak conditions, and a contingency at Nepean TS is projected to become a load security concern by 2029 in the winter if the electrification load materializes are projected.

To meet increasing demand and improve reliability, a new transformer station and an additional 230 kV transmission circuit are required. A preferred option has been identified to connect a new "Kanata North" station to C3S from Chats Falls TS and a new 230 kV circuit from Merivale TS, potentially achieved by rebuilding M32S or C7BM. This not only adds transformation capacity but also helps relieve pressure at Kanata MTS and South March TS while supporting future growth at nearby stations like Marchwood and Bridlewood.

A key component of the recommended solution is the development of a switching station in the area. The switching station will serve as a central hub, enabling better contingency response, operational flexibility, and future expansion potential, including the ability to connect additional infrastructure or circuits as system needs evolve. Consistently highlighted during public engagement, the switching station responds directly to local priorities around improving resiliency and reliability. Strategically, it also positions the system to accommodate future upgrades, including a potential second connection to Chats Falls or integration with a broader 230 kV network, depending on outcomes from the East Bulk Study.

While large-scale non-wires alternatives such as wind, solar, and nuclear were considered, they were found to be potentially economically practical but technically infeasible for the identified needs. A combination of a renewable resource and a BESS requires a substantial amount of land. However, this approach does not address station capacity needs. While it may provide energy to support load growth, the electricity is still constrained by the capacity of the station's transformers. As a result, new transformation stations are still required. However, with consideration of system benefits (i.e. avoided provincial capacity and energy), it is *possible* that these provide ratepayer value, though a larger bulk system study is needed to inform where to optimally place utility-scale resources to address provincial needs.

A proposed BESS project from the LT1 procurement—originally intended for another municipality—has been relocated to the Kanata-Stittsville area, where it can deliver greater grid benefit by discharging during peak periods and improving load-serving capability. This means that the Kanata-Stittsville area will be reinforced with both wires and non-wires solutions.

In summary, the recommended plan for Kanata-Stittsville includes:

A new transformer station north of the existing Kanata MTS,

A new 230 kV transmission line from Merivale TS, 18km

Connection to the existing C3S line,

A strategically located switching station,

Station upgrades at South March TS, and

A second supply to Nepean TS

Together, these elements form a resilient and scalable infrastructure solution that addresses near-term needs while establishing a strong foundation for long-term system performance.

Figure 27 | Kanata-Stittsville Recommendations

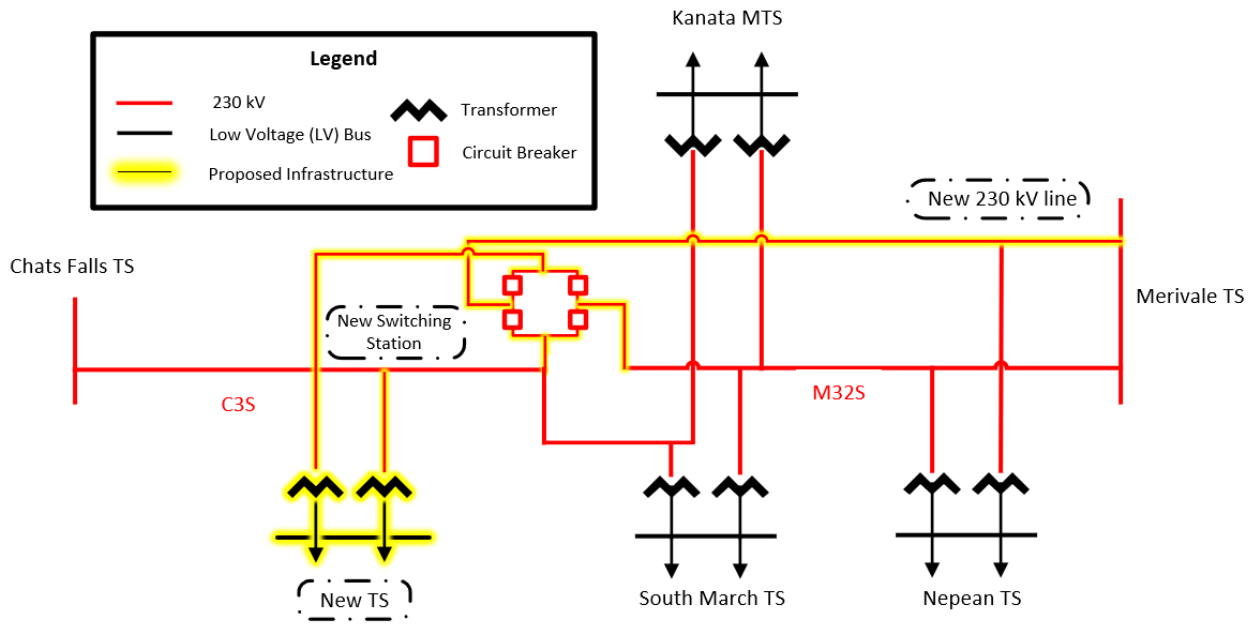


Table 8 | Wires Options for Kanata-Stittsville Subsystem

#	Description	High Level Planning Cost Estimate[5]
1	New 230 kV circuit to connect to the new station and Nepean TS from Merivale TS. The new station will tap to C3S	$185M+$45M
2	New 230 kV circuit from Merivale TS to switching station at South March TS. Nepean TS becomes double supply, all other stations connect to the switching station including a new station	$250M+$45M
3	Station transfer Kanata MTS to new station	$5-10M
4	Station transfer South March TS to new station	$0-5M
5	Station upgrade at South March TS	$40M

[5] All cost estimates are capital cost values

7.4 Options and Recommendations for the Core East Subsystem

7.4.1 Core East Subsystem – Pocket 1

Capacity needs in Pocket 1—especially at Lisgar TS, Carling TS, and Nepean Epworth MTS—are projected to emerge within five years and intensify during winter. Demand at Lisgar and Carling is expected to exceed LTRs by 30–40 MW, requiring a stepwise approach across the short, medium, and long term.

Near-term relief could come from transferring load to Nepean Epworth MTS, which is connected to Merivale TS, where about 15 MW of spare capacity is available. While Slater TS also has capacity, only Lisgar TS is a feasible candidate for transfers due to the lack of distribution ties.

Station upgrades offer another path:

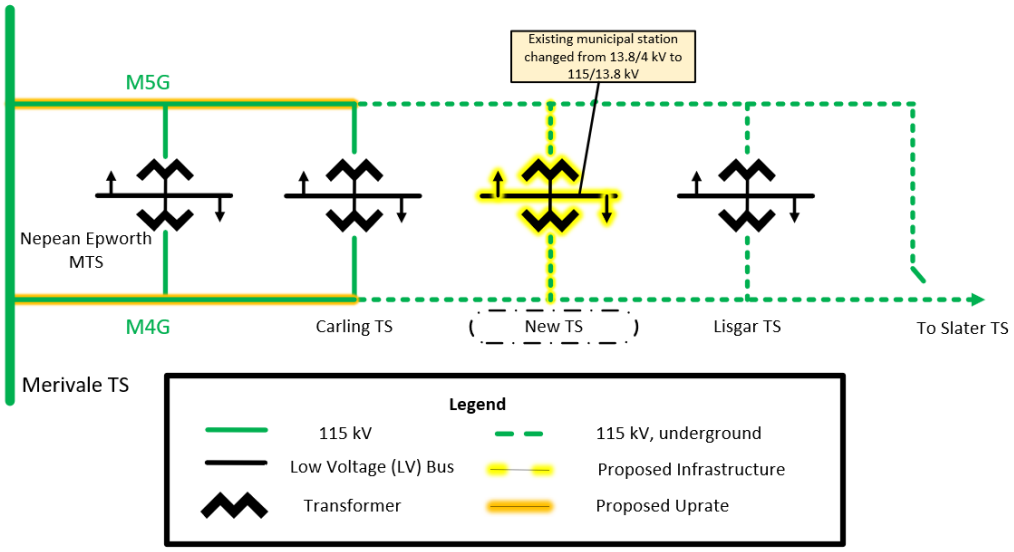
- At Carling TS, an upgrade could mitigate low-voltage limitations.
- At Lisgar TS, replacing transformer T2 and associated equipment could add ~45 MW.

Other options, such as relocating Carling TS to V12M and F10MV, were found to offer limited benefit due to space constraints and their inability to add new capacity.

Building a new transformer station and transmission lines in this dense area is technically viable but faces steep costs and logistical challenges. However, a promising alternative is to convert Bronson Station from a municipal distribution station to a 115 kV DESN station. Located between Carling TS and Lisgar TS along the M4G/M5G corridor, Bronson MTS could relieve adjacent stations via load transfers and by servicing future load. It is situated in a convenient location close to the 115 kV transmission lines but will require new transformers and significant cable connections. The approximate cost for this conversion is $65 million. This option would require uprating M4G and M5G to address thermal constraints.

Given the densely populated area, wind and/or solar options were screened out as feasible NWA's given the size of the need, and the land-use requirement of the facility that would be required to serve this need. However, A BESS-only NWA was assessed as a possible option, though it would only provide transmission deferral value through deferring investment by 2 years, but at a significant cost of $3.8 to 4.2B. Accordingly, the most practical solution for Pocket 1 is a combination of station expansions, targeted load transfers, and development of Bronson MTS.

Figure 28 | Core East Pocket 1 Recommendations



7.4.2 Core East Subsystem – Pocket 2

Pocket 2 encompasses much of Ottawa's downtown and is supplied by a tightly integrated 115 kV network. Nearly all stations are forecast to reach capacity within 20 years, particularly in winter, posing a major long-term planning challenge.

Given the urban density, expanding the network—especially with 230 kV infrastructure—is technically complex and expensive. Required upgrades at Hawthorne TS, the use of underground cables, and land constraints for new stations further limit this pathway.

Instead, the focus is on maximizing existing infrastructure and pursuing targeted improvements while managing the pace of demand growth. Near-term investments include:

- King Edward TS: ~35 MW through breaker and cable upgrades
- Albion TS: potential expansion through transformer upgrades

The upcoming LAPS will help identify eDSM opportunities, including energy efficiency, demand response, and behind-the-meter solar and storage measures. Demand reduction remains the most effective way to delay or avoid large-scale upgrades—every deferred megawatt reduces long-term cost and complexity.

A medium-term solution is to convert Cyrville TS to 230 kV using circuits D5A and a new A25, which would alleviate 115 kV constraints and allow for relocation of Cyrville MT's transformers to Moulton TS, upgrading both stations in the process.

An ongoing project at Merivale will add a third autotransformer by 2029 which will help support growth in the medium/longer term. It is possible to install a fourth autotransformer in the future, but

beyond that, capital investments exceeding $1 billion could be unavoidable if demand continues rising.

Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station

Connect the new Transformer Station to existing 115 kV transmission circuits M4G and M5G

Uprate sections of M4G and M5G, 12km

Proceed with station upgrades at Albion TS, Carling TS, Lisgar TS, Russel TS, King Edward TS

Proceed with distribution load transfers at Riverdale TS, Nepean Epworth MTS, Ellwood MTS

Convert Cyrville MTS from 115kV to 230kV station

Repurpose Cyrville MTS transformers at Moulton TS for station rating increase

Leverage insights from the LAPS to help slow demand growth in the downtown core, while continuing to monitor load trends between planning cycles

Figure 29 | Core East Recommendations

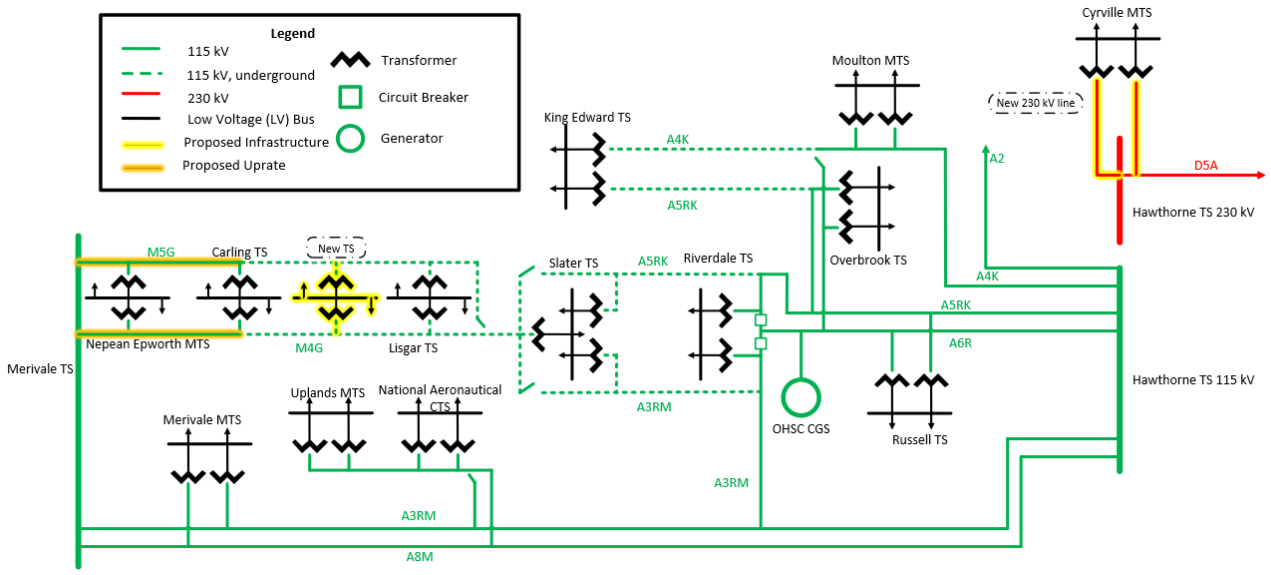


Table 9 | Wires Options for Core East Subsystem

#	Description	High Level Planning Cost Estimate[6]
1	New 115kV Transformer Station Connected to M5G and M4G, Convert Existing Bronson Station	$35M + $65M
2	Connect Carling TS to V12M and F10MV	$30M
3	Convert Cyrville TS to 230kV	$40M
4	Distribution Load Transfers – Hydro Ottawa/Hydro One Distribution	$0-5M per station

7.5 Options and Recommendations for the Core West Subsystem

7.5.1 Core West Subsystem – Pocket 1

For the area supplied by circuits S7M, W6CS, and E34M, three near-term station capacity needs have been identified—Bridlewood MTS, Marchwood MTS, and Fallowfield MTS—with three more expected in the long term.

Bridlewood MTS and Marchwood MTS are located in or near the Kanata-Stittsville area. Addressing their needs should align with broader upgrades planned for Kanata-Stittsville. As described in Section 7.3, the recommended approach for Kanata-Stittsville involves building a new 230 kV transformer station, supplied by a new 230 kV circuit from Merivale TS, which would also provide a secondary supply to Nepean TS. Since South March TS and Kanata TS will also benefit from additional capacity in the area, to address Bridlewood and Marchwood's capacity needs in the short term, the Working Group recommends implementing distribution load transfers—an efficient and cost-effective solution compared to building or upgrading stations.

Fallowfield MTS requires additional consideration. Several factors shape the recommendation:

- Circuit breakers were upgraded in 2018.
- Part of the S7M line has already been refurbished for future 230 kV operation.
- Load growth is expected in the area immediately north of the station, particularly for 28 kV distribution supply.

Based on these factors, multiple options were considered: upgrading the station, transferring load to Cambrian MTS, or transferring to a future new station. The Working Group recommends a phased approach:

- Short term: Transfer load to Cambrian MTS.

[6] All cost estimates are capital cost values

- Medium term: Shift load to a new station north of Fallowfield MTS.
- Long term: Upgrade Fallowfield MTS to 230 kV (requires conversion of S7M to 230 kV operation).

A separate thermal overload concern was identified in Pocket 1 during a contingency involving the loss of E34M and the transfer of Cambrian MTS load onto S7M. To address this long-term need, the Working Group assessed both wires and non-wires options and views the voltage conversion of S7M and the stations in the area to 230 kV would offer several benefits:

- Converting stations to 230 kV would result in increased station capacity to support future load growth.
- Shifting load from the 115 kV system to the 230 kV system would preserve load growth capacity for other stations, particularly those in densely built areas like the downtown core, where expansion is difficult.
- A new circuit could provide a second supply to Terry Fox MTS, which, like Nepean TS, currently relies on a single supply circuit with measures in place to allow for faster restoration.

To manage costs and avoid asset stranding, the S7M conversion should be implemented in phases. The Working Group recommends converting only the southern section of S7M, maintaining the northern portion that supplies Bridlewood MTS and Marchwood MTS and retaining its open-point connection to C7BM to preserve to ensure the 115kV generation connections northwest of the city are maintained.

The first step in the transition involves constructing a new 230 kV circuit from Merivale TS westward to the new station, which could later be extended to supply Terry Fox MTS. Station upgrades would follow at Manotick DS, Richmond South MTS, and Cambrian MTS, with the circuit initially connecting at the S7M junction. Once complete, these upgrades will provide a second 230 kV source to key stations, significantly improving system resilience.

In the medium-term, thermal overload risks remain on the Merivale TS end of S7M during an E34M outage. Until the full conversion is completed, interim relief could be provided through non-wires alternatives and distribution load transfers from Cambrian MTS to the new station if demand rises quickly.

Finally, the Working Group reviewed the proposed Trail Road BESS battery project, announced under the LT1 procurement. While it will support overall grid resilience, it connects to E34M and would not relieve loading on S7M unless a direct connection is also established.

7.5.2 Core West Subsystem – Pocket 2

Two smaller stations in this pocket—Manordale MTS and Centrepoint MTS—are facing capacity constraints. Due to growing demand and specific large customer requests, there is a need for 28 kV distribution in the area. However, both stations currently operate at only 8 kV, making them unable to meet this requirement. As a result, a new transformer station is needed.

One option considered was redeveloping Manordale MTS as a DESN station, but this was deemed unfeasible due to space limitations at the site. The alternative is to construct a new station at a

different location. While a final site has not yet been selected, Hydro Ottawa is actively evaluating several options and is responsible for determining the final location.

The northern portion of the system was found to have thermal overloads. The main stations contributing to this are Lincoln Heights TS and Woodroffe TS and are not forecast to reach their capacity until the winter in the long-term. Therefore, the most economical solution is to simply uprate the segments of cables identified.

Build a new 230kV Transformer Station west of Merivale TS

Build a new 230kV transmission line westwards from Merivale TS along existing corridor, 5 km

Connect the new Transformer Station to E34M and new transmission circuit

Uprate sections of M4G and M5G, 10km

Uprate sections of C7BM and F10MV, 8km

Incorporate BESS resulting from LT1 procurement to improve area's voltage and reliability

Figure 30 | Core West Recommendations

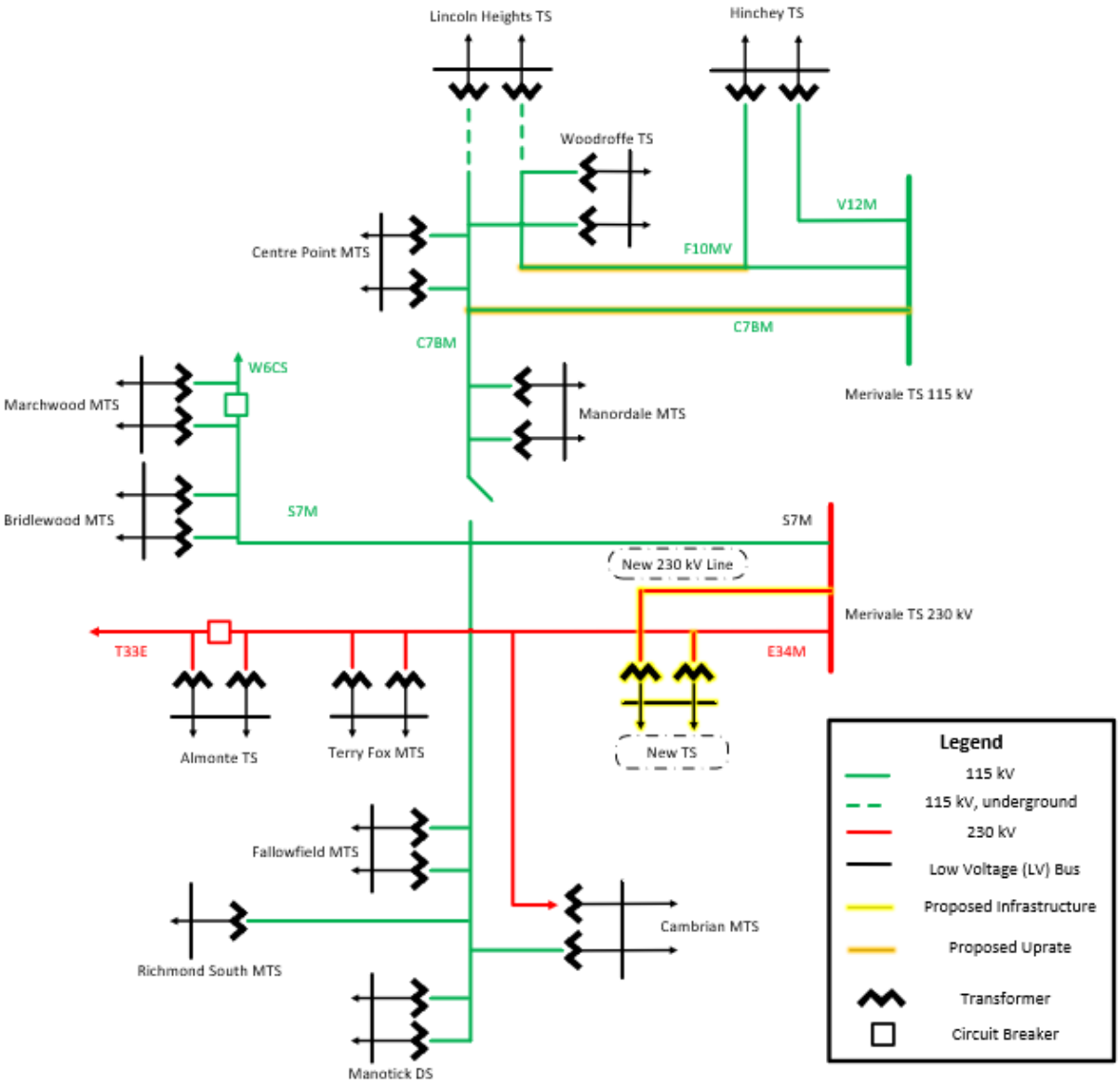


Table 10 | Wires Options for Core West Subsystem

#	Description	High Level Planning Cost Estimate[7]
1a	Fully Convert S7M to 230 kV	-
2a	New 230kV Circuit to S7M STR Junction, Convert Southern Portion of S7M to 230kV, Keep Existing 115kV S7M Connecting to W6CS	$100M
2b	New 230kV Circuit to Connect Terry Fox MTS and new Greenbank MTS	$90M
2c	New 230 kV Circuit to Terry Fox, Convert Southern Portion of S7M to 230 kV, Keep Existing 115 kV S7M Connecting to W6CS	$140M
3a	Fully uprate C7BM and F10MV	$50M
4a	Reconductor S7M, keep 115kV	$15M
5	Distribution Load Transfers – Hydro Ottawa/Hydro One Distribution	$0-5M per station

7.6 Options and Recommendations for the Core South Subsystem

Three stations in Core South—Limebank MTS, Greely DS, and Marionville DS—are forecast to exceed their long-term ratings (LTRs) within the next five years, requiring immediate action to address upcoming capacity shortfalls.

Given the scale and timing of these needs, station transfers and upgrades were the only solutions considered, as building a new station was deemed cost-prohibitive relative to projected demand outlook. In the near term, minor overloads at Limebank MTS can be addressed through distribution-level load transfers to Piperville MTS, which is scheduled for energization in 2026 and will be connected to the 230 kV L24A circuit. This transfer also reduces loading on the 115 kV system, contributing to better overall system balance.

For Marionville DS, the recommended action is to install a second transformer to increase capacity. At Greely DS, the proposed solution involves enabling supervisory control and data acquisition (SCADA) monitoring, allowing for an increase in respected transformer limits and improving station performance.

To meet load security requirements in Core South, the most effective strategy is the installation of a breaker between circuits L2M and M1R at Merivale TS. This change would ensure that a loss of both

[7] All cost estimates are capital cost values

circuits would only occur under a double contingency, which is significantly less likely and subject to a higher load rejection threshold of 600 MW.

For medium-term System Capacity needs, three main options were assessed:

1. Uprating segments of circuit L2M between Merivale TS and Limebank MTS to avoid thermal overloads.
2. Converting Limebank MTS to a 115 kV DESN, supplied by M1R and L2M. While Limebank's projected peak load remains below 150 MW (permissible under single contingency criteria), the station has four transformers, and adding a second supply would significantly improve system reliability.
3. A long-term option involves converting Limebank MTS to a 230 kV DESN, supplied by two new circuits from the St. Lawrence region. However, this would require comprehensive bulk system studies to determine the feasibility of extending 230 kV infrastructure from the St. Lawrence area to Merivale TS. As such, this remains a long-term vision rather than a near- or medium-term solution.

Build a new breaker position at Merivale TS and separate circuits M1R and L2M

Proceed with station upgrades at Greely DS and Marionville DS

Distribution load transfer from Limebank TS to Piperville TS

Figure 31 | Core South Recommendations

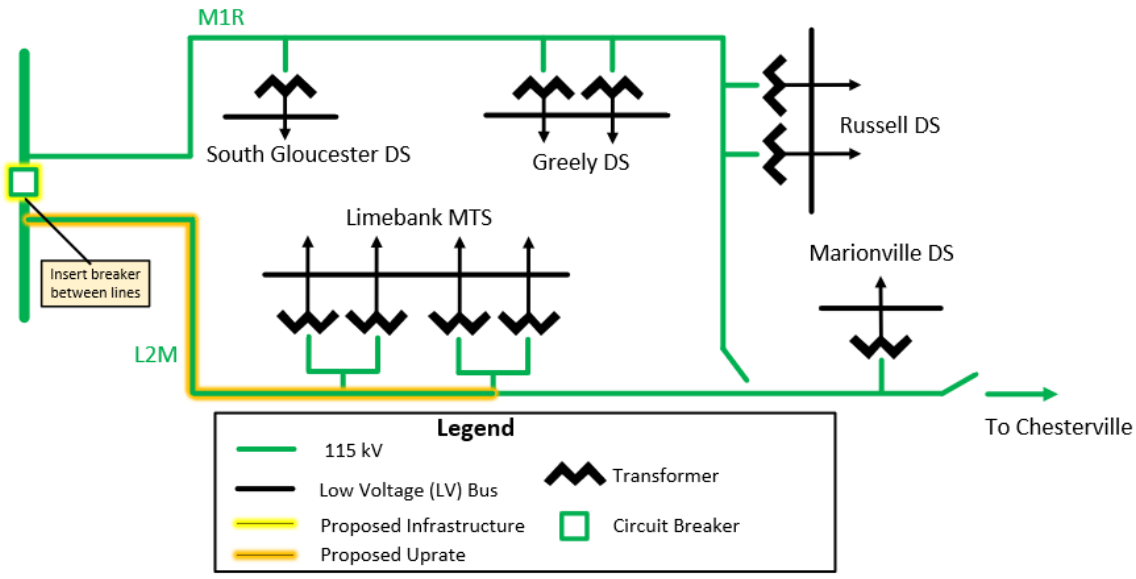


Table 11 | Wires Options for Core South Subsystem

#	Description	High Level Planning Cost Estimate[8]
1	New breaker position at Merivale TS to separate L2M and M1R	$30M
2	Uprate segments of L2M from Merivale TS to Limebank MTS	$25M
3	Convert Limebank MTS to 115 kV DESN	N/A
4	Convert Limebank MTS to 230 kV DESN	N/A
5	Station transfers	$5M
6	Station upgrades	$12M+$3M

[8] All cost estimates are capital cost values

7.7 Long-Term Considerations

7.7.1 Kanata-Stitsville Subsystem

This subsystem, defined by the 230 kV transmission circuits and transformer stations that supply the Kanata-Stittsville area, is experiencing a period of rapid economic development, which will require accessible and reliable electricity. A number of investments—including a new transformer station, transmission circuit, switching station, and potential BESS site—have been recommended in this report to help meet these goals. These investments are designed to increase both station and System Capacity, improve resiliency via the switching station, and enhance power quality and flexibility through the proposed BESS project.

Once these investments are implemented, the Kanata-Stittsville Subsystem will consist of one transmission circuit from the Chats Falls area (C3S), two circuits from Merivale TS (including M32S and the proposed new circuit), four transformer stations to supply power, and a strategically located BESS which can help meet peak demand and support voltage stability in the area.

The long-term vision for this subsystem continues to reinforce each component. The new circuit and switching station significantly improve supply from the Merivale side but do not yet enhance the supply path from Chats Falls. As such, a future consideration is to extend the new transmission circuit to Chats Falls TS, which would increase the LMC of the subsystem and provide a second path for hydroelectric generation to reach Ottawa loads. In general, the growth projected by demand forecasts will require reinforcement of Ottawa's western supply, which is being explored under the East Bulk Plan. One promising option includes the development of a new autotransformer station—similar to Merivale TS and Hawthorne TS—in western Ottawa. The proposed switching station has been recommended with this potential in mind and is being designed to accommodate a connection to this new substation, further strengthening the capability and flexibility of the Kanata-Stittsville system.

If demand grows at a faster pace than forecast—particularly due to unforeseen industrial or large commercial developments—a second transformer station beyond what is currently planned (e.g., in addition to Kanata North MTS) may be required. A more detailed assessment of the Kanata study area will help clarify the actual capacity available within this new configuration and determine the timing and scope of future infrastructure.

7.7.2 Core East Subsystem

This subsystem is defined by the 115 kV network that supplies most of Ottawa's downtown core. Given the complexity and limited physical space for new infrastructure in the downtown area, the focus of this plan is to maximize existing assets and strategically pursue upgrades to avoid large-scale overhauls. This plan recommends increasing station capacity by upgrading Carling TS, Lisgar TS, and Riverdale TS, while also gaining additional capacity through the conversion of Bronson TS from a distribution station to a transmission supply point, and converting Cyrville MTS from 115 kV to 230 kV.

The Working Group recommends implementation of the additional cost-effective eDSM potential that will be identified in the LAPS, which promote non-wires alternatives to mitigate load growth, including energy efficiency programs, distributed energy resources (DERs), and demand response initiatives. Additional optimization is possible by leveraging Slater TS, which is centrally located and supplied by

three independent circuits. Slater's robust configuration makes it a strong candidate for load transfers, and future development should be encouraged near this area to capitalize on its reliability and existing capacity.

Monitoring the evolution of winter peak demand will be critical. If these trends materialize as expected, a major decision will be required, as the 115 kV network alone cannot accommodate long-term growth in its current configuration. One response may involve installing a fourth autotransformer at Merivale TS to support increasing inter-pocket transfers. More broadly, planners will need to decide between:

1. Introducing a new 230 kV supply path into the downtown core;
2. Converting select segments of the 115 kV system to 230 kV; or
3. Build new transmissions lines into the downtown core.

All options would ultimately require significant expansion work at Hawthorne TS, which serves as a key transmission node for the eastern subsystem.

The long-term vision for the broader region anticipates that most expansion will occur west of Ottawa, reducing the need for major downtown build-outs. With the implementation of the upgrades and strategies outlined in this plan, the Core East subsystem will largely be able to rely on enhanced operational efficiency and, at most, require one to two new transformation stations to support long-term growth.

7.7.3 Core West Subsystem

Following the uprate of C7BM and F10MV the rest of the stations in Pocket 2 of the Core West subsystem will be able to grow to their LTR which is sufficient for the 20-year demand forecast. The area will also have a new 230kV transformer station that will help offload the smaller stations in the area. The long-term vision for this subsystem is to expand the 230kV transmission circuit west. By doing so, it allows for multiple successive investments. These include providing a second supply to Terry Fox MTS, converting S7M to 230kV, and providing a second supply to Cambrian MTS as well. Further, depending on the outcomes of the Bulk Study, a potential 230kV autotransformer station will allow for expansion in this area to meet growing demand.

7.7.4 Core South Subsystem

The future of this subsystem will depend on the outcome of the East Bulk study. A potential 230kV transmission line from St. Lawrence presents to opportunity to convert the entire pocket.

The load at Limebank MTS is to be monitored and will eventually require a second supply. The circuits will also need to be uprated as the load grows.

A new auto-transformer station in the west of Ottawa would also impact how this system is planned and depend again on the East Bulk Study.

7.8 Summary of Recommended Actions and Next Steps

The Working Group recommends the actions summarized in **Table 12** to meet identified needs in the Ottawa Area Sub-Region IRRP.

Table 12 | Summary of the Near-Term Plan for the Ottawa Area Sub-Region IRRP

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[9]
System Capacity (Transformation)	Core East Pocket 1	Build new Transformer Station by converting existing Distribution Station. Connect to M4G and M5G. Interim station name: Bronson MTS.	$65M
System Capacity (Thermal Overload)	M4G, M5G	Uprate portions of M5G and M4G.	$35M
System Capacity (Transformation)	Core East Pocket 2 A5RK, A6R, A4RK, A3RM, A8M, A2	Convert Cyrville MTS (115kV) to 230kV thereby preserving capacity on autotransformers for growth on the 115kV downtown system. Pursue eDSM program opportunities as part of LAPS to reduce demand and delay large-scale infrastructure upgrades.	$75M TBD
Station Capacity	Carling TS	Upgrade secondary cables to increase station rating. Distribution load transfer to new Bronson MTS.	$40M $0-5M
Station Capacity	Lisgar TS	Increase station rating by upgrading limiting LV element	$20M
Station Capacity	Riverdale TS	Distribution load transfer to new Bronson MTS.	$0-5M
Station Capacity	Nepean Epworth MTS	Distribution load transfer to Merivale MTS.	$100K
Station Capacity	King Edward TS	Upgrade cables to increase station rating.	$40M

[9] All cost estimates are capital cost values

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[9]
Station Capacity	Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating.	$75M
Station Capacity	Moulton MTS	Repurpose 115kV transformers from Cyrville MTS voltage conversion to increase station rating. Estimate does not consider any circuit upgrade that may be required.	$5M
Station Capacity	Ellwood MTS	Distribution load transfer to Albion TS.	$0-5M
System Capacity (Transformation, Voltage Stability)	Kanata-Stittsville	Build a new Transformer Station north of existing stations. Connect to C3S and new transmission line from Merivale TS. Interim station name: Kanata North MTS. Build a new 230kV transmission line from Merivale TS by rebuilding C7BM corridor, connecting Nepean TS and the new Kanata North MTS. Build a switching station that connects existing and new 230kV stations to improve resiliency and flexibility.	$45M $185M $65M
Load Security	Nepean TS	Provide second supply to Nepean TS via new transmission circuit from Merivale TS. Same circuit that is being built to supply new Kanata North MTS.	$5M
Station Capacity	Kanata MTS Marchwood MTS	Distribution load transfer to new Kanata North MTS.	$6-8M
End-of-Life Station Capacity	South March TS	Upgrade transformers at South March TS to increase station rating.	$40M
System Capacity (Thermal Overload)	Core West Pocket 1 F10MV, C7BM	Uprate portions of C7BM and F10MV.	$50M

Need Type	Affected Element(s)	Recommendation	High Level Planning Cost Estimate[9]
System Capacity (Transformation)	Core West Pocket 2	Build a new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS. Interim station name: Greenbank MTS.	$40M
		Build new 230kV transmission line from Merivale TS to supply new Greenbank MTS.	$40M
Station Capacity	Centrepoint MTS Fallowfield MTS Manordale MTS	Distribution load transfer to new Greenbank MTS.	$0-5M
Station Capacity	Bridlewood MTS	Distribution load transfer to Terry Fox MTS.	$0-2M
Load Security	Core South L2M, M1R	Install a new breaker at Merivale TS and separate L2M and M1R.	$30M
Station Capacity	Marionville DS	Install a second transformer to increase station rating.	$12M
Station Capacity	Greely DS	Install SCADA transformer monitoring to increase station rating.	$3M
Station Capacity	Limebank MTS	Distribution load transfer to Piperville MTS.	$5M
Planning	N/A	Working Group to produce Adaptive Pathways documents for each subsystem following the publishing of the IRRP.	

8. Community and Sector Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the Ottawa Area Sub-Region IRRP.

8.1 Engagement Principles

The IESO's **External Relations Engagement Framework** is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose to foster trust and build understanding as the energy transition continues.

Figure 32 | The IESO's Engagement Principles



8.2 Engagement Tactics

To ensure that the IRRP reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement tactics involved:

- Leveraging the **Ottawa Area Sub-Region engagement webpage** to share information including engagement opportunities, meeting materials, input received and the IESO's response to feedback;

- Leading targeted discussions with key municipal staff to help inform the engagement approach for this planning cycle;
- Hosting public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and;
- Providing written updates through email and IESO's weekly Bulletin updates to all subscribers.

8.3 Engagement Approach

Four public engagement webinars were held at major stages during the Scoping and IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. Unique to the IRRP was a Local Achievable Potential Study (LAPS) for the Ottawa Area taking place in parallel. Feedback on the Local Achievable Potential Study was solicited during the webinar on "Needs and Potential Wire Options."

Public engagement webinars were attended by several representatives from the City of Ottawa, community representatives, businesses, Indigenous communities, and other stakeholders with an identified interest, and written feedback was collected following a comment period after each webinar. The four stages of engagement at which input was invited were:

1. The draft scoping outcome assessment report to share the planning approach before delving into the full IRRP study.
2. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
3. The defined electricity needs for the region and potential wire options to meet the identified needs, as well as
4. The analysis of all feasible wire and non-wire options and draft IRRP recommendations.

Comments received during the development of the IRRP primarily focused on:

- Accounting for growth and economic development projects across the region;
- Ensuring climate impacts are accounted for throughout the development of the IRRP, and;
- Exploring alternative solutions, such as non-wire options, to meeting the area's electricity needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations, and are outlined in the stages below.

8.3.1 Scoping Assessment

As part of the 2020 Ottawa Sub-Region IRRP, the Technical Working Group recommended to monitor the City of Ottawa's Energy Evolution mandate in future planning cycles. During the monitoring, the Technical Working Group recommended to advance the planning cycle. When regional planning kicked off, the draft 2023 Scoping Assessment Outcome Report recommended focused discussions to

take place with the City of Ottawa, the local distribution companies and the IESO on the impacts of Energy Evolution and GHG emission targets on the demand forecast.

Once the draft report was completed, an email communication was sent to all subscribers of the Greater Ottawa Region, including municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and encourage participation on the Greater Ottawa Scoping Assessment Report finalization. A public webinar was held in February 2023 to provide an overview of the regional electricity planning process, the draft report and proposed approach.

Feedback received during this milestone encouraged the IESO to obtain data from large customers electrification plans and to review opportunities for distributed energy resources to reduce electricity demand. The Technical Working Group confirmed a process to collect input from municipalities, businesses, Indigenous communities and other interested parties will take place in the next milestone. The Technical Working Group also committed to explore opportunities for distributed energy resources and will enhance engagement to increase opportunities for input. The final Scoping Assessment was posted in March 2023, identifying the need for a coordinated regional planning approach for the Ottawa Area.

8.3.2 Demand Forecast

Following finalizing the Scoping Assessment, the Technical Working Group began the development of Ottawa's electricity demand forecast. IRRP recommendations are typically driven by the Reference Demand Forecast, which includes firm loads (current and planned), organic growth, residential, electrification and energy plans, and industrial growth. The Technical Working Group sought input from the City of Ottawa and large electricity customers (including school boards). The reference forecast assumes most likely electrification adoption rates based on current policies and includes eDSM forecasts based on provincial and federal policies, as well as the impact of existing and expected DERs in Ottawa.

In parallel, the Technical Working Group determined the need to develop a High Growth Demand Forecast to capture growth and trends that are less certain such as full decarbonization of the city or large-scale customer connections. To achieve this, the City of Ottawa, the local distribution companies and the IESO participated in several focused discussions to capture the effects of economic development, electrification and decarbonization in the city. Hydro One Transmission and Enbridge Gas Inc. participated in these "Decarbonization Focus Group" meetings as observers. In 2023 the IESO piloted an approach in both the Toronto and Ottawa IRRPs, to engage Enbridge Gas Inc. throughout the demand forecasting process as an observer. The observer's role was limited to subject matter experts providing feedback on the discussions where applicable. The purpose of the "Decarbonization Focus Group" was to determine a high growth demand forecast for the Ottawa Area that reflects the full decarbonization of the city.

During this time, six meetings from March to December 2023 took place within the Decarbonization Focus Group to obtain insights including shared experience with decarbonization. Key discussion items raised included the importance of visibility into planned major energy efficiency projects and understanding how to share updates on when this load is materializing. After gathering all insights, Hydro Ottawa engaged a third-party consultant to capture the effects of electrification and decarbonization into five forecasts. The reference and high growth forecast scenarios were chosen

and all forecasts were shared through the launch of a broader public engagement initiative. Communications to IESO subscribers of the Greater Ottawa Region ensured all interested parties were made aware of the opportunity for input.

During this milestone, key information shared was that the electricity demand is growing significantly in the Ottawa area with demand estimated to grow by 33% in the winter and 166% in the summer by 2043. The primary drivers of growth are economic growth and decarbonization initiatives which promote the intensification of electricity use, resulting in a substantial demand increase, particularly in the winter. The reference forecast will be used to drive recommended solutions, however the Technical Working Group will identify options for long-term electricity needs and high-growth scenarios, refining these options in future planning cycles and activating them as growth occurs.

Based on the feedback through this engagement initiative, a key priority was to ensure the IRRP considered climate impacts into the demand forecast and incorporated resiliency into recommended actions. The Technical Working Group ensures the forecast reflects extreme weather conditions in various scenarios, which includes the system's ability to respond to disturbances, and committed to ongoing discussions about resiliency throughout plan development. Additionally, feedback was centred around ensuring alternative solutions, such as non-wire options, are explored. The Technical Working Group committed to evaluating wire and non-wire options and sharing the analysis as planning work advances. Additionally, the IESO informed the public that details about the Local Achievable Potential Study underway for the Ottawa Area will be shared in future engagements.

8.3.3 Electricity Needs and Potential Wire Options

During this milestone, the Technical Working Group identified significant station capacity, System Capacity, end-of-life, load restoration and load security needs throughout the Ottawa area, with several of these needs emerging in the near-term. Therefore, the Technical Working Group determined it was necessary to prioritize options that met near- and medium-term needs. Given the magnitude and timing of the near- and medium-term needs, potential wire options were developed and shared with the community at this milestone with a commitment to presenting a comprehensive analysis for all feasible wire and non-wire options later.

Feedback at this stage of the engagement sought to further clarify the options analysis stage of the IRRP, particularly if wire and non-wire options would be considered as alternatives to each other. Additionally, feedback received urged for resiliency to be considered when finding options to meet needs. The Technical Working Group confirmed wire and non-wire options, or any combination of both, will be evaluated to meet the area's needs. Additionally, the Technical Working Group acknowledges the importance of resiliency and will consider this in the detailed options analysis.

Feedback was also solicited for the Local Achievable Potential Study and the community recommended to broaden the scope of the study. The project team for the local APS confirmed several considerations raised, including leveraging Dunsky's 2022 provincial DER potential study, inclusion of thermal storage, consideration of decreasing costs of technologies overtime and more were incorporated into the report. The IESO also clarified that front-of-meter DER was being considered outside of the Local Achievable Potential Study in the IRRP and explained why vehicle-to-grid technology was excluded. Engagement with the City of Ottawa and the Decarbonization Focus Group were undertaken as part of this milestone.

8.3.4 Options Analysis and Draft Recommendations

During this milestone, the Technical Working Group shared the options analysis for all feasible wire and non-wire options and shared the draft recommendations. The draft recommendations included two new transmission lines within existing corridors, two new stations and two significant upgrades to existing stations. Informed by feedback about resiliency, the draft recommendations also include a switching station to improve transmission reliability by rerouting power during outages or maintenance, minimizing disruptions and enhancing grid flexibility.

The outreach strategy for this milestone included briefing various City of Ottawa staff as well as councillors whose riding is located where the draft recommendations are. A public engagement webinar was hosted to share the detailed analysis and draft recommendations, as well as an update on the Local Achievable Potential Study and a suite of Save on Energy programs available to Ottawa small businesses and residents. A touchpoint with the Decarbonization Focus Group was hosted to solicit feedback into the final IRRP.

8.4 Involving Municipalities in the Plan

Throughout the IRRP engagement, valuable feedback was received and incorporated into the final IRRP including:

- Enhancing webinar materials to share technical updates in a digestible manner.
- Undergoing a Local Achievable Potential Study which would study the potential of behind-the-meter options, including distributed energy resources, with the commitment to hosting a webinar later in Q3 to share the findings and next steps of the study.
- Including the City of Ottawa's Energy Evolution plans in the reference and high forecast scenarios.
- Incorporating information about economic development in Ottawa, particularly around the Kanata North area.
- Incorporating feedback around resiliency into the recommendation of a switching station to enhance transmission reliability.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Ottawa Area Sub-Region throughout the development of the plan. This includes the communities of the Algonquins of Ontario, Pikwakanagan First Nation, and Métis Nation of Ontario Region 5.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

This report documents an IRRP that has been carried out for the Ottawa Sub-Region of the OEB's Greater Ottawa planning region. The IRRP identifies electricity needs in the sub-region over the 20-year period from 2024-2043 and recommends preferred solutions to address near-term needs. The Working Group recommends Hydro One initiate a RIP. The Working Group will continue to provide support throughout the RIP process, and assist with any regulatory matters that may arise during plan implementation.

The IRRP also identifies actions to monitor, defer, and address remaining needs and to inform the next regional planning cycle. The Ottawa Sub-Region Working Group will continue to meet at regular intervals to monitor developments in the sub-region and track progress toward the plan deliverables. In the event that underlying assumptions change a new regional planning cycle may be initiated sooner than the OEB mandated five-year schedule.



REGIONAL INFRASTRUCTURE PLAN REPORT

GREATER OTTAWA

Regional Infrastructure Plan Report

Greater Ottawa

February 09, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Greater Ottawa Technical Working Group

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Disclaimer

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

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

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

Executive Summary

REGION	**Greater Ottawa** (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: August 18, 2025 **END DATE:** February 09, 2026

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Greater Ottawa region, preceded by, the publication of Needs Assessment (NA) report in December 2022 by Hydro One which was triggered early due to high growth in the region followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in March 2023 and in July 2025 respectively, by the Independent Electricity System Operator (IESO).

Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs and publishes a RIP report. The RIP report includes a discussion of all options and plans identified in earlier phases and recommends a preferred wires plan to address the near, medium, and long - term needs over a twenty-year study period.

The objectives and scope of the RIP are:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs (2025-2034) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identify any new need(s) over the 2025-2034 that may have emerged since previous planning phases. Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.
- Consideration of long-term needs identified in the Ottawa area sub-region IRRP, Bulk system studies or as identified by the TWG.

Since the IRRP study addressed needs only for the Ottawa Area Sub-region, the RIP as per TWG discussions developed a new load forecast for stations outside the IRRP scope and revised forecasts for certain stations. For the remaining stations, the IRRP load forecast was adopted for the RIP study, as no material changes were identified. During the IRRP stakeholder engagement process, IESO received municipal input on future load growth for consideration in the IRRP load forecast.

The list of major infrastructure investments recommended by the TWG in the region is given below. The needs include those previously identified in the NA and IRRP, as well as any new needs identified during the RIP phase, if any.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M)
Asset Renewal Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	Hydro One	2031	$60M
Nepean TS	Replacement of T3/T4 transformers based on asset condition	Hydro One	2034	$30M
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	Hydro One	2030	$5M
Station Capacity Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Carling TS	Replacement of limiting LV cables.	Hydro One	2030	$10M
Lisgar TS	Replacement of T2 transformer and LV cables/breakers - Greenfield	Hydro One	2034	$50M
	Replacement of T2 transformer and LV cables/breakers – In Situ	Hydro One	2031	$30M
King Edward TS	Replacement of LV cables and breakers.	Hydro One	2033	$20M

Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating and upgrade station transformation capacity.	Hydro One/ Hydro Ottawa	2029	$85M*
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	Hydro Ottawa	2029	$5M
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	Hydro One/ Hydro Ottawa	2031	$110M*
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	Hydro One/ Hydro Ottawa	2028	$100M*
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and new transmission line from South March TS	Hydro One/ Hydro Ottawa	2028	$100M*
Marionville DS	Install a second transformer to increase station rating.	Hydro One Dx	2029	$12M*
Greely DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland East DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2027	$3M*

Transmission Line Capacity Needs				
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	Hydro One	2030	$30M
L2M	Uprate line section between Merivale TS x Limebank JCT	Hydro One	2032	$30M
System Reliability, Operation and Load restoration Needs				
Kanata Area	Kanata Area Transmission Reinforcement	Hydro One	2033	$250M
Nepean TS – Load Security Criteria	Second 230 kV Supply to station	Hydro One	2032	$70M
M1R+L2M	Split Breaker position for M1R and L2M at Merivale TS	Hydro One	2032	$45M
East Ottawa Area	Supply to East Ottawa	Hydro One	2029-2030	$165M*

* These investment costs include associated distribution system costs.

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are high-level planning estimates and actual costs may vary.

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of the Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs) and publishes a RIP report. The third cycle of the Regional Planning process for the Greater Ottawa region was initiated early due to high growth in the region with the publication of Needs Assessment (NA) and the report was published in December 2022 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) only for the Ottawa Sub-Region Area which were published in March 2023 and July 2025 respectively, by the Independent Electricity System Operator (IESO).

This RIP report is for the "Greater Ottawa Region" and includes the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of County Road 43 (Highway 43) and includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by the Greater Ottawa TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies (LDC), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1-1.

Table 1-1: Greater Ottawa region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission)
2	Independent Electricity System Operator (IESO)
3	Hydro One Networks Inc. (Distribution)
4	Hydro Ottawa Limited
5	Hydro Hawkesbury
6	Renfrew Hydro Inc.
7	Hydro 2000 Inc.
8	Ottawa River Power Corp.

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Greater Ottawa region. Its objectives are to:

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

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, Electricity Demand Side Management ("eDSM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2025-2034 identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2025-2034 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Ottawa area sub-region IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and require longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and.
b) require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, the recommended options are implemented, and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and.
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Electricity Demand Side Management ("eDSM"), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

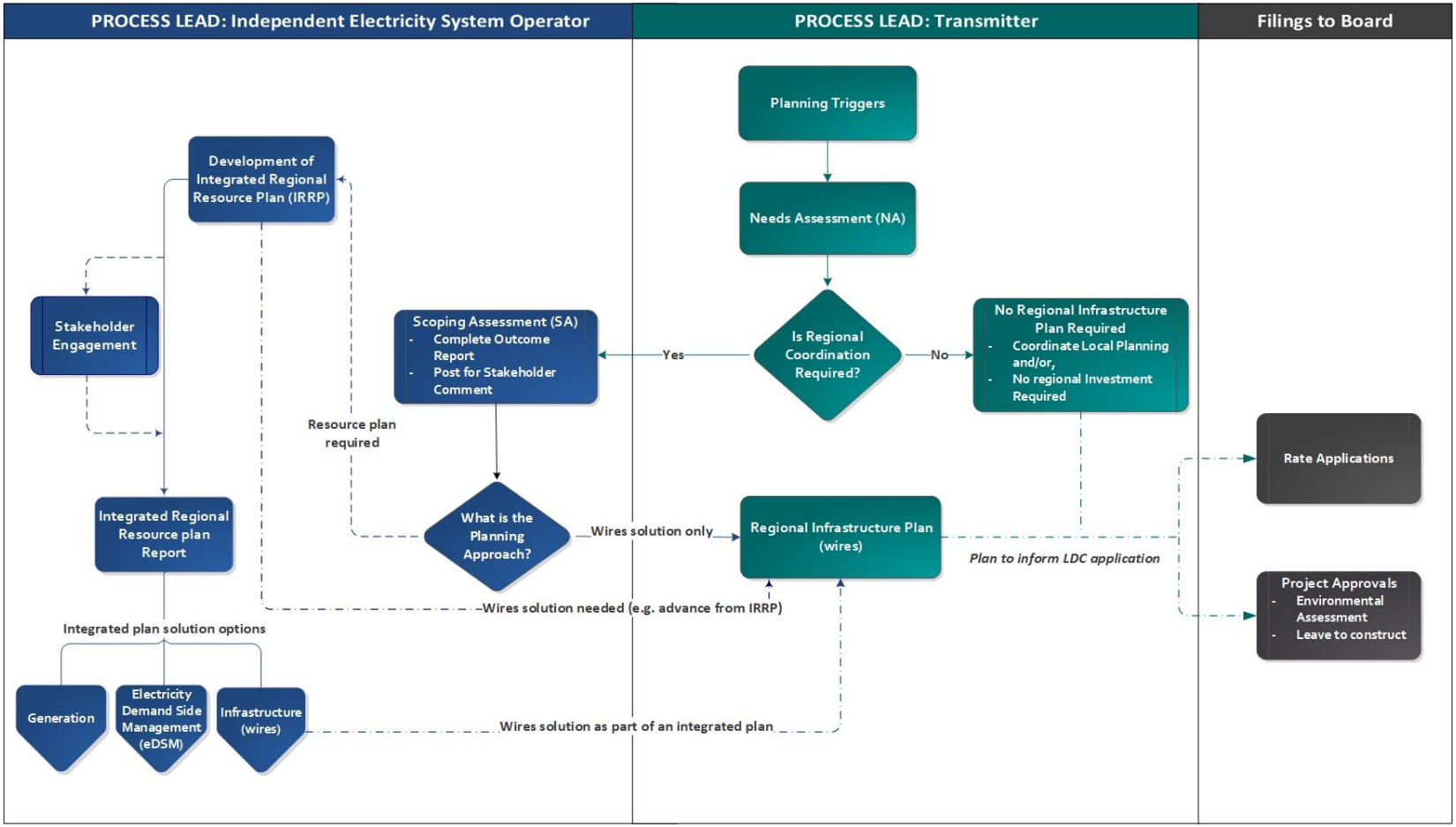
The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' eDSM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

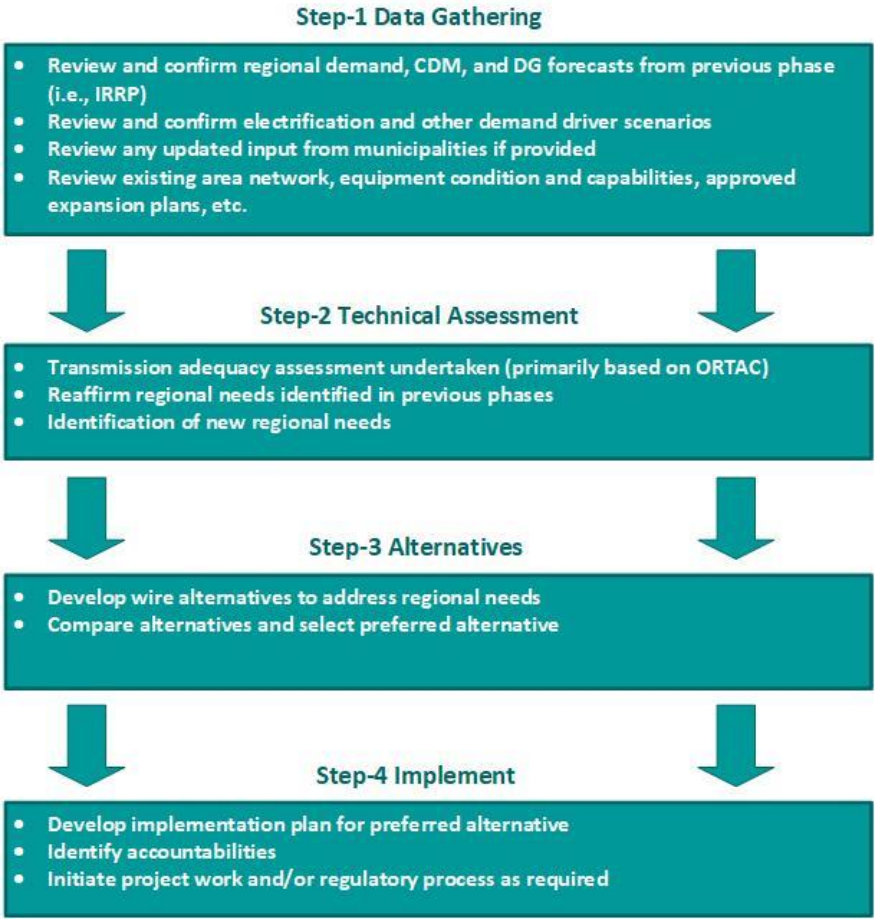
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure 3-1.

Figure 3-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure 3-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or eDSM programs. As agreed by TWG members, the load forecast from the Ottawa Area sub-region IRRP was used for this RIP with modifications to some stations and developed a load forecast for the outer Ottawa stations which were not covered in the IRRP.

- Review and confirm electrification and other growth scenarios which affect the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

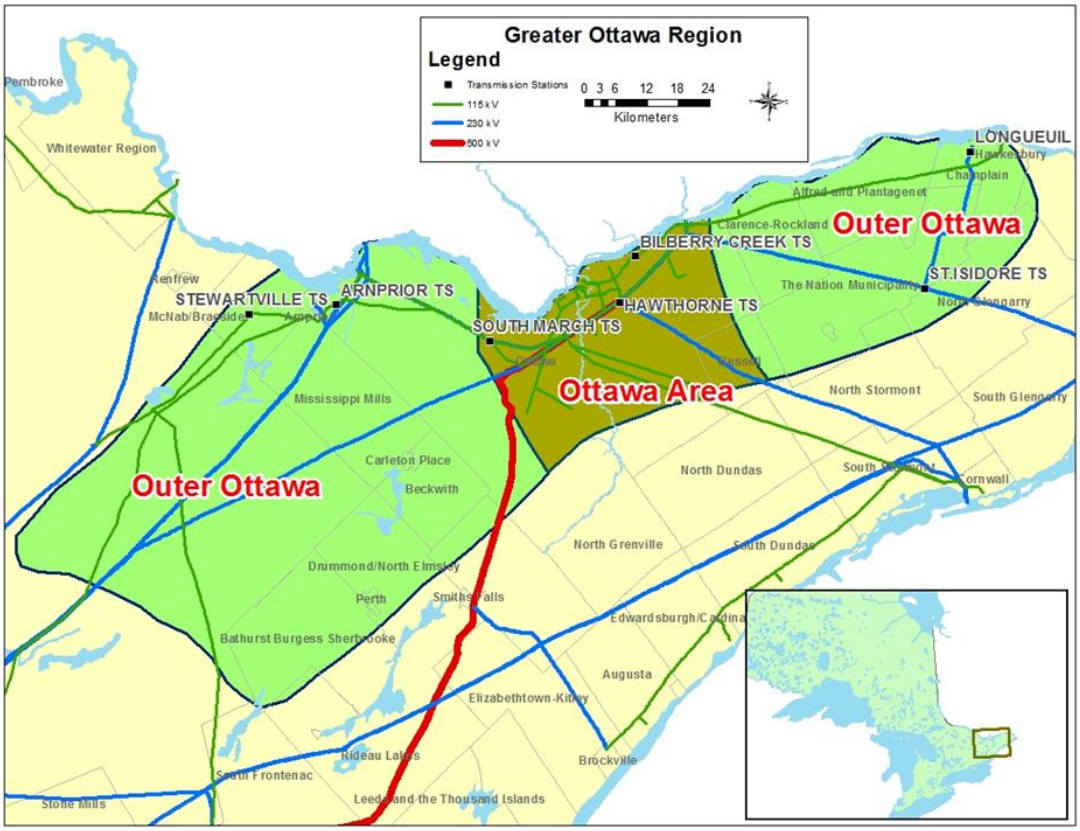
3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identify accountabilities and initiate project work or obtain permissions from the Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Greater Ottawa Region covers the municipalities bordering the Ottawa River from Arnprior in the West to Hawkesbury in the East and North of County Road 43 (Highway 43). At the center of this region is the City of Ottawa. Electrical supply to the Region is provided from fifty-two (52) 230 kV and 115 kV step-down transformer stations. The boundaries of the Region are shown in Figure 4-1 below. The outer regions are referred to as the East and West Outer Ottawa sub-regions. The central region comprising of City of Ottawa is referred to as the Ottawa sub-region

Figure 4-1: Map of Greater Ottawa Regional Planning Area

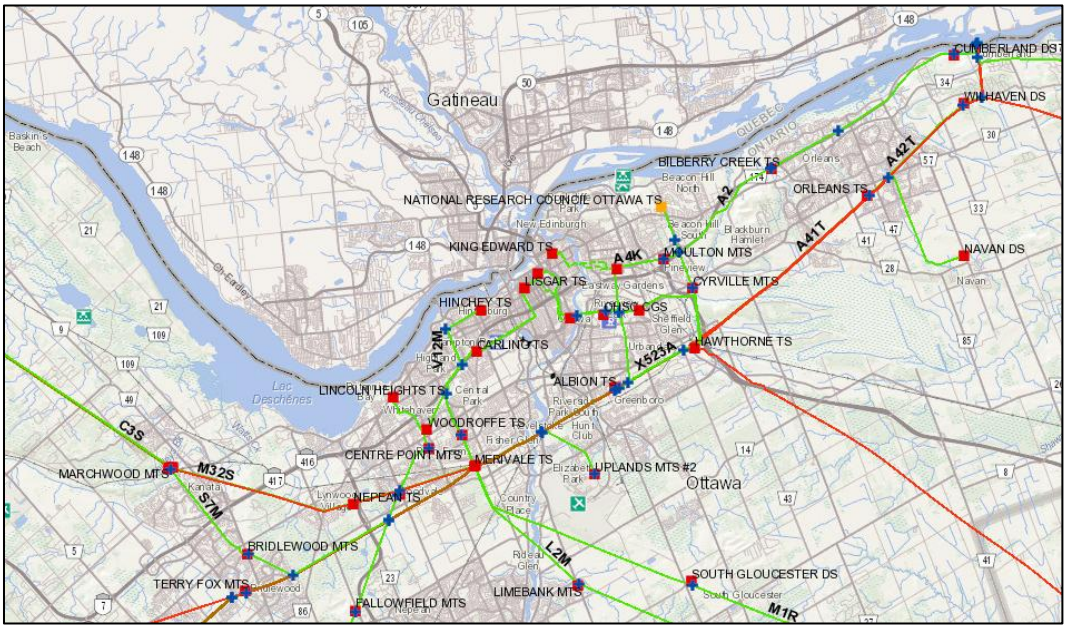


Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS autotransformers and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into two sub-regions as shown in Figure 4-1 and described below:

The Ottawa Area Sub-region comprises primarily the City of Ottawa. It is supplied by two (2) 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS), eight (8) 230 kV and thirty-three (33) 115 kV transformer stations stepping down to lower voltages. Local generation in the area consists of the 74 MW

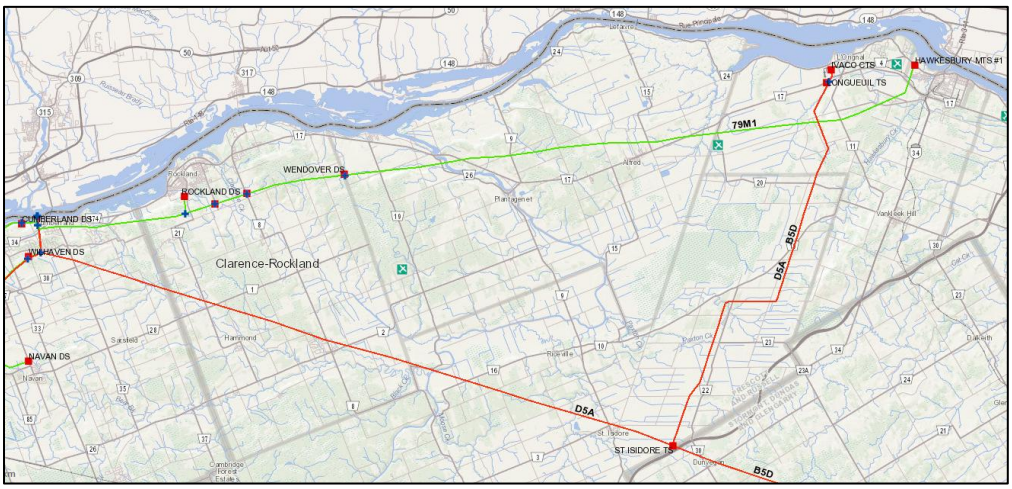
Non-Utility Generator ("NUG") CGS-2 located near the downtown area and connected to the 115 kV network. The Ottawa Area Sub-region is shown in Figure 4-2 below. Hydro Ottawa is the main LDC that serves the electricity demand for the City of Ottawa. Hydro One Distribution supplies load in the outlying areas of the sub-region. Both Hydro Ottawa and Hydro One Distribution receive power at the step-down transformer stations and distribute it to end users, including industrial, commercial and residential customers.

Figure 4-2: City of Ottawa Sub-Region Map



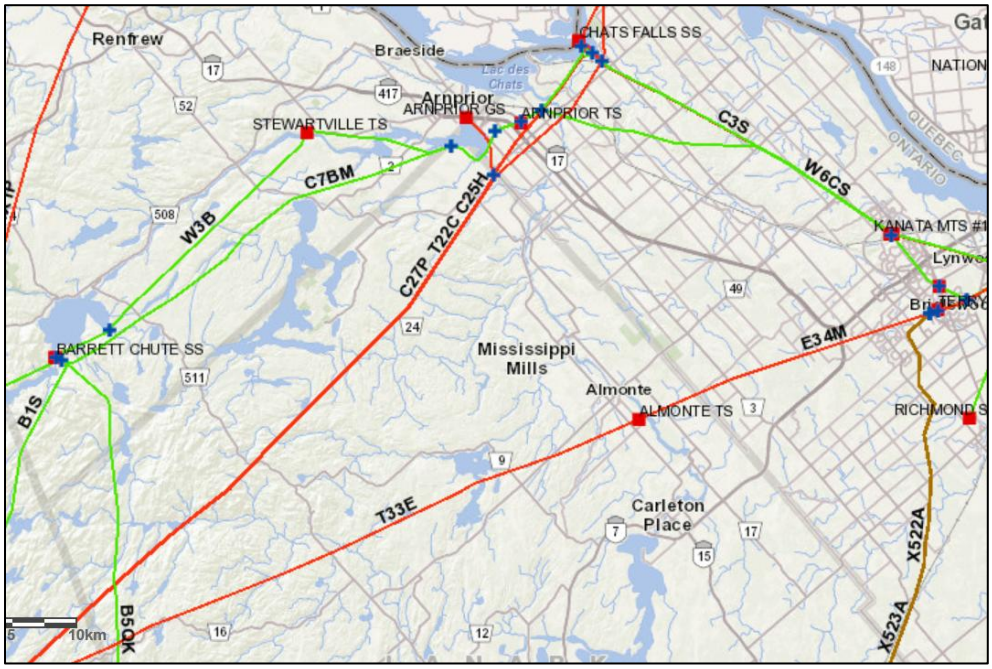
The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area as shown in Figure 4-3 below is served by three (3) 230 and five (5) 115 kV step-down transformer stations. Hydro One Distribution and Hydro Hawkesbury are the LDCs in the area that distribute power from the stations to their end use customers. Hydro 2000 is an embedded LDC that supplies its customers from Longueuil TS via Hydro One Distribution's 44kV feeders. It also includes a large industrial customer, in L'Orignal, Ontario.

Figure 4-3: Outer Ottawa Sub-Region Map (Eastern Part)



The western area of the Outer Ottawa Sub-Region, shown in Figure 4-4 is served by one (1) 230 kV and two (2) 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies its end use customers from these stations. Ottawa River Power Corp. is an embedded LDC that supplies its customers from Almonte TS via Hydro One Distribution's 44kV feeders. Renfrew Hydro is an embedded LDC that supplies its customers from Stewartville TS via Hydro One Distribution's 44kV feeders. The area includes the following generating stations: Barrett Chute GS, Chats Falls GS and Stewartville GS with a peak generation capacity of about 450 MW.

Figure 4-4: Outer Ottawa Sub-Region Map (Western Part)



Electricity demand in the region is projected to grow steadily over the forecast horizon, primarily driven by municipal expansion, increased commercial development, and the accelerating impacts of electrification and decarbonization initiatives. A key factor influencing long-term demand and supply requirements is the planned phase-out of natural gas heating, which is expected to significantly increase electricity consumption in the sub-region, particularly in the latter years of the forecast period. The circuits and stations of the area are summarized in Table 4-1 below:

Table 4-1: Transmission Station and Circuits in the Greater Ottawa region

115kV circuits	230kV circuits	Hydro One Transformer Stations		Generation Stations
A2	B5D	Albion TS	Marchwood MTS	CGS-1
A3RM	C3S	Almonte TS	Marionville DS	CGS-2
A4K	D5A	Arnprior TS	Merivale MTS	Chat Falls GS
A5RK	E34M	Bridlewood MTS	Moulton MTS	Stewartville GS
A6R	L24A	Bilberry Creek TS**	CTS -2	Barret Chute GS
A8M	M30A	Cambrian MTS	NRC TS	
C7BM	M31A	Carling TS	Navan DS	
F10MV	M32S	Centrepoint MTS	Nepean Epworth MTS	
H9A		Clarence DS	Nepean TS	
L2M		Cumberland DS	Orleans TS	
M1R		Cyrville MTS	Overbrook TS	
M4G		Ellwood MTS	Richmond South MTS	
M5G		Fallowfield MTS	Riverdale TS	
S7M		Greely DS	Russell DS	
V12M		Hawthorne TS*	Russell TS	
W6CS		Hawkesbury MTS #1	Rockland DS	
79M1		Merivale TS*	Rockland East DS	
		Hinchey TS	Slater TS	
		CTS-1	South Gloucester DS	

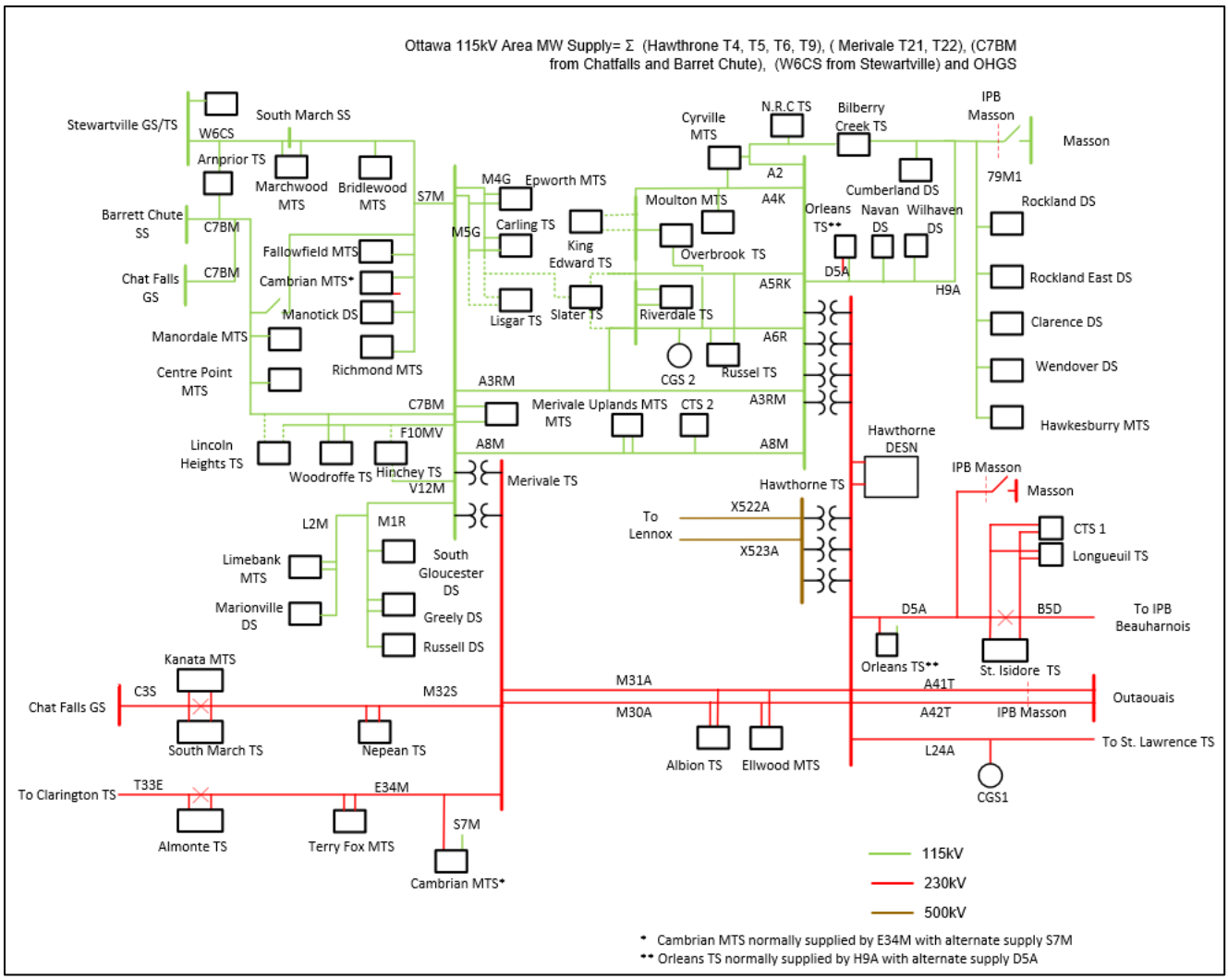
		Kanata MTS King Edward TS Limebank MTS Lincoln Heights TS Lisgar TS Longueuil TS Manotick DS	South March TS St. Isidore TS Stewartville TS Terry Fox MTS Uplands MTS Wendover DS Wilhaven DS Woodroffe TS	

*****Stations with Autotransformers installed

** Planned to decommission

The single line diagram of the existing Transmission Network of Greater Ottawa region is shown in Figure 4-5 below.

Figure 4-5: Greater Ottawa Transmission Single Line Diagram



5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that were completed in the past ten years or are currently underway is provided and is briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the **Greater Ottawa region** to improve the supply capability and reliability.

Hydro One Transmission, Hydo Ottawa Ltd and Hydro Hawkesbury are the Transmission Asset Owner (TAO) in the region and have undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Build New Orleans TS (2015) – built a new step-down transformer station in East Ottawa supplied from 230 kV circuit D5A and 115 kV circuit H9A. This station provides additional load meeting capability to meet Hydro One Distribution and Hydro Ottawa requirements. It provides improved reliability for Hydro One Distribution customers in the Orleans-Cumberland area.
2. Hinchey TS (2015) – Connected idle winding of transformers T1/T2 to new Hydro Ottawa metalclad switchgear to provide additional load meeting capability at the station.
3. Add 230 kV inline breaker on 230 kV circuit M29C at Almonte TS (2015) – added breaker to improve reliability of supply for Almonte TS and Terry Fox MTS and split line M29C into E34M and E29C (now T33E)
4. Overbrook TS (2017): Replaced 45/60/75 MVA, 115/13.8 kV step down transformers with new 60/80/100 MVA, 115/13.8 kV based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
5. Hawthorne TS (2019): Replaced 50/67/83 MVA, 230/44 kV step down transformers with new 75/100/125 MVA, 230/44 kV units based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
6. Change supply to Overbrook TS (2019) – Reduced the loading on A4K by modifying the supply to Overbrook TS by connecting transformer T1 to A6R instead of A4K. This was accomplished by rebuilding the line section of A5RK from Riverdale JCT to Overbrook TS as a double circuit 115 kV line and tapping A6R at Riverdale JCT.
7. Connection of CGS 1 wind farm (2020) – connection of 100 MW wind farm to 230 kV circuit L24A.

8. Hawthorne TS T5 and T6 autotransformer replacement (2021): Replace 225 MVA, 230/115 kV autotransformers T5 and T6 with new 250 MVA, 230/115 kV autotransformers to provide additional 230/115 kV transformation capacity.
9. King Edward TS transformer T3 replacement (2021): Replacement of 45/60/75 MVA, 115/13.8 kV step down transformer T3 with upgraded 60/80/100 MVA, 115/13.8 kV to match the existing rating of T4 and to provide additional load meeting capability at the station.
10. Connection of Cambrian MTS (2022): connect a new Hydro Ottawa owned transformer station in the South Nepean area. The station is supplied from 230kV circuit E34M with alternate supply from 115kV circuit S7M. S7M was rebuilt as a double circuit line from the main line (S7M STR673JCT to Cambrian JCT (~10.9km) with a 1.3km extension to Cambrian MTS.
11. Overbrook TS LV cable review (2022): the transformer cable capacity limitation review was analyzed. The transformer LTR was increased based on the result of the study.
12. Arnprior TS T1/T2 replacement (2023): The two 25/33/42 MVA 115.5kV/44kV transformers were replaced like-for-like with new standard 25/33/42 MVA 110kV/44kV transformers.
13. M30A/M31A upgrade (2023): Increase the power interface limit between Hawthorne TS and Merivale TS by replacing the existing conductor 1843.2kcmil with new twin bundled 1443.7 kcmil conductor (2 conductors per phase).
14. Slater TS T2/T3 replacement (2024): Replaced 38/63 MVA, 110/12 kV step down transformers T2 and T3 with new 60/80/100 MVA, 110/14.2 kV units based on asset condition assessment replaced transformers with higher capacity units to provide additional load meeting capability at the station.
15. Lincoln Heights TS T1/T2 (2024): Like-for-like replacement of the two 45/60/75 MVA 110kV/14.2kV transformers.
16. Longueuil TS T1/T2 replacement (2025): Replacement of 50/75/93 MVA 235kV/44kV transformers T1/T2 with standard 50/67/83 MVA 215.5kV/44kV units.
17. Lisgar TS T1 replacement (2025): Replacement of 45/60/75 MVA 110/14.2-14.2 kV transformer T1 with standard 60/80/100 MVA 110/14.2-14.2kV unit.

II. Following Major projects are underway:

1. Piperville MTS – Connection of Hydro Ottawa's new transformer station to 230 kV L24A circuit with in-service date in Q2 2026.
2. Russell TS – T1/T2 transformers (45/60/75 MVA) will be replaced with 60/80/100 MVA transformers. The planned in-service date is 2027.
3. Connection of Hydro Rd. MTS – Connection of new Hydro Ottawa station to 230kV circuits M30A/M31A near Hawthorne TS. Building ~500m line tap to the new station. The planned in-service date for connection of this new station is October 2027.
4. Connection of Mer Bleue MTS - Connection of new Hydro Ottawa station to 230kV circuits D5A about 10km east of Hawthorne TS. The planned in-service date for connection of this

new station is July 2027. This project is also planned to connect to circuit A25 with expected in-service in June 2029. Please refer to section 8.4.5 for further information.

5. Connection of South March BESS – Connection of new 250MW Battery Energy Storage System to 230kV circuit C3S about 11.5km from South March TS. The planned in-service date for connection is Q2 2027.
6. Connection of Trail Road BESS - Connection of new 159MW Battery Energy Storage System to 230kV circuit E34M about 275m from Cambrian JCT. The planned in-service date for connection is 2027.
7. Hawkesbury MTS: Project for transformer upgrade with a new 15MVA transformer unit is underway and is being led by Hydro Hawkesbury. The planned in-service date is 2027-2028.
8. Merivale TS T22/T23 – The planned in-service date for replacement of autotransformer T22 and addition of new autotransformer T23 and for replacement of six (6) 230 kV circuit breakers and four (4) 115 kV circuit breakers is 2029.
9. Bilberry Creek TS – The station is expected to be retired around 2030. Its load will be transferred to Mer Bleue MTS and Orleans TS. Please refer to section 8.4.5 for further information.
10. Orleans TS – The station will be upgraded from dual supply of 230/27.6 kV 115/27.6 kV to 230/27.6 kV DESN. The planned in-service date is June 2029. Please refer to section 8.4.5 for further information.

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

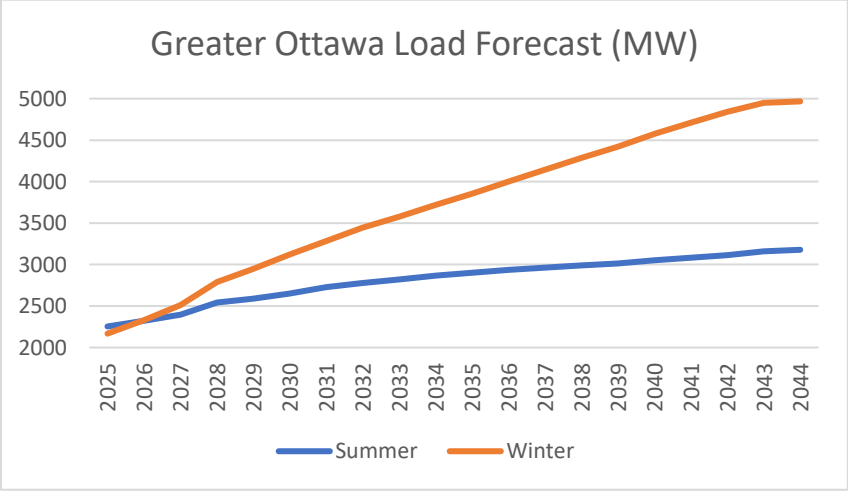
The TWG developed a load forecast for stations in the Outer Ottawa area as these were outside the IRRP scope. The LDCs also reviewed the IRRP forecast and provided revisions for some of the stations. For the remaining stations, the IRRP load forecast was adopted for the RIP study, as no changes were required by the LDCs. TWG participants, including representatives from LDCs, IESO and Hydro One provided information and input for the IRRP and RIP Load forecasts. During the IRRP stakeholder engagement process, IESO received municipal input on future load growth for consideration in the IRRP load forecast.

During the study period, the load in the Greater Ottawa region is expected to grow at an average annual rate of approximately 2% in summer and 4% in winter from 2025 to 2044. The region is currently summer-peaking, however based on the forecast it is expected that the region will transition to winter-peaking in the near future. This shift is largely driven by electrification such as the ongoing transition of heating systems from natural gas to electric or hybrid solutions, which will significantly increase electricity demand during winter months.

Figure 6-1 shows the Greater Ottawa region extreme summer/winter weather net load MW forecast from 2025 to 2044. The load forecasts from the Ottawa sub-region were updated from the IRRP forecast as agreed by the TWG.

The forecast for the individual stations in the region is available in Appendix A and is used to determine any need in the region.

Figure 6-1: Greater Ottawa region summer/winter Net Peak Load Forecast



6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2025-2044.
- LDCs have reviewed the forecast and provided updates where necessary and reconfirmed load forecasts up to 2044 in the area.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is currently summer peaking but expected to become winter peaking within the study period, so this assessment considers both summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the station peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Greater Ottawa region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed as per their respective in-service dates.

In the current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Greater Ottawa region Third cycle Needs Assessment Report, Completed in December 2022 by Hydro One
- Greater Ottawa region Third cycle Scoping Assessment Report, Completed in March 2023 by the IESO
- Greater Ottawa region Third cycle Integrated Regional Resource Plan Report, Completed in July 2025 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in the previous regional planning cycle, Hydro One and TWG have also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Greater Ottawa region. The complete list of major HV transmission equipment requiring replacement in the Greater Ottawa region is provided in Table 7-1 in this sub-section. Hydro One along with Hydro Ottawa Ltd and Hydro Hawkesbury are the only Transmission Asset Owner (TAO) in the Region

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two

- 230 and 115kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 7-1: Major HV Transmission Asset assessed for Replacement in the region planned in next 10 years

Station/Circuit	Need Description	Planned ISD
South March TS	T1/T2 Transformers replacement	2031
Albion TS	T1/T2 Transformers replacement	2031
Nepean TS	T3/T4 Transformers replacement	2034
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	2030

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

7.2. Station Capacity Needs

Over the study period **2025 -2044** RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the **Greater Ottawa region**. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 7-2 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer and winter) Limited Time ratings.

Table 7-2: Greater Ottawa region Station Capacity Needs in the study period

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2024 Loading (MW) (Summer/Winter)	Need Date (Summer/Winter)	High Forecast Need Date (Summer/Winter)
1	Albion TS	86.5/101.7	57.4/47.0	-/2034	2043/2030
2	Arnprior TS	54.9/59.4	36.9/37.5	2044/-	2043/-
3	Bridlewood MTS	23.5/23.5	29.6/19.7	2035/2030	2029/2027
4	Cambrian MTS	114/123.5	58.7/33.6	-/2041	-/2033
5	Carling TS	95/124.3	67.7/64.9	2028/2028	2028/2028
6	Centrepoint MTS	13.3/13.3	14.6/11.9	2032/2027	2027/2025

7	Cumberland DS	6.8/8.6	5.5/5.0	2037/-	2036/-
8	Cyrville MTS	47.5/47.5	33.6/24.4	2028/2030	2028/2028
9	Ellwood MTS	47.0/47.0	44.8/46.5	2027/2027	2027/2025
10	Fallowfield MTS	27.2/27.2	35.6/14.4	2026/2030	2026/2028
11	Greely DS	20.7/25.2	19.5/16.3	2025/2025	2025/2025
12	Hawkesbury MTS	18/18	13.3/14.9	-/2037	-/2036
13	Hawthorne TS	144.8/	106.1/97.1	2038/2031	2038/2028
14	Hinchey TS	85.6/95.0	45.4/40.8	-/2031	-/2029
15	Kanata MTS	51.5/51.5	53.2/55.8	2025/2025	2025/2025
16	King Edward TS	86.9/90.3	80.0/77.7	2033/2026	2030/2025
17	Limebank MTS	75.0/75.0	48.1/38.2	2031/2028	2031/2026
18	Lincoln Heights TS	99.4/113.1	40.3/40.9	-/2039	-/2035
19	Lisgar TS	83.4/105.1	42.7/58.9	2028/2028	2028/2027
20	Manordale MTS	9.6/9.6	11.0/8.4	2026/2026	2025/2025
21	Manotick DS	7.7/10.4	9.5/8.1	2025/2025	2025/2025
22	Marchwood MTS	32.3/32.3	46.3/42.5	2025/2025	2025/2025
23	Marionville DS	13.5/13.5	14.4/12.1	2025/2025	2025/2025
24	Moulton MTS	32/32.0	21.6/16.6	2028/2028	2028/2028
25	Nepean Epworth MTS	12.9/12.9	11.4/11.4	2035/2028	2029/2026
26	Nepean TS	144.1/160.7	113.2/108.6	-/2030	-/2027
28	Richmond South MTS	49.0/49.0	19.4/6.9	2034/2028	2034/2028
29	Riverdale TS	110.8/117.0	92.4/71.5	2030/2028	2029/2026
30	Rockland DS	7.8/10.5	7.8/4.1	2025/2031	2025/2030
31	Rockland East DS	15.5/20.9	14.3/12.4	2026/2040	2026/2040
32	South March TS	99.2/113.7	95.9/72.2	2026/2028	2026/2027
33	Terry Fox MTS	91.7/105.8	53.9/41.7	-/2038	-/2032
34	Woodroffe TS	97.4/102.4	33.4/28.9	-/2039	-/2034

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period **2025-2044** RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the **Greater Ottawa region**. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 7-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 7-3: Greater Ottawa region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Maximum capacity	Current loading	Need Date
1	M4G/M5G	Merivale TS x Carling TS	1279 A	503 A	2030
2	L2M	Merivale TS X Limebank JCT	467 A	339 A	2028
3	S7M	Merivale TS x STR654JCT (Fallowfield tap)	1381 A	488 A	2032
4	C7BM	Merivale TS x NQL1 JCT	777 A	455 A	2034 (winter)
5	F10MV	City View JCT x Woodroffe TS	777 A	402 A	2034 (winter)
6	A4K	Hawthorne TS x Cyrville JCT x Overbrook TS	1214 A	550 A	2032/33 (winter)
7	A4K	Overbrook TS x King Edward TS	800 A	204 A	2032/33 (winter)
8	A3RM	Ellwood JCT x Riverdale JCT	1016 A	235 A	2034
9	A5RK	Hawthorne TS x Russel TS	1595 A	538 A	2034
10	A6R	Hawthorne TS x Russel TS	1703 A	489 A	2034

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operation and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The following load security needs were reviewed as a part of RIP:

M32S

Nepean TS is supplied solely by the 230 kV M32S circuit, and a contingency on M32S would result in the complete loss of load at Nepean TS due to its configuration. Under current load security criteria, no more than 150 MW should be lost for a single element contingency. While this limit is not exceeded in the summer forecast, it is projected to be reached in the winter forecast by 2029. A working group recommendation is discussed in section 8.4.

M1R+L2M

Circuits M1R and L2M share a breaker position at Merivale TS, so the loss of either circuit results in both being tripped. This configuration affects stations including Limebank MTS, Marionville DS, South Gloucester DS, Greely DS, and Russell DS. For this group, the 150 MW load security threshold is expected to be reached in the summer forecast by 2040 and in the winter forecast by 2031. A working group recommendation is discussed in section 8.4.

Load Restoration for C3S/M32S

M32S is a 230kV circuit connecting Merivale TS to South March TS, and 230kV circuit C3S connecting Chats Falls SS to South March TS. The two circuits are connected through an in-line breaker A1A2 at South March TS. Stations South March TS and Kanata MTS are supplied by both C3S and M32S. Nepean TS is only fed from circuit M32S. Load restoration was assessed for A1A2 breaker fail. The breaker fail condition can lead to no supply to all three stations. The loss of the two circuits results in approximately 330MW of load loss during summer. As per ORTAC, 80MW have to be restored in 30 minutes, 150MW restored in 4 hours and the entire load in 8 hours. Nepean TS can be restored by opening circuit switcher M32S-1 within 30 minutes. The breaker A1A2 disconnect switches at South March TS can be opened within 30 minutes to restore load stations from either C3S or M32S. All load can be restored within 4 hours. In addition, as discussed in section 8.4 a new switching station is planned at South March TS, which will eliminate this problem.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

Load Restoration for S7M

Circuit S7M and W6CS are tie via an in-line breaker L6L7 at South March SS. A L6L7 breaker failure results in no supply to Fallowfield MTS, Richmond MTS, Manotick DS, Bridlewood MTS, and Marchwood MTS. The amount of load loss is about 199 MW by the end of the study period in summer. As per ORTAC, all load above 150MW must be restored in 4 hours and all load restored in 8 hours. All load can be restored by opening breaker L6L7 disconnect switches at South March SS within 4 hours. The Study Team recommends that no further action is required at this time.

During winter time under contingency of S7M 150 MW can be interrupted by configuration by 2036. TWG recommends monitoring the winter load and addressing the need in the next regional planning cycle.

Load Restoration for D5A/B5D

Circuits D5A and B5D supply Longueuil TS, St Isidore TS, and Ivaco CTS. The worst contingency for the area can result in approximately 212MW of load loss. Hydro One prepared a Local Planning report which considered the loss of up to 174MW of load for the same contingency. Hydro One has reviewed the report and determined that the conclusions of the report are still applicable to the new load forecast. The report shows that all load can be restored in at least 4 hours, meeting ORTAC restoration criteria. The Study Team recommends that no further action is required at this time.

Load Restoration for M4G/M5G

Load restoration was assessed for the 115 kV double-circuit M4G/M5G supply serving Nepean–Epworth MTS, Carling TS, and Lisgar TS in downtown Ottawa. Although Slater TS is also supplied from M4G, it was excluded from this assessment because it has alternate supply from two other circuits and therefore does not drive the same restoration need. Based on the load forecast, the combined demand on M4G/M5G is expected to exceed 250 MW in the mid-term; under ORTAC, loads greater than 250 MW must be restored within 30 minutes following a contingency. To ensure compliance with this requirement as loading increases, Hydro Ottawa and Hydro One will review restoration options, which may include LV load transfers and/or additional switching and operational restoration actions. The TWG recommends that this review be reviewed as part of the M4G/M5G upgrade and/or the Bronson connection project scopes, where practical restoration enhancements can be implemented and validated against the 30-minute restoration criterion.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Greater Ottawa region. These needs include those previously identified in the NA and IRRP for the Greater Ottawa region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 8-1 below:

Table 8-1: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	2031	8.1.1
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	2031	8.1.2
Nepean TS	Replacement of T3/T4 transformers based on asset condition	2034	8.1.3
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	2030	8.1.4
Station Capacity Needs			
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and a new transmission line from Merivale TS.	2028	8.2.1
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	2031	8.2.2
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	2028	8.2.3

South March TS	Replacement of T1/T2 transformers and associated equipment's with upgraded units based on capacity needs.	2026	8.2.4
Albion TS	Replacement of T1/T2 transformers and associated equipment's with upgraded units based on capacity needs.	2031	8.2.5
Carling TS	Station capacity will be exceeded due to limiting components at LV side. Replacing limiting LV cables will add capacity to station.	2028	8.2.6
Lisgar TS	Station capacity will be exceeded due to limiting LV cables and 75 MVA transformer unit (T2).	2028	8.2.7
King Edward TS	Station capacity will be exceeded due to limiting components at LV side. Replacing LV components will add capacity to station.	2026	8.2.8
Nepean TS	Station capacity will be exceeded during winter season.	2030	8.2.9
Riverdale TS	Station capacity will be exceeded due to limiting LV components and 75 MVA transformer units.	2028	8.2.10
Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating.	2028	8.2.11
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	2028	8.2.12
Marionville DS	Install a second transformer to increase station rating.	2025	8.2.13
Greely DS	Install SCADA transformer fan monitoring	2025	8.2.14
Manotick DS	Load transfer from T1 to T2 at Manotick DS	2025	8.2.15
Hinchey TS	Load to be monitored and necessary actions to be taken as load picks up.	2031	8.2.16
Rockland DS	Install SCADA transformer fan monitoring	2025	8.2.17
Rockland East DS	Install SCADA transformer fan monitoring	2026	8.2.18
Manordale MTS	Load transfers to existing stations	2026	8.2.19

Nepean Epworth MTS	Load transfers to existing stations	2028	8.2.19
Kanata MTS	Load transfers to existing stations	2025	8.2.19
Ellwood MTS	Load transfers to existing stations	2027	8.2.19
Limebank MTS	Load transfers to existing stations	2028	8.2.19
Bridlewood MTS	Load transfers to existing stations	2030	8.2.19
Marchwood MTS	Load transfers to existing stations	2025	8.2.19
Centrepoint MTS	Load transfers to existing stations	2027	8.2.19
Fallowfield MTS	Load transfers to existing stations	2026	8.2.19
Transmission Line Capacity Needs			
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	2030	8.3.1
L2M	Uprate line section between Merivale TS x Limebank JCT	2028	8.3.2
A4K	Continue to monitor the winter load.	2032/33	8.3.3
System Reliability, Operation and Load restoration Needs			
Load Security issue due to contingency of M32S	Provide a second supply to Nepean TS via a new transmission circuit from Merivale TS.	2029	8.4.1
Kanata Area	New Switching Station to improve reliability and flexibility in Kanata Area		8.4.2
Load Security issue due to contingency of M1R+L2M	Install a new breaker at Merivale TS and separate L2M and M1R breaker positions.	2031	8.4.3
Loading and voltage issues on S7M	Continue monitoring load growth and system performance	2032	8.4.4
East Ottawa Area	Supply in East Ottawa Area	2029-2030	8.4.5

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

8.1.1 South March TS T1/T2

The existing transformers 50/83 MVA 230/44 kV T1 and T2 at South March TS were originally commissioned in 1971 and based on asset condition assessment, they are identified for replacement in 2031.

A like-for-like replacement of these units would not be adequate in meeting the load during the study period. However, as discussed in Section 8.2, there are station capacity needs in the near term which require upsizing the transformers.

As outlined in the Ottawa area sub-region IRRP and endorsed by the TWG, the recommended solution is to replace the existing transformers with new 75/125 MVA units. This upgrade will ensure adequate capacity and reliability for the growing load in the South March area. Hydro One is working to accelerate the replacement schedule to 2029–2030 to address reliability risks and align with regional planning objectives.

8.1.2 Albion TS T1/T2

Albion TS has two power transformers rated at 45/60/75 MVA, 230 kV / 14 kV / 14 kV, built in 1970. Based on asset condition assessment, these transformers are identified for replacement in 2031.

The 13.8 kV metalclad switchgear installed since 1971 contains six air circuit breakers and two SF6 capacitor bank breakers. The station also has four 13.8 kV conventional SF6 breakers. All circuit breakers require replacement in the near to medium term planning horizon.

The existing transformers at Albion TS will be replaced with new standard 60/80/100 MVA units. These are closest standard size units to the existing transformers. All existing Hydro One owned circuit breakers will be replaced with breakers of similar rating. This alternative would address the asset renewal needs and would maintain reliable supply to customers.

However, as discussed in Section 8.2, additional station capacity will be required in the mid-term, necessitating upgrades at Albion TS.

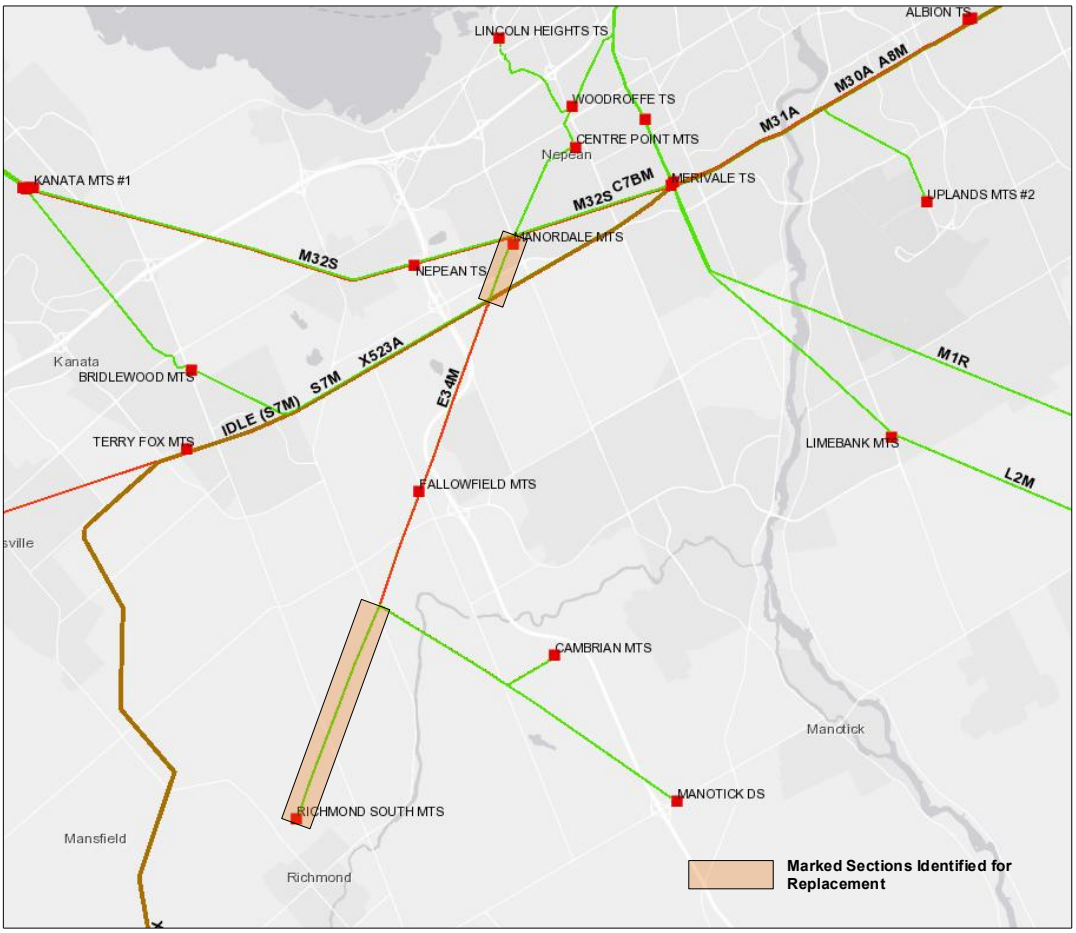
8.1.3 Nepean TS T3/T4

Nepean TS has two power transformers rated at 75/125 MVA, 230 kV / 14 kV / 14 kV, built in 1970's. Based on asset condition assessment, these transformers are identified for replacement in with like-for-like units as this is the highest rating available, with a planned in-service date of 2034.

8.1.4 S7M Line Refurbishment

Two sections of circuit S7M between Manotick JCT × Richmond MTS (5 km) and S7M STR 673N JCT × Manordale JCT (1.4 km) are identified for replacement as shown in Figure 8-1. These sections are 115 kV predominantly wood pole transmission line that was originally placed in service in 1928. Asset renewal is required on these line sections.

Figure 8- 1: S7M section requiring sustainment highlighted



Two possible options are considered for this line section rebuild:

Alternative 1 - Rebuild H frame wood structures: This alternative would be a like for like rebuild of the existing 5km of 115kV transmission line. This would be adequate to supply the forecasted load at Richmond South MTS. The planned in-service date for this refurbishment is 2030.

Alternative 2 - Upgrade to 230 kV ready operation by rebuilding the 115kV single circuit line as a double circuit 230kV line. This would be similar to upgrade done to S7M for the Cambrian MTS Connection as described in Section 5. This alternative considers possible area conversion to 230kV by making the rebuild ready for the upgrade. This would be in accordance with the long-term plan for the area as described in IRRP.

Recommendation:

The recommended near-term plan is to refurbish these line sections to maintain reliability. However, this line section may also be considered for a configuration change refer to Section 8.4.3. Further discussion will occur as part of bulk system planning.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period **2025-2044** for the 230kV and 115kV Transformer stations in the **Greater Ottawa region** using both the summer and winter peak load forecasts that were provided by the study team. This section describes the following capacity needs that have been identified during the study period

To address the station capacity needs, the recommendation of this planning cycle is a combination of new transformer stations and upgrades at existing stations. The new stations are described first, followed by the upgrades considered at the existing stations. The RIP focuses on wire alternatives, however where possible non-wire alternatives are also considered as per the IRRP.

As can be seen in Section 6 Figure 6-1, the area winter load is expected to increase significantly over the study period. The greater Ottawa region has historically been a summer peaking region; however, the region is forecasted to become winter peaking in the near term due to the impact of measures such as electrification and decarbonization. The winter load forecast shows many stations reaching their capacity in the near midterm. Plans have been identified to address these needs and are discussed in this section.

The working group will monitor closely the winter load to track its growth and determine if the forecasted trends materialize in the short term. Many stations are forecasted to go over their transformation capacity and in the long term are expected to far exceed the station LTR. Significant investments will be required at the bulk and regional level to meet this load. Thus, the TWG will monitor the demand in the coming winters and may decide to trigger the next regional planning cycle earlier to address these emerging needs.

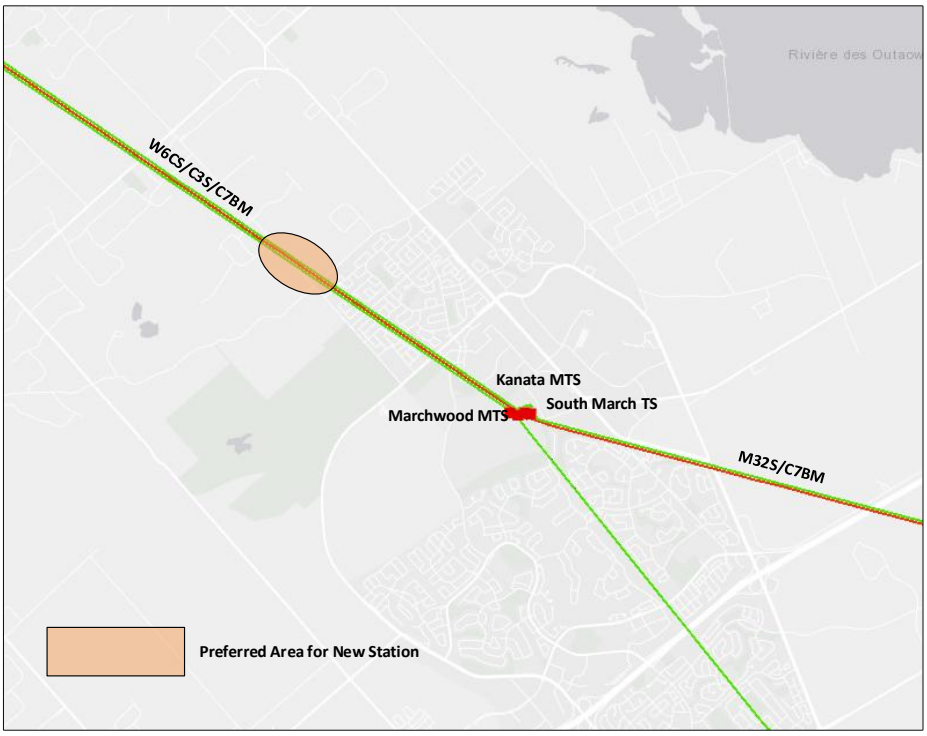
Also, please note there are several downtown stations that are recommended for upgrades in similar timeframes. The ISD highlighted in this section is based on preliminary information. Hydro Ottawa and

Hydro One will work together to review the work required and timing for each upgrade to better coordinate the plans. The dates are subject to change based on the review and determination of the preferred path to achieve all the upgrades listed.

8.2.1 Kanata North – Stittsville Area

Significant growth and capacity needs have been identified in Kanata North and Stittsville area. The area is supplied mainly through three transformer stations: Marchwood MTS, Kanata MTS, and South March TS. Based on the load forecast, all 3 stations will reach their LTR in the short term. Hydro One is proceeding with capacity upgrade at South March TS as described in section 8.2.4. However, additional transformation capacity is required and TWG, as part of the IRRP, has recommended building a new station to address this need. Hydro Ottawa has identified preferred location for the station as shown in Figure 8-2 below.

Figure 8-2: Preferred Location of New Station in Kanata North – Stittsville Area



The following alternatives were considered to meet the growth of the area.

Alternative 1: New station supplied from existing single circuit 230kV line.

Build a new station and connect to 230kV circuit C3S as shown in Figure 8-3. The station would have sufficient capacity to address the growth of the area over the study period. However, a single circuit supply would not provide the same level of reliability as the stations in the area currently have. Also, depending on the dispatch of resources and system configuration of the area, the existing system capacity to meet the demand is limited.

Alternative 2: New station supplied from two 230kV circuits.

Build the station as described in Alternative 1 and bring an additional 230kV supply. Please refer to Figure 8-4 below. The new circuit would be extended from M32S at South March TS and would help meet load growth over a wider range of system conditions. The new circuit would make use of the existing right of way by rebuilding one of the 3 circuits as a double circuit line.

Preliminary review of possible transfers to the new station has been considered and a revised forecast for the stations in the area is shown in Table 8-2.

Table 8-2. Updated summer forecast (MW) with transfers to Kanata North Considered.

	LTR (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035
Marchwood MTS	32.2	52.9	33.1	34.3	35.3	36.4	37.4	38.7	39.4	39.2
Kanata MTS	51.5	53.8	36.8	36.4	36.2	36.0	35.7	35.6	35.6	35.4
Kanata North MTS	108[1]	0	38	38.4	38.7	39.1	39.4	39.8	40	40.4

[1]Capacity for the new station will be confirmed as the project progresses.

Figure 8-3: Connection of New Kanata North MTS to C3S (initial connection)

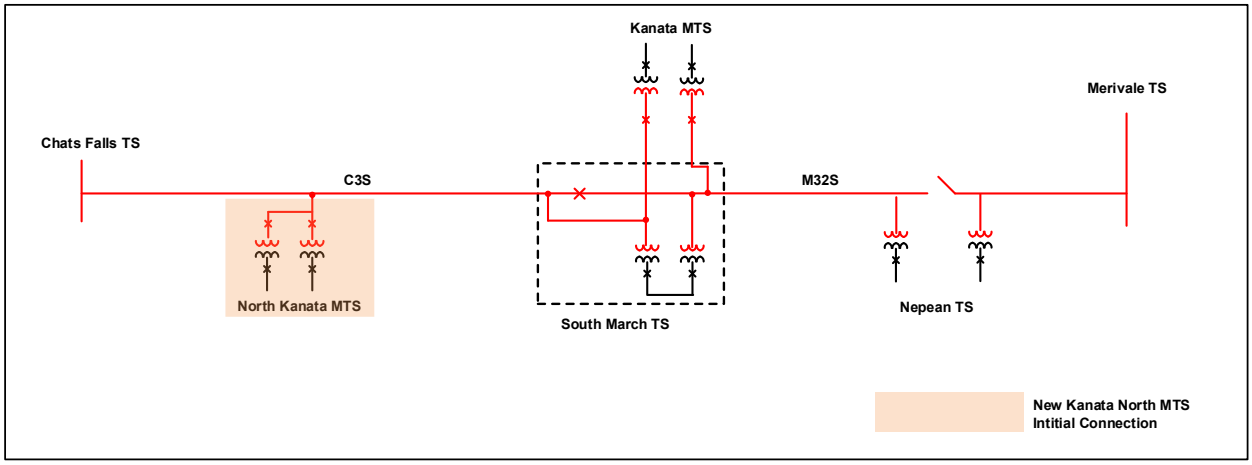
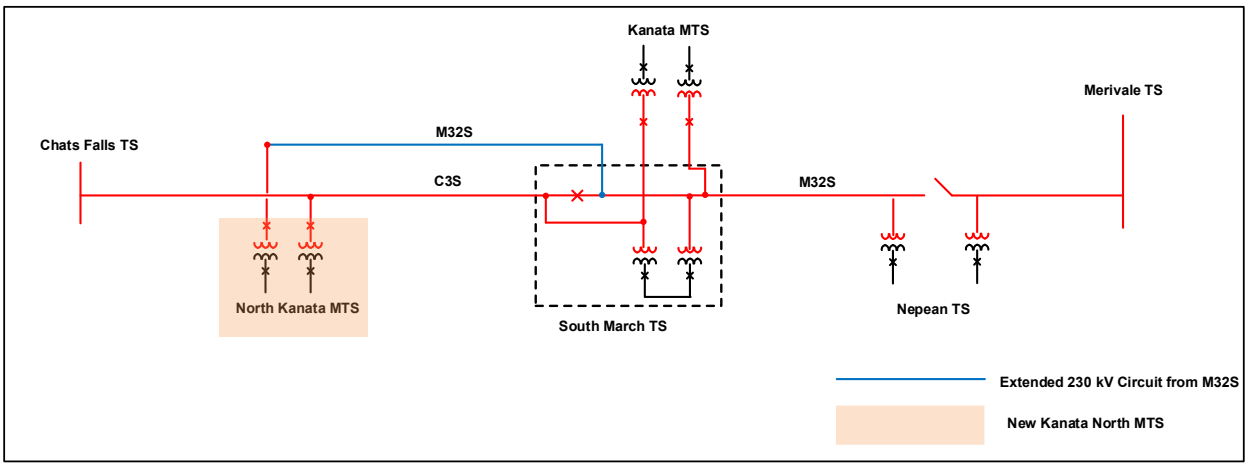


Figure 8-4: Connection of New Kanata North MTS to C3S and New Circuit (recommended alternative)

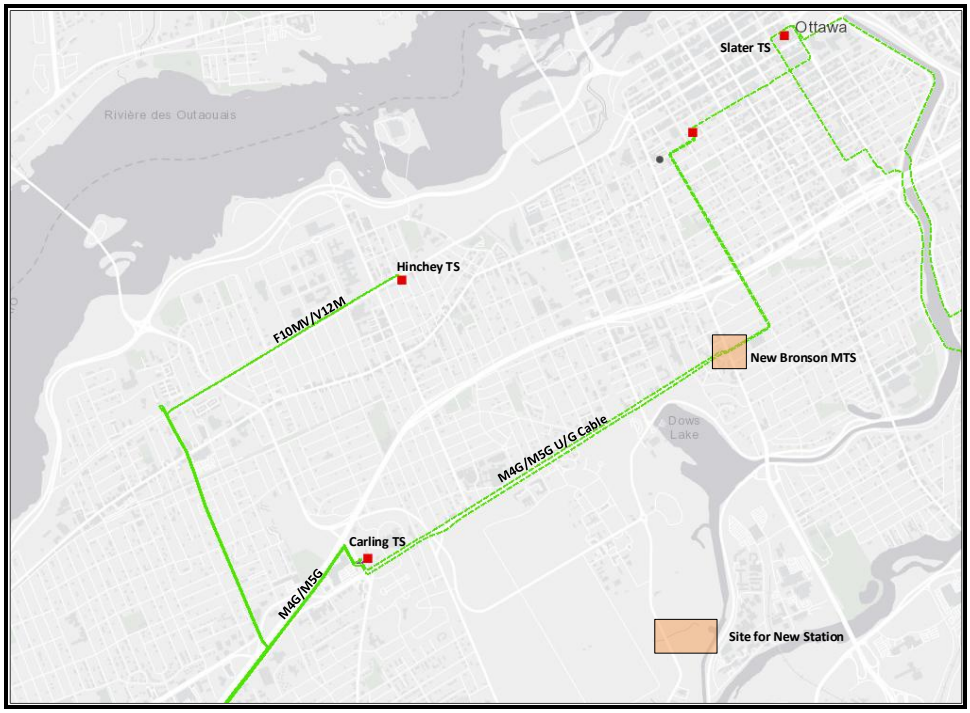


The TWG recommends Hydro Ottawa and Hydro One proceed with Alternative 2. This option will provide the necessary transformation capacity for the area and will provide higher level of reliability by having two circuits supplying the station. Based on the immediate need for transformation capacity, Hydro Ottawa is planning to build the station by 2028. In order to meet this in-service date, the station will be connected initially to existing 230kV circuit C3S only as described in Alternative 1. The second circuit is expected to be completed by 2031.

8.2.2 Bronson MTS

Several stations supplied from the 115kV network in the downtown core have been identified as reaching their capacity in the short term. Upgrading some of these stations is feasible to increase their transformation capacity. However, given the magnitude of the growth expected, additional transformation capacity in the form of a new station is required. Hydro Ottawa has identified a site for a new station: the alternative considered is to convert an existing Hydro Ottawa owned distribution station into a 115 kV DESN. The site of this station is adjacent to an underground cable section of M4G/M5G between Carling TS and Lisgar TS as shown in Figure 8-5.

Figure 8-5: Ottawa Downtown Area Map with new Bronson MTS



This conversion to a 115 kV DESN would increase the transformation capacity of the station. It would also enable load transfers from nearby stations and allow for new developments in Ottawa's Core East area, which is experiencing significant growth driven by urban densification, electrification of heating and transportation, and federal decarbonization initiatives. To note, this option would necessitate uprating circuits M4G and M5G to address thermal limitations, as discussed in Section 8.3 of this report.

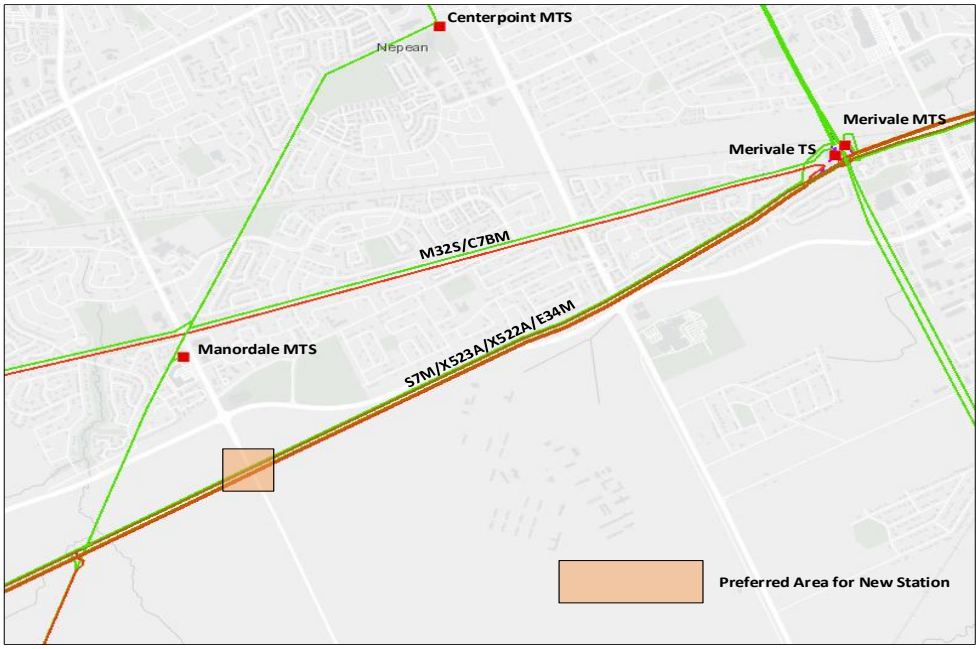
This plan was initially proposed as part of the IRRP. TWG has reviewed the need and proposed solution and reaffirmed the plan as the preferred alternative.

Hydro Ottawa and Hydro One are proceeding into studies to determine how the station will be connected to the existing 115kV underground cables. The proposed in-service date for the station is 2031.

8.2.3 Greenbank MTS

Another area expected to experience high growth is in the west of the city. The existing stations have limited capacity and TWG is recommending a new station to be built to address this need. Hydro Ottawa has identified preferred location for the station as shown in Figure 8-6 below.

Figure 8-6: Preferred Location of New Station in West Ottawa

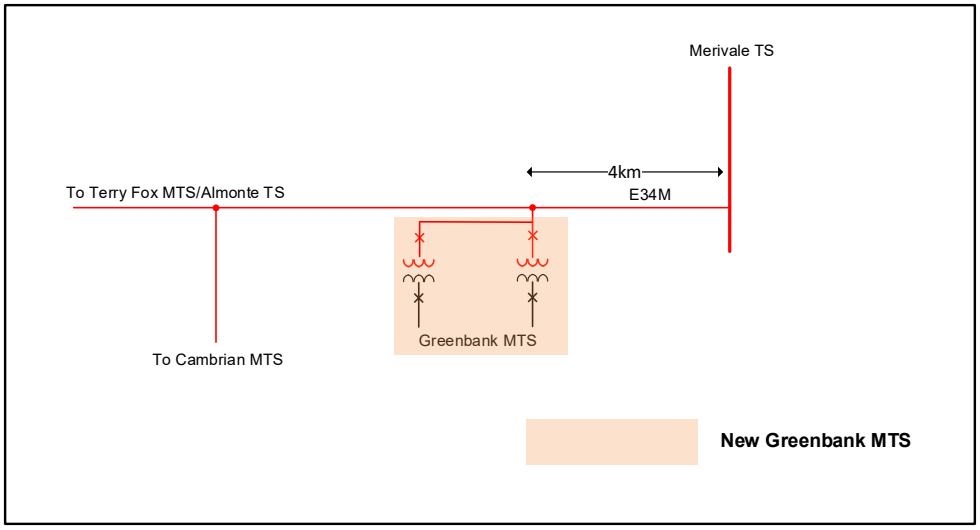


The following alternatives were considered to meet the growth of the area.

Alternative 1: New station supplied from existing single circuit 230kV line.

Build a new station and connect to 230kV circuit E34M as shown in Figure 8-7. The station would have sufficient capacity to address the growth of the area over the study period. However, connection to E34M alone would limit the growth that can be supplied from the station. In addition, the circuit needs to be connected at Merivale TS for the voltage to be acceptable.

Figure 8-7: Connection of New Greenbank MTS to E34M



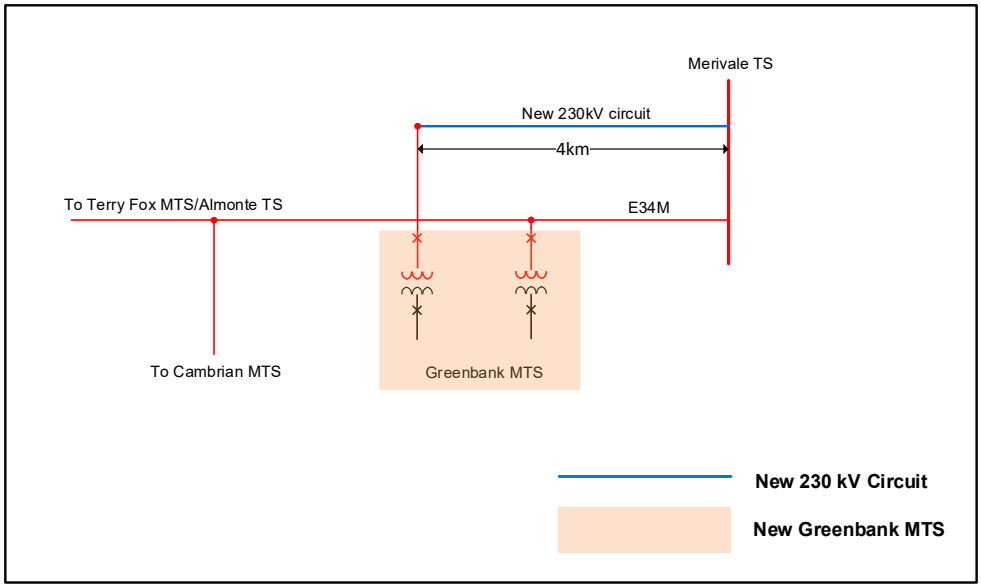
Alternative 2: New station supplied from two 230kV circuits.

Build the station as described in Alternative 1 and bring an additional 230kV supply. Please refer to Figure 8-8 below. The new circuit would be extended from Merivale along the E34M corridor. The new circuit would alleviate the concerns identified for Alternative 1 and would help meet load growth over a wider range of system conditions.

Alternative 2 was initially proposed as part of the IRRP. TWG has reviewed the need and proposed solution and reaffirms the plan as the preferred alternative.

Hydro Ottawa and Hydro One are proceeding with a project to connect the new station to the 230kV system. Hydro Ottawa's new station is planned for in-service in 2028. The new circuit must be coordinated with the Merivale TS upgrade described in Section 6 and is currently expected for in-service in 2031. Both transformers at the new station will be supplied by circuit E34M as per Alternative 1 until the new circuit is available. Operating measures may be required to help supply the load should there be issues with E34M until the second circuit is available.

Figure 8-8: Connection of New Greenbank MTS to E34M and new circuit



8.2.4 South March TS – T1/T2

South March TS, located in the Kanata–Stittsville area currently served by 230 kV circuits M32S and C3S. The station is equipped with two aging 50/83MVA 230kV/44kV transformers (T1/T2) which, based on their condition, were identified for replacement in 2030–2032 as outlined in Section 8.1.1.

Based on the updated load forecast, South March TS is projected to exceed its summer LTR by approximately 3 MW in 2026 and its winter LTR by about 6 MW in 2028, with the high-growth scenario the need date is 2026 for summer and 2027 for winter. TWG has recommended upgrading the existing

transformers to new 75/125 MVA units. The tentative planned ISD for this upgrade project is scheduled in 2031- 2032. Hydro One is working to expedite the replacement work to 2029-2030 to meet the rising load growth.

In the interim, coordination with LDCs will be required to explore load transfer opportunities to adjacent stations or other operating measures to manage short-term capacity constraints until the transformer replacement is completed should there be any issues at the station.

8.2.5 Albion TS T1/T2

Albion TS is a 230 kV / 14-14 kV DESN station supplied from circuits M30A and M31A. The station's two 75 MVA, 230 kV / 14-14 kV transformers were identified for replacement based on condition assessments. Planned in-service date for this work is 2031(refer to Section 8.1.2).

Based on the load forecast, Albion TS is projected to exceed its winter LTR by approximately 3 MW in 2034, while the summer LTR remains within limits over the study period. Under the high-growth scenario, the need date is 2030 for winter and 2043 for summer.

To address the loading issue, TWG has recommended upgrading the two transformers to standard 100 MVA units, along with the metalclad switchgear upgrade. The tentative in-service date for this upgrade is 2031. A feasibility study will be conducted to determine the preferred option to upgrade the metalclad as the existing installation has space limitations which may restrict the possible upgrade.

8.2.6 Carling TS – T1/T2

Carling TS is a transformer station that steps down voltage from 115 kV to 13.2 kV that is supplied from circuits M4G and M5G. Each transformer is rated at 115/14.2/14.2 kV, 60/80/100 MVA.

Based on the forecasts, Carling TS will exceed its summer LTR by approximately 11 MW and its winter LTR by about 1 MW by 2028. The current capacity limitation is primarily due to the existing series-connected low-voltage (LV) cables which limit the station capacity.

To address this constraint, TWG recommends upgrading the LV cables associated with both transformers as the preferred solution, as it will increase station capacity and eliminate low-voltage limitations. This upgrade project is tentatively planned for an in-service date in summer 2030.

8.2.7 Lisgar TS T1/T2

Lisgar TS is an indoor facility that steps down voltage from 115 kV to 13.2 kV that is supplied from circuits M4G and M5G. Replacement of 75 MVA transformer T1 with a 100 MVA unit was recently completed in December 2025. Following this replacement, the forecasts indicate that the station will exceed its summer LTR by approximately 13 MW and its winter LTR by about 8 MW by 2028. Under the high-growth scenario, the winter need date is advanced to 2027.

The current capacity limitation is primarily due to the existing LV cables and metalclad breakers, which limit the station capacity. To address this constraint and meet future demand, TWG recommends replacing 75MVA transformer T2 with a 100 MVA unit that will match T1 and upgrading the LV cables and metalclad breakers. Based on preliminary review by Hydro One, two options are identified for the station upgrade.

Alternative 1: In-Situ replacement of transformer T2

Under this option, transformer T2 will be replaced at its existing location within Lisgar TS. During the replacement process, the entire station load will temporarily be supplied by transformer T1, which will require careful operational planning to avoid overloading. To facilitate this, Hydro Ottawa will need to implement targeted load transfers to adjacent stations to reduce stress on T1 during the outage. This approach minimizes the need for major civil works and leverages existing infrastructure. The target in-service date for this In-Situ replacement is 2031.

Alternative 2: Greenfield Replacement of transformer T2

If operational constraints or stranded load conditions make it impractical to transfer Lisgar TS load to other stations during the replacement, a greenfield approach will be considered. This involves installing the new transformer at a new location within the station property, which will require extension of the existing building and additional civil works. The target in-service date for this approach is 2034.

A conceptual layout for this greenfield approach is shown in Figure 8-9.

Figure 8-9: Lisgar TS extension under alternative 2



Recommendation:

A feasibility study will be conducted to evaluate both alternatives in detail, considering technical, and operational implications. Hydro Ottawa and Hydro One will review the options following the feasibility

study and decide on the preferred alternative. In the interim, coordination with LDCs will be required to explore load transfer opportunities to adjacent stations to manage short-term capacity constraints until the transformer and component replacements are completed should there be any issues at the station.

8.2.8 King Edward TS

King Edward TS, located in the downtown core of Ottawa, supplies Hydro Ottawa customers. The station is fed by two underground 115 kV cables from A4K and A5RK. The station capacity is limited due to the existing metalclad breakers and LV cables. The forecasts indicate that King Edward TS will exceed its winter LTR by approximately 9 MW as early as 2026 and its summer LTR by about 1 MW in 2033. Under the high-growth scenario, the need dates advance significantly to 2025 for winter and 2030 for summer.

The proposed solution involves upgrading the metalclad breakers and LV cables to increase station capacity and support future downtown demand. This upgrade project is tentatively planned for an in-service date of 2033. In the interim, coordination with LDCs will be required to explore load transfer options to manage short-term capacity limitations until the upgrades are completed should there be any issues at the station.

8.2.9 Nepean TS T3/T4

Nepean TS is supplied from 230 kV circuit M32S and steps down voltage to 44 kV for local Hydro Ottawa customers. Regional load forecasts indicate that Nepean TS is expected to exceed its winter LTR by approximately 9 MW in 2030, while summer LTR is projected to remain within limits throughout the study period. Since this need is primarily in the winter timeframe, the TWG recommends monitoring winter load growth and revisiting this capacity need in the next regional planning cycle which can be triggered in advance if load growth is significant.

8.2.10 Riverdale TS T2/T3

Riverdale TS T2/T3 is a 45/75 MVA 115 kV/13.2 kV facility located in downtown Ottawa, supplied by three 115 kV circuits: A5K, A3RM, and A6R. The forecasts indicate that Riverdale TS will exceed its summer LTR by approximately 2 MW in 2030 and its winter LTR by about 9 MW in 2028. Under the high-growth scenario, the summer need date advances to 2029 and the winter need date to 2026.

The station’s transformation capacity is limited due to LV cables. Replacing the LV cables will provide additional capacity, enabling Riverdale TS to support projected load growth and relieve constraints in the Core East area. However, Hydro Ottawa has confirmed that some load transfers to nearby stations are available, which can help manage growth in the foreseeable future. Therefore, TWG recommends monitoring load growth at Riverdale TS and proceed with distribution load transfers as necessary until further upgrades are deemed required.

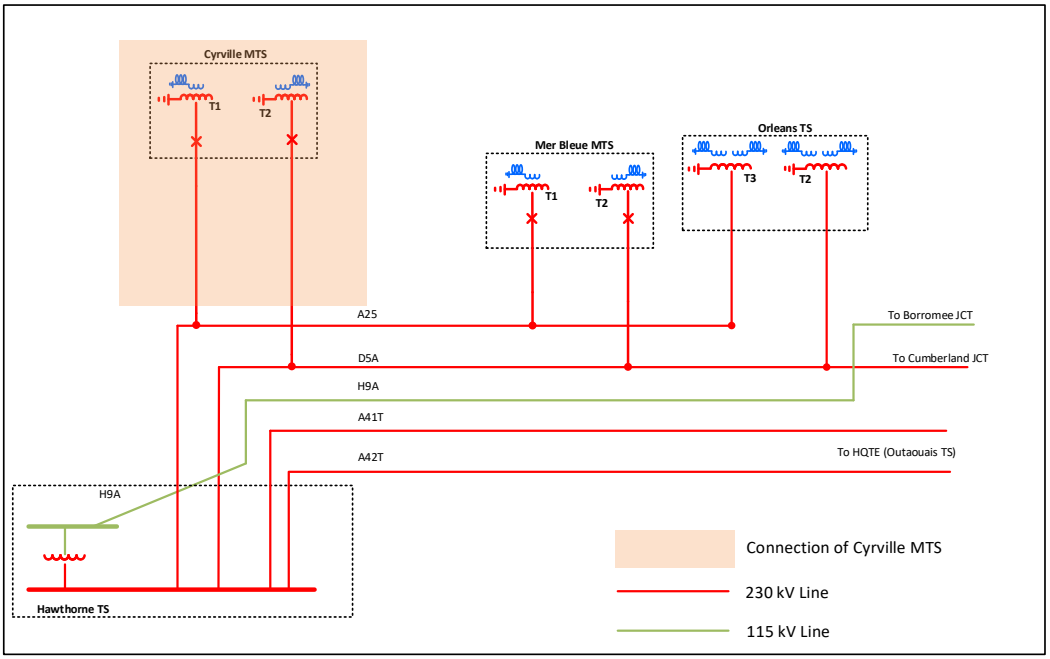
8.2.11 Cyrville MTS

Cyrville MTS is currently supplied by 115 kV circuits A4K and A2. The forecasts indicate that Cyrville MTS will exceed its summer LTR by approximately 1 MW in 2028 and its winter LTR by about 1 MW in 2030. Under the high-growth scenario, the winter need date advances to 2028.

The current plan as recommended in IRRP is to convert Cyrville MTS from a 115 kV station to a 230 kV station with two 100 MVA transformers by connecting to existing circuit D5A and a new 230 kV circuit A25

from Hawthorne TS, with a tentative in-service date of 2029. The planned conversion of Cyrville MTS will not only address near-term capacity needs but also position the station to accommodate future electrification and resilience requirements for Ottawa's east end. Please refer to Figure 8-10 for the planned connection. Hydro One is working on feasibility study to determine the preferred corridor for the connection of the station to the 230kV in collaboration with Hydro Ottawa.

Figure 8-10: New Cyrville MTS connected to D5A and new A25 circuit



8.2.12 Moulton MTS

Moulton MTS has a LTR of 32 MW in both summer and winter seasons. The forecasts indicate that the station will exceed its summer LTR by approximately 5 MW and its winter LTR by about 6 MW by 2028. To address this need, TWG has recommended to repurpose two 50 MVA, 115 kV transformers from Cyrville MTS following its planned conversion to 230 kV. Relocating these transformers to Moulton MTS will provide additional transformation capacity to meet projected demand growth. This approach leverages existing assets efficiently while supporting reliability in the growing east-end area.

8.2.13 Marionville DS

Marionville DS is forecasted to exceed its summer and winter Planned Loading Limit (PLL) as early as 2025.To address this need, the recommended action is to install a second transformer rated at 20 MVA and construct approximately 4.2 km of new distribution feeder to integrate the additional capacity. The tentative in-service date for this upgrade is December 2029. In the interim, Hydro One Distribution will manage load growth through transfers to nearby stations to maintain reliability until the new transformer and feeder build are completed.

8.2.14 Greely DS

Greely DS is projected to reach its summer and winter PLL in 2025. To address this the recommended action is to install SCADA fan monitoring for transformers T1 and T2 (115 kV to 28 kV). This upgrade will enable fan monitoring and allow higher ratings for both transformers, increasing their capacity from 23 MVA to 38 MVA in summer time and 28 MVA to 43 MVA in winter. The planned in-service date for SCADA fan monitoring is scheduled for 2026.

8.2.15 Manotick DS

Manotick DS has a summer PLL of 8.6 MVA and a winter PLL of 11.6 MVA. This PLL considers the loss of one transformer. Load forecasts indicate that the station will exceed these limits in both summer and winter starting in 2025.

Hydro One Distribution has operating measures to deal with station load in the near and medium term should one of the transformers fail such as use of Mobile Unit Substation (MUS)

Other measures such as Scada fan monitoring can be considered and will be reviewed as a part of next regional planning cycle.

8.2.16 Hinchey TS

Load forecasts indicate that Hinchey TS is expected to exceed its winter LTR by approximately 2 MW in 2031, while summer LTR is projected to remain within limits throughout the study period. Since this need is primarily in the winter timeframe. TWG is recommending monitoring winter load growth and revisiting this capacity need in the next regional planning cycle which can be triggered in advance if load growth is significant.

8.2.17 Rockland DS

Rockland DS is forecasted to reach its summer PLL in 2025, TWG recommends the implementation of SCADA monitoring of transformer fan. This will increase the summer PLL to 14.4 MVA and alleviate the overload at station. The planned in-service date for the fan monitoring installation is 2026.

In the interim, LDCs will implement operational measures, to manage loading and maintain system reliability until the permanent solution is in place.

8.2.18 Rockland East DS

Rockland East DS is forecasted to reach its summer PLL in 2026. TWG recommends the implementation of SCADA monitoring for transformer fans. The planned ISD for the fan monitoring installation is 2027.

In the interim, LDCs will implement operational measures to manage loading and maintain system reliability until the permanent solution is in place.

8.2.19 Additional Transformation Capacity needs

Several stations in the Greater Ottawa area are forecasted to exceed their LTR within the study period. The following summarizes the anticipated capacity needs:

- Nepean Epworth MTS – Expected to exceed its LTR in 2028 (winter) and 2035 (summer).
- Kanata MTS – Projected to exceed its summer and winter LTR in 2025.

- Ellwood MTS – Forecasted to exceed its summer and winter LTR in 2027.
- Limebank MTS – Expected to exceed its LTR in 2028 (winter) and 2031 (summer).
- Bridlewood MTS – Projected to exceed its LTR in 2030 (winter) and 2035 (summer).
- Marchwood MTS – Anticipated to exceed its summer and winter LTR in 2025.
- Centrepoint MTS – Expected to exceed its LTR in 2027 (winter) and 2032 (summer).
- Manordale MTS – Forecasted to exceed its LTR in 2026 (winter and summer).
- Fallowfield MTS – Projected to exceed its LTR in 2030 (winter) and 2026 (summer).

Hydro Ottawa has confirmed that loading at these stations can be managed through operational load transfers to nearby stations in the near term. Additionally, the commissioning of new stations—Kanata North MTS, Mer Bleue MTS, Greenbank MTS, Bronson MTS and Piperville MTS—will allow permanent load shifts, providing long-term relief to these stations and addressing regional capacity needs.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period **2025-2044** for the 230kV and 115kV Transmission line circuits in the **Greater Ottawa region** by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater to this need. Based on the results, the following line capacity needs have been identified during the study period:

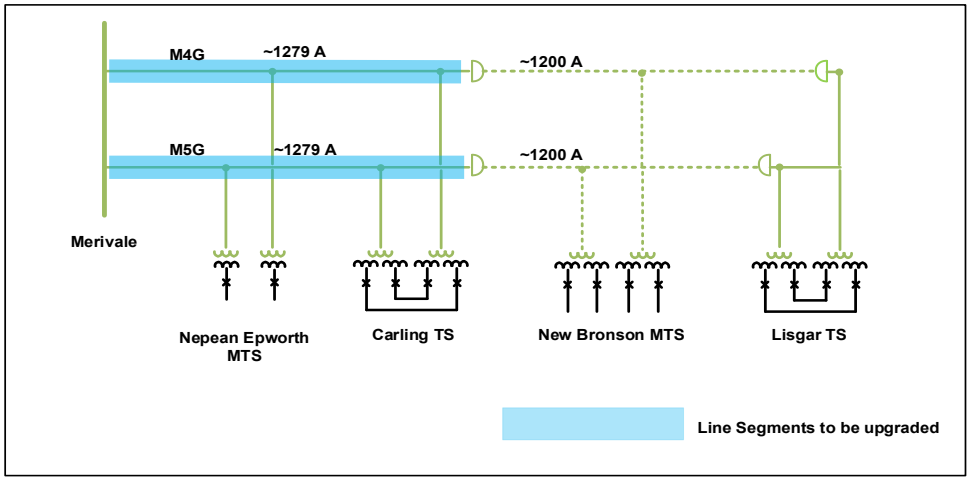
8.3.1 M4G/M5G – 115 kV – Section Uprate

The M4G and M5G circuits, which supply Nepean Epworth MTS, Carling TS and Lisgar TS, are forecasted to experience thermal constraints under contingency conditions as downtown Ottawa load continues to grow. When one circuit is out of service, the remaining circuit would be required to fully supply all stations, resulting in thermal overload conditions. Based on the regional load forecast, this limit is expected to be reached in the summer of 2030 and in the winter of 2032.

To address this issue, the recommended action is to upgrade sections of M4G and M5G between Merivale TS and Carling TS to remove thermal constraints and support higher downtown load.

Based on studies, this load pocket can supply about 360 MW before voltage issues arise. Hydro One will consider different conductor options to meet this load. The feasibility of using ACSS (Aluminum Conductor Steel Supported) conductor options will be explored to provide sufficient capacity while maintaining reliability.

Figure 8-11: Uprate Section from Merivale TS to Carling TS

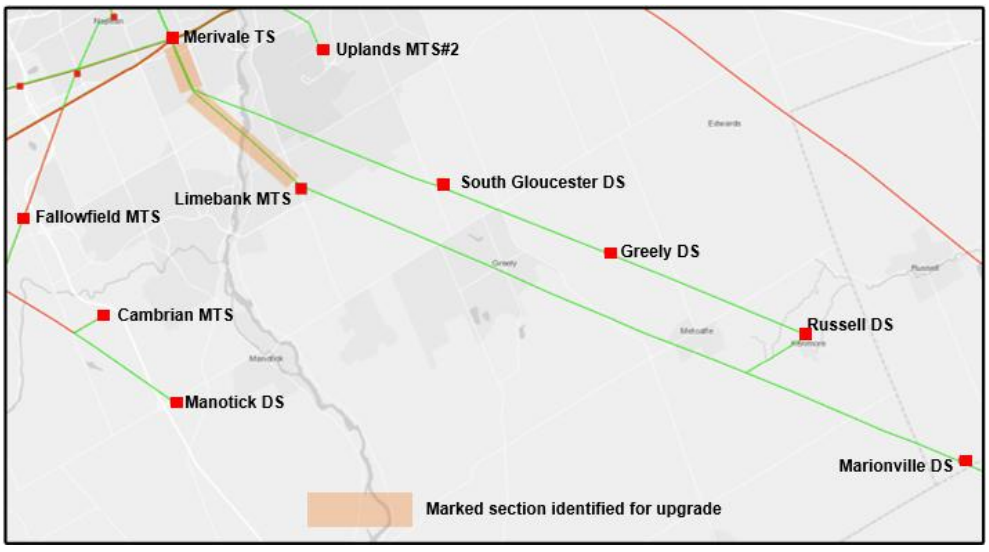


Regional planning emphasizes that downtown Ottawa is a critical load pocket with limited space for new infrastructure, making reinforcement of existing transmission corridors essential. Since Bronson MTS is also planned as a new station to relieve downtown capacity constraints, uprating the M4G/M5G corridor is a key enabler for this project and for supporting long-term growth in the Core East area.

8.3.2 L2M – 115 kV – Uprating Merivale TS x Limebank MTS

Thermal constraints have been identified on the L2M transmission line section between Merivale TS and Limebank MTS, which supplies Limebank MTS and Marionville DS as shown in Figure 8-12. These constraints are primarily driven by the increasing load forecast at Limebank MTS, as identified in the regional planning load forecast. The section of L2M has a summer rating of 93 MVA (477 A) and based on the study results, the 7.8km line section between Merivale TS and Limebank MTS is expected to reach its thermal capacity limit in the near term by 2028.

Figure 8-12: Uprate Section from Merivale TS to Limebank MTS



Alternative 1 - Remove sag limitation

The rating of circuit L2M between Merivale TS and Limebank MTS is currently limited due to clearance concerns. This option looks to increase the thermal capacity of L2M by addressing the conductor's sag issue. Hydro One has previously reviewed the work necessary to remove the limitation and has determined that approximately 3.2km of the line section would have to be rebuilt in addition to modification to some existing towers and insulators where no rebuilding is required. This work would remove the clearance limitation and would allow the circuit capacity to be increased to approximately 106MW in summer and 131 MW in winter. This allows us to meet the demand up to the mid-term.

Alternative 2: Rebuild the circuit

This alternative would look at rebuilding the 7.8km circuit L2M between Merivale TS and Limebank MTS to increase the circuit's thermal rating. Two options were considered.

> **Alt 2a:** This option would rebuild the existing 7.8km as a single circuit 115kV line. It would address the thermal rating constraint currently on the circuit and would be adequate to supply the forecasted load of Marionville DS and Limebank MTS. However, with this option, Limebank MTS and Marionville DS would remain on a single circuit supply.
>
> **Alt 2b:** This option would rebuild the existing 7.8km as a double circuit 115kV line. Similar to Alternative 2a, this option would address the thermal rating issue. This option would also help improve the reliability of supply to Limebank MTS by providing a second supply to the station.

Recommendation

TWG recommends uprating L2M to support the south-end growth and align with recommendations for proactive reinforcement of critical transmission corridors. A feasibility study will be done after which Hydro One and LDCs will review the different options. The selected alternative will follow the recommendation to uprate the section of L2M from Merivale TS to Limebank MTS, with a tentative in-service date of 2032.

8.3.3 A4K – 115 kV

Hawthorne TS x Overbrook TS section

Under the winter peak forecast for 2032, thermal overload has been identified on a critical section of the A4K corridor, specifically between Hawthorne TS x Overbrook TS, under the contingency of either circuit A5RK or A6R. When either of the circuits are out of service, the resulting increased loading on A4K is beyond its thermal capability.

Overbrook TS x King Edward TS section

This section is an underground cable section, and it exceeds its capacity due to King Edward TS being overloaded beyond the capacity described in section 8.2. If the station load is to increase as per the winter forecast, the upgrades to the station (beyond what is described in section 8.2) would have to be done in coordination with upgrades to cables.

TWG has reviewed the overload scenarios, and the recommended approach is to monitor load growth of the stations on A4K over the coming years. As demand continues to increase, TWG will reassess the situation and develop an appropriate action plan, which may include options such as reconductoring, circuit upgrades, or alternative reinforcement strategies to ensure compliance with thermal limits and maintain system reliability.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net load forecast and the loss of one element over the study period 2025-2044 to cater for this need**.** Based on the results, the following system reliability, operating and restoring issues have been identified for this Region.

8.4.1 Load Security issue due to contingency of M32S

Nepean TS currently relies on a single 230 kV transmission supply circuit (M32S) from Merivale TS to South March TS. Under an M32S contingency, the entire load at Nepean TS would be lost due to configuration. According to ORTAC criteria, load security requires that no more than 150 MW of load can be lost for a single element contingency. While this limit is not exceeded in the summer forecast, it is projected to be reached in the winter forecast by 2029, when Nepean TS's peak demand is expected to surpass 150 MW. This creates a load security concern, as an outage of M32S would result in a full load loss, violating ORTAC requirements.

To address this issue, the recommended plan includes providing Nepean TS with a second transmission supply circuit originating from Merivale TS. This will ensure compliance with ORTAC and enhance the station reliability. The timing of this plan will be determined based on ongoing load monitoring and coordination with the Merivale TS upgrade project.

8.4.2 New Switching Station to improve reliability and flexibility in Kanata Area

As discussed in Section 8.2, one of the recommended plans includes the development of a new 230 kV Kanata North MTS, which will initially connect to the existing 230 kV circuit C3S. To enhance reliability, a second supply will be brought from M32S. This second supply will be enabled by rebuilding one of the existing transmission lines in the C7BM/C3S/W6CS corridor to double circuit 230kV line, thus connecting M32S to the new Kanata North MTS.

With the addition of Kanata North MTS and potential load transfers from Marchwood MTS and Kanata MTS, the summer and winter load forecasts were preliminary revised for the stations in the Kanata area as shown in Tables 8-3 below.

Table 8-3: Updated summer and winter load forecast (in MW) with preliminary transfers to Kanata North Considered

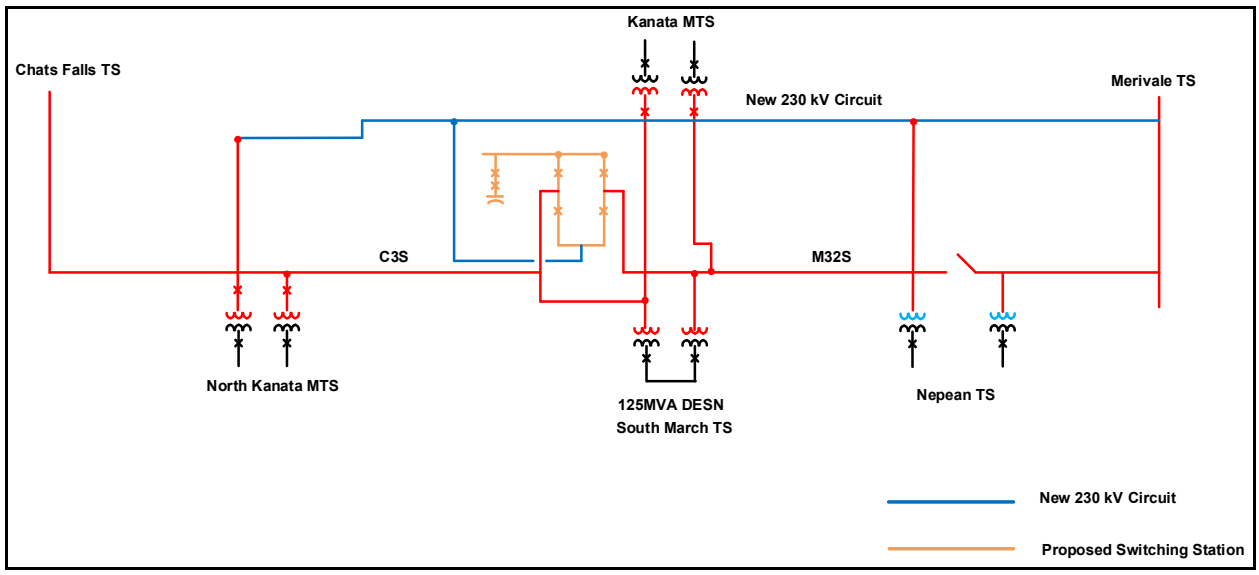
SUMMER											
Station	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
KANATA MTS	37	36	36	36	36	36	36	35	36	36	36
NEPEAN TS	127	128	128	128	128	128	128	129	129	130	131
SOUTH MARCH TS	112	112	114	122	121	122	126	127	128	129	130
Kanata North MTS	38	38	39	39	39	40	40	40	41	41	41
Load in 230 kV area	314	314	317	325	324	325	330	331	333	336	338
WINTER											
	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
KANATA MTS Revised	49	50	52	54	57	59	61	63	65	67	69
NEPEAN TS	148	159	169	176	184	191	198	205	214	223	231
SOUTH MARCH TS	119	124	132	143	147	151	158	162	168	173	179
Kanata North MTS	38	38	39	39	39	40	40	40	41	41	41
Load in 230 kV area	354	371	392	412	427	440	457	471	488	504	520

Analysis of contingencies on the 230 kV system indicates that stations supplied by these circuits can reliably support up to 340 MW of load while maintaining system performance. This threshold is expected to be reached under the summer forecast by 2038 and under the winter forecast as early as 2028.

To address this emerging constraint, the current strategy is to monitor winter load growth closely while advancing plans for a new switching station in the Kanata area. This switching station will facilitate flexible interconnections among Chats Falls TS, Merivale TS, South March TS, Nepean TS, and the new Kanata North MTS, thereby providing support for additional capacity, operational flexibility, and improved resiliency for the regional network. The conceptual layout of this switching station and its integration into the transmission system is illustrated in Figure 8-13.

The line that is planned from Merivale to Nepean as described in section 8.4.1 can be extended to the new switching station.

Figure 8-13: Proposed new 230 kV Line along with Switching Station



8.4.3 Load Security issue due to contingency of M1R+L2M

Merivale TS currently supplies two 115 kV circuits, M1R and L2M, which share a common breaker position. This configuration creates a common-mode outage risk: the loss of either circuit results in both circuits being tripped. Under ORTAC criteria, load security requires that no more than 150 MW of load can be lost for a single element contingency. While this limit is not exceeded in the summer forecast until 2040, it is projected to be reached in the winter forecast by 2031. This creates a load security concern, as an outage of either circuit would result in a full loss of supply to connected stations, violating ORTAC requirements.

To address these issues and improve reliability, the plan includes installing a new breaker at Merivale TS to separate circuits M1R and L2M into two independent 115 kV paths. This will eliminate the common-mode outage risk and ensure compliance with ORTAC load security criteria. The timing of this plan is driven by the emerging winter load security need, with a targeted in-service date of 2032. This solution also supports long-term thermal performance and operational flexibility. Figure 8-14 shows the 115 kV yard at Merivale TS following completion of Merivale TS upgrade project and Figure 8-15 shows the split M1R/L2M configuration that will be providing a separate breaker position for each line.

Figure 8-14: 115 kV Merivale TS after Merivale TS upgrade project

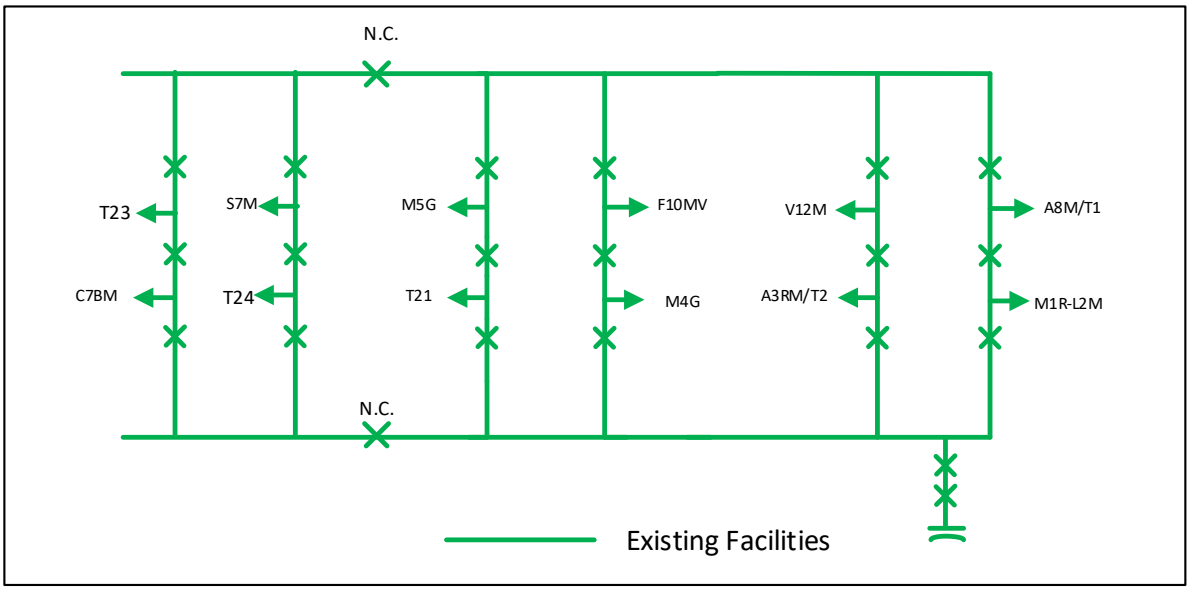
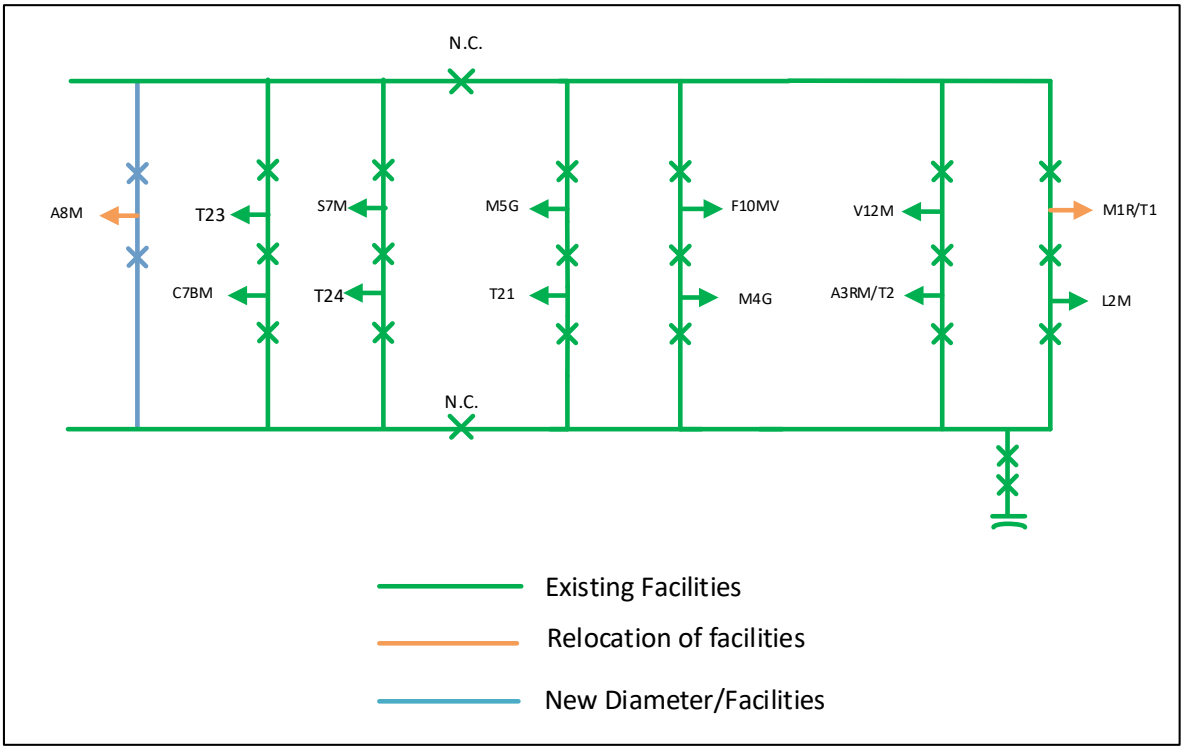


Figure 8-15 Different breaker positions of M1R and L2M



8.4.4 Loading and Voltage issues on S7M

Under the medium-term planning horizon, there is a limitation on the amount of load that can be transferred from Cambrian MTS to S7M under the contingency of E34M. This constraint arises due to both loading and voltage performance issues observed on S7M when additional load from Cambrian MTS is transferred to it during contingency conditions.

To address these challenges, several options are being considered. One potential solution is the planned conversion of S7M to 230 kV, which would significantly improve its capacity and voltage performance under contingency scenarios. Another option is to explore reactive power (VAR) support as load continues to grow, which could help maintain acceptable voltage levels and system stability. At this stage, the recommendation is to continue monitoring load growth and system performance, and to review the needs as part of the next cycle of regional planning. Ongoing bulk study may make recommendations that could impact the area, such as 230kV conversion.

8.4.5 Supply to East Ottawa

In the previous regional planning cycle, the recommended plan for the East Ottawa area included refurbishment of Bilberry Creek TS and the addition of two new feeder breakers. While the Greater Ottawa regional planning process was inactive, new information related to load growth and system conditions prompted a re-evaluation of the supply plan. In 2023, the TWG reviewed updated growth expectations for the area, the sustainment need at Bilberry Creek TS, and the capability of the 115 kV system to support future growth. Based on this review, TWG agreed to revise the recommendations for the area.

TWG's revised plan and new recommendation includes three components.

Retirement of Bilberry Creek TS

The TWG recommends retiring Bilberry Creek TS due to aging infrastructure and associated sustainment requirements. The revised approach shifts supply for the area away from continued reinvestment at Bilberry Creek TS resulting in removing load from 115 kV system and instead transitioning the connected load to the 230 kV system to support longer-term capacity and system reliability.

Upgrade at Orleans TS

As part of this approach, Orleans TS will be upgraded from dual supply 230/27.6 kV and 115/27.6 kV to 230/27.6 kV DESN. This upgrade includes a new 230 kV circuit A25 between Hawthorne TS and Orleans TS (~11km). The planned in-service date for the Orleans TS upgrade and the A25 circuit is June 2029.

Connection of new Mer Bleue MTS

The revised plan also includes the connection of a new Hydro Ottawa station, Mer Bleue MTS, to the 230 kV system. Mer Bleue MTS will be connected to 230 kV circuits D5A approximately 10 km east of Hawthorne TS, with a planned in-service date of July 2027. The project is also planned to connect to circuit A25 with an expected in-service date of June 2029.

This new recommendation provides the following benefits:

i. Addresses the Limited growth available on the 115kV system. The Ottawa 115kV system is mainly supplied via 250MVA autotransformers at Hawthorne TS and Merivale TS. East Ottawa 115kV system is connected to Hawthorne TS and most of its supply is from the station's autotransformers. These autotransformers are heavily loaded and limit the growth that can supplied from 115kV. Installing additional autotransformers at the station will be very challenging due to space constraints and short circuit level considerations. As such removing load from the 115kV system and transferring it to the 230kV wherever possible, helps preserve the current capacity on the 115kV to address the growth at existing stations that cannot be converted to 230kV at reasonable cost. This Project helps by reducing the 115kV loading and transferring the load to 230kV.

ii. The Project avoids significant refurbishment work at the station as the load can be transferred onto the 230kV system and Bilberry Creek TS can be retired instead of refurbished. In addition, there is also limited growth available at Bilberry Creek even if the station is refurbished.

iii. Orlean TS will no longer be subject to momentary interruptions due to its configuration.

iv. The new 230kV circuit will allow more growth and improve supply reliability in the Orleans area. Currently connection on the 230 kV in the Orleans area will have to be limited to 100 MW. With the new circuit the area can support over 300 MW.

The RIP concludes that retiring Bilberry Creek TS, upgrading Orleans TS, and completing the associated 230 kV circuit and station connections is the most cost-effective option to address the long-term needs in East Ottawa. This combined set of projects is being pursued as an alternative to the sustainment and upgrade work at Bilberry Creek TS that was recommended in the previous regional planning cycle.

From a reliability perspective, the revised plan reduces dependence on aging station equipment, increases supply robustness by serving the area from the higher-capacity 230 kV network, and improves operational flexibility during planned outages or contingencies by enabling better load restoration options across the East Ottawa supply area.

Figure 8-16 Existing Orleans Area

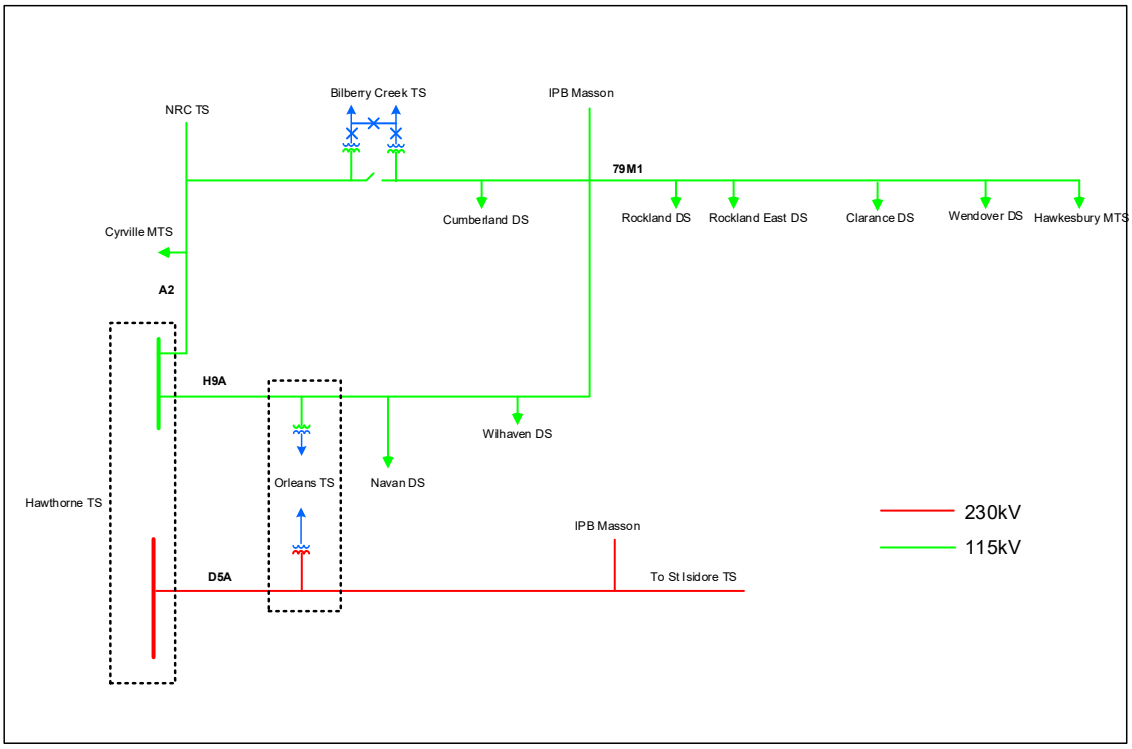
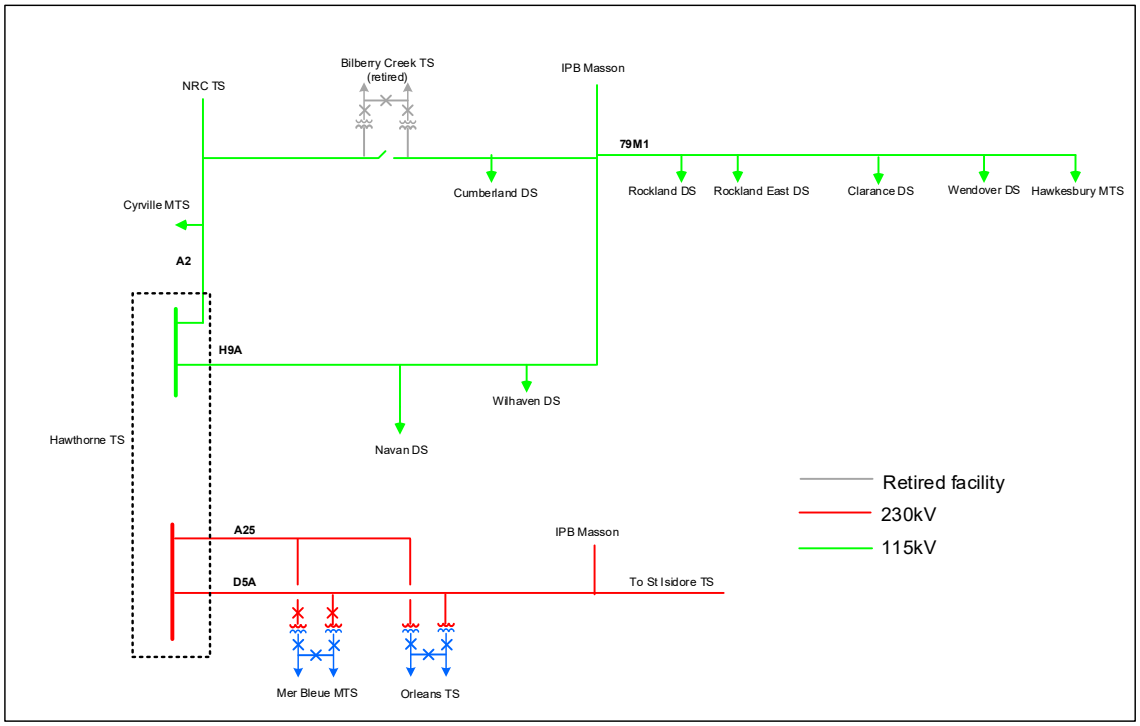


Figure 8-17 Orleans Area after Upgrade



9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for the Greater Ottawa region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2025-2044 are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M)
Asset Renewal Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Albion TS	Replacement of T1/T2 transformers with upgraded units based on asset condition and capacity needs.	Hydro One	2031	$60M
Nepean TS	Replacement of T3/T4 transformers based on asset condition	Hydro One	2034	$30M
S7M	Refurbishment of line section between Manotick JCT x Richmond South MTS and S7M 673N x Manordale JCT	Hydro One	2030	$5M
Station Capacity Needs				
South March TS	Replacement of T1/T2 transformers with upgraded units based on asset conditions and capacity needs.	Hydro One	2029	$40M
Carling TS	Replacement of limiting LV cables.	Hydro One	2030	$10M

Lisgar TS	Replacement of T2 transformer and LV cables/breakers - Greenfield	Hydro One	2034	$50M
	Replacement of T2 transformer and LV cables/breakers – In Situ	Hydro One	2031	$30M
King Edward TS	Replacement of LV cables and breakers.	Hydro One	2033	$20M
Cyrville MTS	Station voltage conversion from 115kV to 230kV to increase station rating and upgrade station transformation capacity.	Hydro One/ Hydro Ottawa	2029	$85M*
Moulton MTS	Relocate 50 MVA ,115kV transformers from Cyrville MTS after voltage conversion to increase station rating at Moulton TS.	Hydro Ottawa	2029	$5M
Bronson MTS	Build a new 115kV Transformer Station east of Carling TS by converting existing Bronson distribution station	Hydro One/ Hydro Ottawa	2031	$110M*
Greenbank MTS	Build new Transformer Station to meet demand growth and need for 28kV supply west of Merivale TS.	Hydro One/ Hydro Ottawa	2028	$100M*
Kanata North MTS	Build a new Transformer Station by connecting 230 kV C3S and new transmission line from South March TS	Hydro One/ Hydro Ottawa	2028	$100M*
Marionville DS	Install a second transformer to increase station rating.	Hydro One Dx	2029	$12M*
Greely DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*

Rockland DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2026	$2M*
Rockland East DS	Install Scada Fan monitoring to increase transformer rating.	Hydro One Dx	2027	$3M*
Transmission Line Capacity Needs				
M4G/M5G	Uprate Line section between Merivale TS x Carling TS	Hydro One	2030	$30M
L2M	Uprate line section between Merivale TS x Limebank JCT	Hydro One	2032	$30M
System Reliability, Operation and Load restoration Needs				
Kanata Area	Kanata Area Transmission Reinforcement	Hydro One	2033	$250M
Nepean TS – Load Security Criteria	Second 230 kV Supply to station	Hydro One	2032	$70M
M1R+L2M	Split Breaker position for M1R and L2M at Merivale TS	Hydro One	2032	$45M
East Ottawa Area	Supply to East Ottawa	Hydro One	2029-2030	$165M*

* These investment costs include associated distribution system costs.

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are high-level planning estimates and actual costs may vary.

10. REFERENCES

[1] Hydro One, RIP Report – Greater Ottawa (Second cycle), published on December 18, 2020

[2] Hydro One, NA Report – Greater Ottawa (Third cycle), published on December 20, 2022

[3] Independent Electricity System Operator, SA Report – Greater Ottawa (Third cycle), published on March 21, 2023

[4] Independent Electricity System Operator, IRRP Report – Ottawa Area Sub-region (Third cycle), published on July 31, 2025

[5] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[6] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[7] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[8] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Greater Ottawa region – Summer - Reference Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	86.5	58.6	59.2	59.7	60.3	60.7	61.2	61.9	62.6	63.5	64.5	65.2	65.5	65.9	66.4	66.8	67.2	67.8	68.4	69.0	69.0
ALMONTE TS	96.7	55.4	56.1	56.7	57.4	58.0	62.4	63.8	64.9	68.4	71.8	72.8	74.1	75.4	76.8	78.1	79.6	81.0	82.5	83.9	85.5
ARNPRIOR TS	54.9	39.5	39.8	39.9	40.7	41.3	44.2	47.3	48.6	48.9	49.3	49.8	50.4	51.0	51.6	52.2	53.0	53.7	54.3	54.9	55.6
BILBERRY CREEK TS	85.3	64.0	64.2	64.4	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	21.7	22.0	22.2	22.4	22.6	22.8	22.9	23.1	23.2	23.4	23.6	23.5	23.7	23.7	23.7	23.7	23.9	24.2	24.4	24.4
CAMBRIAN MTS	114.0	58.9	62.7	68.3	71.9	74.7	77.1	80.6	84.2	87.8	91.4	95.1	99.1	101.8	102.3	102.5	103.0	103.7	104.4	105.1	105.8
CARLING TS	95.0	89.2	90.6	91.6	105.9	106.6	113.8	126.4	139.2	139.6	140.0	141.2	140.9	140.9	141.1	141.3	141.4	142.6	143.7	144.9	144.9
CENTREPOINT MTS	13.3	12.8	12.9	13.0	13.0	13.1	13.1	13.2	13.4	13.5	13.7	13.8	13.9	14.0	14.1	14.2	14.3	14.6	14.8	15.1	15.1
CLARENCE DS	7.8	2.6	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.5
CUMBERLAND DS	6.8	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.2	7.3	7.4	7.5	7.7	7.8
CYRVILLE MTS	47.5	31.9	34.1	35.0	48.4	49.1	49.0	49.1	49.0	49.2	49.2	49.4	49.8	50.2	50.6	50.5	50.5	50.8	51.2	51.5	51.9
ELLWOOD MTS	47.0	41.7	45.0	47.3	48.4	49.4	49.4	49.3	49.2	49.3	49.2	49.3	49.6	49.9	50.2	50.4	50.7	51.1	51.4	51.8	52.2
FALLOWFIELD MTS	27.2	24.1	27.3	30.5	33.1	33.3	33.3	33.3	33.4	33.3	33.2	33.3	33.5	33.7	33.8	33.8	34.0	34.2	34.5	34.7	35.0
GREELY DS	20.7	22.4	22.6	22.9	23.2	23.4	23.9	24.2	24.5	24.9	25.2	25.9	26.6	27.6	28.4	29.3	30.1	30.6	30.9	30.9	30.9
HAWKESBURY MTS #1	18.0	12.1	12.3	12.4	12.6	12.7	12.9	13.0	13.1	13.2	13.4	13.6	13.9	14.1	14.4	14.7	15.0	15.3	15.6	15.9	16.2
HAWTHORNE TS	144.8	136.6	137.1	137.3	138.0	138.4	139.1	139.6	140.2	141.0	141.7	143.1	143.8	144.7	145.7	146.5	147.4	148.1	148.7	148.6	148.7
HINCHEY TS	85.6	21.6	22.2	28.6	36.5	40.9	44.8	47.7	49.6	50.9	51.7	52.3	52.3	52.3	52.3	52.2	52.2	52.7	53.2	70.3	70.8
HYDRO RD MTS	114.0	-	-	13.0	18.5	23.9	29.3	32.9	36.5	40.0	43.6	47.2	47.7	48.2	48.6	49.1	49.6	49.8	50.0	50.2	50.2
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	54.1	54.1	53.8	53.8	53.6	53.5	53.5	53.3	53.4	53.5	53.5	53.9	54.3	54.7	55.0	55.3	55.7	56.1	56.4	56.8
KING EDWARD TS	86.9	77.6	78.8	79.8	80.8	81.6	82.6	85.0	86.4	87.7	89.0	90.1	91.4	92.7	94.0	95.4	96.8	98.9	101.1	103.2	103.2
LIMEBANK MTS	75.0	50.9	57.2	63.1	68.6	71.5	73.7	75.8	77.8	79.5	80.7	82.0	83.6	85.2	86.9	88.5	90.1	90.8	91.4	91.9	92.6
LINCOLN HEIGHTS TS	99.4	46.4	46.7	46.9	47.0	47.1	47.3	47.8	48.3	48.9	49.5	50.0	50.1	50.3	50.5	50.7	50.9	51.5	52.1	52.7	52.7
LISGAR TS	83.4	78.5	80.2	81.5	96.6	97.7	98.9	109.8	109.8	109.8	109.9	110.7	109.9	109.2	108.6	108.0	107.4	107.7	108.0	108.3	108.3
LONGUEUIL TS	123.5	45.6	48.1	50.4	51.8	52.1	52.6	53.0	53.5	61.3	64.5	65.2	68.6	69.7	70.8	71.9	73.0	73.9	74.9	75.8	76.8

MANORDALE MTS	9.6	9.5	9.7	9.8	10.0	10.1	10.3	10.4	10.4	10.5	10.6	10.7	10.7	10.8	10.8	11.0	11.1	11.2	11.4	11.6	11.6
MANOTICK DS	7.7	10.5	10.7	10.8	11.0	11.1	11.3	11.4	11.6	11.8	12.0	12.3	12.5	12.8	13.1	13.3	13.6	13.9	14.2	14.6	14.9
MARCHWOOD MTS	32.3	51.3	52.2	52.9	54.1	55.5	56.7	58.0	59.2	60.7	61.5	61.5	61.8	62.2	62.5	62.9	63.2	63.6	64.0	64.4	64.8
MARIONVILLE DS	13.5	15.5	15.6	15.7	15.9	16.0	16.3	16.4	16.6	16.8	17.0	17.3	17.8	18.2	18.7	19.2	19.7	20.0	20.2	20.1	20.1
Mer Bleue MTS	114.0	-	-	-	65.3	66.0	66.7	67.4	68.2	69.0	69.9	70.7	71.3	72.0	72.8	73.5	74.2	75.2	76.3	77.3	77.3
MERIVALE MTS	32.9	18.3	18.2	18.0	17.8	17.6	17.4	17.5	17.6	17.7	17.8	17.9	17.9	17.8	17.8	17.8	17.8	18.0	18.2	18.4	18.4
MOULTON MTS	32.0	23.7	23.5	23.2	36.7	36.2	35.9	35.9	36.0	36.1	36.2	36.3	36.2	36.1	36.1	36.1	36.0	36.2	36.3	36.5	36.5
CTS-2	14.0	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
NRC TS	77.4	5.1	5.1	5.0	17.1	16.8	16.5	16.4	16.4	16.3	16.2	16.0	15.8	15.8	15.8	15.8	15.8	15.7	15.7	15.7	15.7
NAVAN DS	13.5	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.1
NEPEAN EPWORTH MTS	12.9	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.7	12.8	12.9	13.0	13.0	13.0	13.1	13.1	13.1	13.3	13.5	13.6	13.6
NEPEAN TS	144.1	126.1	126.7	126.9	127.3	127.5	127.9	128.0	127.8	128.0	128.1	128.5	129.3	130.2	131.1	131.9	132.8	133.7	134.6	135.4	136.3
ORLEANS TS	118.2	118.5	123.0	120.3	123.8	126.6	143.9	146.9	149.8	151.6	153.5	155.7	158.3	160.2	162.1	163.9	165.8	167.7	169.5	171.3	173.2
OVERBROOK TS	116.8	86.1	88.3	90.2	92.2	94.0	95.9	96.8	97.9	98.9	100.0	101.1	101.7	102.4	103.2	104.0	104.8	106.5	108.2	109.8	110.8
PIPERVILLE MTS	108.0	-	2.3	4.6	6.8	9.0	11.2	11.4	11.7	11.9	12.2	12.4	12.7	13.1	13.4	13.8	14.1	14.4	14.6	14.8	14.8
RICHMOND SOUTH MTS	49.0	20.7	24.2	27.0	29.8	32.0	34.3	38.3	42.1	45.6	49.2	52.3	55.6	56.3	57.1	57.8	58.5	58.9	59.3	59.6	60.0
RIVERDALE TS	110.8	96.8	100.1	103.2	106.3	109.1	112.1	112.8	113.6	114.5	115.3	116.0	116.5	117.2	117.9	118.7	119.5	121.4	123.3	125.1	125.1
ROCKLAND DS	7.8	8.3	8.6	8.8	9.0	10.3	11.5	12.6	13.7	14.8	17.4	18.8	20.4	21.9	23.5	25.0	26.5	28.1	29.6	31.1	32.7
ROCKLAND EAST DS	15.5	15.3	15.9	16.4	16.9	17.4	18.0	18.5	19.0	19.6	20.1	20.7	21.3	22.0	22.7	23.3	24.0	24.7	25.1	25.4	25.8
RUSSELL DS	6.8	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.1	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.9	5.9
RUSSELL TS	72.7	72.0	76.6	78.8	78.9	79.0	79.1	79.4	79.9	80.3	81.0	81.4	81.5	81.6	81.8	81.9	92.2	92.4	92.8	93.1	93.1
SLATER TS	158.7	96.1	96.9	98.2	102.3	107.0	111.8	115.9	117.7	119.1	119.3	119.5	120.2	120.8	121.5	122.1	122.7	123.6	124.4	125.2	126.1
SOUTH GLOUCESTER DS	6.8	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.6	6.7	6.7	6.7
SOUTH MARCH TS	99.2	98.1	102.8	108.6	111.8	111.7	114.2	122.1	121.4	121.6	126.2	126.6	127.6	128.6	129.7	130.7	131.7	133.0	134.0	135.1	136.4
ST. ISIDORE TS	117.8	44.9	47.4	48.6	49.9	51.2	52.5	56.4	60.5	61.6	63.7	64.4	65.1	66.0	66.8	67.6	68.5	69.4	70.3	71.1	72.0
STEWARTVILLE TS	49.5	28.5	28.8	29.0	29.3	29.5	29.8	30.1	30.4	30.8	31.2	31.6	34.7	35.6	36.1	36.6	37.1	37.7	38.2	38.7	39.2
TERRY FOX MTS	91.7	63.3	64.2	64.9	65.7	66.4	67.2	67.0	66.9	66.9	66.9	67.0	66.7	66.5	66.3	66.0	65.9	66.3	66.8	67.3	67.8
UPLANDS MTS	57.6	29.4	33.3	40.7	43.2	44.8	45.6	46.3	47.0	47.7	48.4	49.2	50.2	50.9	51.7	52.4	53.1	53.4	53.8	54.1	54.5
WENDOVER DS	30.4	15.8	16.1	16.3	16.5	16.7	16.9	17.1	17.4	17.8	18.1	18.4	18.8	19.2	19.7	20.1	23.6	24.0	24.5	24.9	25.3
WILHAVEN DS	34.2	7.8	7.9	7.9	8.0	8.0	8.0	8.1	8.1	8.2	8.4	8.7	8.9	9.1	9.2	9.3	9.4	9.5	9.7	9.8	9.9
WOODROFFE TS	97.4	48.3	49.4	50.5	51.5	52.4	53.4	53.8	54.2	54.7	55.2	55.6	56.1	56.6	57.2	57.8	58.4	59.3	60.2	61.1	61.1

Table A.2: Greater Ottawa region –Winter - Reference Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	101.7	59.8	65.7	71.5	77.3	82.8	88.4	92.3	96.2	100.2	104.2	108.1	112.9	117.8	122.5	127.0	131.7	136.2	140.6	145.0	145.0
ALMONTE TS	125.1	52.2	53.1	54.0	54.9	55.6	60.1	61.6	62.7	63.7	64.6	65.8	67.1	68.4	69.8	71.3	72.8	74.3	75.7	77.3	78.8
ARNPRIOR TS	59.4	39.4	39.8	40.2	41.1	41.9	42.2	42.7	44.1	44.5	45.0	45.6	46.2	46.9	47.6	48.3	49.0	49.8	50.4	51.2	51.9
BILBERRY CREEK TS	95.5	54.1	46.0	38.0	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	17.1	18.7	20.3	21.9	23.4	25.0	26.1	27.3	28.5	29.7	30.9	32.2	33.6	34.9	36.2	37.6	38.9	40.3	41.7	41.7
CAMBRIAN MTS	123.5	43.7	48.4	52.9	67.3	71.5	75.6	79.0	98.8	102.2	105.7	109.2	112.1	115.0	117.8	120.6	123.5	127.7	131.9	136.2	136.2
CARLING TS	124.3	84.7	94.0	103.1	125.3	133.9	148.9	167.9	187.0	193.7	200.3	207.6	214.2	220.9	227.2	233.1	239.6	246.3	253.0	259.6	259.6
CENTREPOINT MTS	13.3	12.0	13.2	14.4	15.6	16.7	17.8	18.9	20.0	21.0	22.1	23.2	24.4	25.5	26.7	27.8	29.0	30.1	31.2	32.4	32.4
CLARENCE DS	10.5	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1
CUMBERLAND DS	8.6	5.2	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.6	6.7	6.8	6.9
CYRVILLE MTS	47.5	31.6	35.1	38.5	41.9	45.2	48.4	50.6	52.7	54.9	57.1	59.3	62.1	65.0	67.8	70.5	73.3	75.7	78.1	80.5	83.6
ELLWOOD MTS	47.0	39.5	43.6	47.7	51.7	55.6	59.5	63.0	66.5	70.0	73.5	76.9	80.5	84.2	87.7	91.0	94.6	97.9	101.3	104.6	104.6
FALLOWFIELD MTS	27.2	13.3	15.8	18.3	22.8	25.2	27.5	29.7	31.8	34.0	36.2	38.4	42.1	45.9	49.7	53.3	57.1	59.4	61.7	64.1	64.1
GREELY DS	25.2	27.1	27.4	27.7	28.2	28.5	29.0	29.4	29.7	30.1	30.6	31.3	32.3	33.2	34.2	35.1	36.1	36.7	37.1	37.1	37.1
HAWKESBURY MTS #1	18.0	13.0	13.5	13.9	14.4	14.9	15.3	15.7	16.1	16.6	17.1	17.5	17.9	18.4	18.8	19.3	19.8	20.3	20.8	21.3	21.8
HAWTHORNE TS	171.6	132.7	140.4	147.7	155.2	162.4	169.8	177.3	184.8	192.5	200.1	207.9	214.9	222.1	228.8	235.2	242.2	248.1	253.8	236.3	236.3
HINCHEY TS	95.0	54.4	62.2	69.7	77.3	84.5	91.8	96.9	102.0	107.2	112.4	117.5	123.4	129.4	135.1	140.6	146.5	151.7	156.8	161.9	161.9
HYDRO RD MTS	123.5	-	-	10.0	14.3	18.5	22.8	25.6	28.5	31.3	34.1	37.0	37.9	38.8	39.7	40.6	41.6	42.0	42.4	42.9	42.9
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	53.9	56.1	63.5	65.6	67.6	69.6	71.8	74.1	76.5	78.9	81.2	83.2	85.3	87.2	89.1	91.1	93.4	95.7	98.0	98.0
KING EDWARD TS	90.3	89.6	99.1	108.3	117.5	126.5	135.5	145.2	153.7	162.3	170.8	179.2	188.5	198.0	207.0	215.6	224.8	233.7	242.5	251.3	251.3
LIMEBANK MTS	75.0	60.9	66.8	72.6	78.4	83.9	89.4	92.9	96.5	100.1	103.9	107.6	111.4	115.3	119.1	122.9	126.7	130.6	134.5	138.4	138.4
LINCOLN HEIGHTS TS	113.1	53.8	59.0	64.0	69.1	73.9	78.7	82.5	86.2	90.0	93.9	97.7	102.3	106.9	111.4	115.8	120.3	124.2	128.2	132.1	132.1
LISGAR TS	105.1	77.0	84.6	91.8	112.8	119.8	126.8	143.3	148.8	154.4	159.9	165.3	171.3	177.3	182.9	188.2	194.1	199.5	205.0	210.4	210.4
LONGUEUIL TS	133.0	50.7	53.4	56.0	57.8	58.3	58.9	59.6	60.2	60.9	61.7	62.7	63.7	64.8	66.0	67.1	68.3	69.5	70.6	71.9	73.1
MANORDALE MTS	9.6	9.5	10.4	11.2	12.1	12.9	13.7	14.5	15.2	16.0	16.8	17.5	18.4	19.3	20.1	20.9	21.7	22.6	23.4	24.2	24.2

MANOTICK DS	10.4	12.0	12.1	12.2	12.4	12.5	12.8	12.9	13.1	13.3	13.5	13.8	14.2	14.6	15.0	15.4	15.8	16.1	16.3	16.3	16.3
MARCHWOOD MTS	32.3	32.5	35.4	38.3	41.2	43.9	46.7	48.6	50.5	52.5	54.5	56.5	58.8	61.1	63.3	65.4	67.7	69.7	71.7	73.7	73.7
MARIONVILLE DS	13.5	18.4	18.6	18.8	19.0	19.2	19.5	19.7	19.9	20.1	20.3	20.8	21.3	21.9	22.5	23.0	23.7	24.0	24.2	24.2	24.2
Mer Bleue MTS	123.5	-	-	-	75.4	81.3	87.2	91.5	95.8	100.3	104.8	109.2	114.0	118.9	123.6	128.3	133.1	138.0	142.9	147.8	147.8
MERIVALE MTS	37.3	15.4	17.3	19.1	20.9	22.7	24.5	25.8	27.2	28.7	30.1	31.4	33.0	34.7	36.2	37.7	39.3	40.7	42.2	43.6	43.6
MOULTON MTS	32.0	18.6	20.5	22.3	37.9	39.6	41.2	42.6	43.9	45.3	46.7	48.1	49.5	50.9	52.2	53.5	54.9	56.1	57.3	58.6	58.6
CTS-2	14.0	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
NRC TS	87.7	6.1	6.0	5.9	20.3	20.0	19.7	19.6	19.6	19.5	19.4	19.2	19.0	18.9	18.9	18.9	18.9	18.9	18.8	18.8	18.8
NAVAN DS	13.5	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.9	5.0	5.0	5.1	5.2	5.2	5.3
NEPEAN EPWORTH MTS	12.9	10.1	11.1	12.0	13.0	13.9	14.8	15.6	16.5	17.3	18.2	19.0	19.9	20.8	21.6	22.5	23.3	24.2	25.0	25.8	25.8
NEPEAN TS	160.7	116.4	127.3	137.8	148.4	158.7	169.0	176.2	183.5	190.9	198.1	205.2	213.9	222.9	231.2	239.1	247.8	257.1	266.3	275.6	275.6
ORLEANS TS	134.5	78.2	78.0	77.6	70.6	73.3	90.5	93.3	96.1	97.8	99.6	101.5	103.6	104.8	106.0	107.1	108.4	109.6	110.7	111.9	113.1
OVERBROOK TS	135.6	87.7	96.6	105.2	113.8	122.2	130.6	138.2	145.8	153.5	161.1	168.5	176.4	184.3	191.8	199.0	206.7	214.2	221.6	228.9	228.9
PIPERVILLE MTS	117.0	-	3.0	5.9	8.8	11.7	14.5	15.5	16.4	17.4	18.4	19.4	20.8	22.2	23.6	25.0	26.4	27.4	28.4	29.4	29.4
RICHMOND South MTS	49.0	17.9	19.5	42.2	49.9	51.2	52.5	53.7	54.9	56.2	64.7	66.0	67.3	68.7	70.1	71.3	72.7	74.1	75.5	76.9	76.9
RIVERDALE TS	117.0	97.7	107.3	116.6	125.9	134.9	144.0	150.9	157.8	164.9	171.9	178.7	186.6	194.7	202.3	209.7	217.6	224.7	231.8	238.9	238.9
ROCKLAND DS	10.5	6.9	7.2	7.4	7.6	9.0	10.2	11.3	12.5	13.6	16.2	17.8	19.3	20.9	22.4	24.0	25.6	27.1	28.7	30.2	31.8
ROCKLAND EAST DS	20.9	12.4	13.0	13.6	14.2	14.7	15.3	15.8	16.3	16.9	17.4	18.0	18.6	19.2	19.9	20.5	21.2	21.9	22.2	22.5	22.8
RUSSELL DS	8.6	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.1	6.2	6.4	6.6	6.8	6.9	7.1	7.1	7.1	7.1
RUSSELL TS	79.9	67.7	78.5	86.8	93.1	99.1	105.2	109.8	114.5	119.2	123.9	128.5	133.5	138.6	143.3	147.8	163.0	167.6	172.1	176.6	176.6
SLATER TS	163.0	89.9	94.6	99.1	103.6	107.8	112.2	116.2	120.2	124.3	128.3	132.2	137.8	143.4	148.8	153.8	159.3	164.0	168.7	173.4	173.4
SOUTH GLOUCESTER DS	8.6	5.9	6.0	6.0	6.1	6.2	6.3	6.4	6.4	6.5	6.6	6.8	7.0	7.2	7.4	7.6	7.8	7.9	8.0	8.0	8.0
SOUTH MARCH TS	113.7	98.0	105.9	111.7	119.4	123.7	132.0	142.7	147.0	150.7	158.2	162.3	167.9	172.9	178.8	183.8	189.6	193.9	198.8	203.3	208.1
ST. ISIDORE TS	124.5	47.7	50.3	51.9	53.5	54.9	56.3	57.8	59.4	60.4	62.6	63.4	64.2	65.2	66.2	67.1	68.2	69.2	70.2	69.1	70.1
STEWARTVILLE TS	56.7	27.8	28.2	28.6	29.0	29.2	29.6	29.9	30.2	30.6	31.0	31.5	34.5	35.0	35.6	36.1	36.6	37.2	37.7	38.3	38.8
TERRY FOX MTS	105.8	50.3	55.5	60.5	65.5	70.3	75.0	79.0	83.1	87.2	91.4	95.6	100.6	105.6	110.6	115.5	120.5	124.8	129.1	133.4	133.4
UPLANDS MTS	65.8	25.9	28.6	31.2	33.9	36.4	38.9	41.0	43.1	45.3	47.5	49.6	51.8	54.1	56.2	58.3	60.5	62.7	64.8	66.9	66.9
WENDOVER DS	35.1	16.2	16.6	16.9	17.2	17.4	17.7	18.0	18.2	18.7	19.0	19.4	19.8	20.2	20.7	21.1	21.6	22.0	22.5	22.8	23.3
WILHAVEN DS	41.4	7.4	7.4	7.5	7.6	7.6	7.7	7.8	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.7	8.8	8.9	9.0	9.1
WOODROFFE TS	102.4	47.6	52.6	57.4	62.2	66.8	71.5	75.4	79.4	83.5	87.6	91.6	95.1	98.6	102.0	105.3	108.8	112.8	116.8	120.8	120.8

Table A.3: Greater Ottawa region – Summer - High Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Albion TS	86.5	59.9	60.9	61.8	62.7	63.5	64.4	66.4	68.3	70.4	72.5	74.5	76.0	77.5	79.1	80.7	82.3	83.9	85.5	87.1	87.1
ALMONTE TS	96.7	55.6	56.5	57.0	57.8	58.3	64.8	64.6	65.5	70.3	73.6	73.4	74.7	76.1	77.5	78.8	80.3	81.7	83.2	84.7	86.3
ARNPRIOR TS	54.9	39.7	40.0	40.0	41.1	41.7	45.7	48.9	49.2	49.1	49.6	50.0	50.7	51.3	52.0	52.5	53.4	54.0	54.7	55.2	56.0
BILBERRY CREEK TS	85.3	64.4	65.0	65.5	14.3	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	22.4	22.7	23.0	23.4	23.6	23.9	24.5	25.1	25.8	26.4	27.1	27.6	28.2	28.7	29.3	29.8	30.4	30.9	31.4	31.4
CAMBRIAN MTS	114.0	59.8	64.7	71.3	73.8	76.1	78.3	82.5	86.0	89.6	93.3	97.0	101.1	103.1	102.5	102.7	103.3	104.1	104.8	105.5	106.2
CARLING TS	95.0	91.7	93.4	94.8	109.4	110.5	111.5	131.9	146.0	147.6	149.4	151.8	153.2	154.8	156.6	158.4	160.3	162.5	164.6	166.8	166.8
CENTREPOINT MTS	13.3	13.0	13.2	13.4	13.6	13.8	14.0	14.5	15.1	15.6	16.1	16.6	17.1	17.6	18.1	18.6	19.1	19.5	20.0	20.5	20.5
CLARENCE DS	7.8	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.1	3.1	3.2	3.2	3.3	3.4	3.4	3.5
CUMBERLAND DS	6.8	6.1	6.2	6.2	6.2	6.3	6.3	6.4	6.5	6.5	6.7	6.7	6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.8
CYRVILLE MTS	47.5	32.4	35.3	35.4	57.6	49.5	49.0	49.1	48.9	49.3	49.1	49.6	50.0	50.4	50.8	50.5	50.5	51.0	51.4	51.6	52.1
ELLWOOD MTS	47.0	41.9	46.8	48.5	48.9	50.0	49.4	49.2	49.1	49.3	49.1	49.4	49.7	50.0	50.3	50.5	50.9	51.3	51.6	51.9	52.4
FALLOWFIELD MTS	27.2	24.3	29.1	32.2	34.6	33.4	33.3	33.4	33.4	33.2	33.2	33.3	33.5	33.8	33.8	33.8	34.1	34.3	34.7	34.8	35.1
GREELY DS	20.7	22.4	22.6	22.9	23.2	23.4	23.9	24.2	24.5	24.9	25.2	25.9	26.6	27.6	28.4	29.3	30.1	30.6	30.9	30.9	30.9
HAWKESBURY MTS #1	18.0	12.2	12.4	12.5	12.7	12.8	12.9	13.0	13.2	13.3	13.5	13.7	14.0	14.3	14.6	14.8	15.1	15.4	15.7	16.0	16.4
HAWTHORNE TS	144.8	136.6	137.3	137.3	138.2	138.4	139.2	139.7	140.3	141.2	142.0	143.4	143.8	144.7	145.7	146.4	147.4	148.1	148.8	148.6	148.8
HINCHEY TS	85.6	21.9	22.5	32.8	41.4	43.4	47.0	49.2	50.6	51.5	52.2	52.6	52.2	52.3	52.3	52.1	52.2	52.9	53.4	81.7	71.1
HYDRO RD MTS	114.0	-	-	14.2	19.0	24.4	29.8	33.2	36.8	40.4	43.9	47.5	47.9	48.4	48.9	49.3	49.8	49.9	50.1	50.3	50.3
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	54.1	54.1	53.7	53.8	53.5	53.5	53.5	53.3	53.4	53.5	53.6	54.0	54.5	54.9	55.2	55.4	55.9	56.3	56.6	57.0
KING EDWARD TS	86.9	79.0	80.8	82.4	84.0	85.5	87.1	90.8	93.4	96.0	98.6	101.0	103.6	106.2	109.0	111.7	114.5	117.7	120.9	124.1	124.1
LIMEBANK MTS	75.0	51.7	60.8	66.3	71.7	72.9	74.8	76.9	78.8	80.4	81.3	82.7	84.5	86.0	87.8	89.3	90.9	91.2	91.7	92.1	92.9
LINCOLN HEIGHTS TS	99.4	46.4	46.8	47.6	48.5	49.2	50.1	51.3	52.6	53.9	55.2	56.4	57.6	58.8	60.0	61.3	62.6	63.9	65.3	66.7	66.7
LISGAR TS	83.4	78.5	80.7	82.7	98.3	100.0	101.9	112.7	112.7	112.7	112.7	113.5	113.5	113.5	113.7	113.9	114.1	115.5	116.9	118.3	118.3
LONGUEUIL TS	123.5	46.3	49.4	51.6	52.5	52.3	52.8	53.3	53.7	65.8	66.2	65.5	70.5	70.2	71.4	72.4	73.5	74.4	75.4	76.3	77.3
MANORDALE MTS	9.6	10.3	10.5	10.6	10.7	10.9	11.0	11.4	11.8	12.2	12.6	13.0	13.3	13.7	14.1	14.6	15.0	15.3	15.7	16.1	16.1
MANOTICK DS	7.7	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7	11.9	12.1	12.4	12.6	12.9	13.2	13.5	13.8	14.1	14.4	14.7	15.0
MARCHWOOD MTS	32.3	51.6	52.6	53.2	54.8	56.1	57.4	58.6	59.9	61.4	61.9	61.5	62.0	62.4	62.7	63.0	63.3	63.8	64.2	64.6	65.0

MARIONVILLE DS	13.5	15.5	15.6	15.7	15.9	16.0	16.3	16.4	16.6	16.8	17.0	17.3	17.8	18.2	18.7	19.2	19.7	20.0	20.2	20.1	20.1
Mer Bleue MTS	114.0	0.0	0.0	0.0	67.5	68.7	70.1	72.2	74.5	76.8	79.1	81.4	83.3	85.1	87.1	89.0	90.9	92.6	94.4	96.1	96.1
MERIVALE MTS	32.9	18.5	18.3	18.1	17.9	17.9	18.1	18.1	18.2	18.3	18.4	18.5	18.6	18.7	18.9	19.0	19.2	19.5	19.7	20.0	20.0
MOULTON MTS	32.0	24.4	23.9	23.5	36.8	36.8	36.7	37.0	37.3	37.7	38.0	38.3	38.6	38.9	39.2	39.5	39.9	40.2	40.6	40.9	40.9
CTS-2	14.0	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
NRC TS	77.4	5.1	5.1	5.0	17.1	16.8	16.5	16.4	16.4	16.3	16.2	16.0	15.8	15.8	15.8	15.8	15.8	15.7	15.7	15.7	15.7
NAVAN DS	13.5	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.4	5.4	5.4	5.5	5.7	5.7	5.8	5.9	6.0	6.0	6.1	6.2
NEPEAN EPWORTH MTS	12.9	12.6	12.7	12.8	12.9	13.0	13.1	13.3	13.5	13.7	14.0	14.2	14.4	14.6	14.9	15.1	15.4	15.6	15.9	16.1	16.1
NEPEAN TS	144.1	126.1	127.0	127.0	127.5	127.7	128.1	128.0	127.7	128.1	128.2	128.7	129.8	130.7	131.6	132.3	133.2	134.1	135.0	135.8	136.8
ORLEANS TS	118.2	119.6	125.4	119.9	125.6	128.1	153.8	148.5	151.2	152.6	154.4	156.7	159.7	161.1	163.0	164.8	166.7	168.7	170.4	172.2	174.2
OVERBROOK TS	116.8	89.4	91.9	94.1	96.3	98.4	100.6	103.1	105.7	108.3	110.9	113.6	115.9	118.4	120.9	123.5	126.0	128.8	131.6	134.4	134.4
PIPERVILLE MTS	108.0	0.0	2.4	4.8	7.2	9.5	11.8	12.1	12.5	12.9	13.3	13.7	14.2	14.7	15.2	15.7	16.2	16.6	16.9	17.3	17.3
RICHMOND SOUTH MTS	49.0	21.4	26.3	28.6	31.2	33.3	35.4	40.5	44.2	47.6	51.0	54.0	57.3	56.6	57.5	58.2	58.8	59.1	59.5	59.8	60.2
RIVERDALE TS	110.8	98.6	102.4	105.9	109.4	112.6	116.0	117.8	119.7	121.6	123.5	125.3	127.2	129.3	131.5	133.7	135.9	138.7	141.4	144.2	144.2
ROCKLAND DS	7.8	8.4	8.7	8.9	9.1	11.1	12.1	13.2	14.3	15.4	18.9	19.6	21.2	22.7	24.3	25.8	27.3	28.9	30.4	31.9	33.5
ROCKLAND EAST DS	15.5	15.5	16.2	16.6	17.2	17.7	18.3	18.8	19.3	19.8	20.4	20.9	21.6	22.3	23.0	23.6	24.3	25.0	25.2	25.6	26.0
RUSSELL DS	6.8	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.1	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.9	5.9
RUSSELL TS	72.7	74.2	78.9	79.0	79.8	80.4	81.2	81.6	82.2	82.8	83.6	84.2	84.7	85.1	85.6	86.1	96.7	97.5	98.4	99.3	99.3
SLATER TS	158.7	96.6	97.3	98.8	104.4	109.4	114.4	118.0	118.7	119.8	119.4	119.6	120.5	121.1	121.8	122.5	123.0	124.1	124.8	125.6	126.5
SOUTH GLOUCESTER DS	6.8	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.6	6.7	6.7	6.7
SOUTH MARCH TS	99.2	98.5	104.1	111.0	112.3	111.6	113.8	123.4	121.0	121.6	126.9	126.7	127.9	128.9	130.0	131.0	132.0	133.3	134.3	135.4	136.6
ST. ISIDORE TS	117.8	45.6	48.7	49.2	50.6	51.8	53.1	58.5	62.8	62.2	64.8	64.7	65.5	66.5	67.3	68.0	69.0	69.8	70.7	71.6	72.5
STEWARTVILLE TS	49.5	28.6	29.0	29.1	29.5	29.7	30.0	30.2	30.5	31.0	31.4	31.8	36.4	36.0	36.4	36.9	37.4	37.9	38.4	38.9	39.5
TERRY FOX MTS	91.7	63.6	64.7	65.2	66.1	66.7	67.6	66.9	66.9	66.9	66.9	67.0	66.6	66.4	66.2	65.9	65.9	66.5	67.1	67.5	68.0
UPLANDS MTS	57.6	29.8	35.6	45.2	44.5	45.7	46.0	46.7	47.3	48.0	48.7	49.7	50.7	51.2	52.1	52.8	53.5	53.6	54.0	54.3	54.7
WENDOVER DS	30.4	16.0	16.2	16.4	16.6	16.8	17.0	17.3	17.5	18.1	18.3	18.6	19.0	19.4	20.0	20.3	25.7	24.3	24.7	25.1	25.6
WILHAVEN DS	34.2	7.9	7.9	7.9	8.0	8.0	8.1	8.1	8.2	8.3	8.4	8.9	8.9	9.2	9.3	9.4	9.5	9.6	9.7	9.9	10.0
WOODROFFE TS	97.4	50.2	51.5	52.6	53.7	54.8	55.9	57.1	58.5	59.8	61.2	62.5	63.8	65.2	66.6	68.1	69.6	70.9	72.3	73.7	73.7

Table A.4: Greater Ottawa region – Winter - High Load Forecast

Name of Station	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
ALBION TS	101.7	71.2	78.6	85.7	92.9	99.8	106.8	111.3	115.8	120.5	125.1	129.7	135.1	140.6	145.8	151.0	156.3	161.2	166.0	170.9	170.9
ALMONTE TS	0.0	52.7	53.6	54.4	55.4	56.0	62.6	62.4	63.2	64.2	65.0	66.4	67.7	69.1	70.6	72.0	73.5	75.0	76.5	78.1	79.6
ARNPRIOR TS	59.4	39.6	40.0	40.4	41.6	42.3	42.4	43.0	44.8	44.8	45.3	45.9	46.6	47.3	48.0	48.7	49.4	50.1	50.8	51.6	52.2
BILBERRY CREEK TS	95.5	62.2	67.2	72.1	14.3	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BRIDLEWOOD MTS	23.5	20.5	22.6	24.6	26.7	28.6	30.6	32.0	33.4	34.8	36.3	37.7	39.3	40.9	42.5	44.0	45.6	47.1	48.6	50.1	50.1
CAMBRIAN MTS	123.5	56.0	62.5	68.9	85.2	91.2	97.2	101.3	121.8	126.0	130.3	134.6	138.3	142.0	145.6	149.3	153.0	157.7	162.5	167.3	167.3
CARLING TS	124.3	101.9	112.7	123.1	146.7	156.8	186.1	192.2	211.4	218.2	224.9	232.3	239.9	247.8	255.1	262.1	269.8	276.8	283.8	290.8	290.8
CENTREPOINT MTS	13.3	15.0	16.6	18.2	19.8	21.3	22.8	24.1	25.4	26.7	28.0	29.3	30.7	32.0	33.3	34.6	36.0	37.2	38.5	39.7	39.7
CLARENCE DS	10.5	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.1
CUMBERLAND DS	8.6	5.3	5.3	5.4	5.5	5.5	5.6	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.8	6.9	7.0
CYRVILLE MTS	47.5	38.1	42.5	46.9	51.3	55.5	59.8	62.4	65.1	67.9	70.7	73.4	76.4	79.4	82.3	85.2	88.2	90.8	93.5	96.1	96.1
ELLWOOD MTS	47.0	48.3	53.3	58.3	63.2	68.0	72.8	76.7	80.7	84.7	88.6	92.5	96.5	100.4	104.2	107.9	111.8	115.4	119.1	122.7	122.7
FALLOWFIELD MTS	27.2	19.0	22.4	25.7	31.0	34.2	37.4	40.3	43.3	46.2	49.2	52.1	55.9	59.6	63.4	67.0	70.7	73.3	75.8	78.4	78.4
GREELY DS	25.2	27.4	27.6	27.9	28.4	28.6	29.3	29.5	29.9	30.3	30.8	31.7	32.7	33.7	34.7	35.6	36.6	37.0	37.3	37.1	37.1
HAWKESBURY MTS #1	18.0	13.2	13.7	14.2	14.7	15.1	15.5	15.9	16.4	16.9	17.4	17.7	18.1	18.6	19.1	19.5	20.0	20.5	21.0	21.5	22.1
HAWTHORNE TS	171.6	150.0	158.2	166.2	174.2	182.0	190.0	197.2	204.5	211.9	219.3	226.8	234.9	243.1	250.9	258.3	266.4	272.6	278.5	285.9	285.9
HINCHEY TS	95.0	67.8	76.7	85.3	93.9	102.3	110.7	116.2	121.9	127.6	133.3	138.9	145.0	151.1	157.0	162.7	168.7	174.0	179.2	184.5	184.5
HYDRO RD MTS	123.5	-	-	10.0	14.3	18.5	22.8	25.7	28.6	31.4	34.3	37.2	38.0	38.9	39.8	40.7	41.6	41.6	41.6	41.6	41.6
CTS-1	100.0	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
KANATA MTS	51.5	60.3	63.1	71.2	73.9	76.5	79.1	81.1	83.1	85.2	87.2	89.2	92.0	94.9	97.6	100.2	103.0	105.4	107.9	110.3	110.3
KING EDWARD TS	90.3	108.4	119.5	130.2	141.0	151.4	162.0	172.2	181.3	190.4	199.4	208.3	218.6	228.9	238.8	248.4	258.6	267.8	277.0	286.2	286.2
LIMEBANK MTS	75.0	71.7	79.3	86.7	94.2	101.3	108.4	112.5	116.7	121.0	125.3	129.6	134.1	138.6	142.9	147.2	151.7	156.0	160.3	164.6	164.6
LINCOLN HEIGHTS TS	113.1	64.5	70.9	77.3	83.6	89.7	95.8	99.9	104.0	108.2	112.4	116.5	121.7	127.0	132.1	137.1	142.3	146.6	150.9	155.2	155.2
LISGAR TS	105.1	90.7	98.9	106.8	128.4	136.0	143.8	160.2	165.8	171.4	177.0	183.5	189.8	196.3	202.4	208.2	214.5	219.8	225.1	230.4	230.4
LONGUEUIL TS	133.0	51.2	54.8	57.4	58.6	58.5	59.2	59.9	60.6	61.3	62.2	63.2	64.2	65.4	66.5	67.7	68.9	70.1	71.2	72.5	73.7
MANORDALE MTS	9.6	11.6	12.8	13.9	15.1	16.2	17.3	18.3	19.2	20.1	21.1	22.0	23.0	24.1	25.1	26.0	27.0	28.0	29.0	29.9	29.9
MANOTICK DS	10.4	12.0	12.3	12.5	12.8	13.0	13.4	13.7	14.1	14.5	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.2	21.7	21.6	21.6
MARCHWOOD MTS	32.3	37.5	41.0	44.5	47.9	51.2	54.6	56.9	59.2	61.6	64.0	66.3	68.8	71.3	73.8	76.1	78.6	80.8	83.1	85.3	85.3

MARIONVILLE DS	13.5	18.4	18.6	18.9	19.2	19.7	19.9	20.5	20.8	21.2	21.7	22.2	23.2	24.4	25.7	27.0	28.4	30.1	30.9	31.4	31.4
Mer Bleue MTS	123.5	0.0	0.0	0.0	92.5	100.1	107.7	112.6	117.5	122.6	127.7	132.7	138.2	143.8	149.3	154.8	160.3	165.5	170.7	175.9	175.9
MERIVALE MTS	37.3	19.5	21.6	23.7	25.8	27.8	29.9	31.3	32.7	34.1	35.5	36.9	38.5	40.2	41.8	43.3	44.9	46.3	47.7	49.2	49.2
MOULTON MTS	32.0	22.0	24.1	26.2	42.0	43.9	45.9	47.3	48.7	50.2	51.7	53.1	54.7	56.2	57.7	59.2	60.8	62.1	63.4	64.8	64.8
CTS-2	14.0	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
NRC TS	87.7	6.1	6.0	5.9	20.3	20.0	19.7	19.6	19.6	19.5	19.4	19.2	19.0	18.9	18.9	18.9	18.9	18.9	18.8	18.8	18.8
NAVAN DS	13.5	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.7	4.8	4.8	4.9	5.0	5.1	5.1	5.2	5.3	5.3
NEPEAN EPWORTH MTS	12.9	12.3	13.5	14.6	15.8	16.9	18.0	18.9	19.8	20.8	21.7	22.6	23.6	24.5	25.5	26.4	27.3	28.2	29.1	29.9	29.9
NEPEAN TS	160.7	138.9	152.2	165.2	178.1	190.8	203.6	212.1	220.6	229.3	237.8	246.1	255.9	265.8	275.1	284.0	293.7	303.5	313.4	323.2	323.2
ORLEANS TS	134.5	82.9	90.3	96.7	72.2	74.7	101.0	94.7	97.6	98.6	100.4	102.5	104.6	105.4	106.6	107.7	109.0	110.2	111.3	112.6	113.6
OVERBROOK TS	135.6	105.5	116.3	126.8	137.3	147.6	157.9	166.2	174.6	183.0	191.4	199.6	208.4	217.4	225.9	234.1	242.9	250.7	258.6	266.4	266.4
PIPERVILLE MTS	117.0	0.0	3.7	7.3	10.9	14.4	17.9	19.0	20.1	21.2	22.3	23.5	25.1	26.6	28.2	29.8	31.4	32.5	33.7	34.8	34.8
RICHMOND South MTS	49.0	21.6	23.7	47.0	55.3	57.0	58.9	60.4	61.9	63.4	72.2	73.8	75.4	77.1	78.7	80.3	81.9	83.5	85.1	86.7	86.7
RIVERDALE TS	117.0	112.3	123.7	134.9	146.0	156.8	167.7	175.5	183.4	191.4	199.2	207.0	215.3	223.8	231.9	239.7	248.0	255.7	263.2	270.8	270.8
ROCKLAND DS	10.5	7.0	7.3	7.5	7.8	9.8	10.8	12.0	13.1	14.2	17.8	18.6	20.1	21.7	23.3	24.8	26.4	28.0	29.5	31.1	32.6
ROCKLAND EAST DS	20.9	12.6	13.3	13.9	14.5	15.0	15.6	16.1	16.6	17.1	17.7	18.3	18.9	19.6	20.2	20.9	21.5	22.2	22.3	22.7	23.0
RUSSELL DS	8.6	5.3	5.4	5.5	5.6	5.7	5.8	6.0	6.1	6.2	6.4	6.5	6.8	7.2	7.6	8.1	8.5	9.0	9.2	9.4	9.4
RUSSELL TS	79.9	79.2	90.5	99.5	106.3	112.9	119.6	124.2	128.8	133.5	138.1	142.6	147.7	152.9	157.8	162.4	166.9	171.4	175.8	180.3	180.3
SLATER TS	163.0	100.4	105.7	110.9	116.0	121.0	126.0	130.5	134.9	139.5	143.9	148.3	153.8	159.4	164.6	169.6	175.1	179.4	183.7	187.9	187.9
SOUTH GLOUCESTER DS	8.6	5.9	6.0	6.1	6.2	6.4	6.5	6.7	6.8	6.9	7.1	7.3	7.6	8.1	8.6	9.1	9.6	10.1	10.4	10.6	12.5
SOUTH MARCH TS		100.1	110.2	114.8	123.5	125.9	136.5	148.7	149.3	152.6	162.2	164.4	170.9	175.5	181.8	186.4	192.7	196.1	201.2	205.6	210.6
ST. ISIDORE TS	124.5	48.2	51.7	52.7	54.3	55.6	57.1	58.5	60.2	61.0	63.7	63.8	64.7	65.7	66.7	67.6	68.8	69.8	70.7	68.6	70.6
STEWARTVILLE TS	56.7	28.0	28.4	28.7	29.2	29.4	29.7	30.1	30.4	30.8	31.2	31.7	36.1	35.3	35.8	36.4	36.9	37.5	38.0	38.5	39.0
TERRY FOX MTS	105.8	62.5	69.4	76.0	82.7	89.1	95.5	100.8	106.2	111.7	117.1	122.6	127.7	132.9	137.9	142.9	148.0	152.8	157.6	162.4	162.4
UPLANDS MTS	65.8	31.7	35.0	38.3	41.5	44.7	47.8	50.1	52.5	54.8	57.2	59.5	62.0	64.6	67.1	69.5	72.0	74.3	76.6	78.9	78.9
WENDOVER DS	35.1	16.4	16.7	17.0	17.3	17.5	17.8	18.1	18.4	19.0	19.2	19.6	20.0	20.5	20.9	21.3	21.8	22.3	22.7	23.0	23.5
WILHAVEN DS	41.4	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.9	7.9	8.0	8.1	8.2	8.4	8.5	8.6	8.7	8.9	9.0	9.1	9.2
WOODROFFE TS	102.4	57.9	64.1	70.2	76.2	82.0	87.9	92.2	96.5	100.9	105.3	109.6	113.7	117.8	121.7	125.5	129.6	133.8	138.1	142.3	142.3

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Albion TS	230	M30A, M31A
2	Almonte TS	230	E34M, T33E
3	Arnprior TS	115	W6CS, C7BM
4	Bilberry Creek TS**	115	A2, H9A
5	Bridlewood MTS	115	S7M
6	Cambrian MTS	230/115	S7M, E34M
7	Carling TS	115	M4G, M5G
8	Centrepoint MTS	115	C7BM
9	Clarence DS	115	79M1
10	CTS -1	230	B5D, D5A
11	CTS-2	115	A8M
12	Cumberland DS	115	H9A
13	Cyrville MTS	115	A2, A4K
14	Ellwood MTS	230	M30A, M31A
15	Fallowfield MTS	115	S7M
16	Greely DS	115	M1R
17	Hawkesbury MTS #1	115	79M1
18	Hawthorne TS*	230/115	A6R M30A A8M H9A D5A A42T M31A A3RM A4K A2 A41T A5RK L24A
19	Hinchey TS	115	F10MV, V12M
20	Kanata MTS	230	C3S, M32S
21	King Edward TS	115	A4K, A5RK
22	Limebank MTS	115	S7M
23	Lincoln Heights TS	115	C7BM, F10MV
24	Lisgar TS	115	M4G, M5G
25	Longueuil TS	230	B5D, D5A
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M

29	Merivale MTS	115	-
30	Merivale TS*	230	M30A S7M E34M A8M M5G M32S M1R M31A F10MV C7BM A3RM M4G V12M L2M
31	Moulton MTS	115	A4K
32	National Research Council TS	115	A2
33	Navan DS	115	H9A
34	Nepean Epworth MTS	115	M5G M4G
35	Nepean TS	230	M32S
36	Orleans TS	230/115	D5A, H9A
37	Overbrook TS	115	A5RK, A6R
38	Richmond South MTS	115	S7M
39	Riverdale TS	115	A3RM, A5RK, A6R
40	Rockland DS	115	79M1
41	Rockland East DS	115	79M1
42	Russell DS	115	L2M, M1R
43	Russell TS	115	A5RK, A6R
44	Slater TS	115	A3RM, A5RK, M4G
45	South Gloucester DS	115	M1R
46	South March TS	230	C3S, M32S
47	St. Isidore TS	230	B5D, D5A
48	Stewartville TS	115	W3B, W6CS
49	Terry Fox MTS	230	E34M
50	Uplands MTS	115	A8M
51	Wendover DS	115	79M1
52	Wilhaven DS	115	H9A
53	Woodroffe TS	115	C7BM, F10MV

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hawthorne TS – Merivale TS	M30A, M31A	230
2	Hawthorne TS – St Isidore TS	D5A	230
3	Merivale TS – Almonte TS	E34M	230
4	Merivale TS – South March TS	M32S	230
5	South March SS – Chats Falls SS	C3S	230
6	Hawthorne TS – Bilberry Creek TS	A2	115
7	Hawthorne TS - Merivale TS	A3RM, A8M	115
8	Hawthorne TS – Overbrook TS	A4K, A5RK	115
9	Hawthorne TS – Riverdale TS	A6R	115
10	Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
11	Merivale TS – Chats Falls TS	C7BM	115
12	Merivale TS – Hinchey TS	F10MV, V12M	115
13	Merivale TS – Lisgar TS	M4G, M5G	115
14	Merivale TS – South March SS	S7M	115
15	Stewartville TS – South March SS	W6CS	115
16	Stewartville TS – Barrett Chute TS	W3B	115
17	Hawthorne TS – Merivale TS	M30A, M31A	230
18	Hawthorne TS – St Isidore TS	D5A	230
19	Merivale TS – Almonte TS	E34M	230
20	Merivale TS – South March TS	M32S	230
21	South March SS – Chats Falls SS	C3S	230
22	Hawthorne TS – Bilberry Creek TS	A2	115
23	Hawthorne TS - Merivale TS	A3RM, A8M	115
24	Hawthorne TS – Overbrook TS	A4K, A5RK	115
25	Hawthorne TS – Riverdale TS	A6R	115
26	Hawthorne TS – Hawkesbury MTS	H9A/79M1	115

27	Merivale TS – Chats Falls TS	C7BM	115
28	Merivale TS – Hinchey TS	F10MV, V12M	115
29	Merivale TS – Lisgar TS	M4G, M5G	115
30	Merivale TS – South March SS	S7M	115
31	Stewartville TS – South March SS	W6CS	115
32	Stewartville TS – Barrett Chute TS	W3B	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Hydro One
2	Hydro Ottawa Ltd.
3	Hydro 2000 Inc.
4	Hydro Hawkesbury
5	Ottawa River Power Corporation
6	Renfrew Hydro Inc.

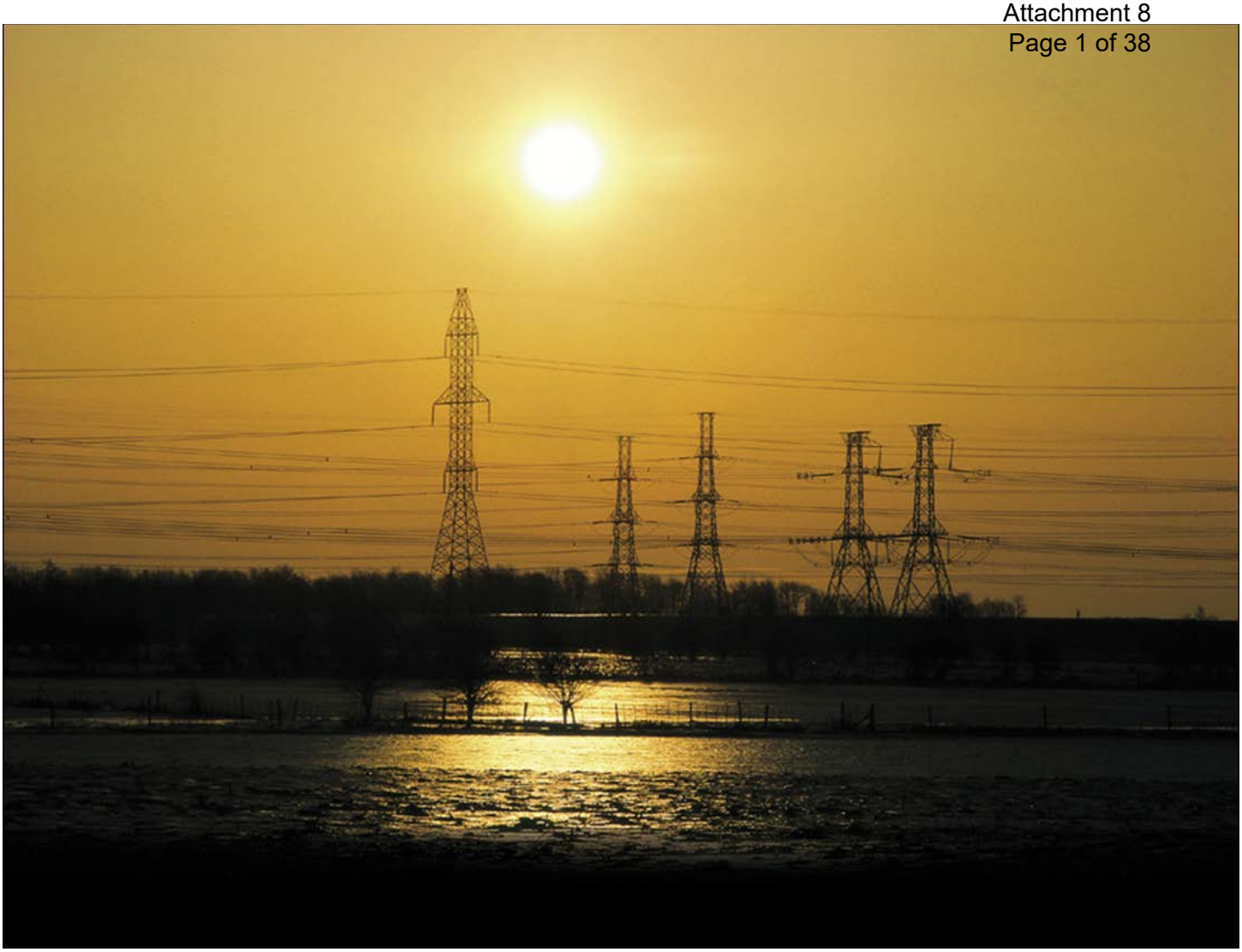
Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	City of Ottawa
2	City of Clarence-Rockland
3	Town of Arnprior
4	Town of Carleton Place
5	Municipality of Mississippi Mills
6	Municipality of The Nation
7	Township of East Hawkesbury
8	Township of Champlain
9	Township of Alfred and Plantagenet
10	Township of Russell
11	Township of Beckwith
12	Township of Drummond/North Elmsley
13	Township of Tay Valley
14	Township of North Frontenac
15	Township of Lanark Highlands
16	Township of McNab/Braeside
17	Township of Greater Madawaska

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	Electricity Demand Side Management
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.

NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station
TAO	Transmission Asset Owner
TWG	Technical Working Group



GTA East

2019-2024 REGIONAL INFRASTRUCTURE PLAN
FEBRUARY 29, 2020

hydro one

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Prepared and supported by:

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)









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Disclaimer

This Regional Infrastructure Plan ("RIP") report is an electricity infrastructure plan to identify and address near and long-term based on information provided and/or collected by the Study Team.

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

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA EAST REGION.

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

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the GTA East Region was completed in January 2017 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle GTA East Region's Needs Assessment ("NA") in August 2019. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, RIP is based on the recommendations of NA report.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the GTA East region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the Needs Assessment report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

- Enfield TS: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

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

Table 1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends:

- Continue with the investments listed in Table 1 while keeping the Study Team apprised of project status.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION BETWEEN 2019 AND 2029.

The report was prepared by Hydro One Networks Inc. ("Hydro One") with input from Study Team members during the NA phase and documents the results of the Needs Assessments and recommended plan. RIP Study Team members included representative from Elexicon Energy Inc. ("Elexicon"), Oshawa PUC Networks Inc. ("OPUCN"), Hydro One Distribution, and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, Clarington, and Durham area. Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington TS and five 230 kV transmission lines connecting Cherrywood TS to Eastern Ontario. There are five Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV. The boundaries of the GTA East Region are shown below in Figure 1-1.

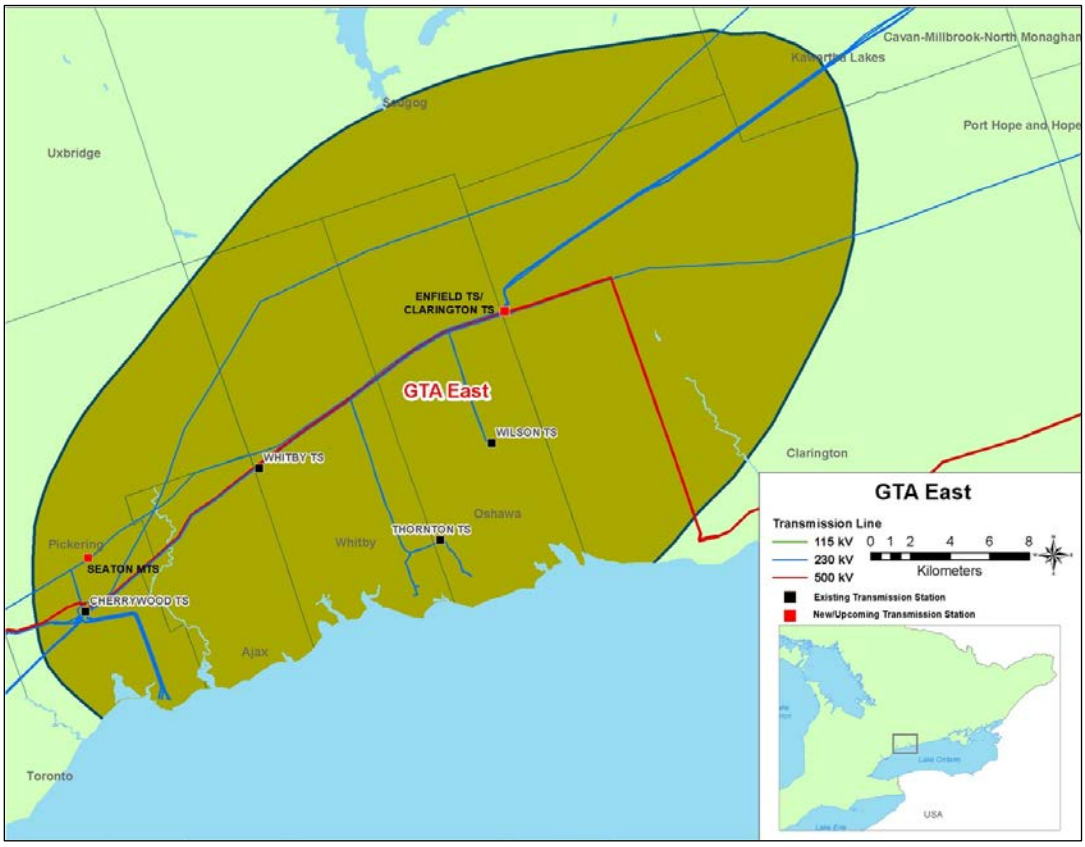


Figure 1-1: GTA East Region

1.1 Objective and Scope

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

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA") and/or Integrated Regional Resource Plan("IRRP");
- Assess and develop a wires plan to address these new needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid and long-term, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion and reconfirmation of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, SA, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

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

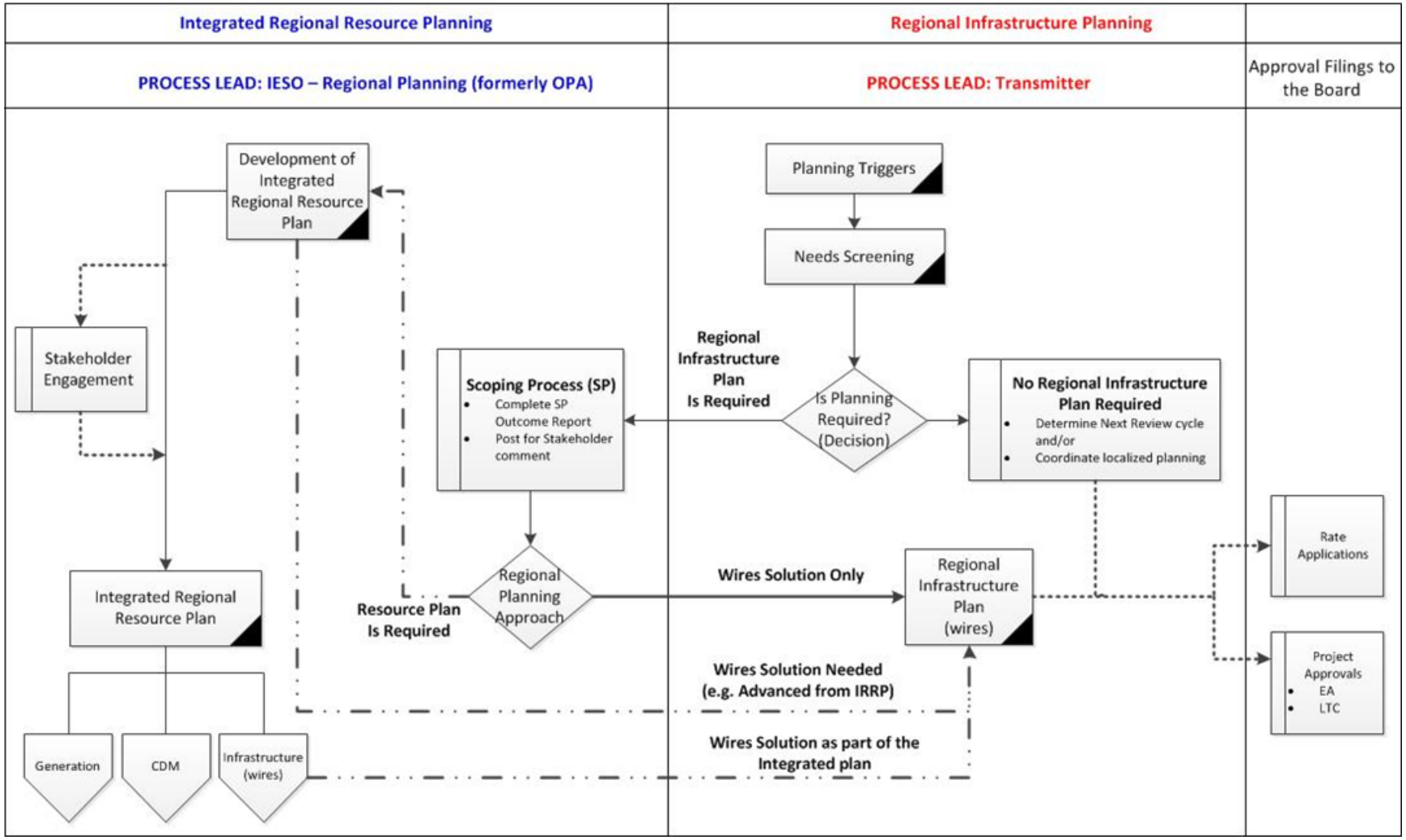


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

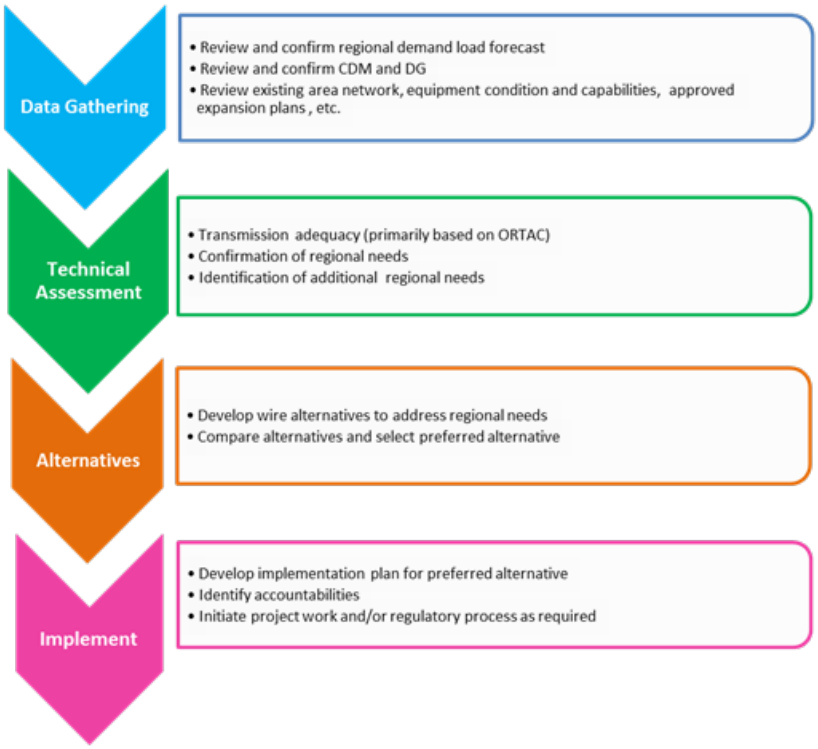


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIVE 230KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS and Clarington TS, two major 500/230kV autotransformer station in the region, and five 230kV circuits emanating east from Cherrywood TS. Five local area step-down transformer stations and three other direct transmission connected load customers are connected to the 230 kV system in the region. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2019 GTA East Region NA report, prepared by Hydro One, considered the entire GTA East Region. For simplicity, this report divides GTA East Region into two sub-regions, Pickering-Ajax-Whitby Sub-region and Oshawa-Clarington Sub-region, as described below.

3.1 Pickering-Ajax-Whitby Sub-region

The Pickering-Ajax-Whitby Sub-region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-region are Hydro One Distribution, and Elexicon.

The Pickering-Ajax-Whitby Sub-region transmission facilities are shown in Figure 3-1.

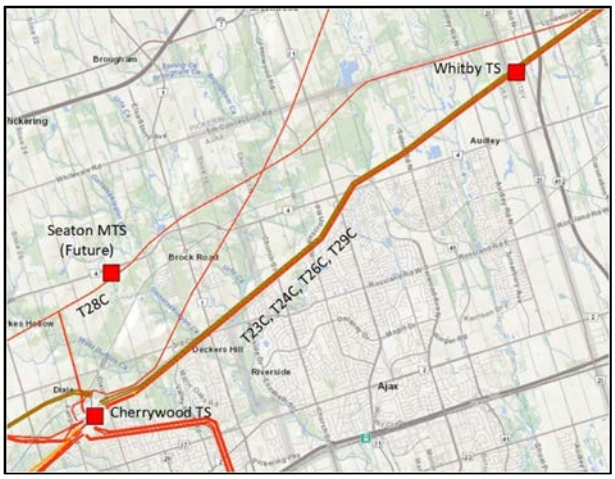


Figure 3-1: Pickering-Ajax-Whitby Sub-region

3.2 Oshawa-Clarington Sub-region

The Oshawa-Clarington sub-region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station to the west, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV at distribution level. The sub-region also includes three direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit T26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby sub-region. The LDCs supplied in the sub-region are Elexicon, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington, Clarington TS, went into service in 2018. The new Clarington TS provided additional load meeting capability in the region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS in the near future.

The new autotransformer station consists of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become a major supply source for the GTA East Region load.

A new 230/44kV transformer station, Enfield TS, was in-serviced in March 2019. The transformer station provided relief to overloading at Wilson TS and supplies Hydro One Distribution and Oshawa PUC. The station is located inside the Clarington TS yard and is directly connected to the Clarington TS 230 kV bus.

The Oshawa-Clarington Sub-region transmission facilities are shown in Figure 3-2.



Figure 3-2: Oshawa-Clarington Sub-region

A single line diagram of the GTA East Region transmission system is shown in Figure 3-3.

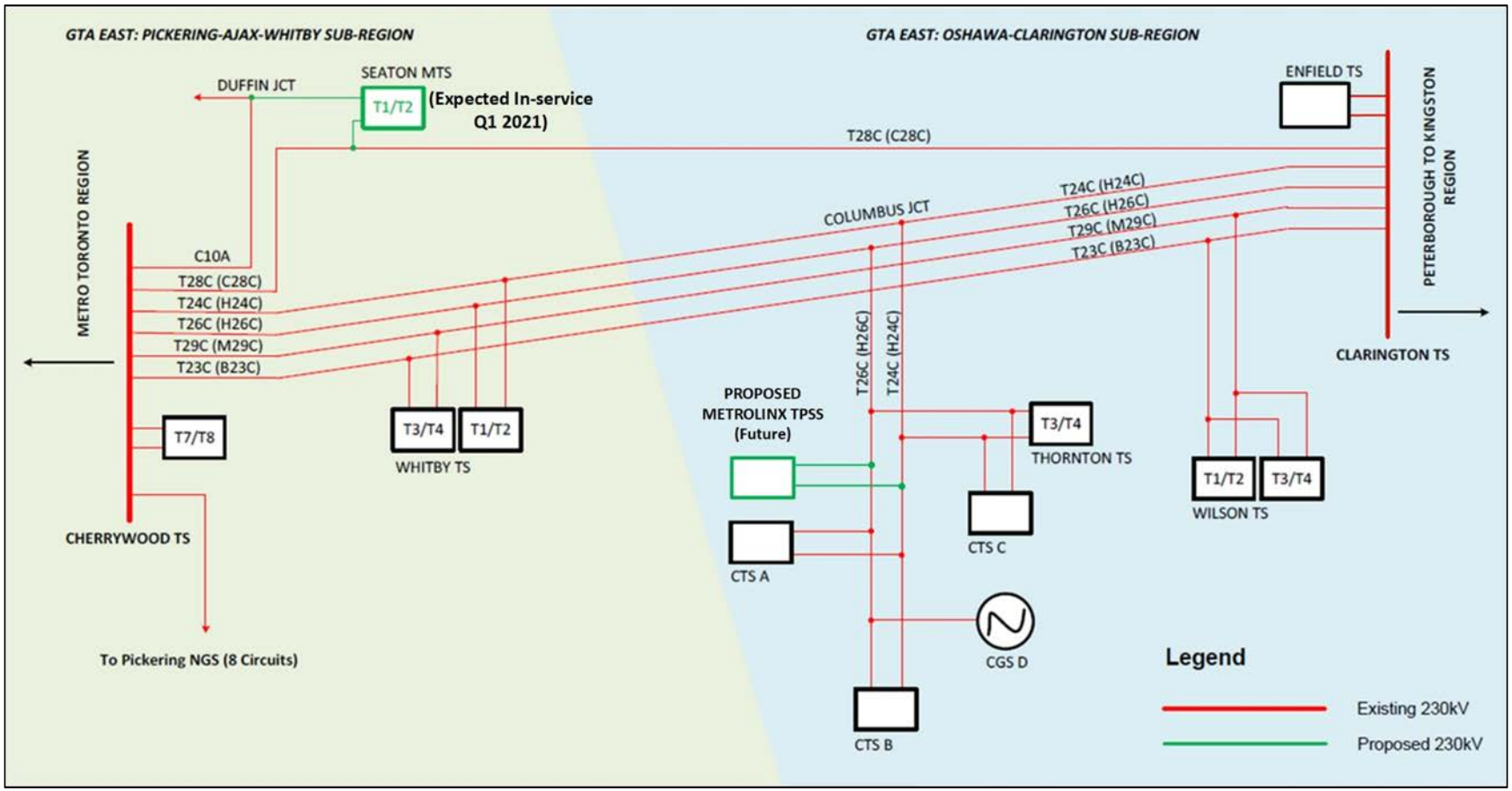


Figure 3-3: Single Line Diagram of GTA East Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE GTA EAST REGION.

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

- Whitby TS T1/T2 (2009) – built a new step-down transformer station supplied from 230kV circuits T24C and T26C in municipality of Whitby to increase transformation capacity for Elexicon requirements.

- Wilson TS T1/T2 DESN1 (2015) – installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 (2016) – replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Clarington TS (2018) – built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region.

- Enfield TS (2019) – built a new 230/44kV transformer station to provide relief for Wilson TS and for future load growth in Oshawa-Clarington sub-region.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

Figure 5-1 shows the GTA East Region's summer peak coincident and non-coincident load forecast. The non-coincident load forecast was used to determine the need for station capacity and the coincident load forecast was used to assess need for transmission line capacity in the region.

The load forecasts for the region were developed using the summer 2018 actual peak adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The load in the GTA East Region is expected to increase at an annual rate of approximately 2.8% between 2019 and 2029. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix D and E.

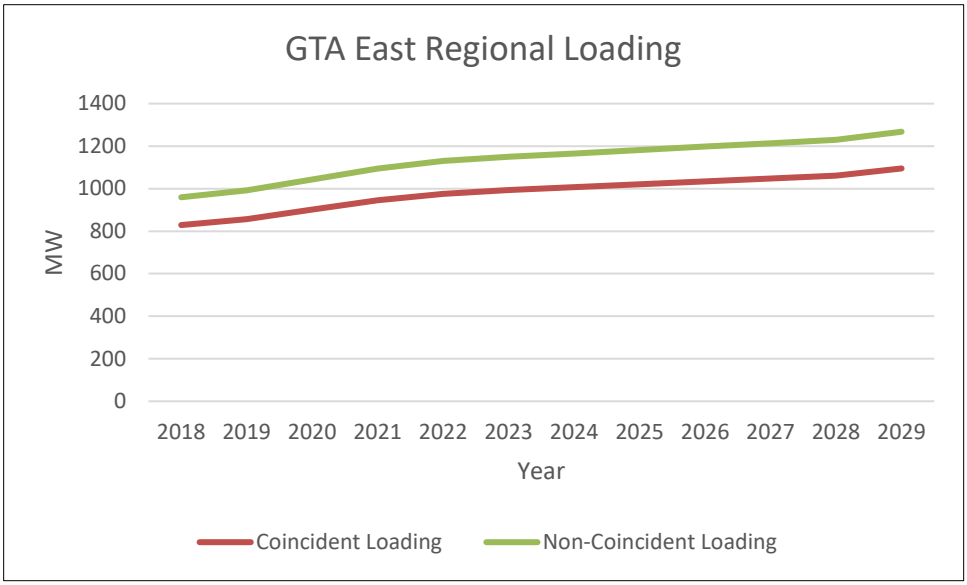


Figure 5-1 GTA East Region Net Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities listed in Section 4 are in-service.
- Where applicable, industrial loads have been assumed based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect a Traction Power Substation (TPSS) to Hydro One's 230 kV circuits T24C and T26C in East Whitby. The Metrolinx TPSS loads have not been included in the forecast as the timing is uncertain and the loads do not impact the need or timing of new facilities.

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GTA EAST REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the GTA East Region. The study is shown below:

1) 2019 GTA East Needs Assessment (NA) Report

The NA report identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the GTA East Region was also carried out as part of the RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the needs in the previous RIP have been addressed. Enfield TS is in-service and Seaton MTS is under contstruction.

6.1 230 kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, T23C/T29C, T24C/T26C, and T28C, supplying both the Pickering-Ajax-Whitby Sub-region and the Oshawa-Clarington Sub-region. Refer to Figure 3-3 for the single line diagram of the transmission facilities in the Region.

1. Cherrywood TS to Clarington TS 230 kV circuits - T23C, T29C, T24C, T26C, and T28C

The Cherrywood TS to Clarington TS circuits, carry bulk transmission flows as well as serve local area station loads within the Region. These circuits are adequate over the study period. Pickering NGS is connected to the Cherrywood TS through 8 dedicated 230 kV circuits. Pickering NGS is expected to be retire in 2025.

6.2 500/230 kV Autotransformer Facilities

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

a. Cherrywood TS 500/230 kV autotransformers: T14, T15, T16, T17
b. Clarington TS 500/230 kV autotransformers: T2, T3

The autotransformers at Cherrywood TS and Clarington TS serve the 230 kV transmission network and local loads in GTA East. The Cherrywood TS autotransformer and Clarington TS autotransformer facilities are adequate over the study period.

6.3 Pickering-Ajax-Whitby Sub-region's Step-Down Transformer Station Facilities

There are two step-down transformer stations connected in the Pickering-Ajax-Whitby sub-region, summarized in Table 6-2. The station coincident and non-coincident forecasts are given in Appendix D.

Table 6-2: Transformation Capacities in the Pickering-Ajax-Whitby Sub-region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Cherrywood TS T7/T8 (44 kV)	160	160	160	160	2040+
Whitby TS T1/T2 (27.6 kV)	90	90	90	90	2040+
Whitby TS T1/T2 (44 kV)	70	74	83	90	2040+
Whitby TS T3/T4 (44 kV)	162	170	179	187	2040+
Seaton MTS (27.6kV)	75	79	83	153	2040+

Based on the submitted load forecasts, the stations in Pickering-Ajax-Whitby sub-region have adequate transformation capacity to supply the load in long term.

6.4 Oshawa-Clarington Sub-region's Step-Down Transformer Station Facilities

There are three step-down transformer stations in the Oshawa-Clarington Sub-region, summarized in Table 6-3.

Table 6-3: Transformation Capacities in the Oshawa-Clarington Sub-Region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Wilson TS T1/T2 (44 kV)	161	161	161	161	2040+
Wilson TS T3/T4 (44 kV)	134	134	134	134	2040+
Thornton TS T3/T4 (44 kV)	143	149	154	159	2040+
Enfield TS T1/T2 (44 kV)	144	171	202	157	2030-2035

The previous Regional Planning cycle recommended a new station, named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located on the the Clarington TS site and will supply OPUC through four (4) feeders and Hydro One Dx

through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.
Based on the submitted load forecasts, additional transformation capacity will be required in the long term.

6.5 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, from Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Accordingly, major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity in section 7.

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within 8 hours.
b. Load interrupted in excess of 150 MW must be restored within 4 hours.
c. Load interrupted in excess of 250 MW must be restored within 30 minutes.

The previous regional planning (RP) comprehensively assessed circuit pairs T29C/T23C and T24C/T26C as they are on the same tower line and the possibility of loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively. However, based on the analysis, historical performance and reliability data for these circuits in the region, the Study Team recommended that no action is required at this time. There is no change on the assumptions used in this report resulting in any significant system reliability or load restoration concerns in the region.

6.7 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040.

No long term needs for the Pickering-Ajax-Whitby Sub-Region have been identified. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will provide load relief to Wilson TS through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs, if any.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in-service facilities to address these needs.

There are no new needs identified in the GTA East Region. Current development and sustainment plans are further discussed below.

7.1 Seaton MTS - Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

7.1.1 Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.9% annually.

With the proceeding of a new residential and mixed use commercial area in the Seaton are, significant increase in load demand is expected at 27.6kV level resulting in a shortage of transformation capacity at Whitby TS 27.6kV by 2021.

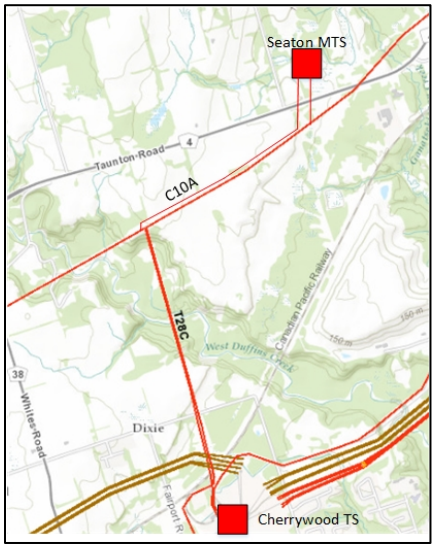


Figure 7-1: Location of Seaton MTS

The following alternatives were considered to address the Transformation Capacity in Pickering-Ajax-Whitby Sub-Region need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV due to the load growth in the Sub-Region.
2. **Alternative 2 – Build Seaton MTS:** Elexicon to proceed with the installation of a new Seaton MTS. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. This alternative would address the expected thermal overloading at Whitby TS 27.6kV due to the load growth in the Sub-Region.

7.2 Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project) Mid-Term End of Life Transformer Replacements

7.2.1 Description

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. These are Bulk System elements and not in the scope of regional planning. Discussion is provided for information only.

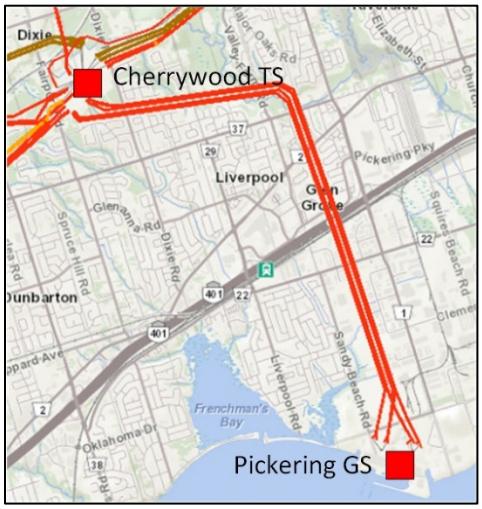


Figure 7-2: Cherrywood TS

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2027.

The following alternatives were considered to address Cherrywood TS HV Breakers end-of-life assets need:

3. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
4. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per existing refurbishment plan for the HV breakers at Cherrywood TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.3 Cherrywood TS – LV DESN Switchyard Refurbishment Mid-Term End of Life Breaker Replacement

7.3.1 Description

The LV switchyard for the 44 kV DESN T7/T8 at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The following alternatives were considered to address Cherrywood TS DESN LV breaker end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the LV breakers at Cherrywood TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.4 Wilson TS – T1, T2 and Switchyard Refurbishment

7.4.1 Description

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through OPUCN feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

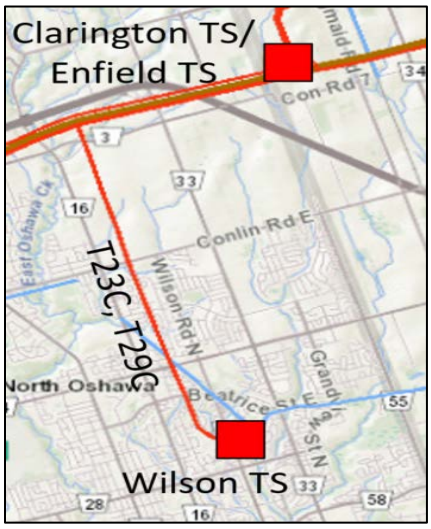


Figure 7-3: Wilson TS

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2022.

The Study Team has assessed downsizing and/or upsizing need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the only "right sizing" option.

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Wilson TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION.

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

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

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends that:

- Hydro One and Elexicon continue with the infrastructure projects as listed above in Table 8-1 while keeping the Study Team apprised of project status.
- No additional transformation capacity is required in the Pickering-Ajax-Whitby sub-region in the long term.
- Additional transformation capacity may be required in the Oshawa-Clarington sub-region in the long term.

9. REFERENCES

[1]. Hydro One, “Needs Assessment Report, GTA East Region”, 15 August 2019

[2]. Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[3]. IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[4]. Needs Assessment Report GTA East – August 2014

[5]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[6]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

APPENDIX A: TRANSMISSION LINES IN THE GTA EAST REGION

Location	Circuit Designation	Voltage Level
Cherrywood TS to Clarington TS	T23C/T24C/T26C/T29C	230kV
Cherrywood TS to Clarington TS	T28C	230kV

APPENDIX B: STATIONS IN THE GTA EAST REGION

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
Whitby TS T3/T4	230/44kV	T23C/T29C
Wilson TS T1/T2	230/44kV	T23C/T29C
Wilson TS T3/T4	230/44kV	T23C/T29C
Thornton TS T3/T4	230/44kV	T24C/T26C
Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
Seaton MTS*	230/44kV	C10A/T28C

*Future – Expected In-service 2021

APPENDIX C: DISTRIBUTORS IN THE GTA EAST REGION

Distributor Name	Station Name	Connection Type
Elexicon Inc.	Whitby TS	Tx
	Thornton TS	Dx
	Cherrywood TS	Dx
	Wilson TS	Dx
	Seaton MTS	Tx
Oshawa PUC	Wilson TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx
Hydro One Networks Inc.	Cherrywood TS	Tx
	Wilson TS	Tx
	Whitby TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx

Appendix D: Area Stations Non Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	132	137	143	148	150	152	154	156	158	160	162	170	179
Whitby TS T1/T2 (27.6kV)	90	56	59	74	90	90	90	90	90	90	90	90	90	90	90	90
Whitby TS T1/T2 (44kV)	90	44	57	58	60	61	62	63	64	66	67	68	69	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CTS B		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
CTS C		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
CGS D		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Area Total		545	545	568	594	617	631	642	651	661	671	682	694	698	714	736
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	138.3	137.9	130.7	132.9	135.2	136.2	137.2	138.2	139.2	140.3	141.3	142.4	143	149	154
Wilson TS T1/T2	161	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	161.0	161.0	161.0	161.0
Wilson TS T3/T3	134	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.0	134.0	134.0	134.0
Area Total		434	451	482	509	524	532	539	547	556	563	570	576	582	614	652
Regional Total		979	996	1050	1103	1141	1163	1181	1199	1217	1234	1252	1271	1280	1329	1387

Appendix E: Area Stations Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	160	164	163	163	162	162	161	161	161	160	160	159	159	159	159
Whitby TS T3/T4	187	135	134	141	146	152	156	158	160	162	163	165	167	169	177	187
Whitby TS T1/T2 (27.6kV)	90	41	43	54	66	65	65	65	65	65	65	64	65	90	90	90
Whitby TS T1/T2 (44kV)	90	56	57	58	60	61	62	63	64	66	67	68	70	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CTS B		36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
CTS C		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CGS D		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Total		456	462	480	502	525	538	548	557	566	575	586	598	626	643	665
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	136.6	134.8	126.7	128.8	130.6	131.1	131.7	132.3	133.0	133.5	134.2	135.6	143	149	154
Wilson TS T1/T2	161	137.5	116.6	117.0	115.8	117.7	119.6	120.7	122.6	123.9	125.0	125.4	125.8	161.0	161.0	161.0
Wilson TS T3/T3	134	122.3	122.3	105.0	106.0	114.0	115.5	117.0	118.5	120.0	121.4	122.9	124.4	126.0	134.0	134.0
Area Total		396	393	432	459	474	481	488	495	503	510	517	525	574	614	652
Regional Total		853	855	912	961	998	1019	1036	1052	1070	1085	1103	1123	1201	1257	1317

APPENDIX F: LIST OF ACRONYMS

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



NEEDS ASSESSMENT REPORT

Greater Toronto Area East

December 11, 2024

Needs Assessment Report

Greater Toronto Area (GTA) East Region

December 11, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

GTA East Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Toronto Area East and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the Needs Assessment phase and b) require further assessment and regional coordination. The results reported in this Need Assessment are based on the input and information provided by the Technical Working Group (the "TWG") for this region at the time. Updates may be made based on best available information throughout the planning process.

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

Executive Summary

REGION	Greater Toronto Area East (GTA East) Region (the "Region")
LEAD	Hydro One Networks Inc. ("Hydro One")
START DATE: August 13, 2024	**END DATE:** December 11, 2024

1. INTRODUCTION

The second Regional Planning cycle for the GTA East Region was completed in February 2020 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report). This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered for the GTA East Region on August 13th , 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA East Region NA includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),

b) Identify any new needs resulting from this assessment,

c) Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area.

5. INPUTS/DATA

The TWG comprises of representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the Region regarding capacity needs, reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The need assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy
b) System reliability needs and operational concerns
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs discussed in the GTA East Region second cycle RIP have been completed:

- Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region: Seaton MTS has been built and placed in-service in 2023.
- Wilson TS – T1, T2 and Switchyard Refurbishment: Wilson TS T1/T2 have been replaced and new T7/T8 were placed in service in early 2024, maintaining station reliability and ensuring continued supply reliability to Oshawa PUC Inc. (OPUC) and Hydro One Distribution (H1DX) customers.

The following needs and projects discussed in the GTA East second cycle RIP are currently underway:

- Cherrywood TS 230kV Breaker Replacement (multi-phase projects): Two phases are underway with currently planned in-service dates of 2033 and 2037 respetively.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Wilson TS - T3/T4 Replacement

b) Station Capacity

- Whitby TS T1/T2 DESN (44kV)
- Thornton TS T3/T4 DESN
- Wilson TS T7/T8 DESN
- Wilson TS T3/T4 DESN

c) Transmission Line Capacity

- No new transmission Line Capacity need identified

d) System Reliability, Operation and Load Restoration

- T23C/T29C corridor may exceed load security limit of 600MW in 2032 if all forecasted loads at the current stations are supplied from original connection points

e) Transmission System Reinforcement

- Major transmission expansion in Oshawa-Clarington sub-region area will be needed to accommodate increasing new large load connection requests. Existing 230kV transmission facilities do not have sufficient capacity to supply the new demand.

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and new station capacity needs. These needs will be assessed again during the next phases of this Regional Planning cycle.

No.	Need Identified	Need Date		
		Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Whitby TS T1/T2 (44kV) LTR	2032	2030	Beyond 2033
2	Thornton TS T3/T4 LTR	2031	2027	Beyond 2033
3	Wilson TS T7/T8 LTR	2032	2029	Beyond 2033
4	Wilson TS T3/T4 LTR	2024 (2025*)	2024 (2025*)	2024 (Beyond 2033*)
Additional capacity needs under high growth scenario				
5	Cherrywood T7/T8 LTR	Beyond 2033	2031	Beyond 2033
6	Seaton MTS LTR**	Beyond 2033	2032	Beyond 2033
7	Whitby TS T3/T4 LTR	Beyond 2033	2031	Beyond 2033

* If the transformers are replaced with higher LTR rating units as planned.

** Based on the LDC provided LTRs of 153MW (Summer) and 180MW (Winter) for Seaton MTS

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

a) Integrated Transmission reinforcement at Oshawa-Clarington Sub-region area to accommodate large load connection requests and address T23C/T29C corridor load security issue
b) Station capacity need at Thornton TS in Oshawa area due to load growth
c) Station capacity need at Wilson TS T7/T8 in Oshawa area due to load growth
d) Station capacity need at Wilson TS T3/T4 in Oshawa area due to load growth

II. Needs that do not require further regional coordination

These needs can be addressed by a straightforward transmission and/or distribution wires solution, or they are local in nature and do not have a regional impact. They either do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

a) Cherrywood TS 230kV Breaker Replacement
b) Wilson TS - T3/T4 Transformer Replacement
c) Station capacity need at Whitby TS T1/T2 (44kV) in North Whitby area due to load growth

List of LDC(s) to be involved in further regional planning phases:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Hydro One Networks Inc. (Distribution)

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

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1. Introduction

The second cycle of the Regional Planning process for the GTA East Region was completed in February 2020 with the publication of the Regional Infrastructure Plan ("RIP") Report [1] - (RIP link). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the GTA East Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is shown in Figure 1 below.

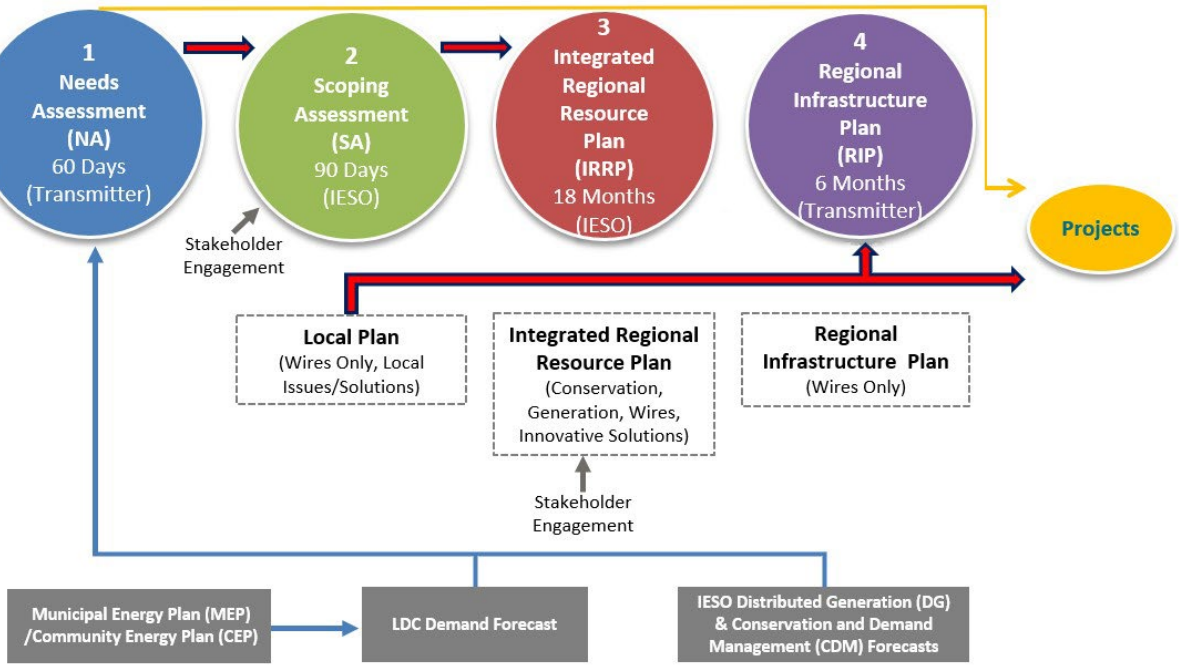


Figure 1: Regional Planning Process

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

Table 1: GTA East Region TWG Participants

No.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission) - (Lead Transmitter)
2	Independent Electricity System Operator
3	Elexicon Energy Inc.
4	Oshawa PUC Networks Inc.
5	Hydro One Networks Inc. (Distribution)

2. Regional Issue/Trigger

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the third Regional Planning cycle was triggered for the GTA East Region.

3. Scope of Needs Assessment

The scope of this NA covers the GTA East region and includes:

- Review and update needs and plans identified in the previous cycle RIP,
- Identify any new needs resulting from this assessment,
- Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan, and
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is 10 years.

4. Regional Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area.

The geographical boundaries of the Region are shown in Figure 2.

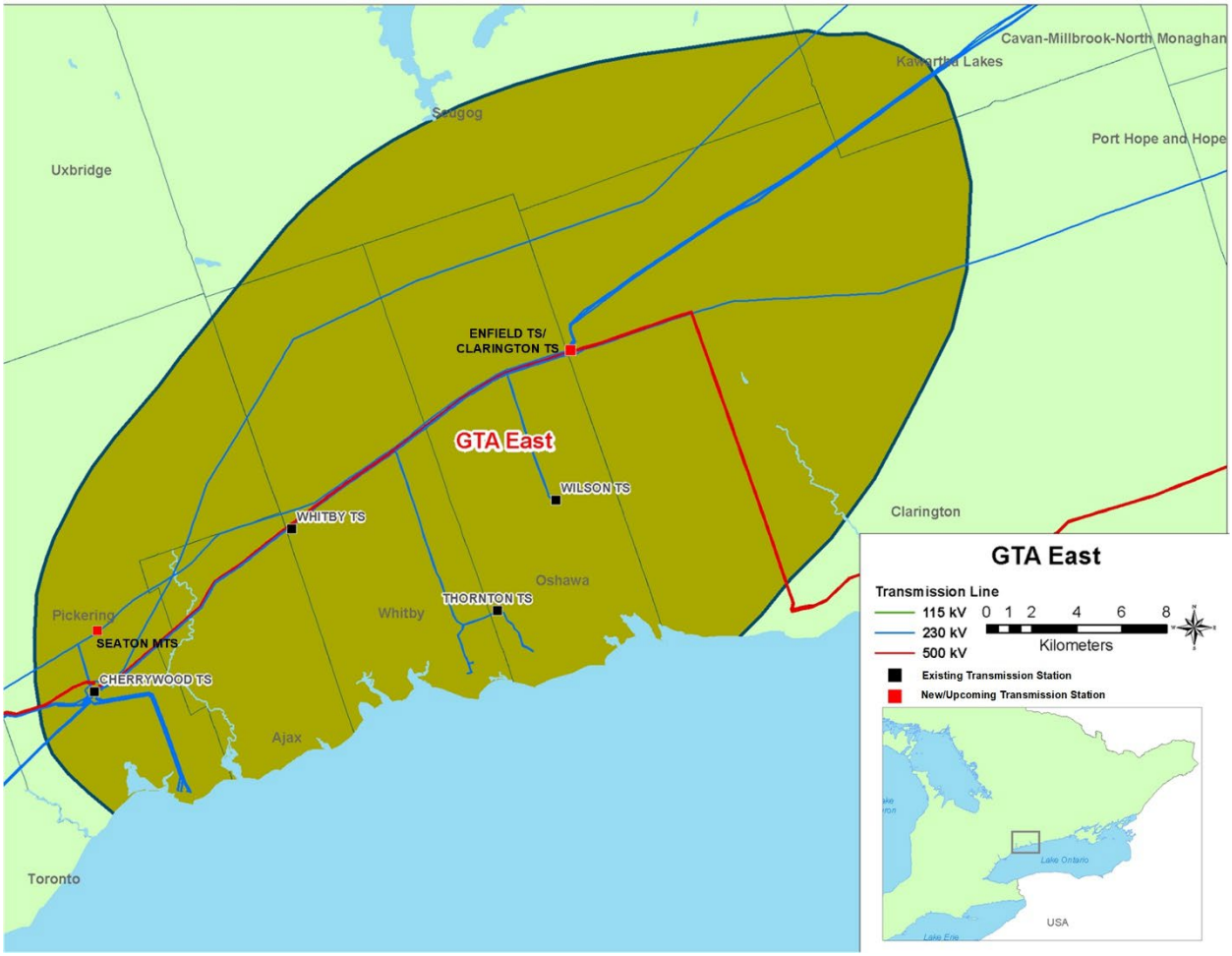


Figure 2: Map of GTA East Regional Planning Area

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington Transformer Station (TS) and six 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are six step-down transformer stations (five Hydro One owned and one LDC owned), and three direct transmission connected load customers. Metrolinx Traction Power Substation (TPSS) is proposed to be in service in 2029. The distribution system is at two voltage levels, 44kV and 27.6kV.

The Local Distribution Customers (LDC) in the Region include Elexicon Energy Inc., Oshawa PUC Networks Inc. and Hydro One Networks Inc. (Distribution). An electrical single line diagram for the GTA East Region facilities is shown in Figure 3.

The circuits and stations of the area are summarized in Table 2 below:

Table 2: Transmission Station and Circuits in the GTA East Region

230kV circuits	Transformer Stations	Generation Stations
T23C T24C T26C T28C T29C C10A	Cherrywood TS[1] Seaton MTS Thornton TS Whitby TS Wilson TS Enfield TS CTS A CTS B CTS C Metrolinx TPSS (in-service 2029)	CGS D, 60MW gas-fired cogeneration Pickering Nuclear Generating Station (NGS), approximately 3000 MW

1: 500kV Stations with Autotransformers installed

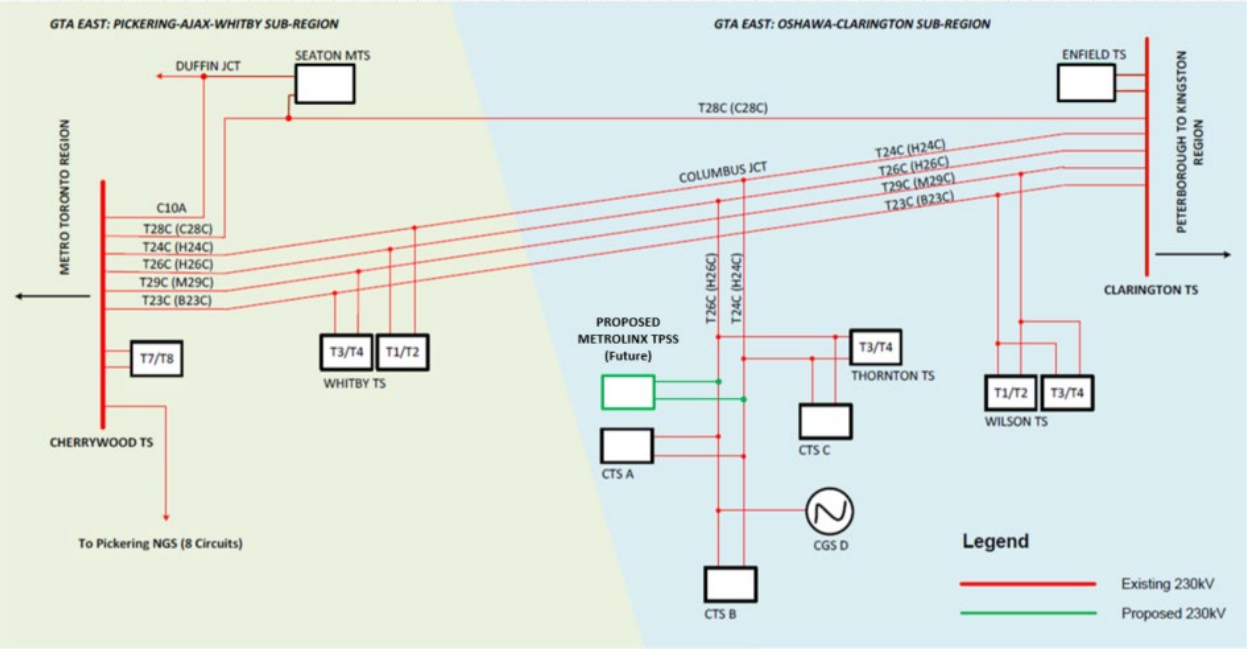


Figure 3: GTA East Transmission Single Line Diagram

5. Inputs and Data

TWG participants, including representatives from LDCs, IESO, and Hydro One provided input for the GTA East NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022 [2]. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the followings:

- GTA East 10-year summer and winter load forecast for all supply stations inclusive of the inputs provided by the municipalities listed in Appendix E
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement or refurbishment
- Planned transmission and distribution investments that are relevant to Regional Planning for the GTA East
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. Assessment Methodology

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy
- System reliability and operational considerations
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"
- Load forecast data requested from industrial customers in the region
- Summer and Winter peak load conditions. Three load forecasts were developed for Summer and Winter respectively, i.e. normal growth scenario, high and low growth scenario. The high and low growth load forecasts are developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, government policies, higher than expected EV charging trend during peak load conditions, etc.

The following assumptions are made in this report:

- The study period for this Needs Assessment is 2024-2033.
- The Region is summer peaking, but will be transitioning to winter peaking for most of transformer stations in this study period, so this assessment is based on both summer and winter peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One Summer/Winter 10-Day Limited Time Rating (LTR) at 35 and 10 degree celcius respectively for Summer/Winter of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC)[3] .

6.2 Information Gathering Process

6.2.1 Load forecast

The LDCs provided their summer and winter load forecast for all the stations supplying their loads in the GTA East region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Region. The net extreme summer weather load

forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Region is given in Appendix A.

6.2.2 Sensitivity analysis

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3 Asset renewal needs for major HV equipment

A list is generated for major HV transmission equipment planned or identified to be replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4 System reliability and operational issues

Relevant information regarding system reliability and operational issues in the region as feedback is provided by the IESO during the NA phase.

7. Needs

This section describes new needs identified in the Region and updates on previously identified needs since the completion of previous regional planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway, are briefly described below with relevant updates:

- Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region: Seaton MTS has been built and placed in-service in 2023.
- Wilson TS – T1, T2 and Switchyard Refurbishment: Wilson TS T1/T2 have been replaced and new T7/T8 were placed inservice in early 2024, maintaining station reliability and ensuring continued supply reliability to Oshawa PUC Inc. (OPUC) and Hydro One Distribution (H1DX) customers.
- Cherrywood TS – 230kV Breaker Replacements (multi-phase projects): Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.

All near and midterm needs that are discussed as a part of this report are summarized in Table 3. Note the planned in-service year for the projects is tentative and is subject to change.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cherrywood TS 230kV Breaker Replacements (multi-phase projects)	Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.	Sec. 7.2	Sec. 7.1
Wilson TS T3/T4 Transformer Replacement	Replacement of T3/T4 transformers with planned in-service date of 2031.	N/A	Sec. 7.1
Station Capacity Needs			
Whitby TS T1/T2 (44kV) Station Capacity need	Plan a new Transformer Station at North Whitby area, tapping on 230kV circuits of P15C and T28C. TWG agreed to proceed with local planning, no further regional coordination is required.	N/A	Sec. 7.2.1
Thornton TS T3/T4 Station Capacity need	Further regional coordination to address this need along with the identified new needs at Wilson TS T3/T4 and Wilson TS T7/T8 in Oshawa area (see Section 7.2.3 and 7.2.4).	N/A	Sec. 7.2.2

Wilson TS T7/T8 Station Capacity need	Further regional coordination required to address this need along with the identified new needs at Wilson TS T3/T4 (Section 7.2.4), and a new Transformer Station will be required.	N/A	Sec. 7.2.3
Wilson TS T3/T4 Station Capacity need	A new Transformer Station will be required as early as 2028/2029 and further regional coordination to address this need along with the needs at Wilson TS T7/T8 and Thornton TS T3/T4 (Section 7.2.2 and 7.2.3). As a near term solution, the LDCs are encouraged to continue transferring loads to Enfield TS.	N/A	Sec. 7.2.4
System Reliability, Operation and Load restoration Needs			
T23C/T29C corridor exceeds load security limit of 600MW	Further regional coordination required, especially when determining where to connect new Transformer Station to accommodate new needs identified in Section 7.2.2, 7.2.3 and 7.2.4.	N/A	Sec. 7.4
Transmission System Reinforcement Needs			
Oshawa-Clarington Sub-region area transmission reinforcement for load supply	Further regional coordination to address the capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.	N/A	Sec. 7.5

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal need for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Region. The complete list of planned major HV transmission equipment requiring replacement is provided in Table 4. Note the in service year is subject to change as the asset renewal planning is a dynamic process.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors
- Technical obsolescence due to outdated design
- Lack of spare parts availability or manufacturer support and/or
- Potential health and safety hazards.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230 load serving step down transformers
- 230kV breakers where:

replacement of six breakers or more than 50% of station breakers, the lesser of the two

- 230kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

7.1.1 Wilson TS T3/T4

Based on asset condition assessment, Wilson TS T3/T4 transformers are newly identified assets for replacement with currently planned in-service date of 2031. The existing T3 and T4 (75/100/125 MVA) transformers at Wilson TS and associated LV equipment require replacement. It is expected that Wilson TS T3/T4 capacity will increase to approximate 160 MW for Summer and 180 MW for Winter, once being replaced with the new standard 75/100/125 MVA transformers (Section 7.2.4).

No other HV station equipment or transmission lines in the GTA East region have been identified for replacement at this time over the next ten year. If and when new and/or additional information is available, it will be provided during the next regional planning phases.

The needs below in Table 4 do not need further regional coordination.

Table 4: Major HV Transmission Asset Assessed for Replacement in the Region in Next 10 Years

Station/Circuit	Need Description	Planned ISD
Cherrywood TS	230kV Breaker Replacements (multi-phase projects), two phases are underway	2033/2037
Wilson TS T3/T4	Asset condition based replacement with "like for like" standard units	2031

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV Transforming stations in the Region using the summer and winter peak load forecasts. Based on the results, the identified station capacity needs are flagged in Table 5. Comparing with the recommendations in RIP 2022 [1], all Transformer Stations below are newly identified needs in this NA period.

Table 5: Stations with Capacity Need

TS	Season	LTR (MW)	Net Load Forecast (MW)									
			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Whitby TS T1/T2 (44kV)	Winter	113.2	36.6	47.5	56.9	66.6	76.7	87.1	98.1	107.4	118.2	130.1
Thornton TS T3/T4	Summer	154.9	138.0	138.8	139.5	140.0	141.1	142.4	144.7	147.7	151.5	156.2
	Winter	175.5	154.5	157.8	160.3	162.6	165.6	168.9	173.3	178.0	183.7	190.4
Wilson TS T7/T8	Summer	169.1	139.7	147.5	149.1	150.8	155.7	159.5	163.4	168.2	174.1	181.3
Wilson TS T3/T4	Summer	130.2	144.6	161.2	176.0	187.7	198.8	213.6	232.2	254.6	290.5	311.6
	Winter	152.0	136.1	154.7	171.5	185.1	198.2	214.6	234.6	257.2	293.0	312.8

7.2.1 Whitby TS T1/T2 (44kV)

Whitby TS T1/T2 (44kV) supplies loads from one LDC - Elexicon at 44kV level. Elexicon forecasts rapid annual gross load growth of approximate 6.3% at its 44kV service area in North Whitby in next ten years. With forecasted DG and CDM in place, the forecasted net load at Whitby TS T1/T2 (44kV) is expected to exceed its Winter LTR in 2032/2033 by 5MW or 17 MW respectively. In addition, the LDC has indicated that its 44kV distribution capacity at Whitby area will be exceeded by Summer 2032, and majority of the load growth in North Whitby area, which is currently supplied through Whitby TS T3/T4 and Whitby T1/T2 (27.6kV and 44kV), is highly expected post 2033. Also, in Northeast Pickering, there is projected load in the region that cannot be supplied by Whitby TS due to the long distance of the load center from the station.

In order to accommodate these needs, the LDC is currently consulting with Hydro One Tx to build a new Transformer Station, with preliminary option of tapping on two 230kV transmission circuits in the region, namely T28C and P15C. This new Transformer Station will address future projected load growth from North Whiby and North Pickering area. The TWG recommends LDC and Hydro One to proceed to local planning as no expected network reinforcement is required. No further regional coordination is required.

7.2.2 Thornton TS T3/T4

Thornton TS T3/T4 supplies loads from two LDCs, namely Hydro One Distribution (H1DX, with Elexicon's load embedded in) and Oshawa PUC Networks Inc. (OPUC), at 44kV level. OPUC forecasts rapid annual load growth of approximate 4.6% at Thornton TS T3/T4 in next ten years, while Elexicon load forecast remains flat in the study period. With forecasted DG and CDM in place, the net forecasted load at

Thornton TS T3/T4 is expected to exceed its LTRs as early as 2031 for Winter, or 2033 for Summer. The TWG recommends further regional coordination to address this need along with the identified new needs at Wilson TS T7/T8 and Wilson TS T3/T4 in Oshawa area (see Section 7.2.3 and 7.2.4 below).

7.2.3 Wilson TS T7/T8

Wilson TS T7/T8 serves loads from two LDCs, including OPUC and Hydro One Distribution (H1DX) at 44kV level. The two transformers have recently been replaced in early 2024 with largest size as per Hydro One standard transformer specification. Both LDCs forecast similar moderate annual gross load growth of approximate 3.2-3.7% at Wilson TS T7/T8 in next ten years. The net forecasted load at Wilson TS T7/T8 is expected to exceed its LTR as early as 2032 for Summer. The TWG recommends further regional coordination to address this need along with the identified new needs at Wilson TS T3/T4 (Section 7.2.4), and acknowledges that a new Transformer Station will be required for these needs.

7.2.4 Wilson TS T3/T4

Wilson TS T3/T4 serves loads from LDCs OPUC and Hydro One Distribution (H1DX) at 44kV level, with Elexicon's load embedded in H1DX. H1DX (including Elexicon) forecasts approximate 12% annual load growth at Wilson TS T3/T4 in next ten years, while OPUC forecasts moderate growth of approximate 3.6% annually in next ten years. The net forecasted load at Wilson TS T3/T4 is expected to exceed its LTR as early as 2024 for Summer, and 2025 for Winter.

As mentioned in Section 7.1.1, based on asset condition assessment, the T3 and T4 transformers at Wilson TS and associated LV equipment have been identified for replacement. Hydro One has identified the replacement of Wilson TS T3/T4 with planned in-service date of 2031. As the existing transformers have substandard LTRs, it is expected that Wilson TS T3/T4 will be replaced with standard 75/100/125 MVA transformers, and the capacity will increase from the current 130 MW for Summer and 152 MW for Winter to approximately 160 MW for Summer and 180 MW for Winter.

However, even with higher ratings of the new transformers, Wilson TS T3/T4 LTRs will still be exceeded based on load forecast. As a near term solution, the LDCs are encouraged to continue transferring loads to Enfield TS which can accommodate the additional loads that exceed Wilson TS T3/T4 station capacity. By doing so, the station capacity need could potentially be deferred for a few years. The TWG acknowledges that a new station will be required as early as 2028/2029 even with load transfers, and recommends further regional coordination to address this need along with the need in Section 7.2.2 and 7.2.3.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A

Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV Transmission line circuits in the Region by assessing thermal limits of the circuit and the voltage range as per ORTAC[3].

Based on the results, there is no new transmission line capacity need identified.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The system should also meet load security and load restoration criteria as defined in ORTAC[3]. Based on input from the IESO and LDCs, the following system reliability, operational and restoration issues were identified:

- The new load forecast suggests T23C/T29C corridor will exceed load security limit of 600MW[3] in 2032. Table 6 shows load growth of all double-circuit corridors in the Region (assuming all forecasted loads were supplied from original connection points). The TWG recommends further regional coordination to address the T23C/T29C corridor load security issue, especially when determining where to connect the new Transformer Station to accommodate new needs identified in Section 7.2.3 and 7.2.4. The other T24C/T28C corridor will not have more than 600MW net loads in the assessment window.

Table 6: Double-circuit Corridor Non-coincident Load

Circuits		Non-coincident Load served by the double circuits (MW)									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
T23C/T29C	Summer	442.6	468.3	486.1	500.7	518.2	538.2	562.8	592.4	638.0	671.0
	Winter	362.1	395.3	420.3	442.1	466.3	493.1	524.0	557.0	605.3	639.5
T24C/T26C	Summer	412.9	418.5	424.1	429.5	435.7	472.5	480.9	489.8	501.5	515.4
	Winter	399.0	414.9	428.3	441.7	456.4	501.6	518.7	534.2	552.6	573.3

- All double-circuit corridor loads will exceed 250MW in this assessment timeframe. The ORTAC[3] requires the amount of load interruption in excess of 250MW must be restored within 30 minutes (and within 4 hours for load loss more than 150MW). The TWG surveyed transmission load interruption performance data from 2014 to 2024 for the Region. The results show that delivery points supplied by the circuits in Table 6 did not log load loss of more than 250MW for longer than 30 minutes, or loss of more than 150MW for longer than 4 hours in the past 10 years. Based on past performance data, the TWG would not recommends capital investment for load restoration at this point. Hydro One shall proactively monitor load restoration data and identify opportunities to reduce risk of prolonged load restoration.

7.5 Transmission System Reinforcement Needs

Oshawa-Clarington Sub-region area transmission reinforcement:

In addition to the rapid organic load growth forecasted in T23C/T29C/T24C/T26C corridors, multiple proponents have requested to connect large-scale loads in Oshawa-Clarington Sub-region area. Majority of the requests are large data centers. It is not feasible for the existing 230kV transmission infrastructure in Oshawa-Clarington Sub-region area to accommodate such sizeable loads. Due to the scale and complexity of such connections, the TWG recommends further regional coordination to address these potential capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.

8. Sensitivity Analysis

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the GTA East region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The impact of sensitivity analysis for the high and low growth scenario is shown in Table 7. The additional capacity needs identified towards the end of the study period will be assessed again during the next phases of the Regional Planning cycle where another sensitivity anaylyis will be undertaken based on updated information.

Table 7: Impact of Sensitivity Analysis on Capacity Needs in the Region

No.	Need Identified	Need Date		
		Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Whitby TS T1/T2 (44kV) LTR	2032	2030	Beyond 2033
2	Thornton TS T3/T4 LTR	2031	2027	Beyond 2033
3	Wilson TS T7/T8 LTR	2032	2029	Beyond 2033
4	Wilson TS T3/T4 LTR	2024 (2025*)	2024 (2025*)	2024 (Beyond 2033*)
Additional capacity needs under high growth scenario				
5	Cherrywood T7/T8 LTR	Beyond 2033	2031	Beyond 2033
6	Seaton MTS LTR**	Beyond 2033	2032	Beyond 2033
7	Whitby TS T3/T4 LTR	Beyond 2033	2031	Beyond 2033

* If the transformers are replaced with higher LTR rating units as planned.

** Based on the LDC provided LTRs of 153MW (Summer) and 180MW (Winter) for Seaton MTS

9. Conclusion and Recommendation

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs that Do Not Require Further Regional Coordination

No.	Need	Recommendation
1	Cherrywood TS 230kV Breaker Replacement	Replace 230kV Breaker in multi phases. Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.
2	Wilson TS T3/T4 Transformer Replacement	Replace Wilson TS T3/T4 transformers with "like for like" standard units with currently planned in service date of 2031.
3	Station capacity need at Whitby TS T1/T2 (44kV) due to load growth	Plan a new Transformer Station at North Whitby area, tapping on 230kV circuits of P15C and T28C. TWG agreed to proceed with local planning and no further regional coordination is required.

Table 9: Needs Requiring Further Regional Coordination

No.	Need
1	Transmission reinforcement at Oshawa-Clarington Sub-region area to accommodate large load connection requests and address potential load security issue
2	Station capacity need at Thornton TS T3/T4 due to load growth
3	Station capacity need at Wilson TS T7/T8 due to load growth
4	Station capacity need at Wilson TS T3/T4 due to load growth

List of LDC(s) to be involved in further regional planning activities:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Hydro One Networks Inc. (Distribution)

10. References

[1] Hydro One, RIP Report GTA East 2020 (hydroone.com) (issue February 29, 2020)

[2] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[3] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[4] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[5] Ontario Energy Board, Distribution System Code (issue July 14, 2000 rev. March 27, 2024)

Appendix A: Extreme Summer and Winter Weather Adjusted Net Load Forecast

Table A.1: GTA East Region – Summer Non-coincident Normal Growth Net Load Forecast

Transformer Station		Summer LTR (MW)	Summer Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	167.2	143.4	145.8	148.3	150.8	153.5	156.2	159.3	162.8	163.6	163.1
Seaton MTS	T1/T2	N/A	4.1	10.1	17.0	25.6	36.9	47.0	56.8	66.7	76.7	86.7
Thornton TS	T3/T4	154.9	138.0	138.8	139.5	140.0	141.1	142.4	144.7	147.7	151.5	156.2
Whitby TS	T3/T4	182.4	158.2	159.5	161.0	162.2	163.6	165.1	167.1	169.6	173.4	178.1
Whitby TS	T1/T2 (27.6kV)	99.9	51.8	52.1	52.4	52.6	52.9	53.2	53.7	54.3	55.4	56.8
Whitby TS	T1/T2 (44kV)	100.8	46.1	50.6	55.2	59.9	64.7	69.8	75.5	80.8	87.6	95.4
Wilson TS	T7/T8	169.1	139.7	147.5	149.1	150.8	155.7	159.5	163.4	168.2	174.1	181.3
Wilson TS	T3/T4	130.2	144.6	161.2	176.0	187.7	198.8	213.6	232.2	254.6	290.5	311.6
Enfield TS	T5/T6	161.5	91.7	96.4	99.7	104.0	107.3	110.7	113.5	117.0	121.4	126.5
CTS A	N/A		40	40	40	40	40	40	40	40	40	40
CTS B			97	97	97	97	97	97	97	97	97	97
CTS C			40	40	40	40	40	40	40	40	40	40
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Note:
1. All LTRs are based on 35C for Summer and 10C for Winter.
2. Cherrywood TS DESN LTR is limited by outdoor AL tube, decreasing summer LTR by 8MW.
3. Wilson TS T3/T4 will be replaced by 2031 with higher rating of approximate 160MW for Summer and 180MW for Winter.

Table A.2: GTA East Region – Summer Coincident Normal Growth Net Load Forecast

Transformer Station		Summer LTR (MW)	Summer Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	167.2	136.2	138.5	140.9	143.3	145.8	148.4	151.4	154.7	155.5	154.9
Seaton MTS	T1/T2	N/A	2.7	6.8	11.4	17.1	24.8	31.5	38.1	44.7	51.4	58.1
Thornton TS	T3/T4	154.9	127.0	127.7	128.3	128.8	129.8	131.0	133.1	135.9	139.4	143.7
Whitby TS	T3/T4	182.4	150.3	151.5	152.9	154.0	155.5	156.9	158.8	161.1	164.7	169.2
Whitby TS	T1/T2 (27.6kV)	99.9	49.2	49.5	49.8	50.0	50.3	50.6	51.0	51.6	52.6	53.9
Whitby TS	T1/T2 (44kV)	100.8	43.8	48.1	52.4	56.9	61.4	66.3	71.7	76.8	83.2	90.7
Wilson TS	T7/T8	169.1	125.8	132.8	134.2	135.8	140.2	143.5	147.1	151.4	156.7	163.2
Wilson TS	T3/T4	130.2	130.2	145.1	158.4	168.9	178.9	192.2	209.0	229.1	261.4	280.5
Enfield TS	T5/T6	161.5	85.3	89.7	92.7	96.8	99.8	102.9	105.5	108.8	112.9	117.7
CTS A	N/A		30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
CTS B			46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6
CTS C			38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Table A.3: GTA East Region – Winter Non-coincident Normal Growth Net Load Forecast

Transformer Station		Winter LTR (MW)	Winter Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	204.5	127.8	134.8	140.9	147.0	153.6	160.0	167.1	170.9	170.2	169.6
Seaton MTS	T1/T2	N/A	4.2	10.4	17.5	26.5	38.3	48.8	59.0	69.3	79.7	90.1
Thornton TS	T3/T4	175.5	154.5	157.8	160.3	162.6	165.6	168.9	173.3	178.0	183.7	190.4
Whitby TS	T3/T4	206.2	111.0	117.0	122.3	127.4	132.9	138.3	144.3	149.6	156.1	163.4
Whitby TS	T1/T2 (27.6kV)	112.5	30.9	32.6	34.1	35.5	37.1	38.6	40.3	41.8	43.7	45.8
Whitby TS	T1/T2 (44kV)	113.2	36.6	47.5	56.9	66.6	76.7	87.1	98.1	107.4	118.2	130.1
Wilson TS	T7/T8	184.3	114.9	123.6	126.5	129.6	135.3	140.2	145.1	150.2	156.3	163.4
Wilson TS	T3/T4	152.0	136.1	154.7	171.5	185.1	198.2	214.6	234.6	257.2	293.0	312.8
Enfield TS	T5/T6	183.4	94.7	101.0	105.7	111.3	116.0	120.7	124.7	129.3	134.7	140.9
CTS A	N/A		40	40	40	40	40	40	40	40	40	40
CTS B			97	97	97	97	97	97	97	97	97	97
CTS C			40	40	40	40	40	40	40	40	40	40
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Note:
1. All LTRs are based on 35C for Summer and 10C for Winter.
2. Cherrywood TS DESN LTR is limited by outdoor AL tube, decreasing summer LTR by 8MW.
3. Wilson TS T3/T4 will be replaced by 2031 with higher rating of approximate 160MW for Summer and 180MW for Winter.

Table A.4: GTA East Region – Winter Coincident Normal Growth Net Load Forecast

Transformer Station		Winter LTR (MW)	Winter Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	204.5	125.2	132.1	138.1	144.1	150.5	156.8	163.7	167.5	166.8	166.2
Seaton MTS	T1/T2	N/A	2.6	6.4	10.9	16.4	23.8	30.2	36.6	43.0	49.4	55.9
Thornton TS	T3/T4	175.5	140.6	143.6	145.9	148.0	150.7	153.7	157.7	162.0	167.2	173.3
Whitby TS	T3/T4	206.2	108.8	114.7	119.8	124.8	130.2	135.6	141.4	146.6	153.0	160.1
Whitby TS	T1/T2 (27.6kV)	112.5	30.2	31.9	33.4	34.8	36.3	37.8	39.5	41.0	42.8	44.8
Whitby TS	T1/T2 (44kV)	113.2	35.9	46.6	55.8	65.3	75.1	85.4	96.1	105.2	115.8	127.5
Wilson TS	T7/T8	184.3	108.0	116.2	118.9	121.8	127.2	131.8	136.4	141.2	146.9	153.6
Wilson TS	T3/T4	152.0	128.0	145.4	161.2	174.0	186.3	201.7	220.5	241.8	275.4	294.0
Enfield TS	T5/T6	183.4	87.1	92.9	97.2	102.4	106.7	111.1	114.7	118.9	123.9	129.6
CTS A	N/A		35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2
CTS B			86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3
CTS C			34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station		Voltage (kV)	Supply Circuits
1	Cherrywood TS	T7/T8	230/44	Cherrywood TS, DK Bus
2	Seaton MTS	N/A	230/27.6	C10A/T28C
3	Thornton TS	T3/T4	230/44	T24C/T26C
4	Whitby TS	T1/T2	230/27.6	T24C/T26C
			230/44	
		T3/T4	230/44	T23C/T29C
5	Wilson TS	T1/T2	230/44	T23C/T29C
		T3/T4	230/44	
6	Enfield TS	T5/T6	230/44	Clarington TS, PK Bus
7	CTS A	N/A	N/A	T24C/T26C
8	CTS B	N/A	N/A	T24C/T26C
9	CTS C	N/A	N/A	T24C/T26C

Appendix C: Lists of Transmission Circuits

No.	Circuit ID	From Station	To Station	Voltage (kV)
1	C10A	Cherrywood TS	Seaton MTS	230
2	T23C	Cherrywood TS	Clarington TS	230
3	T24C	Cherrywood TS	Clarington TS	230
4	T26C	Cherrywood TS	Clarington TS	230
5	T28C	Cherrywood TS	Clarington TS	230
6	T29C	Cherrywood TS	Clarington TS	230

Appendix D: List of LDC's

No.	Name of LDC	Connection Type (TX/DX)
1	Elexicon Energy Inc.	TX / DX
2	Oshawa PUC Networks Inc.	TX / DX
3	Hydro One Networks Inc. (Distribution)	TX

Appendix E: List of Municipalities in the region

No.	Name of Municipality
1	City of Pickering
2	Town of Ajax
3	Town of Whitby
4	City of Oshawa
5	Municipality of Clarington
6	Township of Scugog
7	Township of Uxbridge
8	Regional Municipality of Durham

Appendix F: Acronyms

Acronym	Description
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
KOP	Key Operating Point
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LP	Local Plan
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
MVGIS	Medium Voltage Gas Insulated Switchgear
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SS	Switching Station
TS	Transformer Station

GTA North (York Region) Integrated Regional Resource Plan

October 10, 2025

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-Level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
eDSM	Electricity Demand Side Management
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

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Appendix A. Overview of the Regional Planning Process

Appendix B. Peak Demand Forecast

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Executive Summary

The GTA North (York Region) Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the GTA North Region over a 20-year period, from 2024 to 2043. The GTA North Region is located in southern Ontario and is defined by electrical infrastructure boundaries, not municipal, yet roughly includes the municipalities of Aurora, East Gwillimbury, Georgina, King, Markham, Newmarket, Richmond Hill, Vaughan, Whitchurch-Stouffville, and parts of Simcoe County, including Bradford-West Gwillimbury. Because these municipalities primarily fall within York Region, the terms "GTA North Region" and "York Region" are used interchangeably in this study.

For the purposes of this IRRP, the region is often divided into four electrical subsystems: Northern York, Kleinburg, Southern Vaughan-Richmond Hill, and Markham and Area. These subsystems reflect the configuration of the transmission system and the location of major step-down transformer stations and other points of system supply. The IRRP focuses on identifying and addressing electricity needs in each of these subsystems, while also coordinating with broader bulk system planning and other coordinated planning efforts, including regional planning in GTA West and South Georgian Bay-Muskoka, and corridor identification and preservation initiatives.

The Region of York is growing rapidly, with a population of 1.26 million in 2024, and is expected to grow to over 2 million by 2051. Existing infrastructure supplying York Region is insufficient to meet anticipated growth in electricity demand. Some sections of northern York in particular are already experiencing challenges in connecting new customer loads. Investing in new transmission infrastructure would have a positive impact on the region, especially increasing the ability for new loads to connect, and maintaining the reliability of existing customers throughout York Region.

The electricity demand forecast for York Region shows significant growth over the planning horizon, driven by residential intensification, commercial development (including large energy-intensive customers), and electrification trends (such as electric vehicles and heat pumps). Summer peak demand is expected to nearly double by 2043, while winter peaks could potentially triple depending on the pace of electrification. While the region has historically been summer-peaking, winter peaks could become more limiting by the early-2030s. Given the uncertainty associated with long-term growth forecasts, particularly with respect to winter peaks that rely on new customer behaviour and technological availability, this study has placed a greater emphasis on managing uncertainty and risk in demand forecasts. In practice, only summer peak forecasts have been used to make recommendations which require immediate action. For longer term needs, dates associated with summer peaks have been the primary driver for planning during this cycle. The impacts of higher potential winter peaks have been considered and will continue to be monitored through the Annual Working Group to determine the need to trigger long term system reinforcements.

To identify near-, medium-, and long-term needs, the Technical Working Group assessed station capacity, supply capacity, reliability, and load security needs across the region. A combination of wires and non-wires solutions were evaluated, with a number of recommendations made to address near-term needs. Options for addressing longer-term needs are also proposed, but do not yet require action, except to preserve long-term viability of the solution options. Non-wires alternatives (NWAs) such as targeted electricity demand-side management (eDSM) and distributed energy resources

(DERs) have been recommended to help manage near-term reliability risks and potentially defer longer-term infrastructure requirements.

Additional consideration has also been given to long term impacts of reduced reliance on York Energy Centre, following its contract expiry in 2035. This includes evaluation of the impact of the loss of supply on the local system, and potential solutions which may need to be pursued if this facility is no longer available.

The study has also considered points of coordination with an ongoing bulk planning initiative, the South and Central Bulk Plan, which is studying bulk system needs and potential upgrades with a notional 2035 focus. A second, longer-term bulk planning study, expected to be initiated in 2026 with a focus on bulk system needs into the 2040s, will similarly consider potential impact of bulk enhancements on regional supply. Both studies have the potential to affect longer-term needs and feasibility of solutions available to in the area, particularly for needs emerging post 2035 or 2040.

Engagement was a key component of this IRRP. The IESO engaged with municipalities, Indigenous communities, stakeholders, and the public throughout the planning process. Feedback received helped shape the demand forecast, identify local priorities, and inform the recommended solutions.

The Technical Working Group will continue to monitor growth, electrification trends, and large customer connections across the region. The group will meet regularly to track progress, assess changing conditions, and update the plan as needed. If underlying assumptions change significantly, the IRRP may be amended, or a new planning cycle initiated ahead of the standard five-year schedule mandated by the Ontario Energy Board.

Summary of Recommendations

Near-term recommendations emerging from this plan will provide increased station and system capacity across the region and allow for anticipated load growth to be reliably met into the 2030s. Immediate action is recommended to implement the following:

Table 1| Summary of Near-Term Recommendations

Project	Need	Need Timing	Expected In-Service
Additional targeted incremental eDSM to manage demand and ease pressure on the system	Station and Supply Capacity in Northern York, Markham, Richmond Hill, and Whitchurch-Stouffville	Ongoing	Ongoing
Reconfigure York Energy Centre Station Service Supply	Supply Capacity in Northern York	Immediate	2026
Develop Northern York TS #1	Station Capacity in Northern York	Immediate	2030
Develop Markham MTS #5	Station Capacity in Markham	2029	2028/2029

Project	Need	Need Timing	Expected In-Service
Develop Richmond Hill MTS #3	Station Capacity in Richmond Hill	2030	2030
Install new breakers along Parkway to Claireville corridor	Load Security in Vaughan and Richmond Hill	Immediate	2028/2029
Reconductor Circuit P45/46 from Parkway to Buttonville TS to support Markham TS #5 (in phases)	Supply Capacity in Markham	2029	2029
Build a new 230kV transmission line along the future Highway 413 corridor (Kleinburg – Kirby Transmission Line)	Supply Capacity in Northern York	2030	2031/2032
Develop/preserve viability of long-term capacity options through corridor identification and preservation initiatives	Station and Supply Capacity	Ongoing	Ongoing

The Technical Working Group will continue to monitor and may recommend action based on revised forecasts and demand growth for these medium- to long-term needs and recommendations:

Table 2| Summary of Medium- to Long Term Recommendations

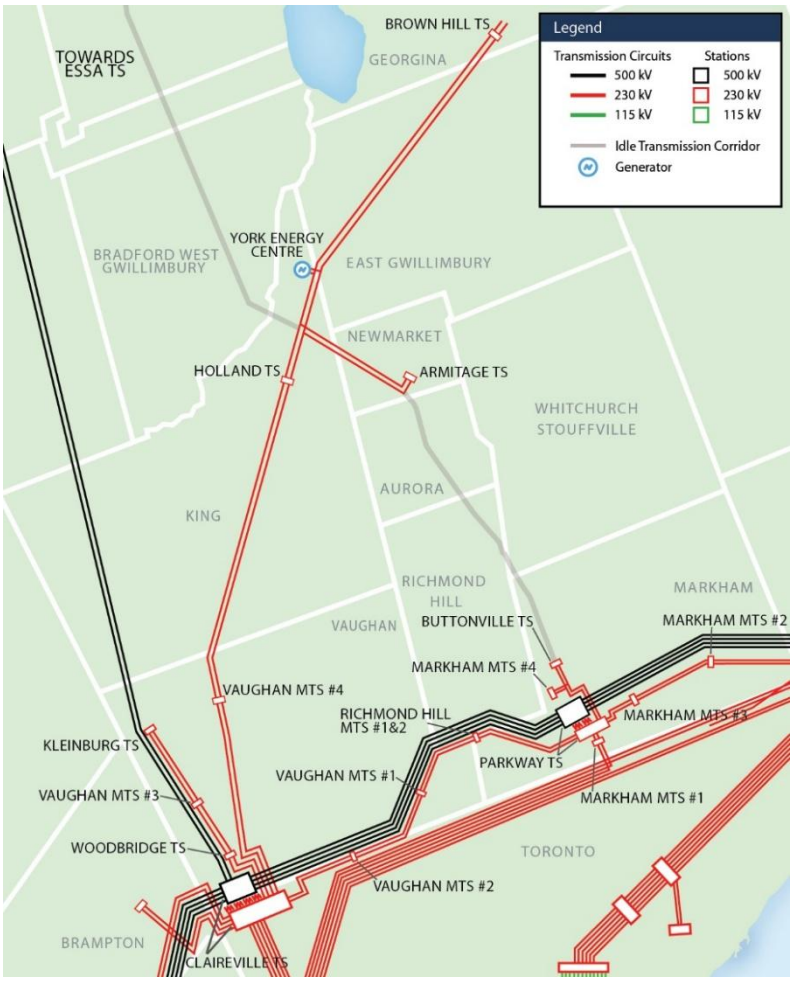
Project	Need	Need Timing	Expected In-Service
Develop Vaughan MTS #5	Station Capacity in Vaughan	2033	2033
Extend transmission from Buttonville TS and develop Northern York TS #2 and Markham TS #6	Station Capacity in Markham, Richmond Hill, and Whitchurch-Stouffville	2034	2034
Monitor future electricity needs and begin early planning for new infrastructure including Northern York TS #3 and the Holland switching station	Station and Supply Capacity in Northern York	2035	2035

1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses electricity needs for the GTA North Regional Planning area ("GTA North" or "York Region") between 2025 and 2043. This report was prepared by the Independent Electricity System Operator (IESO) on behalf of the York Region Technical Working Group comprising the IESO, Alectra Utilities Corporation (Alectra), Newmarket-Tay Power Distribution Ltd. (NT Power), Hydro One Networks Inc. (Hydro One Distribution), and Hydro One Networks Inc. (Hydro One Transmission).

In Ontario, planning to meet the electrical supply and reliability needs of a local area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. The GTA North Region, shown in Figure 1, roughly corresponds with the municipal boundaries of York Region. For the purposes of this plan, GTA North and York Region can be used interchangeably.

Figure 1| Overview of the GTA North (York) Region



Development of the GTA North (York Region) IRRP was initiated in October 2023, following the publication of the Needs Assessment report in July 2023 by Hydro One and the Scoping Assessment Outcome Report in October 2023 by the IESO. The Scoping Assessment identified the area's needs should be further assessed through an IRRP. The Technical Working Group was then formed to gather data, identify near-, medium-, and long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2
- The process and methodology used to develop the plan are discussed in Section 3
- The background for electricity planning in the region and the study scope is discussed in Section 4
- The development of the demand forecast, including electricity Demand Side Management (eDSM) and distributed generation assumptions, are described in Section 5
- Electricity needs in the region are presented in Section 6
- Alternatives and recommendations for meeting needs are addressed in Section 7
- Linkages to the South and Central Bulk Study is outlined Section 8
- A summary of engagement activities is provided in Section 9, and
- The conclusion is provided in Section 10.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of York Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of different options to address the region's needs in consideration of reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from communities and stakeholders.

2.1 Status of Projects from Previous IRRP Cycles

Following the previous cycle of regional planning, which concluded with the 2nd Cycle RIP report, several projects were recommended that have now been completed or are presently underway. The status of these projects is summarized in Table 3.

Table 3| Needs Identified in the Previous Cycle with Revised In-Service Date

Project	Need	Expected In-Service
Collect Information on future NWAs and opportunities in York Region to inform the next IRRP	Station and Supply Capacity	Ongoing
Reconfigure York Energy Centre Station Service Supply	Supply Capacity	2026
Develop Markham MTS #5	Station Capacity	Expected in Service Date in 2028/2029
Reconductor Circuit P45/46 from Parkway to Markham MTS #4	Supply Capacity	Expected in Service Date in 2029
Develop Northern York TS #1	Station Capacity	Expected in Service Date in 2030
Develop/Preserve Viability of Long-term Capacity Options	Station and Supply Capacity	Ongoing

2.2 Plan for Near-Term Needs (2026-2030)

The near-term plan consists of several recommendations to enable load growth and maintain reliability. Many of these needs are immediate, and based on today's peak demand, while others are based on strong anticipated load growth over the next five years. Implementation should be initiated immediately to ensure required in service dates can be met.

Additional targeted incremental eDSM to manage demand and ease pressure on the system. As an interim measure, eDSM may be considered to manage shortfalls where the infrastructure solution is not expected to be in service in time to meet existing or anticipated needs. eDSM also has the potential to defer the need for additional infrastructure investments anticipated to be required in the medium- to long-term.

Reconfigure York Energy Centre (YEC) Station Service Supply. Upgrading the station supply arrangement for YEC would allow for this facility to remain operational for a wider range of transmission outage conditions. This would have an immediate reliability benefit for local customers and improve the ability to supply load in the area. Cost and in-service timelines will be evaluated following more detailed site-specific analysis.

Develop Northern York TS #1. The need for additional station capacity in Northern York is immediate. Based on existing loads and near-term demand forecast, it is recommended that Hydro One proceed with the acquisition of land, the design, and the construction of a new step-down station by 2029 to serve Northern York Region, in the vicinity the Holland TS area. Typical development costs for these types of stations, including real estate, are generally $60 million.

Develop Markham TS #5. The need for additional station capacity for Markham area was identified in the previous IRRP and reaffirmed with the latest demand forecast to be required by 2029. Alectra has identified a suitable location for the next Markham MTS #5 near the existing Buttonville TS on the P45/46 circuits, and this project is currently under development. Typical development costs for these types of stations, including real estate, are generally $60 million.

Develop Richmond Hill MTS #3. The need for additional station capacity in Richmond Hill is expected by 2030, triggered by new development applications in proximity to the planned Yonge subway extension. Alectra has identified a suitable location for the next Richmond Hill MTS #3, and this project is currently under development. The proposed connection point will be along the V71/75V circuits, near the existing Richmond Hill MTS #1 and #2. Typical development costs for these types of stations, including real estate, are generally $60 million.

Install new breakers along Parkway to Claireville corridor. The existing V71/75P transmission corridor between Claireville TS and Parkway TS are currently loaded at over 600 MW during summer peak, with demand having exceeded 730 MW in 2025. This violates applicable security criteria, and loading is expected to worsen following the connection and loading of Richmond Hill MTS #3 in 2030 and Vaughan MTS #5 in 2033. Estimated costs are $30-35 million.

Reconductor Circuit P45/46 from Parkway to Buttonville TS to support Markham TS #5. Connection and loading of the new Markham MTS #5 is expected to trigger thermal needs on P45/46. Reconductoring of the existing lines will enable full loading of this station, which comes into service in 2028/2029. The cost of reconductoring the entire facility is estimated at $14, though there are opportunities to carry out this work on a phased basis.

Build a new 230kV transmission line along the future Highway 413 corridor (Kleinburg – Kirby Transmission Line). A new, six-km double circuit 230kV transmission line is proposed adjacent to the planned Highway 413 in Vaughan. This new transmission line, referred to as the Kleinburg – Kirby Transmission Link, would create a connection between the existing Kleinburg radial tap, and connect to a point north of the exiting Vaughan MTS #4 along the H82/83V circuits. It would enable the connection and full loading of the next Northern York TS #1 step down station. The cost of this transmission is estimated at $40 million, with an estimated in-service date of 2031-2032. Operation of this facility will require coordination with bulk system upgrades at Kleinburg TS, as under development in the ongoing Bulk System Plan for South & Central Ontario (see Section 8).

2.3 Plan for Medium to Long-Term Needs (2031-2040)

While most recommended actions from this plan are concerned with addressing near term needs (within the next five years), the sections below outline potential medium- to long-term recommendations beyond that horizon. These recommendations, including their targeted in-service dates, are subject to change and will be continuously re-evaluated as planning progresses, based on new information and actual load growth. Early identification of these plans is important to ensure ongoing engagement with potentially affected communities, coordination with broader regional and bulk system planning, and to enable timely implementation when required. It is recommended that the Working Group finalize a long-term adaptive pathway[1] for each subsystem following the completion of this cycle of regional planning.

Develop Vaughan MTS #5. The need for additional station capacity in downtown Vaughan is expected in 2033, triggered by intensified development in the Vaughan Metropolitan Centre (VMC). Alectra is in the process of evaluating potential locations for the next Vaughan MTS #5. The ultimate connection point will likely be along the V71/75V circuits, between the existing Vaughan MTS #1 and the Richmond Hill MTSs. Typical development costs for these types of stations, including real estate, are generally $60 million.

Extend transmission from Buttonville TS and develop Northern York TS #2 and Markham TS #6. The need for additional station capacity in the areas of northern Markham, northern Richmond Hill, and Whitchurch-Stouffville is expected to trigger the need for the development of two new step-down stations, Markham MTS #6 and Northern York TS #2, in the mid 2030s. In order to supply these stations, an approximate 7-km extension of the existing P45/46 circuits is recommended into northern Markham, along an existing, idle transmission right of way. Costs of this transmission could range from $45 million to $175 million, depending on the technology selected during the project scoping and environmental assessment process (e.g., overhead versus underground). This solution would also require development of a new transmission tap to remove Markham MTS #4 from P45/46 supply. The preferred location to supply this station would be the C35/36P circuits, with a likely additional cost of $9 million.

[1] Adaptation pathways are sequences of actions, which can be implemented progressively, depending on future dynamics and uncertain variables.

Monitor future electricity needs in northern York and begin early planning for new infrastructure including Northern York TS #3 and the Holland switching station. Longer-term station capacity needs will likely trigger additional transmission upgrades in Northern York including, at a minimum, a new switching station in the vicinity of Holland Marsh junction to coincide with the development of Northern York TS #3 in the mid 2030s. Switching stations typically cost $200-250 million, though it would also have bulk system benefits. The potential retirement of York Energy Centre post-2035 has also been identified as a key driver of future supply needs and would likely trigger the development of additional infrastructure in the area. The exact nature of options and recommendations will continue to be evaluated and will be informed by ongoing bulk system studies.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a local area – defined by common electricity supply infrastructure – over the near, medium, and long term periods. The result is a plan aimed at ensuring cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. The IESO also carries out bulk system planning and Local Distribution Companies are responsible for distribution system planning. There are inherent linkages in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

3.2 GTA North IRRP Development

The process to develop the GTA North (York) Region IRRP was initiated in October 2023, following the publications of the Needs Assessment Report in July 2023 by Hydro One and the Scoping Assessment Outcome Report in October 2023 by the IESO. The Scoping Assessment recommended that the needs identified for GTA North Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4 Background and Study Scope

This is the third cycle of regional planning for the GTA North (York) Region. This Region is located in southern Ontario and includes all or part of the following cities, towns and townships:

Aurora	Bradford West Gwillimbury	East Gwillimbury	Georgina
King	Markham	Newmarket	Richmond Hill
Simcoe County	Vaughan	Whitchurch-Stouffville	

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries. This Region also includes several Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use:

Alderville First Nation, Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, Métis Nation of Ontario.

Following a Needs Assessment in March 2018 and a Scoping Assessment in August 2018, an IRRP and subsequent RIP were initiated and published in February 2020 and October 2020, concluding the second planning cycle for the Region.

This IRRP develops and recommends options to meet the electricity needs of the GTA North (York) Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, eDSM, distributed energy resources (DERs) transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The GTA North (York) Region covers a large portion of the transmission system in both the Toronto and Essa IESO electrical zones. As all the transmission facilities in the region are included in the scope of this study, it has often been broken up into four subsystems:

- **Northern York Subsystem (B88H/B89H, H82V/H83V) Subsystem**

  This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York Region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and the Chippewas of Georgina Island). York Energy Centre is connected to these 230 kV circuits. This subsystem also serves as a pathway for power to flow between northern and southern Ontario.

- **Kleinburg (V44/V43) Subsystem**

  This subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, as well as some areas of Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.

- **Southern Vaughan-Richmond Hill Subsystem (V75P/V71P, P21R/P22R)**

  This subsystem consists of four step-down transformer stations that supply the southern parts of urban communities in the Markham, Richmond Hill and Vaughan areas.

- **Markham and Area Subsystem (P45/P46, C35P/C36P)**

  This subsystem consists of 6 step-down transformer stations that are located in urban communities primarily in the Markham. This subsystem also serves as a pathway for power to flow across the GTA along the Parkway Belt/Highway 407 transmission corridor.

The Northern York subsystem consists of the following stations:

Brown Hill TS	Armitage TS	Holland TS	Vaughan MTS #4

The Kleinburg subsystem consists of the following stations:

Kleinburg TS	Vaughan MTS #3	Woodbridge TS

The Southern Vaughan-Richmond Hill subsystem consists of the following stations:

Vaughan MTS #1	Vaughan MTS #2	Richmond Hill MTS #1	Richmond Hill MTS #2

The Markham and Area subsystem consists of the following stations:

Buttonville TS	Markham MTS #1	Markham MTS #2	Markham MTS #3	Markham MTS #4

The GTA North (York) IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over the 2024-2043 timeframe (as described in Section 5);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and the performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying the criteria and standards from ORTAC, NPCC, and NERC.
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
- Confirming identified asset replacement needs and timing with the transmitter and LDCs.

- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wire alternatives including eDSM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near-, medium-, and long-term needs; and communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the GTA North (York) Region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of eDSM and DG. The LDCs in the region provided both a winter and summer 20-year forecast that incorporates organic growth and growth associated with drivers like electrification (e.g., heating load and electric vehicles).

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum.

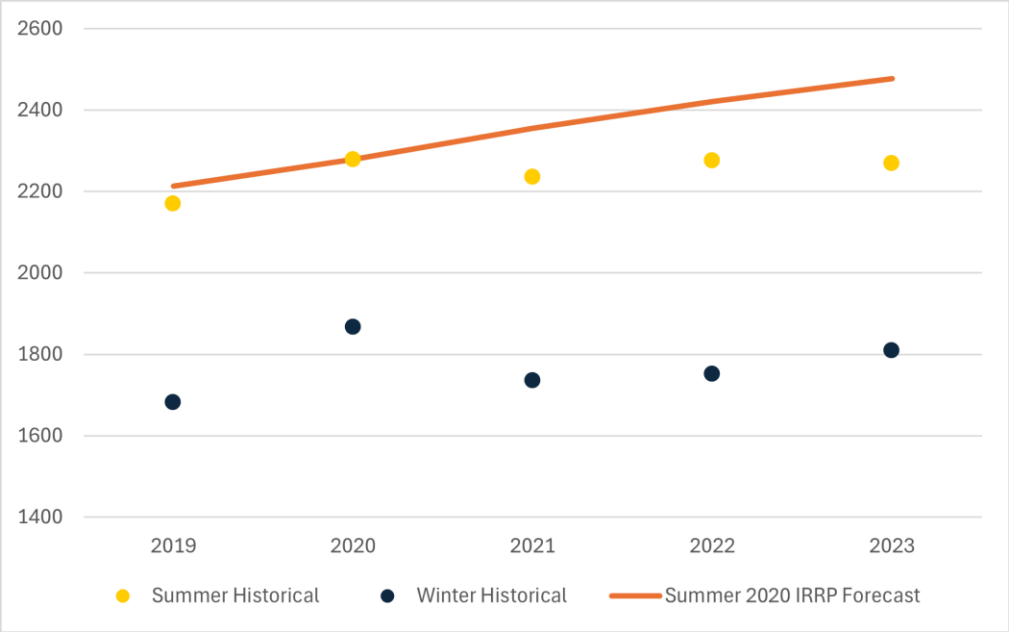
The regional planning process also considered non-coincident peaks which refers to each station's individual peak, regardless of whether these peaks occur at different times. Non-coincident peaks are used to understand the potential needs of the stations.

5.1 Historical Demand

Peak electricity demand within GTA North has historically occurred in the summer season. Figure 2, below, shows both the winter and summer coincident gross normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for the GTA North region. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand, as they are more appropriate for evaluating growth trends. For context, Figure 2 also includes the summer peak demand forecast for the same years from the 2020 IRRP.

The gross weather-corrected demand for the GTA North region has averaged 2,245 MW in the summer and 1769 MW in the winter over the last five years preceding the IRRP start date (2019-2023).

Figure 2| Summer and Winter Historical Weather-Corrected Coincident Peak

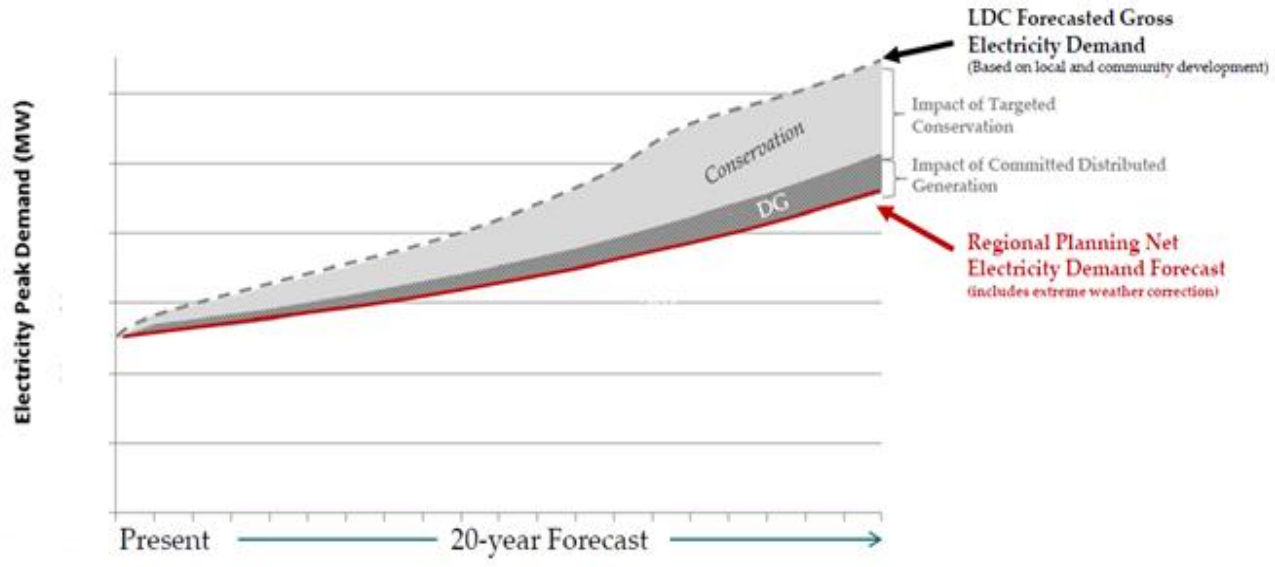


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast is illustrated in Figure 3. A gross demand forecast, which assumes the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), was developed by the LDCs. This forecast was then adjusted to reflect the expected impact of extreme weather conditions to produce a reference forecast for planning assessments. Extreme weather conditions, as defined by the IESO, assume the worst observed weather over the previous 30 years. The forecast was then modified to reflect the expected peak demand impacts of provincial demand side management programs and DG contracted through previous provincial programs, such as renewable Feed-In Tariff (FIT) and microFIT standard offer programs. This net demand forecast was used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The load forecast methodology is also informed by the Load Forecast Guideline for regional planning, which was formalized by the OEB's Regional Planning Process Advisory Group.

Figure 3| Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

LDCs are responsible for preparing the gross demand forecast as they have the most direct understanding of future local demand growth and drivers, informed by involvement with their customers, connection applicants, municipalities and the communities which they serve. Gross demand forecasts were prepared by the participating LDCs at the station level, or at the station bus level for multi-bus stations. The gross demand forecast generally accounts for increases in demand from new or intensified development, plus known connection applications. In addition, when producing the gross demand forecast, the impact of existing DG was removed, as DG impacts are accounted for later (see Section 5.5). More details are provided in Appendix B.

The LDCs' forecasts considered the appropriate municipal plans for their service territories. The LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices (natural conservation), but not for the impact of future DG or new demand side management activities (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes normal weather conditions (e.g. median weather, expected 1 in 2 years), and provided station level loading at the time of the regional peak.

The IESO typically carries out demand forecasting at the provincial level, which is more applicable for bulk system analysis than regional. More details on the LDC load forecast assumptions can be found in Appendix B.

5.4 Contribution of Electricity demand Side Management

Electricity demand side management (eDSM, formerly Conservation and Demand Management or CDM) is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak demand and has become an integral component of provincial and regional planning. Electricity savings from demand side management is achieved

through a mix of efficiency codes and standards, as well as eDSM program-related activities. These approaches complement each other to maximize results.

The estimated demand reduction from codes and standards is based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (e.g., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities was based on the IESO's 2024 Annual Planning Outlook eDSM savings forecast informed by the then current 2021-2024 Conservation and Demand Management (CDM) Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs assumed to be consistent with 2021-2024 framework savings levels. Through the 2021-2024 CDM Framework the IESO centrally delivered programs under the Save on Energy brand s to serve business and residential customers, as well as Indigenous communities. Following finalization of the IRRP's demand forecast, the Ontario government provided the IESO with the directive for the 2025-2036 Electricity Demand Side Management Framework, which expands the scale and scope of the Save on Energy programs, including launch of the Home Renovations Saving program for residential customers and new incentives for rooftop solar for both residential and business customers. Higher savings targets under the new framework may impact the timing or reduce the magnitude of identified needs.

Figure 4 and Figure 5 show the estimated total yearly reduction to the demand forecast due to demand side management (from codes, standards, and eDSM programs). Additional details are provided in Appendix B.

Figure 4| Summer Peak Demand Reduction Due to Demand Side Management

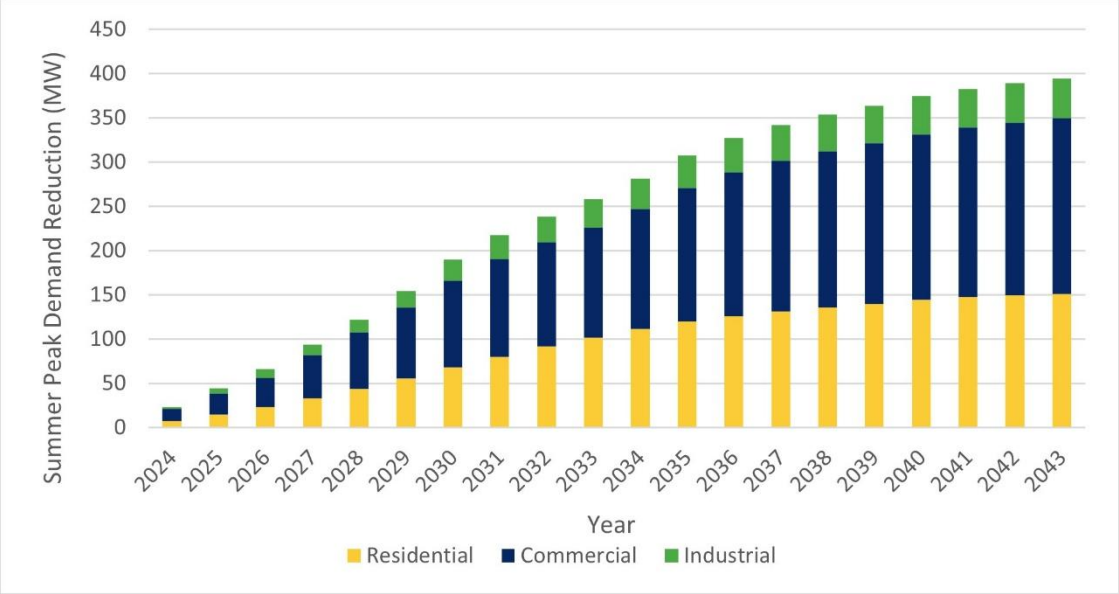
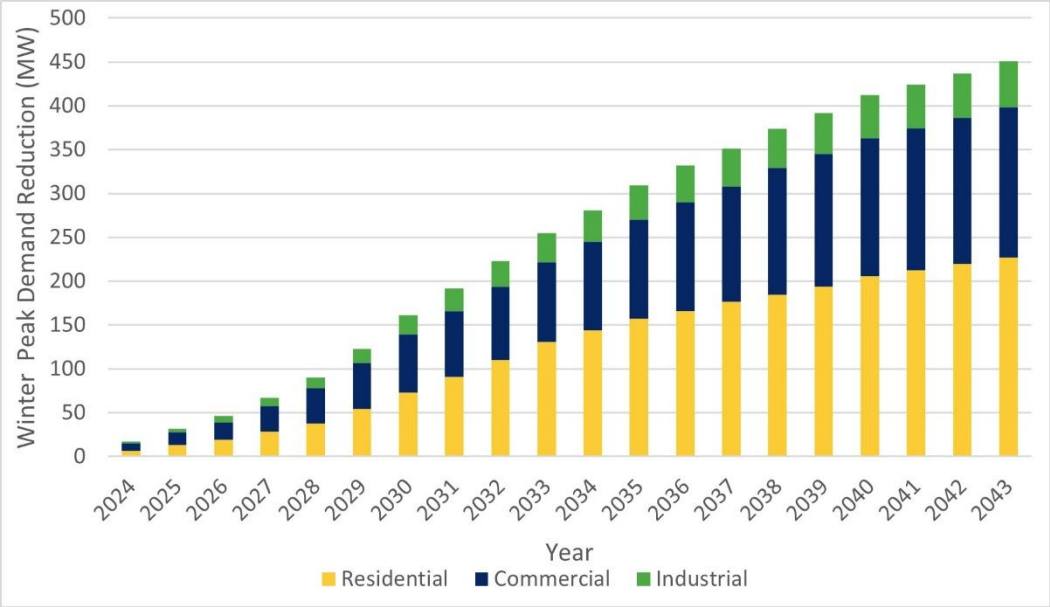


Figure 5| Winter Peak Demand Reduction Due to Demand Side Management

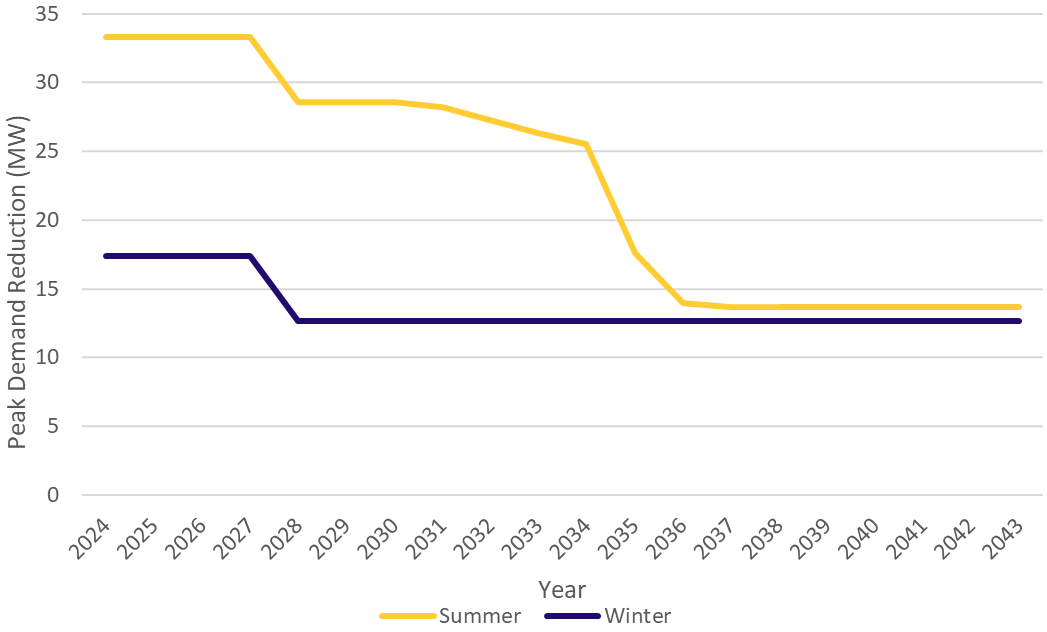


5.5 Contribution of Distributed Energy Resources to the Forecast

In addition to demand side management programs (which can include behind the meter DG), DG is forecasted to offset peak-demand requirements. The introduction of Ontario's FIT and microFIT Programs increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and the associated contribution factor assumptions can be found in Appendix B. The total contracted installed DG capacity in the GTA North Region is composed of a mix of renewable and non-renewable sources.

Figure 6 shows the estimated impact of DG on the GTA North Region demand forecast. The forecasted impact declines as existing FIT and microFIT contracted facilities reach the end of their contract terms throughout the late 2020s and into the mid-2030s.

Figure 6| Peak Demand Reduction Due to Distributed Energy Resources



5.6 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is traditionally a region-wide coincident forecast, meaning that each station forecast reflects its expected contribution to the regional peak demand. This supports the identification of need dates for regional needs driven by more than one station.

The planning forecast is produced from two main steps: adjusting for extreme weather and converting to a net forecast.

The first step is to adjust the coincident gross normal weather forecast for extreme weather conditions. The weather correction methodology is described in Appendix B. This results in a coincident gross forecast which assumes extreme weather. Two separate weather scenarios were prepared; one for extreme summer conditions, and one for extreme winter conditions.

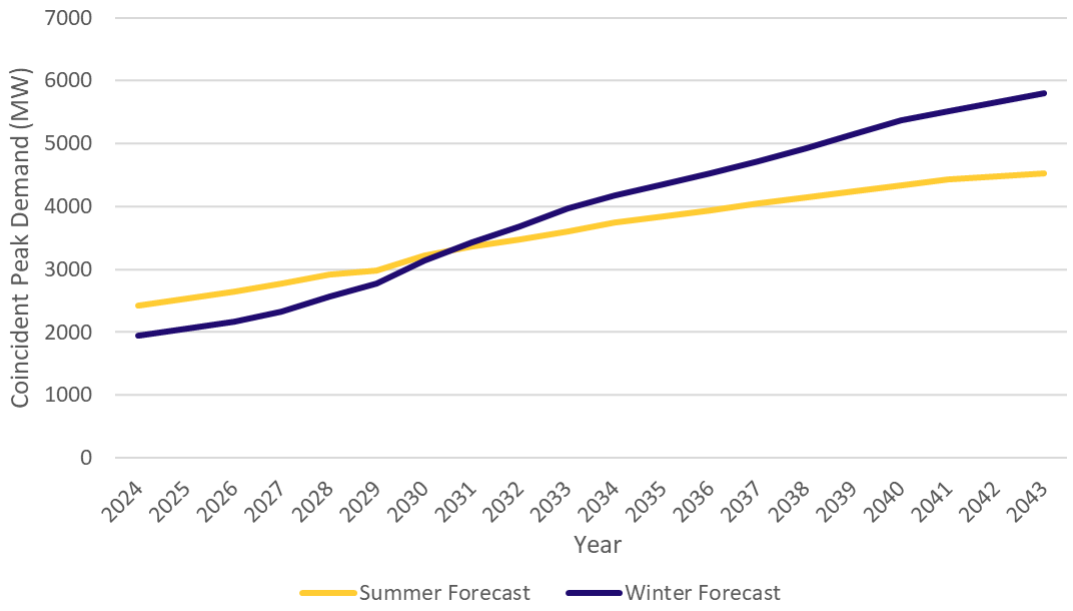
Historically, York Region has experienced its highest loading conditions during summer months, driven by air conditioning loads. This is consistent with overall provincial peak conditions, which often occur on the same day and on similar, late afternoon hours as York Region. However, the expected adoption of electrified heating, namely heat-pumps, is forecast to significantly increase winter demand over the coming decades. While there is uncertainty around the rate of uptake, technology types, and operational decisions, a winter demand forecast was also developed to study the impact of higher winter peak growth rates. Both summer and winter peak forecasts were considered in this IRRP.

The last step is to adjust the resulting coincident gross extreme weather forecast for the impact of DG and demand side management. This is done by subtracting the forecasted DG and electricity demand side management (as described in the above Sections) from the coincident gross extreme weather forecast. This results in a coincident net extreme weather forecast, which is the "planning" forecast used to identify needs. Separate impacts were calculated based on typical summer and

winter contributions of the load modifying resources during the peak hours, based on technology type.

The coincident net extreme weather forecasts ("planning" forecasts) for GTA North Region are shown in Figure 7.

Figure 7| GTA North Region Net Extreme Weather Coincident Forecast



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles (8,760 hours per year over the 20-year forecast horizon) for various collections of stations were developed to better assess the potential for non-wire alternatives to address needs. These profiles were used to quantify the magnitude, frequency, and duration of needs, as described later in Section 7. The profiles were based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year.

Additional details on how load profiles were created can be found in Appendix C. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes through an Annual Working Group Meeting and as part of implementation of the plan.

5.8 Uncertainty in the Demand Forecast

The forecast for GTA North considers various growth drivers that each have an associated degree of uncertainty. The uncertainty in the regional planning process is managed through a flexible and adaptive approach that emphasizes monitoring, scenario analysis, and preserving future options. Development is only triggered when specific conditions are met within the designated development window, ensuring that investments are made based on clear and timely signals.

Based on the current forecast, the possibility of significantly higher winter growth rates may drive winter conditions to become more "limiting", or determine station capacity need dates, within the 2030s. This is in spite of winter ratings for transmission lines and stations being higher in winter than in the summer.

However, these winter forecasts also carry higher uncertainty due to factors like technology adoption and operational decisions, making them less reliable for immediate investment planning. Unlike summer peaks, which are largely informed by existing customer behaviour and technologies (notably widely used air conditioning), winter peaks assume continuous shifting of behaviour through adoption of electric heating and phase-out of existing gas heating. The adoption of electric heating is currently mainly driven through various level of government policies, economic incentives, and customer preferences. Due to the challenges with assuming how policy and technology will evolve over 20 years, the longer-term winter forecasts (2031-2043), have a greater level of uncertainty associated with them. They are considered in this IRRP for determining measures to preserve future options, but emphasis was placed on summer needs when determining timing of the required reinforcements.

Summer peak demand was used as a more certain foundation for guiding investment decisions, while actual winter demand trends will continue to be closely monitored to inform future adjustments. This strategy lays the groundwork for the plan to evolve cycle-to-cycle as clearer patterns emerge.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of established power system reliability standards and criteria (IESO ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards), the Technical Working Group identified electricity needs in the near-term, medium-, and long-term timeframes. Near-term needs are expected to emerge within 5 years, and/or where immediate action is required. Medium- and Long-term needs are expected to emerge more than 5 years out, and immediate actions are not generally required, unless to preserve future options.

These needs are categorized according to the following:

Station Capacity Needs describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during periods of peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by the thermal ratings of downstream or upstream equipment, e.g., breakers, disconnect switches, medium-voltage bus or high voltage circuits; or, by voltage drop limitations, which are independent of thermal ratings.

Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the load meeting capability (LMC) of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using industry standard power system simulations.

Asset Replacement Needs are identified by the transmitter, informed by asset condition assessments, based on a range of considerations such as equipment deterioration due to age, weathering, heat stress or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Asset replacement needs identified in the near-term timeframe would typically reflect condition-based information, while replacement needs identified in the longer term are often based on the equipment's expected service life. As such, any recommendations for medium- or long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

Load Security and Load Restoration Needs describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power

to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements for Ontario are described in Section 7 of the ORTAC.

Technical study results for the GTA North IRRP can be found in Appendix E. The needs identified are discussed in the following sections and are shown in the proceeding sections.

6.2 Near-Term Needs (2026-2030)

6.2.1 Station Capacity Needs

Step-down station capacity needs are determined by comparing the station peak demand forecast to the facility's LTR. In many cases, need dates can be deferred by transferring load at a station expected to reach or exceed its LTR to another nearby station that has available capacity. Feasible load transfers are already assumed in the station-level demand forecast based on input from LDC members of the Technical Working Group about the transfer capabilities and typical loading practices.

Stations will typically have a lower LTR for summer months than for winter months, as colder ambient temperatures allow more power to flow through equipment without overheating transformers and other station equipment. When a station reaches its annual peak during summer months, this becomes the only forecast scenario which requires study, as it is the most limiting condition. When stations reach their peak during winter months, however, both summer and winter forecasts should be considered as the higher winter loading may be offset with higher ratings, and either season could ultimately be the more "limiting" scenario.

When a step-down station's capacity is reached (summer or winter), and after feasible load transfers are accounted for, options for addressing the need include reducing peak demand in the supply area (i.e.., through EE or DERs) or building new step-down transformer capacity to serve incremental growth.

Typically, where there is sustained new urban growth and development in an area, measures to reduce the peak demand cannot defer or avoid the need for new station capacity indefinitely. Planning recommendations are informed by comparing the cost of these measures to the value of deferring construction of a new or expanded station.

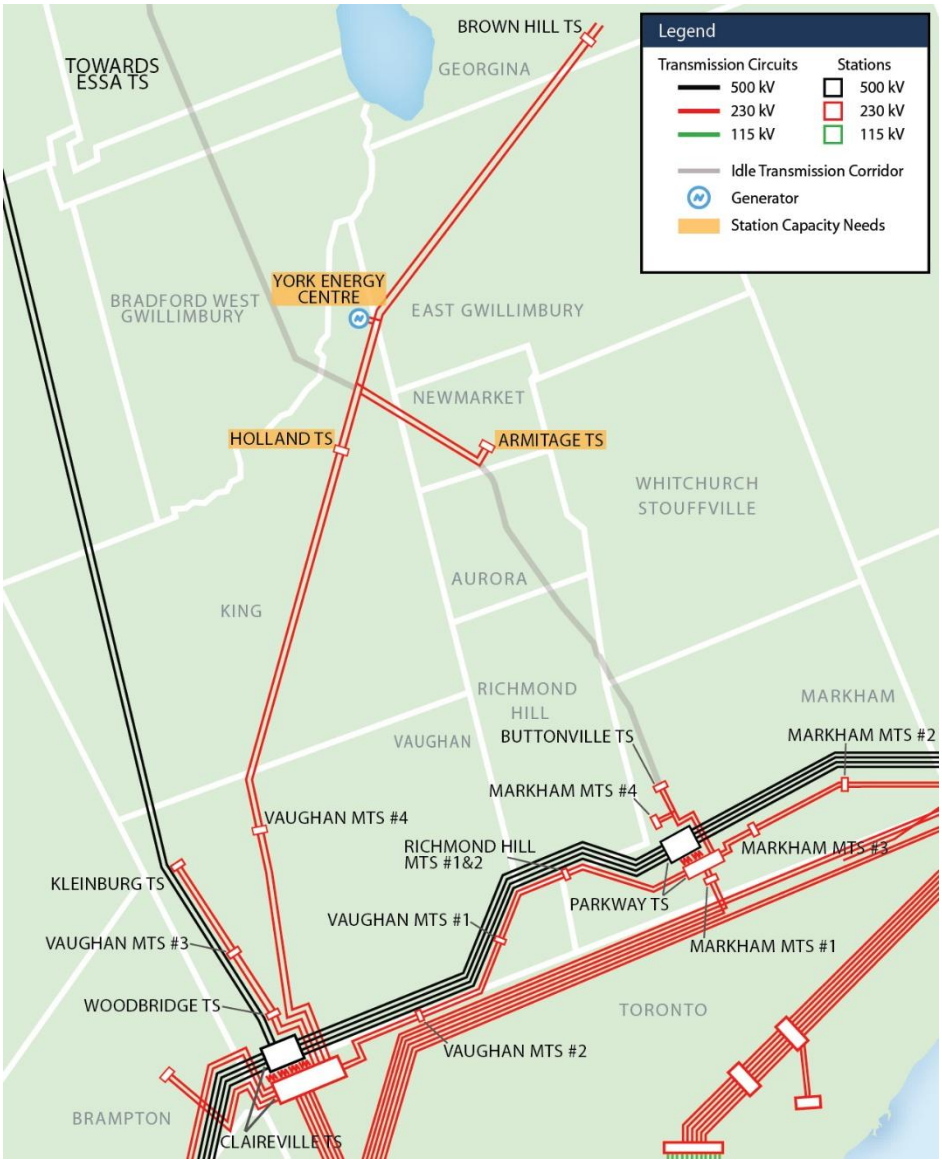
Before a new step-down station can be built, a suitable location must be identified. Stations must be connected to a part of the broader transmission system with enough incremental capacity available to reliably supply the station load. The station must also be located close enough to the anticipated customer demand to ensure that the distribution network is capable of supplying customers reliably.

Additional information on specific station capacity needs anticipated in GTA North in the near term are provided in the sections that follow.

6.2.1.1 Northern York

Northern York Region[2] electrical service territory is currently supplied by four step-down stations. Armitage TS and Holland TS are located in proximity to Newmarket and Holland Marsh, respectively, while Brown Hill TS is located further north, near Georgina, and Kleinburg TS further south, at the border between Caledon and Vaughan. Recent load growth within northern York has been served through Armitage TS and Holland TS, and forecast growth continues to be concentrated in the areas supplied by these two stations.

Figure 8| Northern York Station Needs



Although electrical service territories do not correspond directly to municipal boundaries, Armitage TS and Holland TS generally supply Newmarket, Aurora, East Gwillimbury, and parts of Bradford-West Gwillimbury, King Township, and Whitchurch-Stouffville.

[2] Term is used to refer to areas served by electrical infrastructure in the northern half of the North GTA planning area. While this roughly aligns with northern York Region, it is also inclusive of parts of neighbouring municipalities such as Bradford West Gwillimbury (county of Simcoe)

Brown Hill TS, being further north and east, supplies mainly rural areas with lower anticipated growth rates, though there is potential for longer term growth within its service territory, primarily Georgina and East Gwillimbury.

Kleinburg TS primarily serves loads in and around Bolton, as well as some rural loads throughout King township and Caledon. Supply options to meet growth in the Kleinburg TS service area, primarily concentrated in Bolton and Caledon, are currently being studied in the GTA West IRRP, though outcomes have been factored into system models used in this study.

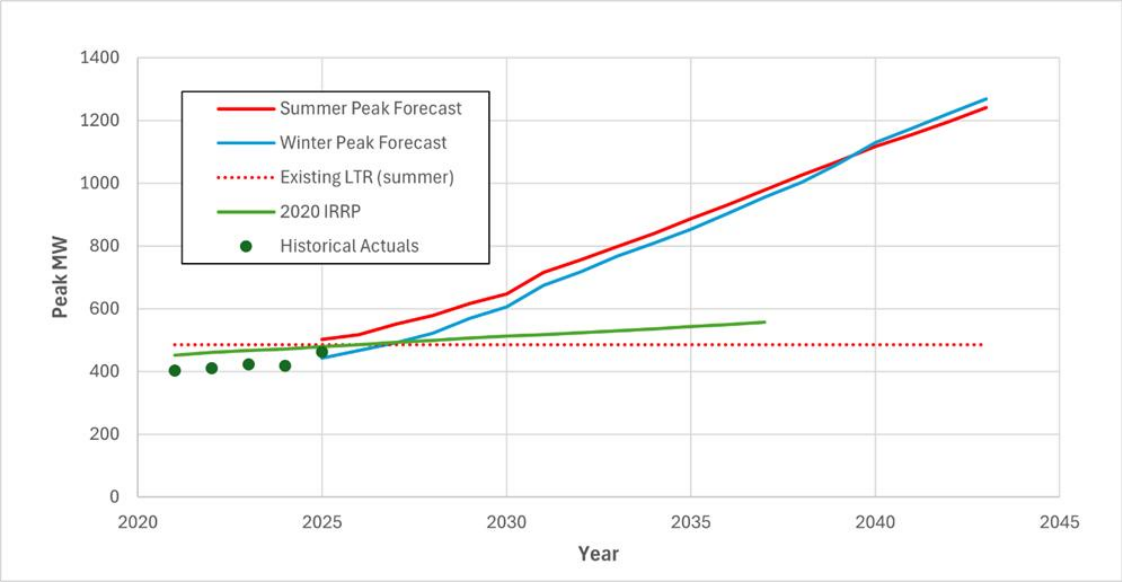
Of the four existing step-down stations, all but Brown Hill TS are currently loaded close to the maximum capability. Due to the distance between Brown Hill TS and the Armitage TS and Holland TS service territory, Brown Hill TS is not a suitable facility for transferring excess load without incurring significant distribution costs. The combined station capacity need in Northern York is summarized in Table 4. There is an immediate need to supply an additional 16 MW of demand and thus need increases to 750 MW by the end of the study forecast period.

Table 4| Northern York Station Capacity Needs

Stations	Timing	2025	2035	2043
Holland TS Armitage TS	Immediate	16 MW	400 MW	755 MW

The combined summer peak demand forecast of the approximate Armitage TS and Holland TS service territory is shown in Figure 9 along with their combined maximum rated station capacity. Also shown for comparison is the demand forecast from the 2020 York IRRP.

Figure 9| Northern York Demand Forecast

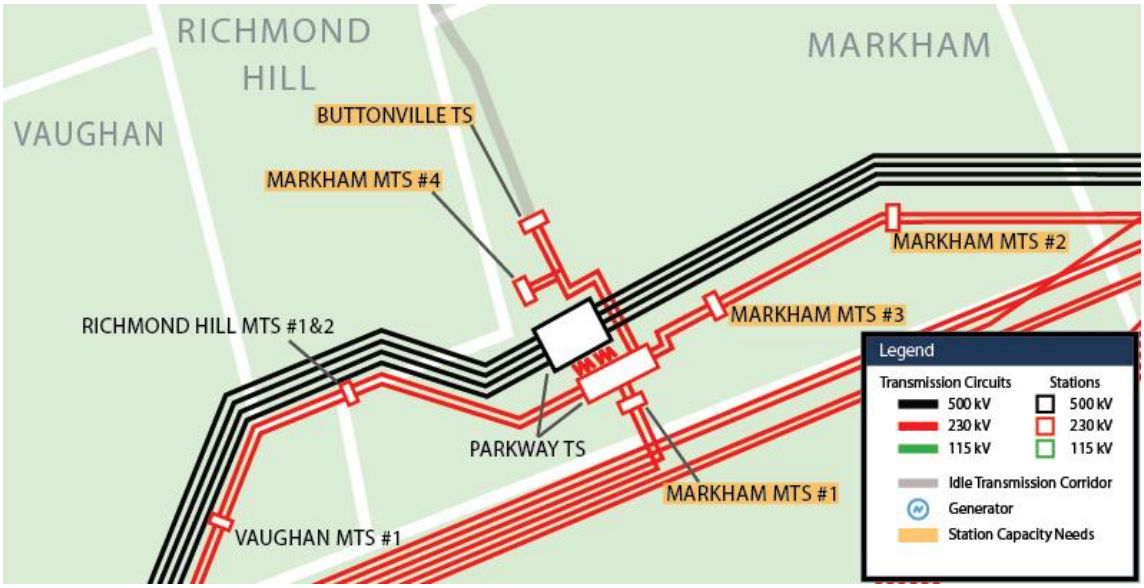


The previous IRRP had identified Northern York as having station capacity needs emerging in 2027. The development of Northern York TS #1 was recommended to address this need with a targeted in-service date of 2027, and a connection point in the vicinity of the existing Holland TS. However, based on revised demand forecasts, the need has been advanced and is now considered immediate.

6.2.1.2 Markham

Due to the ability to transfer loads between their southern stations, Alectra has typically alternated construction and loading of new stations between Markham and Vaughan to serve loads within their southern York service territory (roughly aligned with Vaughan, Richmond Hill, and Markham).

Figure 10| Markham and Area Station Needs



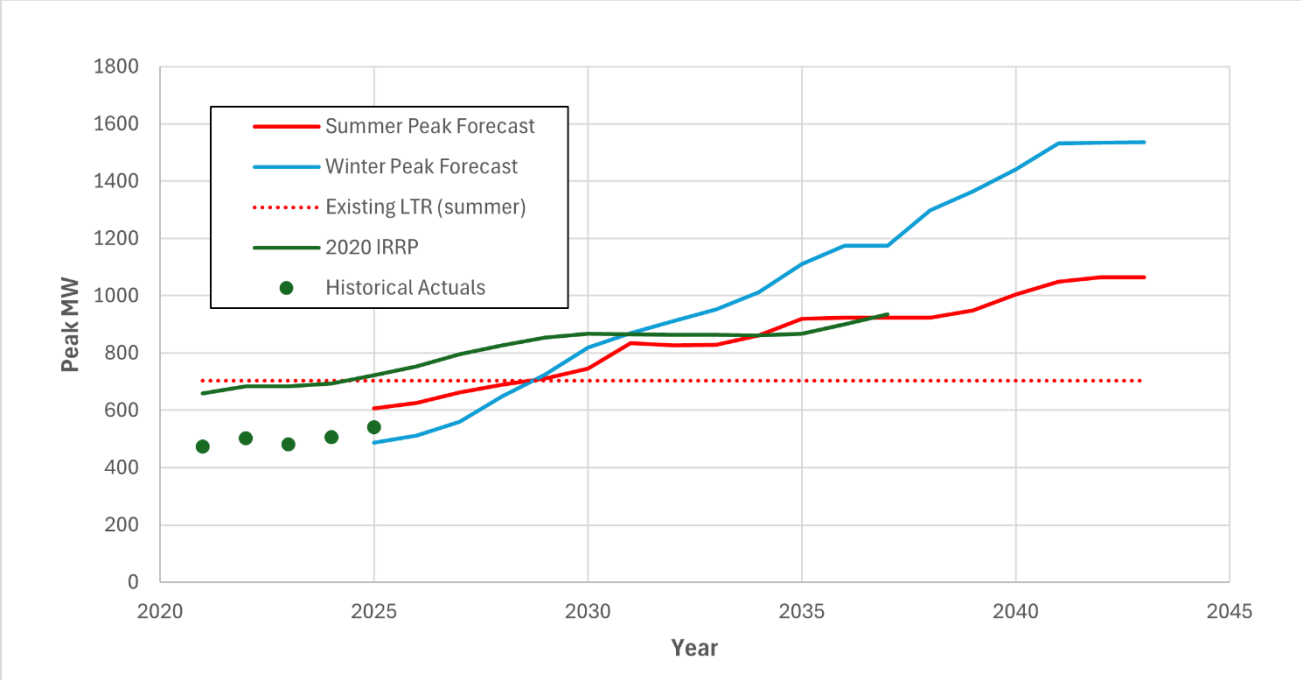
The last stations placed in service for southern York Alectra customers was Vaughan MTS #4 in 2018, preceded by Markham MTS #4 in 2011. Both of these stations had been located along the two possible transmission sections which span north from the main transmission supply path along the southern border of York region (adjacent to Highway 407). This had been done to meet the challenge of connecting increasingly northern development despite a transmission system that remains concentrated to the south.

Table 5| Markham and Area Station Capacity Needs

Stations	Timing	2025	2035	2043
Markham MTSs	Near-term	0 MW	241 MW	426 MW

The combined summer peak demand forecasts of Markham area stations (including Markham MTS #1, #2, #3, #4, and Buttonville TS) are shown in Figure 11, below, along with their combined maximum rated station capacity. Also shown for comparison is the equivalent demand forecast from the 2020 York IRRP.

Figure 11| Markham and Area Demand Forecast



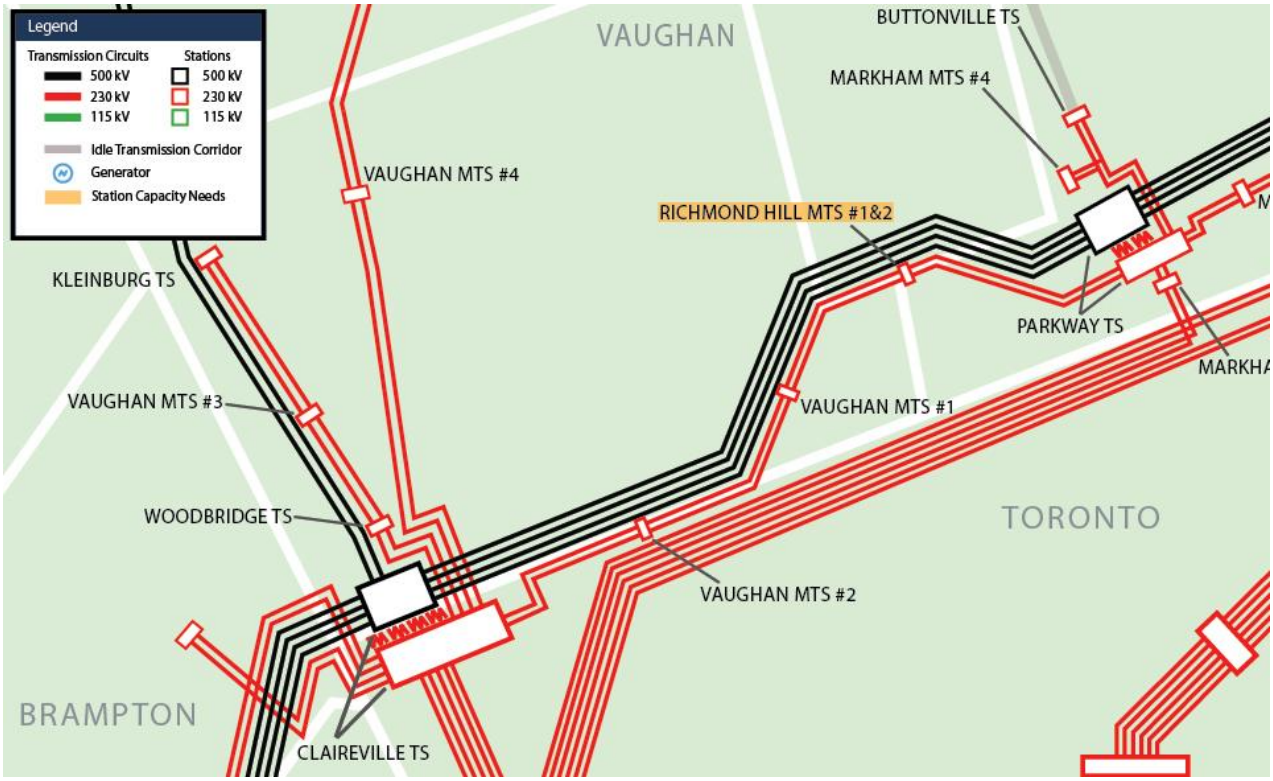
Periods of the forecast which show a relatively flat profile indicate the years in which incremental growth is expected to be met through allocation to a future Vaughan area station, resulting in no incremental growth being applied to Markham area stations. The next Vaughan area station is not expected to be required until the early 2030s (See section 7.4.1.1).

In addition to meeting total supply capacity needs of customers, addressing stations needs will also require consideration of the suitable location to site future stations, to ensure proximity to end use customers. Locating step down stations too far from customers can result in lower customer reliability and power quality, and additional distribution costs to run feeders to connect customers. Finding suitable locations to site stations to serve southern York customer loads has been increasingly challenging in recent years, as limited transmission paths exist north of the southern border.

6.2.1.3 Richmond Hill

Richmond Hill is currently the site of two step-down stations, Richmond Hill MTS #1, and Richmond Hill MTS #2. Both stations have been loaded to capacity for most of the past few summers, with new load growth in Richmond Hill supplied via load transfers to stations in Vaughan or Markham.

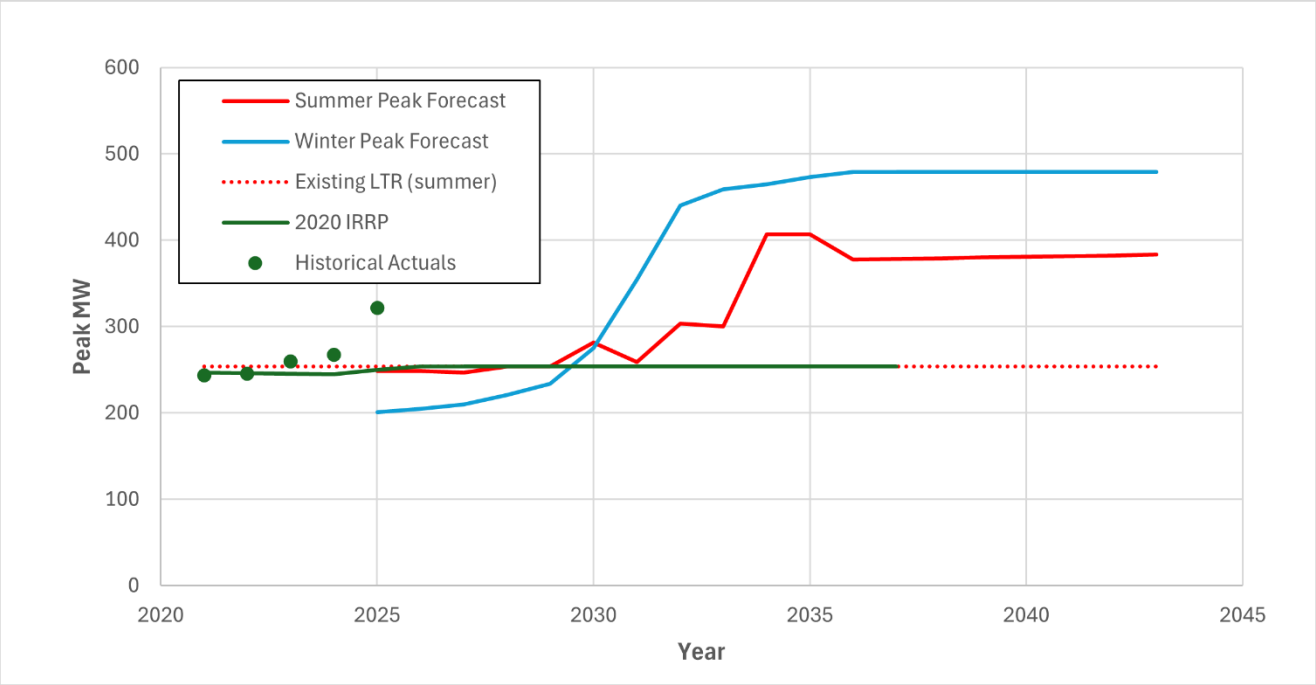
Figure 12| Richmond Hill Station Capacity Needs



Although Richmond Hill has been managing similar complexities of providing supply to increasingly northern development, a new area of intensification is emerging in the southern part of this municipality. The area, roughly corresponding to the Richmond Hill Centre (RHC) Urban Growth Centre, is the result of the planned extension of the Yonge subway into Richmond Hill and Markham. Significant, intensified development, with associated electrical demand, is anticipated in the vicinity of these new development zones.

Figure 13 shows the relatively steady loading at the existing Richmond Hill stations in recent years, and the expected impact of new growth over the coming years in the surrounding area. Growth anticipated around the new subway extension has been included in this grouped area, while growth further north (better served through northern stations in Markham and Vaughan) has not been included. Note a large jump in actual peak demand for the summer of 2025 is the result of load transfers supplied by Richmond Hill TSs during emergency conditions. The irregular loading of the summer forecast is the result of anticipated load shifting as new stations come online.

Figure 13| Richmond Hill Demand Forecast



The need for a new step-down station in Richmond Hill was not identified in the previous IRRP published in 2020. Instead, this new need is in direct response to new, intensified development in proximity to the planned Yonge subway extension. The anticipated need date for additional station capacity is 2030.

6.2.2 Supply Capacity Needs

Supply capacity needs are often described in terms of a system's Load Meeting Capability (LMC), which is the maximum amount of demand that can be supplied by a transmission circuit or group of circuits, before specific system criteria are violated. Where the demand forecast is expected to exceed the LMC, mitigation measures will be required. These can vary from lowering load to at or below the system LMC (through NWA or similar measures), upgrading the system to a higher LMC, or, depending on the type of criteria, arming load rejection (to automatically disconnect loads during a contingency to keep total demand below the LMC).

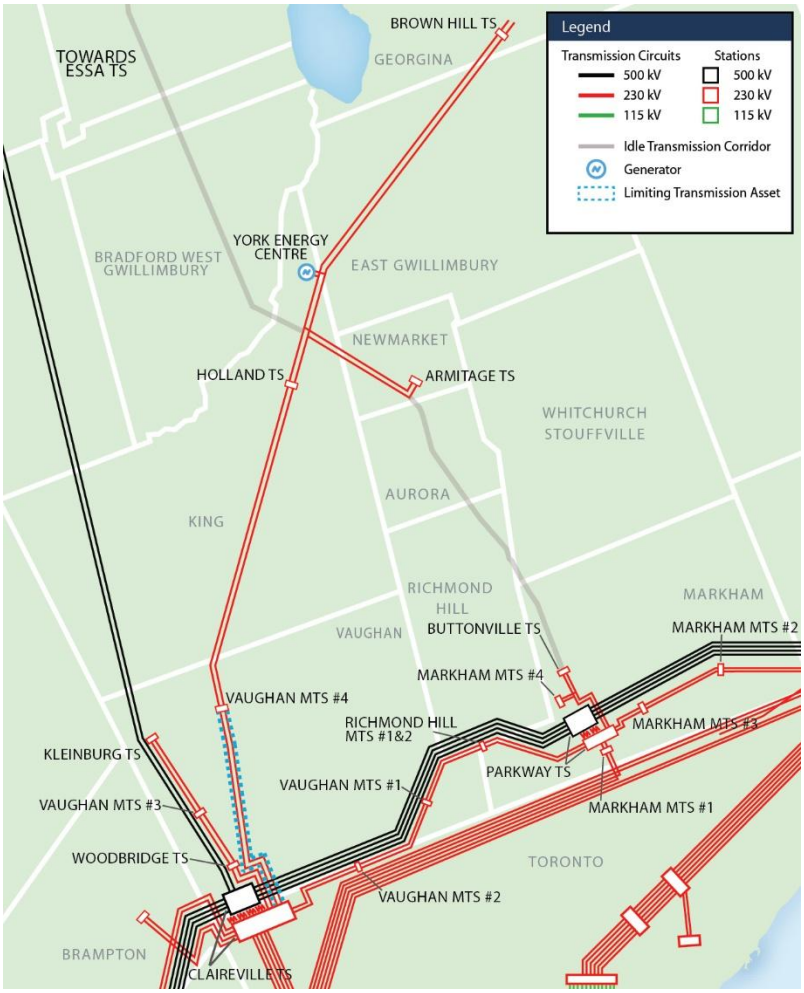
Supply capacity needs are determined based on the system performance following the simulation of standard criteria or "contingency events" during peak demand conditions. The loss of a single transmission element is referred to as an N-1 event, while simultaneous loss of 2 elements is N-2. Following N-2 events, the criteria allow for customer load loss up to a certain amount in order to keep loading on the remaining transmission facilities within acceptable limits. These "load rejection", or LR events, represent lower reliability for customers, but only in the event of a major transmission outage occurring during peak loading conditions. Although a certain amount of LR is permitted in these cases, it is not a preferred outcome, particularly when designing solutions to fully address

system needs. As a result, this study distinguishes between needs and solutions required to meet N-2 conditions both with and without LR. No load loss is permitted following N-1 contingencies.

6.2.2.1 Northern York

The Northern York electrical region is primarily supplied by one double-circuit 230 kV transmission line, which transfers power stepped down from the bulk 500 kV network at Claireville TS, and transports it northward to supply the step-down stations of Northern York. The line also directly supplies large customer connections and will supply a planned Go Transit power traction station. A second supply source connected to these 230 kV circuits is the York Energy Centre (YEC) peaker plant. This 400 MW gas-powered facility generates power when local demand exceeds the ability of the existing transmission line to reliably supply local needs and can also be dispatched to ensure provincial resource adequacy in high-demand periods. Due to its ability to rapidly respond to sudden changes in demand, YEC is useful for balancing output from intermittent energy sources, or to respond quickly following system contingencies and outages.

Figure 14| Northern York Supply Capacity Needs



There are two main double-element contingencies that result in the thermal overload on H82/83V based on the current demand forecast.

- The loss of T1B breaker at Holland TS causes the simultaneous loss of H83V and the York Energy Centre from service as YEC's stations service is supplied from Holland TS. Due to the loss of YEC's station service, approximately 400 MW of capacity is also lost. Due to these conditions, the companion circuit, H82V becomes overloaded in 2025.[3] Note that the recently commissioned Battery Energy Storage System (BESS) at YEC remains in service during this outage and improves the LMC of the system by approximately 50 MW.
- A breaker failure at L82L88 at Holland TS simultaneously removes circuits H82V and B88H from service. While this does not remove YEC from service, under normal operating conditions it will remove the G1 unit, and up to ~200 MW of generation. The BESS unit, which is connected through the G1 yard, would also be removed from service during this contingency. At peak demand, due to these conditions, the companion circuit, H82V would become overloaded in 2027.[4]

Additional Needs in Northern York – Under and Over Voltage

Undervoltage

In the event of the simultaneous loss of H82V + H83V, this sub-system becomes radially supplied from the north, via Minden TS through B88/89H. Due to the length of B88/89H, especially in high load conditions, the subsystem's voltage drops to unacceptable levels. With the loss of H82/83V, York Energy Centre is unable to provide voltage support due the station supply coming from Holland TS (which is lost by configuration following this contingency).

In addition to unacceptably low voltage levels within York region, under high load conditions this contingency would cause overloads on sections of the M6E circuits running between Essa TS and Minden TS, as this becomes one of the few remaining routes for power to flow into northern York.

The YEC BESS is not removed from service by this contingency, and while it does help provide support, it is not sufficient to address voltage needs in Northern York or overloads on M6E. Based on the current forecast, this need materializes in 2025.[5]

Overvoltage

The simultaneous loss of B88H and B89H removes Armitage TS, Brown Hill TS, and YEC from service, and leaves a lightly loaded radial circuit from Minden TS supplying the relatively smaller load centres at Beaverton TS and Lindsay TS. Due to the length of the circuits from Minden TS towards Northern York, especially in lighter load conditions, the subsystem is like to experience an unacceptable increase in voltage. This is further exacerbated by the presence of the use of capacitor banks at Beaverton TS and Lindsay TS, which help support low voltage conditions when the full system is in service and voltages are at risk of running low. This need had been identified within the last IRRP. Although actions have not yet been taken to fully address it, unacceptably high voltages haves not been observed within the area

[3] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

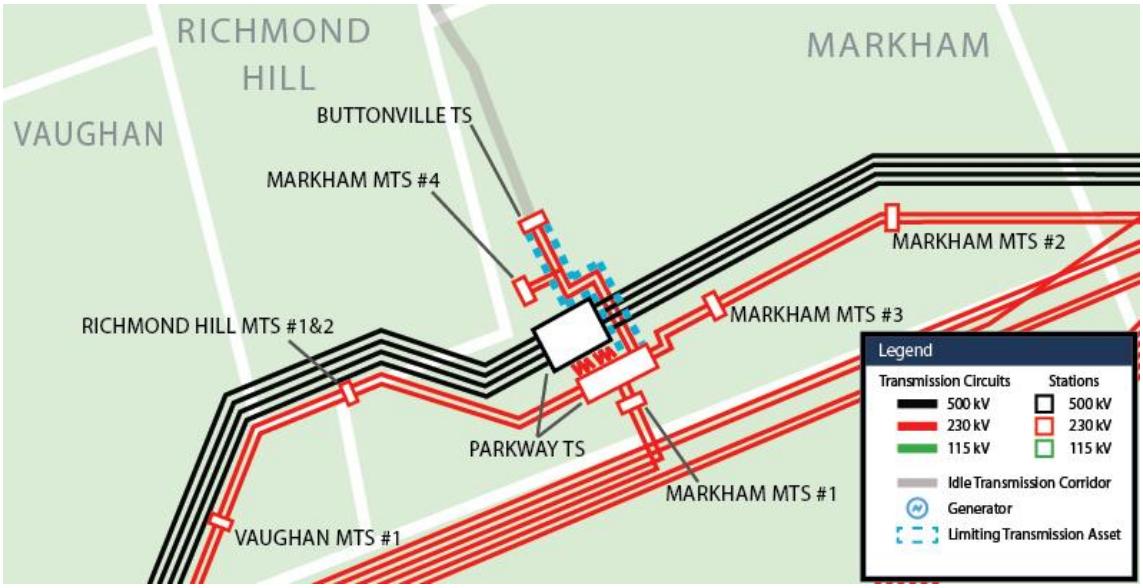
[4] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

[5] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

6.2.2.2 Markham and Area (Parkway-Buttonville)

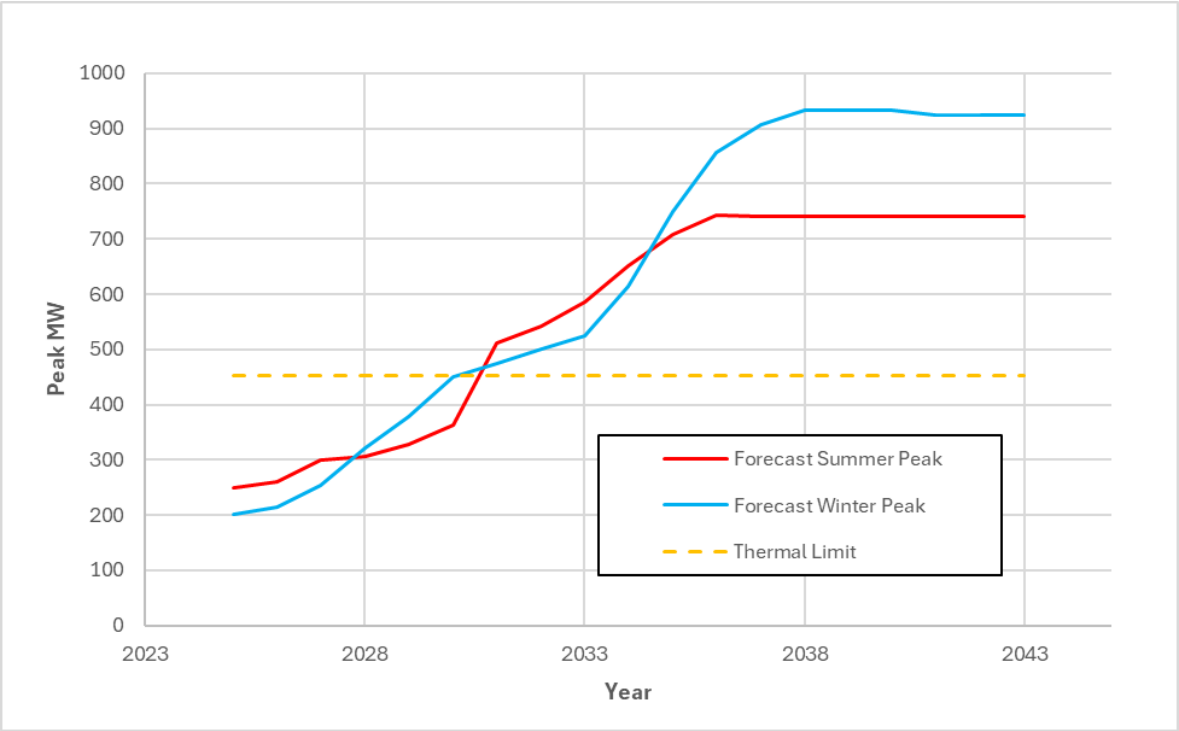
The Parkway – Buttonville radial circuit is a two circuit (P45/46), 230 kV transmission tap which currently stretches approximately 6 km north of Parkway TS into Markham region. Power stepped down from the bulk 500 kV system at Parkway TS and flows north to supply two step-down stations, Markham MTS #4 and Buttonville TS.

Figure 15| Parkway-Buttonville Supply Capacity Needs



As the only existing northern link into Markham region, this circuit is expected to be loaded with a new step-down station, Markham MTS #5, recommended in the previous IRRP. The maximum loading on this circuit is approximately 450 MW and is based on the thermal limit of the companion circuit when one of either P45 or P46 is out of service. The forecast load to be served by this circuit is shown in the graph below, along with the existing transmission thermal limit:

Figure 16| P45/46 loading forecast for southern section, and Thermal Limit



The existing transmission circuits are roughly sufficient for serving both existing stations to their summer LTR, plus an additional 133 MW from a new step-down station. Based on the planned in-service date of Markham MTS #5, and loading rate, this need is expected to be reached in 2031.

6.2.3 Load Security and Load Restoration Needs

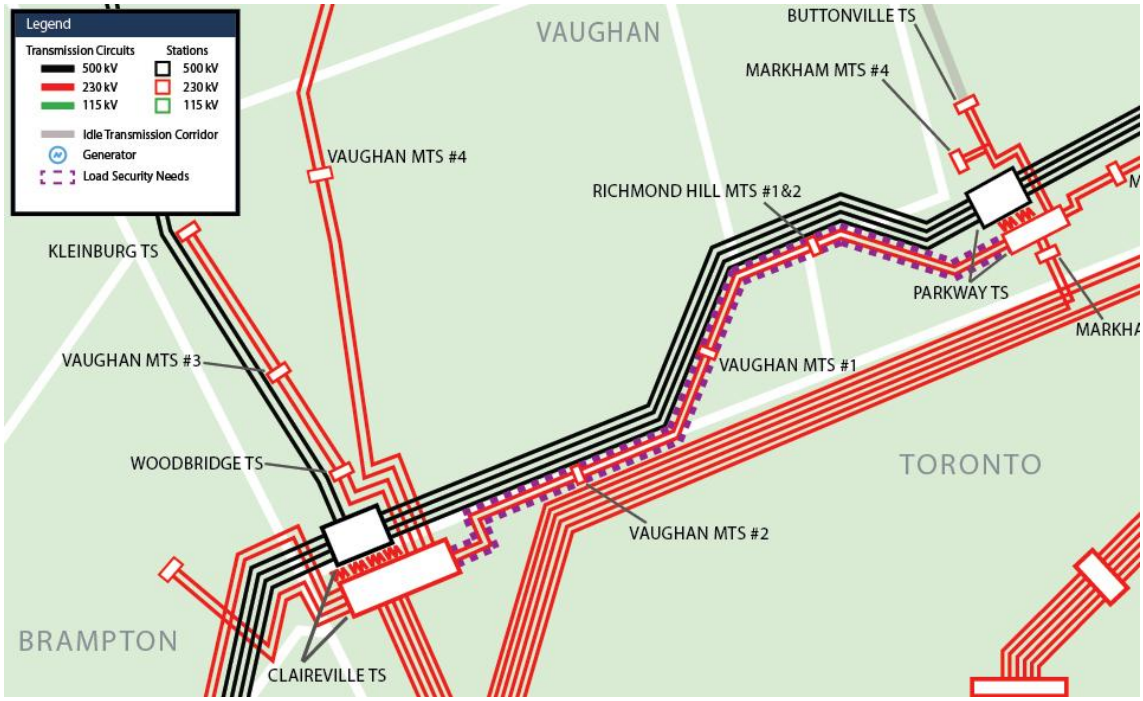
Load Security and Load Restoration needs refer to the level of reliability customers can expect when major contingencies occur. Security refers to the maximum amount of load which can be simultaneously lost following any of the defined planning contingency types as specified in ORTAC. In general, no more than 600 MW is permitted to be lost after an N-2 contingency through a combination of loss by configuration (from loss of supply to a station), or Load Rejection (automatically tripped load to keep remaining facilities within their applicable loading limits). Load Restoration refers to how quickly load can be reconnected after a major transmission outage. It can be determined by factors such as the distribution network's ability to transfer loads to other nearby stations, remoteness, and the nature of the interruption/equipment affected (e.g., overhead versus underground facilities) York Region typically performs well for restoration, given Alectra's meshed distribution network, the proximity of Hydro One crews and equipment to the GTA, and the mainly overhead transmission system. Due to good historical performance, no restoration needs have been identified in this area which require actions to be taken at this time. Security needs are outlined below.

6.2.3.1 Southern Vaughan/Richmond Hill (Parkway-Claireville) Security Needs

The Parkway to Claireville circuits are a double 230 kV transmission line which spans between Claireville TS and Parkway TS, roughly adjacent to Highway 407, along the southern border of Vaughan, Richmond Hill, and western Markham. Supply is provided from the bulk network at both ends of this corridor, as Claireville TS and Parkway TS both have autotransformer connections to supply the 230 kV system from the 500 kV system.

Five municipal step-down stations are connected to the corridor today (Vaughan MTS #1, Vaughan MTS #1E, Vaughan MTS #2, Richmond Hill MTS #1, and Richmond Hill MTS #2). When all stations are fully loaded to their LTRs, up to 713 MW can be supplied at once, with the 600 MW security limit frequently being exceeded. These load levels were exceeded during the recent 2025 summer peak, when total loads reached 734 MW due to load transfers from neighbouring stations to address a separate distribution outage.

Figure 17| Parkway to Claireville circuits (V71/75P)



This corridor has previously been flagged as being at risk of violating security limits. In previous regional plans, it was recommended that remote operated switching facilities be installed along this corridor. These have since come into service and allow approximately half the load along this corridor to be restored in a short amount of time in the event of an N-2 contingency removing the entire corridor from service. Although this does not eliminate the risk of losing over 600 MW, it was determined that this solution would substantially address customer reliability needs, at a relatively low cost, while improving operational flexibility.

However, the present-day security need is expected to worsen when the planned Richmond Hill MTS #3 comes into service, tentatively scheduled for 2030. When all stations are fully loaded up to their LTRs, up to 866 MW could potentially be at risk of interruption in the event of a N-2 contingency occurring during summer peak.

Table 6| Parkway to Claireville Load Security Needs

Infrastructure	Timing	2025	2035	2043
Parkway to Claireville 230 kV	Immediate	94 MW	293 MW	359 MW

This represents a significant increase in the potential violation of security criteria for the area. The application of security criteria has also recently been amended through a revision to ORTAC, placing greater urgency on the need to address outstanding security needs, and only consider exemptions (as had been in place) as a temporary measure. Both the increases in demand forecasts and changes to security criteria, now require this security need to be treated as urgent.

6.3 Medium- and Long-Term Needs (2031-2040)

This section outlines longer term needs (expected to arise in 5+ years timeline), where development actions are not yet required to be undertaken. However, actions may still be required to preserve options, for instance, in the identification and preservation of land to accommodate future facilities. This is particularly the case for needs anticipated within the 5 to 10 year timeframe (medium- term needs).

GTA North is expected to be a winter-peaking region by early 2030s. As discussed in Section 5.8, demand forecasts associated with winter peaks carry a level of uncertainty as they are associated with customer behaviours and the rate of adoption of electric heating. Understanding where future needs are expected to emerge will influence planning on the transmission system to ensure upgrades can be made in time to allow for reliable connection.

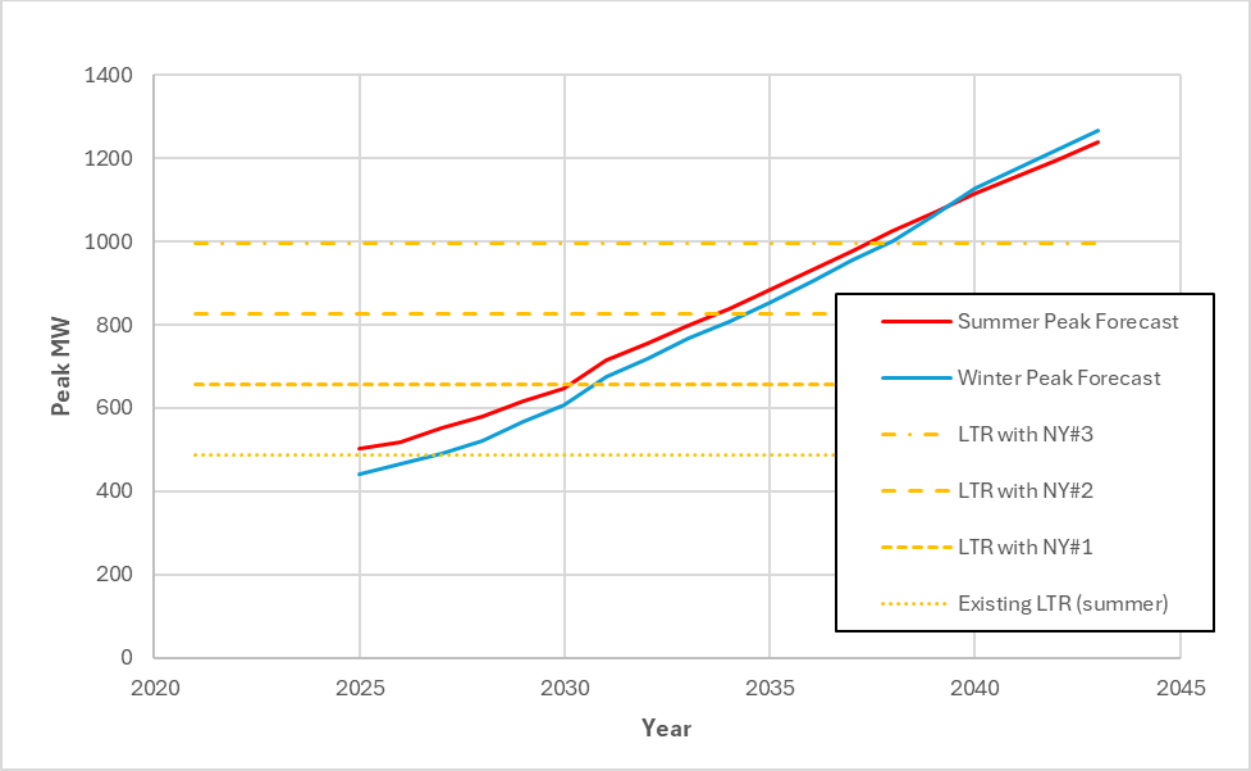
6.3.1 Station Capacity Needs

The need for step-down stations beyond the next five years is predominantly based on longer-term municipal growth forecasts and is subject to change as actual connection requests and development occurs. In particular, sudden large connection requests for major commercial customers (such as data centres) could significantly advance need dates. Longer-term step-down station needs may also need to account for winter loading conditions.

6.3.1.1 Northern York

Northern York Region is expected to continue to see significant increases in electrical demand over the next 5-15 years, driven by new development, large customer loads, and electrification of transportation and home heating. After the planned development of the future Northern York TS #1, whose need was described section 6.2.1.1, growth is expected to continue throughout the area. The graph below shows the incremental long-term challenges of meeting station capacity needs when both summer and winter needs are considered:

Figure 18| Northern York station capacity limits

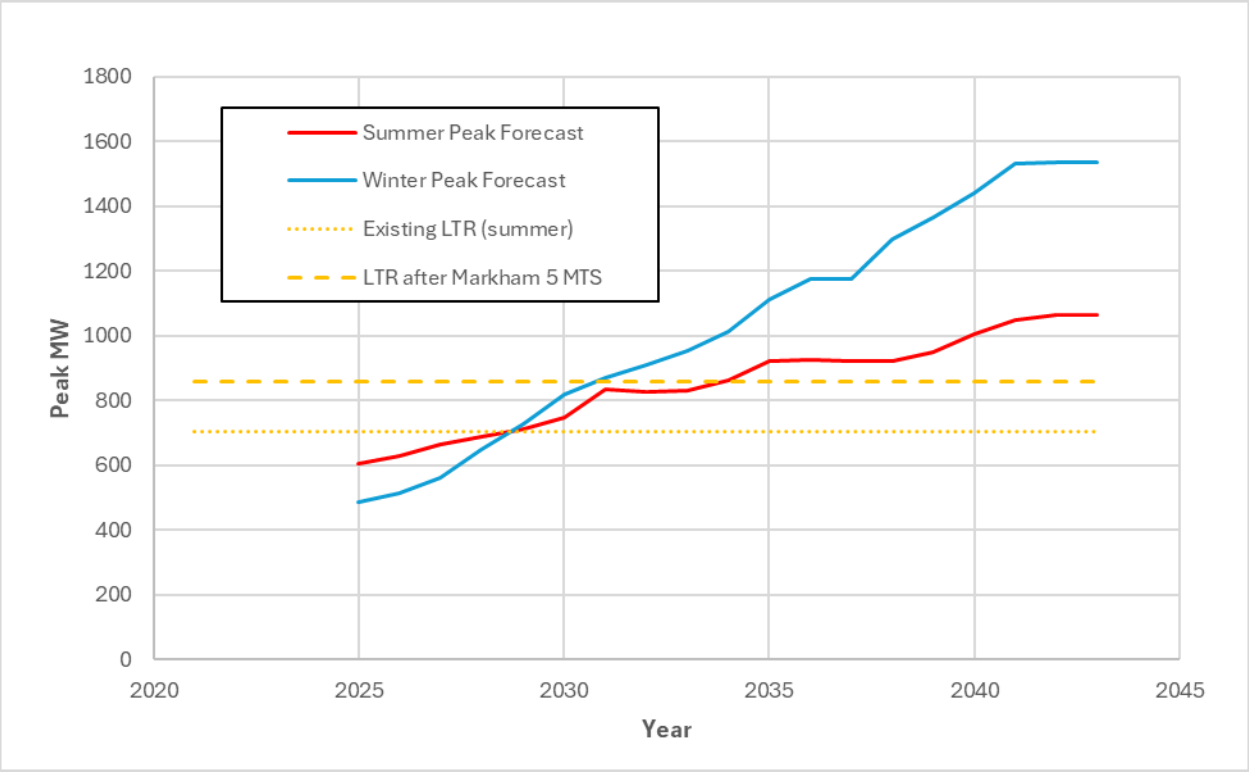


Need-dates for the second new station will depend on actual growth rates. Given the size of northern York regional, there may also be challenges associated with serving growth in the Whitchurch-Stouffville area from the future Northern York TS #1 (expected to be located over 20 km away, in King). As a result, a second new station to serve Northern York (notionally Northern York TS #2) is recommended to be located in closer proximity to eastern York load centres. In the longer term, current growth rates suggest new Northern York step-down stations may be triggered roughly every four or five years for summer-peaking conditions, or more frequently if winter-peak demand growth conditions emerge as per the forecast.

6.3.1.2 Markham

Long-term growth throughout the Alectra service territory of southern York is expected to continue at an aggressive pace in the longer term. Based on the existing summer peak forecast, and assuming the near-term need for capacity is met through Markham MTS #5, additional step-down capacity would be required in 2034.

Figure 19| Markham supplying stations, and station capacity limits



Factors such as DER uptake, pace of electrification, and residential and commercial development rates can all affect the actual need date.

As described in section 6.2.1.2, finding locations suitable for new step-down stations to meet forecast load growth in Markham has been challenging in recent years, as the existing bulk transmission system runs roughly along Highway 407 in the area, with only a 3 km extension northward. Solutions to meet near term stations capacity needs generally only consider connections to the existing transmission system as new transmission cannot be developed in less than five years. However, for longer term station needs, consideration can be given to connection points along new transmission if no feasible connection points exist from either a capacity perspective or geographic proximity. Based on concerns expressed by LDCs with serving anticipated growth centres throughout northern Markham (and northern Richmond Hill) from the existing network, siting Markham MTS #6 cannot be accomplished without new transmission in order to site the step-down capacity closer to the anticipated growth.

6.3.1.3 Vaughan

Similar to the near-term needs identified in southern Richmond Hill (described in section 6.2.1.3), there is a longer term need to provide step-down station capacity in southern Vaughan. This is directly the result of new major commercial and residential development and intensification from the Vaughan Metropolitan Centre (VMC) Urban Growth Centre. As a result, the need is not linked to remaining capacity at other nearby stations, but to the intensified demand associated with growth in this pocket. The current anticipated need date is 2033, and while this is just outside the 5-year horizon defined as near term, work is ongoing by Alectra to find suitable land and begin development to meet the targeted in-service date. The notional Vaughan MTS #5 is likely to seek connection to the existing V71/75P circuits, as these transmission facilities are near the anticipated VMC growth area. This would exacerbate existing security needs along V71/75P corridor. This would exacerbate existing security needs along V71/75P corridor.

6.3.2 Supply Capacity Needs

Supply capacity needs emerging in the longer term are generally a result of either higher loading requirements due to new step-down stations or impacts on local supply capacity resulting from potential phase out of local generators as contracts expire. System conditions can also be impacted by planned changes to the bulk system, with implications for both system needs and available solutions.

6.3.2.1 Northern York

Capacity needs for supplying incremental load growth in the near term were described in section 6.2.2.16.2.1.1, and roughly correspond to the amount of supply required to enable the connection and full loading of one additional step down station, notionally Northern York TS #1, in addition to incremental loading to bring existing stations up to their full summer LTR, and additional loads associated with electrification of Go Transit. Assuming recommendations to address these needs are put into service, additional needs will begin to emerge in the long term based on two main drivers: Continued incremental load growth associated with an additional new step-down station in Northern York and the potential retirement of York Energy Centre.

Accommodating further step-down stations in Northern York

As described in section 6.3.1.1, ongoing load growth in Northern York Region is expected to trigger the need for new step-down stations roughly every four years (summer peaking) or potentially as often as every three years (assuming high electrified heating and winter growth scenario) in the longer term.

Measures to address near term needs will be sufficient to meet the need for Northern York TS #1, while the assumed location for future Northern York TS #2 is eastward, outside of the electrical system defined as Northern York. Assuming the next station is once again sited in this area, needs should be evaluated on the assumption that additional station loading emerges in roughly the mid 2030s.

Given uncertainty with long-term growth rates, and the risk of sudden, large surges in customer demand from new development or electrification, the local system should be designed to be capable of supplying the full load of this future station, before permitting its connection. The exact nature of needs emerging from this station would depend on its connection location, as well as system changes which may be required to address the potential phase out of YEC.

At a minimum, adding this future station would trigger security needs regardless of whether it is connected on the H82/83V circuits (same protection zone as Vaughan MTS #4, Holland TS, and future Northern York TS #1), or B88/89H circuits (Armitage TS and Brown Hill TS). Seeking exemptions to security needs is not desirable in this area, given the existing operational challenges for managing this system, including maintaining adequate voltage and finding suitable windows for regular outages for maintenance.

Both scenarios, where YEC (or similar-sized generation) would remain in service, or new transmission is added to provide supply from elsewhere in the system, contribute unique challenges to the operation of this system. With the addition of potential security violations, new sectionalization should be considered a mandatory starting point to accommodate a future station. The manner of this sectionalization will ultimately influence the maximum system capability (LMC).

These options are described in more detail in section 7.4.3.4.

Considering a Potential Future without YEC

The York Energy Centre (YEC) currently serves roughly 400 MW of peak summer demand for Northern York, reducing the amount which needs to be supplied into the area from elsewhere. This facility was originally sited in Northern York specifically to offset the need for new transmission and has successfully managed the ability for the area to grow without new transmission since 2012. The contract for YEC is currently set to expire in 2035, and if it is removed from service, would represent an immediate 400 MW shortfall to local capacity to meet the area's peak demand. This 400 MW shortfall would be in addition to incremental needs from regular customer growth.

Even after the incremental upgrades recommended in section 7.3.2.2 are implemented, there would be a significant mismatch between local demand and the ability of the system to provide reliable supply. Where options to address near term needs considered measures such as reconductoring, bypassing limiting sections, and NWAs, options to meet needs of 400 MW or more are generally

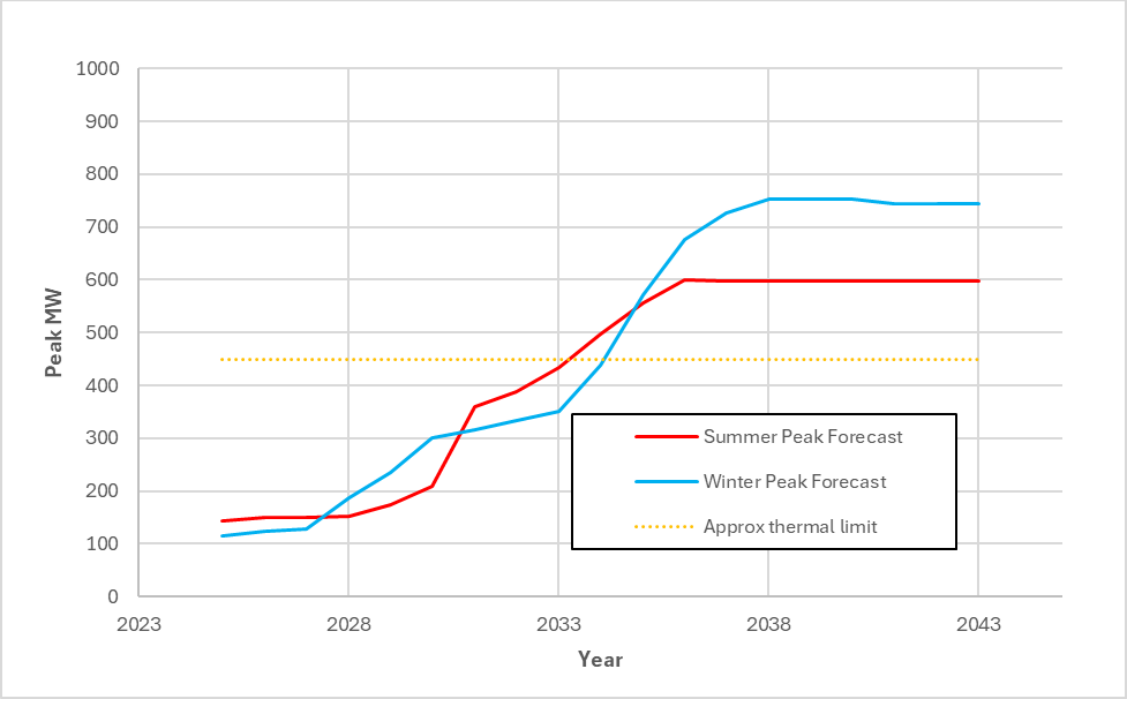
limited to new transmission lines (typically ~600 MW or more of new capacity), or local generation of a similar size and operational characteristics as what had been phased out. These options are explored in greater detail in section 7.4.3.3. If YEC were phased out without a major new supply source, it would severely affect reliability for existing customers and likely limit the ability to connect any incremental load within northern York.

6.3.2.2 Parkway-Buttonville

Capacity needs associated with the Parkway-Buttonville pocket arising in the near term were described in section 6.2.2.2, and emerge along the southern end of the P45/46 circuits, between Parkway TS and Markham MTS #4. In the longer term, demand for additional step-down stations to supply growing loads in Northern Markham, Northern Richmond Hill, and the eastern section of Northern York (including Whitchurch-Stouffville), is expected to further load this corridor. This will trigger similar thermal needs on the remaining northern section of P45/46, between Markham MTS #4 and present-day Buttonville TS. These needs are expected to be triggered when the total load of Buttonville TS, Markham MTS #5, (future) Markham MTS #6, and (future) Northern York TS #2 reach approximately 450 MW, although actual LMC could vary depending on future station, circuit and customer load characteristics. This is in addition to security needs described in section 6.3.3.1, below.

The graph below shows the impact this will have on anticipated need dates for further upgrades, under anticipated summer peak conditions, and a potential higher growth winter peak scenario.

Figure 20|Circuit loading on northern section of P45/46 circuits (Markham MTS #4 to Buttonville), and thermal limit



Note that total summer load is expected to plateau in the mid to late 2030s, as stations reach their individual LTR, and incremental growth is instead supplied by stations in neighbouring systems. This profile could change if future stations are instead located within this supply pocket.

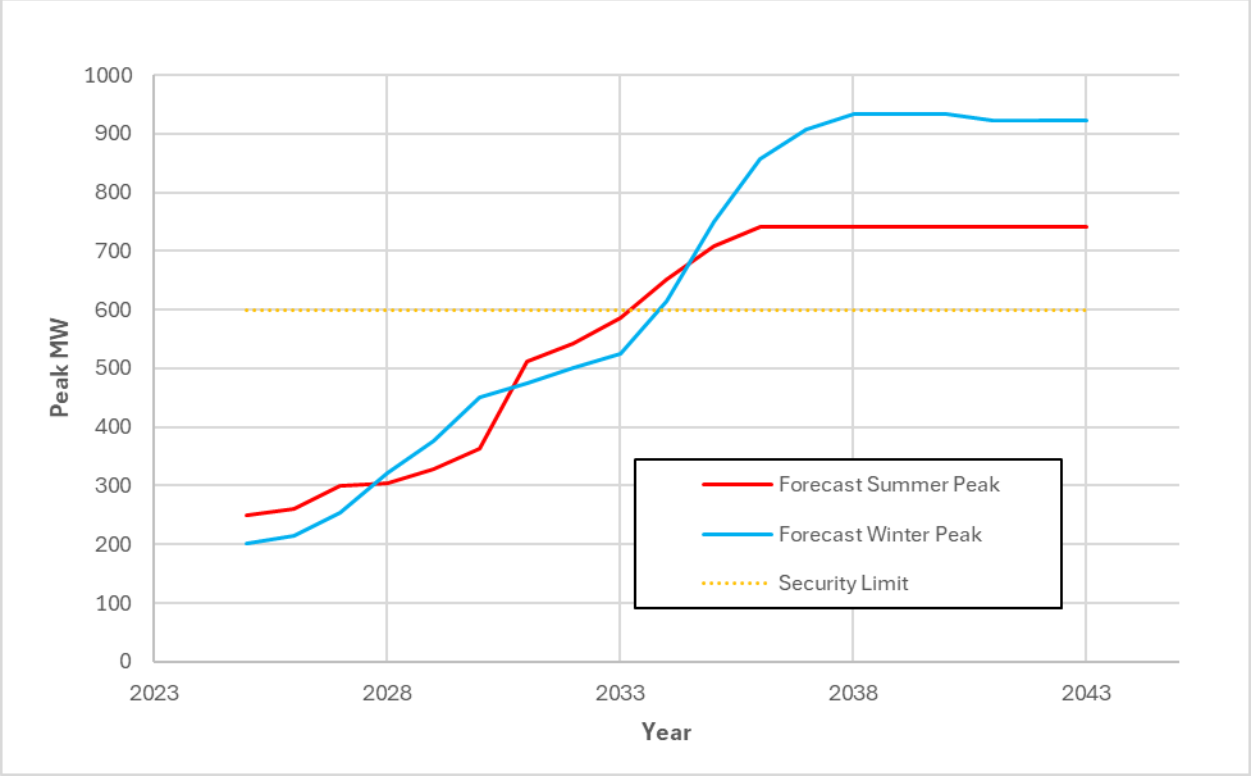
6.3.3 Load Security and Load Restoration Needs

New load security needs have the potential to emerge in the longer term as load growth increases the areas supplying over 600 MW during peak conditions. This becomes more severe when higher growth winter peak scenarios are considered. In many cases, load growth can trigger both capacity needs as well as security needs, with common solution often able to address both. The conditions under which security needs are triggered, and whether they are expected to be addressed through other initiatives, is described below.

6.3.3.1 Markham and Area (Parkway-Buttonville)

The demand forecast for this load pocket load is expected to exceed 600 MW in 2034 (both summer and winter peak forecast) which would violate applicable load security criteria. The graph in Figure 21 below shows the applicable loading, which accounts for all P45/46 connected stations (this is different from Figure 20, above, which only considered load north of Markham MTS #4):

Figure 21 | Full circuit loading on P45/46 circuits, and security limit



This assumes that the need for future step-down stations (either Markham MTS #6 or Northern York TS #2) is triggered, and transmission is available to enable their connection via a Parkway-Buttonville transmission extension. These options are described in sections 7.4.2.1, 7.4.2.2 and 7.4.2.3 and, are preconditions for triggering this security need. Note that this security need is in addition to thermal needs which are triggered in the same approximate time and are described in section 6.3.2.2. Separate solutions are required for each.

6.3.3.2 Kleinburg Radial Tap

The Kleinburg Radial tap refers to the pair of 230 kV circuits, V43 and V44, which span northwest from Claireville TS. These circuits currently supply Woodbridge TS, Vaughan MTS #3, and Kleinburg TS, with plans underway to develop a new step-down station, Vaughan MTS #6, to supply commercial loads in the area. Under normal operating conditions, part of the southern end of this corridor also partially supplies the neighbouring Goreway TS, in Brampton.

Peak demand for the Kleinburg radial pocket is expected to exceed 600 MW in summer 2029, and potentially in winter as soon as 2030. Recommendations to address supply capacity needs for Northern York are expected to address these security needs as well. Details on these proposed solutions are provided in section 7.3.2.2.

6.3.3.3 Parkway-Claireville

Based on the near-term need for an additional station to serve southern Richmond Hill (notionally Richmond Hill MTS #3), and a longer-term need for an additional step-down station to serve southern Vaughan (notionally Vaughan MTS #5), the Parkway to Claireville corridor could potentially be exposed to interruption of approximately 960 MW of peak demand. This would assume all stations are loaded to their LTR, and an N-2 contingency occurring during summer peak. In the event of winter peaks emerging in the longer term, this security risk could approach 1200 MW.

Although the security limit is exceeded today, it is unlikely that a similar exemption would be approved as additional stations seek connection. Load losses of these magnitudes, especially without comparable generation tripped from loss of the same circuits, can introduce significant challenges for balance of supply and demand at the broader bulk level. Updates to applicable security criteria in ORTAC have also introduced a requirement to pursue a permanent solution for load security needs and to only consider exemptions as a temporary measure to avoid delaying the connection of new customer loads.

Near-term recommendation outlined in section 7.3.3.1 are expected to also address this longer-term need.

6.4 Post-2040 System Considerations

Near the end of the planning horizon considered in this IRRP (2040 and beyond), identifying specific needs and developing options to address them becomes more challenging. There is, however, time to study options in subsequent planning cycles.

Understanding needs requires detailed assumptions about anticipated customer demand, seasonal peaks, and hourly profiles on a geographic basis. Given the potential for very high growth rates resulting from electrification, major new large commercial/industrial load centres, in addition to more typical growth rates associated with organic population and employment growth, predicting actual demand this far out cannot be accomplished with sufficient confidence.

The demand forecasts for summer peak, which relies more closely on existing customer behaviour and more modest electrified technology uptake, currently forecasts up to 2,100 MW of demand growth throughout York region over the next 20 years, of which roughly 1,500 MW is accounted for in this IRRP through new step-down stations and associated system upgrades to supply them. If a higher growth winter forecast is used, with more aggressive assumptions related to electrified heating in particular, up to 3,400 MW of demand growth is possible in the same time frame, with approximately 2,200 MW accounted for in this IRRP.

Supplying growth at the higher end of these projections would require greater consideration of the impact on the broader bulk electrical network. Typically, regional planning assumes the bulk system is a static source of power with sufficient ability to supply any required level of local demand. This assumption becomes challenged when considering levels of demand with the potential to affect provincial interface flows, and approach loading limits on what is typically much higher rated bulk equipment. Additionally, a future scenario where extreme demand growth is observed throughout York region would likely mean similar levels of extreme growth are emerging throughout the province, which would trigger the need for significant upgrades on the bulk system as a whole.

The combination of local demand driving bulk system needs, and assumption that bulk upgrades are required throughout the province, means that planning under this long-term high growth scenarios require close coordination between regional and bulk system plans.

Long-term bulk planning is currently underway through the development of the South and Central Bulk Plan, which considers transmission needs out to 2035, in addition to accommodating several planned changes to the provincial supply portfolio. The York IRRP has been carried out in close coordination with this plan, with implications for system assumptions and options available. These points of coordination are highlighted in the following section when options are described in greater detail.

7 Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in York Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included feasibility, cost, lead time, system benefits, and consistency potential options for addressing longer-term needs in the area.

There are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new or reinforce transmission or distribution systems. These are commonly referred to as "wire" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to manage the peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wire" options and can include alternatives such as local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or eDSM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wire options. Subsequently, Section 0 to Section 7.4 present the options that were ultimately developed and evaluated to the address near- and longer-term needs, respectively. Opportunities for NWAs are highlighted in their relevant options sections, with additional details provided in section 7.5.

7.1 Options Considered in IRRPs

Both wire and non-wire options are considered in regional planning, although some options may be more suitable for specific need types and characteristics. When evaluating non-wire options such as generation, local distributed energy resources, or energy storage, additional work is required to understand these specific need characteristics, including creation of hourly load profiles, as described in Section 5.7. The suitable technology types and capacities are determined by examining "unserved energy" profiles, representing the hourly demand above the existing LMC. The load profile indicates duration, frequency, magnitude, and total energy associated with each need.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. In contrast, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and decarbonization efforts, new natural gas-fired generation was not considered as a generation option for local needs identified by the regional plan. Energy storage, solar generation, and wind generation were considered for generation options.

New eDSM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already

included in the load forecast, as discussed in the Section 5.4. As part of this framework and the new 2025-2036 framework, the IESO has flexibility to deliver new programs or offer regional incentive adders for existing province-wide programs to help address regional and/or local system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. NWA considerations are discussed further in Section 7.2, as part of the screening of options that was conducted. (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. At time of IRRP publication, the Ontario Energy Board is currently considering a proposal from the IESO and the Local Distribution Company community to enhance this existing mechanism to better enable IESO-LDC collaboration and co-funding of eDSM initiatives that provide both local and provincial system benefits. NWA considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wire and non-wire options, the upfront capital and operating costs are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wire option (typically 70 years for transmission line infrastructure). The net present value (in 2025 CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around cost estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The transmitter-led RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. Costs are typically further refined over the course of project development work. The IESO continues to participate in the Technical Working Group during the RIP and will revisit a recommendation if estimates change significantly. Furthermore, smaller scale demonstration projects can be explored in cases where other barriers (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options following the completion of the IRRP.

The list of assumptions made in the economic analysis is found in Appendix F.

7.2 Screening Options

As described in the previous section, an array of options is developed to meet identified needs during an IRRP, and each option is then evaluated to determine which are feasible and successfully address all needs. Final recommendations are typically made for those which are the most cost effective, although increasingly a wider range of factors are considered, including community preferences, flexibility, or providing some degree of reliability and demand forecast uncertainty risk mitigation. This process is complemented by stakeholder engagement and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 22 and further discussed in the next sections for the identified needs.

More details on the steps and inputs used in the screening mechanism can be found in Appendix C, and a summary of the options screening results for York Region is provided in Table 7**Error! Reference source not found.** for station capacity needs, and in Table 8| for supply capacity needs.

Figure 22|IRRP NWAs Screening Mechanism

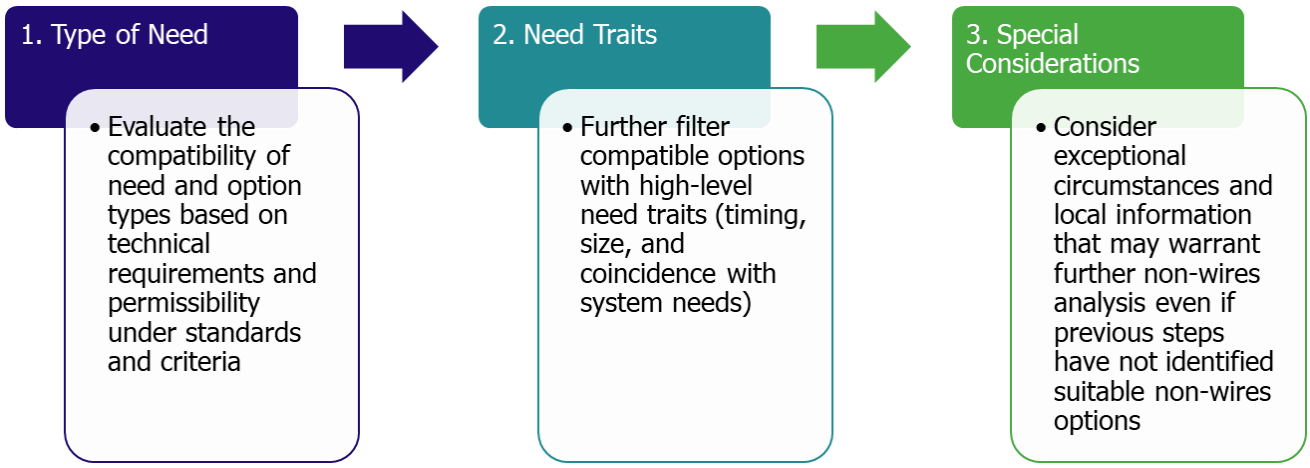


Table 7| Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity: All Subregions	• Operational measures • eDSM • Distributed generation • Wires options	• Demand response – due to magnitude and timing of need

Table 8| Options Screening Results for Supply Capacity Needs

Need	Screened In	Screened Out
Supply Capacity: Parkway TS to Buttonville TS Claireville TS to Brown Hill TS	• Operational measures • eDSM • Distributed generation • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of need

7.3 Options and Recommendations for Addressing Near-Term Needs

The following sections describe recommendations for addressing near-term needs. Unless stated otherwise, implementation is recommended to proceed immediately to ensure upgrades can be in place to address expected need dates. Where options are not expected to be in place in time, alternative measures have been highlighted to help address short term needs.

7.3.1 Options for Addressing Station Capacity Needs

The need for three step-down stations has been identified in the near term. Work should continue to identify and secure appropriate land and proceed with station development.

7.3.1.1 Northern York TS #1

The need for a new step-down station to serve growing customer demand in Northern York Region is immediate. However, the timeline for design, approval, and construction of this type of infrastructure typically spans around 4-5 years. As a result, this station is not expected to come into service any earlier than 2029.

Several approaches are recommended in the interim to manage growing customer demands before the infrastructure solution can come into service:

1. Additional electricity demand side management should be targeted in northern York region, to assist in ensuring some capacity remains available for growth of existing customer loads. Additionally, lowering peak demand through incremental eDSM would reduce the risk of Load Rejection in the event of an outage during peak load conditions, thereby improving customer reliability. Programming targeting the areas of Newmarket, Aurora, East Gwillimbury, and West Gwillimbury would be the most effective at deferring these step-down station needs.
2. Hydro One Distribution is investigating options to transfer additional loads at the boundary between the Holland TS/Armitage TS service territory and neighbouring Brown Hill TS service territory. Although large scale transfers are unlikely to be feasible given the distances between these stations, small service territory adjustments at the boundary may be effective to manage growth in the near term and still provide longer term reliability benefit due to enhanced restoration capability. Enhancing restoration capability ensures this interim measure remains cost effective by providing enduring customer benefit, even once the future station comes into service.
3. New, load connections have to seek connection through other Northern York stations with remaining capacity. It should be noted, however, that this may incur larger distribution related costs as new feeder lines may be required to cover long distances. The nearest step-down station with significant remaining or unallocated capacity is Brown Hill TS, which is located approximately 15 km northeast from the preferred location of Northern York TS #1. Until connection costs are brought down with a nearer connection point, this may delay Northern York's ability to connect new large load customers.

Based on existing loads and near-term demand forecast, it is recommended that Hydro One proceed with the acquisition of land, the design, and the construction of a new step-down station by 2029 to serve Northern York Region, in the vicinity the Holland TS area. Typical development costs for these types of stations, including real estate, are generally $60 Million[6].

For the purposes of this study, the new step-down station was modelled as connecting to the H82/83V circuits, which exacerbates the existing supply needs for this corridor, as described in section 6.2.2.1. Measures to address these needs are described and recommendations made in section 7.3.2.2. Timelines to address these needs should not interfere with the immediate development of the step-down station, as incremental needs can be met on an interim basis through the arming of load rejection through the existing Remedial Action Scheme (RAS) for Northern York Region.

7.3.1.2 Markham MTS #5

Based on existing peak demand and forecast near-term growth, the need for the next Markham area station is anticipated by 2029. Alectra has identified a suitable location for the next Markham MTS #5, and this project is currently under development. Based on recommendation from the previous IRRP, Markham MTS #5 is planned for connection near the existing Buttonville TS, supplied from the P45/46 circuits. The expected in-service date of this station is 2028-2029. Typical development costs for these types of stations, including real estate, are generally $60 Million. Supplying the full rated capacity of this station and the existing Buttonville TS and Markham MTS #4 will require supply capacity increases to the southern section of P45/46 circuits, further described in section 7.3.2.3.

7.3.1.3 Richmond Hill MTS #3

As described in section 6.2.1.3, significant development pressure in the vicinity of the Richmond Hill Centre Urban Growth Centre will require additional step-down station capacity by 2030 to reliably supply new and intensified customer demand. The area of intensification to be supplied by this new station is roughly bounded by Yonge St to the west, Steeles Ave to the south, 16th Ave to the north and Leslie St to the east. Alectra has identified a suitable location for the next step-down station to supply this forecasted growth, Richmond Hill MTS #3, which is currently under development. The proposed connection point will be along the V71/75V circuits, near the existing Richmond Hill MTS #1 and #2. The expected in-service date of this station is 2030. Typical development costs for these types of stations, including real estate, are generally $60 Million.

Once connected, loading up this new station will exacerbate existing security needs along the corridor. Although an exemption to security criteria is in place today, continued load growth on this corridor, as anticipated through the connection of Richmond Hill MTS #3 in the near term and Vaughan MTS #5 in the longer term, will require a wires solution to be put in place to address security needs. This is further described in section 7.3.3.1.

[6] Actual costs can vary depending on factors such as land costs and equipment ratings

7.3.2 Options for Addressing Supply Capacity Needs

In some cases, measures to address capacity needs will also have the benefit of addressing security needs. Where a proposed solution addresses both sets of needs, it is discussed in the sections below.

7.3.2.1 York Energy Centre Station Service

When operating, the York Energy Centre (YEC) injects power through its transmission connection point along the B88/89H circuits. However, the station service (power used to run station equipment), is normally supplied through a distribution connection from Holland TS, which is connected to the H82/83V circuits to the south of YEC. These two sets of circuits, B88/89H and H82/83V, are connected through a set of breakers that were installed in 2017, several years after YEC came into service. This created a condition where the loss of H82/83V will remove Holland TS, and subsequently YEC, from service without interrupting supply to B88/89H. This creates potential capacity and voltage related needs for the local system (described in section 6.2.2.1), which would not be as severe if YEC remained in service.

Changing the station supply arrangement for YEC would allow for YEC to remain operational under the loss of H82/83V, and the loss of the T1B breaker at Holland TS (current worst-case N-2 contingency). The impact of resolving the YEC station service issue would result in an increase of approximately 90MW in the LMC from the worst-case contingency.

There are different potential ways in which YEC station service could be addressed including:

- Installing second step-down transformer via the B89H tap point, allowing for station service to be drawn under regular operating conditions from B89H as well as the existing supply available from B88H, or;
- Installing a potential automatic station service transfer arrangement to allow for automatic transfer between the Holland TS distribution service and B88H supply points during a contingency.

The ultimate preferred service arrangement should be determined based on deeper engineering study of the cost and technical feasibility of different possible arrangements. It is recommended that the station owner work with the connecting transmitter, Hydro One, to identify and implement this system upgrade. The final configuration should allow for uninterrupted operation of YEC under all applicable N-1 and N-2 transmission planning contingencies affecting H82/83V, as well as all N-1 contingencies affecting either B88H or B89H.

Although cost estimates for this upgrade are not yet available, alternatives to provide to similar level of reliability would be orders of magnitude more costly and disruptive than the proposed station service work, and either require new transmission to create redundant supply paths into the area, or the construction of a similar sized generation facility (~400 MW) to provide redundant supply. By contrast, all anticipated upgrade options could be accommodated entirely within the existing station boundary.

In addition to improving reliability for the local area, this will allow YEC to remain operational under a wider range of system conditions, which in turn improves power and ancillary service availability for the province as a whole.

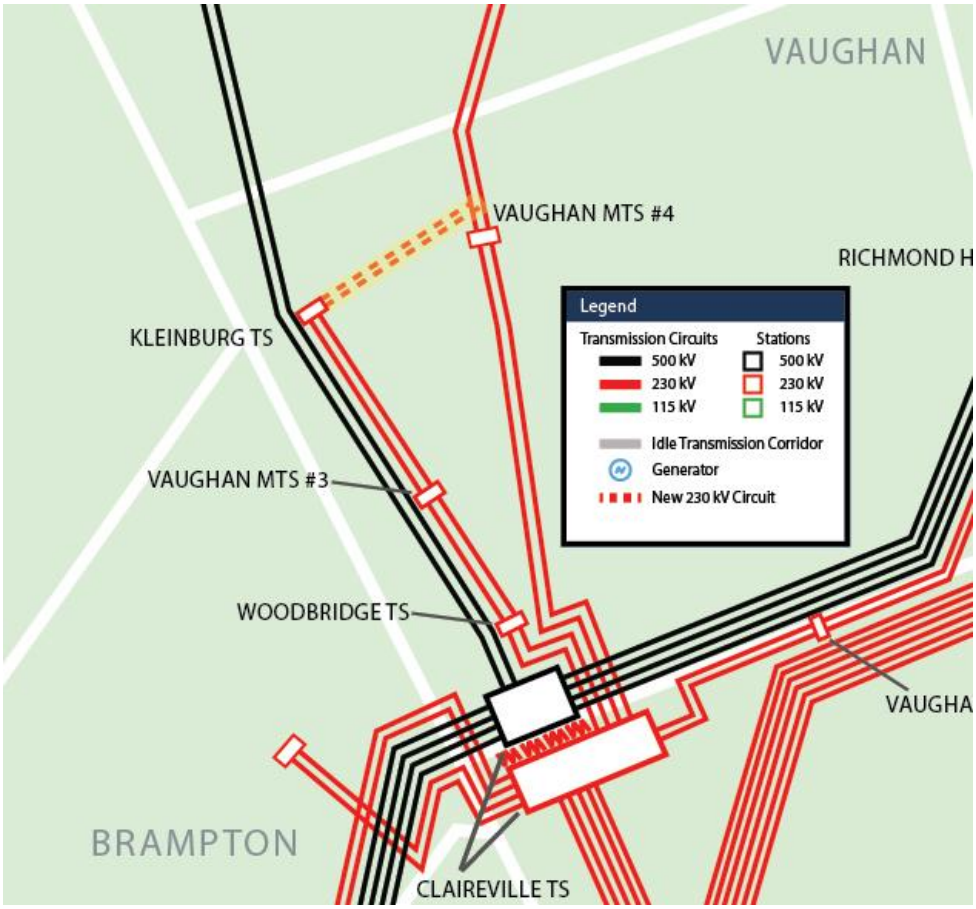
Consideration of new regulatory or contractual mechanisms may be required to finance this type of system upgrade. There is no existing mechanism for costs incurred by the station owner to be reimbursed, and it also does not fit within the existing competitive procurement streams.

Addressing this station service issue will have an immediate benefit to local customer reliability by lowering exposure to Load Rejection (LR) events, and allowing the local system to accommodate some of the additional load growth associated with the connection and loading of Northern York TS #1. Additional technical details of this analysis are included in Appendix E.

7.3.2.2 Kleinburg-Kirby Transmission Link

After addressing the York Energy Centre (YEC) station service issue (see section, 7.3.2.1), the next most limiting contingency affecting Northern York is triggered by thermal violations of the southernmost section of circuits H82/83V, which span from Claireville TS to Vaughan MTS #4. Due to a narrow transmission corridor, and close proximity to development along this route, this section is not a good candidate for reconductoring to increase capacity of the line. Instead, a new transmission route is proposed to bypass this limiting section and improve supply capacity into Northern York. This new transmission line, referred to as the Kleinburg – Kirby Transmission Link, would create a connection between the existing Kleinburg radial tap, and connect to a point north of the exiting Vaughan MTS #4. The notional location of the facilities is shown in Figure 23.

Figure 23| Potential Kleinburg – Kirby location



Creating this bypass would reduce the amount of power that would have to flow north from Claireville TS to Vaughan MTS #4 to reach stations further to the north. The impact on LMC depends on where new stations are ultimately located in Northern York, and the balance of demand between them, however this upgrade is expected to allow for the connection and full loading of Northern York TS #1.

The long-term need for this corridor to supply Northern York, as well as northern Peel and Halton regions, had previously been identified through the regional planning process. Additionally, the Ministry of Transportation (MTO), dealing with similar growth and intensification needs from a transportation perspective, has been working to develop the proposed Highway 413 in the same general area. More information on MTO's process is available on the project website, linked here. In accordance with the Provincial Policy Statement, which recognizes the value of co-locating linear infrastructure from a land use perspective, the IESO and Ministry of Energy and Mines have been working for over a decade to identify and preserve land in the same general vicinity as the proposed highway. This new transmission corridor would roughly parallel Highway 413, with minor deviations where required to connect with specific transmission supply points or avoid areas unsuitable for transmission. The final route, when fully built, would provide a transmission route connecting a future Milton TS to Kleinburg TS. This line would connect with the extension further east to the H82/83V

circuits in Vaughan, at a point north of Vaughan MTS #4, close to the intersection of Kipling and Kirby Rd. This proposed transmission line is referred to as the Kleinburg to Kirby link.

As an initial configuration, a double-circuit 230 kV is envisioned along this route. In the longer term, a second double-circuit line could potentially be required to further reinforce and create a separate redundant supply path to serve the southern sections of H82/83V, if additional step-down stations are required in the vicinity of the existing Vaughan MTS #4. The initial 6 km double-circuit 230 kV Kleinburg to Kirby link is estimated to cost $40 million and would likely take 6-7 years from project initiation until in service date (timelines aligned with Bulk Kleinburg TS build out, described in section 8.1). This assumes a steel lattice tower design and does not account for any additional land costs.

7.3.2.3 Reconductoring P45/46

As described in section 6.3.2.2, thermal limits of the existing P45/46 circuits are expected to be exceeded following the loss of the companion circuit when total loading on the stations supplied by these circuits (Markham MTS #4, Buttonville TS, and the future Markham MTS #5) exceeds approximately 450 MW.

Based on a review by Hydro One, it is technically feasible to upgrade the limiting conductors along this transmission corridor. Reconductoring the section between Parkway TS and Markham MTS #4 would allow the P45/46 corridor to support the full LTR at Markham MTS #4, Buttonville TS, and the future Markham MTS #5. The estimated cost would be $4.3 million.

Based on current forecasts, the need date for this upgrade is approximately 2031. However, there is value in advancing this work to coincide with the planned in-service date of Markham MTS #5 (2028-2029) for two reasons. First, once connected, there may be value in utilizing new step-down station assets at a quicker rate, such as when transferring loads during an outage on a neighbouring station, or to make more efficient use of distribution assets closer to actual customer loads. For that reason, it may not be efficient to curtail load at this station once it is connected. The second reason deals with operational and logistic challenges of managing reconductoring work. Typically, one of the conductors being upgraded would need to be taken out of service for long periods of time, limiting supply capacity of the system for weeks, or even months at a time. This timing of work will need to be carefully planned to coincide with periods of time when demand is expected to be lower. However, the longer the work is delayed, the more challenging it can be to carry out, as available windows for taking these types of long outages become shorter.

Hydro One, with the IESO, should determine a preferred window for carrying out this work as part of the RIP process.

7.3.3 Options for Addressing Load Security Needs

The sections below describe preferred solutions to address load security needs. In the past, LDCs and transmitters have had the option of jointly applying for exemptions to security criteria, where the cost of upgrades is expected to exceed customer benefit. Although the IESO has typically granted these exemptions, revisions to applicable criteria now only permit exemptions as a temporary, or stop gap measure, where longer term solutions may take additional time to implement.

7.3.3.1 V71/75P Circuit Breakers

As described in sections 6.2.1.3 and 6.3.1.3, security limits are exceeded along the V71/75P circuits today, and this is expected to worsen once Richmond Hill MTS #3 connects, and in the longer term Vaughan MTS #5. Although an exemption to security criteria is in place today, it is not anticipated that it will continue to apply as revisions to security criteria now require longer term plans to address needs to be in place. Additionally, the scale of the security need has surpassed 730 MW during the most recent 2025 summer peak, and rapid anticipated load growth from new stations on the corridor is (linked to existing urban development plans). As a result, there is an immediate need to address load security for stations supplied by these circuits.

Existing switching facilities along this corridor allow for the partial restoration of load following the loss of two transmission elements, but they do not prevent the full load along the corridor from being lost immediately following a double contingency affecting both circuits. By adding inline breakers near the midpoint of the V71/75P circuits, a contingency affecting both circuits would only cause the loss of roughly half of the connected stations, significantly reducing the amount of load interrupted. The exact amount of load lost would depend both on the placement of the breakers, and the future connection points of Richmond Hill MTS #3 and Vaughan MTS #5. A suitable location for these breakers would be one where the simultaneous loss of the V71/75P circuits at a single point along the corridor (i.e., a credible common tower contingency) would not interrupt more than 600 MW of load.

Given the proposed connection point for Richmond Hill MTS #3, one notional option would be to locate these breakers along the 6 km stretch between present day Vaughan MTS #1, and Richmond Hill MTS #1. When Richmond Hill MTS #3 is connected, and all six stations on the corridor are fully loaded to their summer LTRs, this would expose a maximum of 459 MW to interruption for a common tower double-circuit contingency. Assuming the future Vaughan MTS #5 is connected east of these breakers, along the same section as the Richmond Hill MTSs #1, #2, and #3, the longer-term maximum interruptible load would be 560 MW, still within acceptable security limits. An ideal location for these breakers would therefore be between present day Vaughan MTS #1 and the future Vaughan MTS #5.

Identifying the exact location for the future breakers will require detailed review of the existing transmission corridor, both to find an area where they can be accommodated without requiring additional land acquisition and ensure development work can be undertaken without disrupting operation of any existing facilities. The Working Group recommends that Hydro One identify a preferred location for connecting in line breakers along V71/75P within the scope of the upcoming York RIP and then proceed to implement this project. Typical costs for this type of infrastructure range from $30 million to 35 million and take approximately three to four years to develop. As the V71/75P circuits are owned and operated by Hydro One, it is not a suitable candidate for competitive procurement.

7.4 Options for Longer-Term Needs

Longer term options to address needs throughout York Region will be informed by actual demand growth, location of future step-down stations, and longer-term local generation supply availability. The following sections describe potential outcomes based on best available estimates of how these factors will evolve. Unless stated specifically, actions are generally not required at this time, unless it is to preserve longer term options.

7.4.1 Options to Address Southern Vaughan, Richmond Hill, and Markham Needs

The area served by stations connected to the V71/75P circuits roughly aligns with Southern Vaughan, Richmond Hill, and Markham. Security needs exist today, though are managed through exemptions to applicable criteria. Longer-term needs and options are linked to ongoing customer growth, intensification, and managing security needs as they worsen when new step-down stations connect.

7.4.1.1 Vaughan MTS #5

The longer-term need for a new step-down station to supply southern Vaughan is described in section 6.3.1.3. The preferred location for future connection would be in the vicinity of Vaughan Metropolitan Centre (VMC), which is easily accessible from connection points along the V71/75P circuits. Although security limits are already exceeded along this corridor today, the ideal location of these circuits make any other connection point for a station intended to supply VMC impractical. Instead, Vaughan MTS #5 is recommended for connection along V71/75P, and measures to address outstanding and worsening security needs will be explored separately. Near-term recommendations for addressing security needs have considered the anticipated longer-term impact of connecting this step-down station. Details on recommendations to address security needs are provided in section 7.3.3.1.

The need date for Vaughan MTS #5 is linked to growth within the VMC pocket, and not to overall capacity at remaining southern York stations. Alectra has indicated that they are working towards a 2033 in service date, based on connection applications and approved municipal plans. Actual need date may vary depending on develop timelines for new customers in the area. Although the need date is outside of the five-year near-term window, work should continue towards this targeted completion date. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2 Options to Address Northern Markham, Richmond Hill, and Whitchurch-Stouffville Needs

The areas of northern Markham and Richmond Hill, in addition to eastern sections of Northern York, currently have limiting step down station capacity due to their long distances from the existing transmission network. As urban boundaries continue to expand northward, and rural loads intensify, this will trigger the need for new transmission stations, and transmission infrastructure to supply them. Individual options and their timing are described below.

7.4.2.1 Northern York TS #2

As described in section 6.3.1.1, the preferred location for the future Northern York TS #2 would be in closer proximity to growing load centres in the eastern half of Northern York. Whitchurch-Stouffville has been identified as a particularly challenging area for meeting long term distribution connection requests as it is expected to see significant load growth over the coming 20 years, and is also far removed from existing transmission infrastructure. Supplying customer loads, especially denser demand from high electricity use customers or more urban/suburban development, becomes more challenging for distribution networks the further they are from the transmission supply point. This can result in more expensive connections, and poor customer reliability.

Additionally, the most recent step-down stations built to supply Northern York (Holland TS and Northern York TS #1) have been or will be built in the same general area in western Northern York, with connection to the same supplying circuits. Diversifying the location of step-down stations provides benefit to customer reliability by allowing alternate supply paths through the distribution network to manage planned or emergency outage conditions.

An ideal location for Northern York TS #2 would therefore be close to the eastern sections of Northern York. No transmission infrastructure currently exists in this area, which means triggering development of this step-down station will also require development of new transmission to supply the station. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2.2 Markham MTS #6

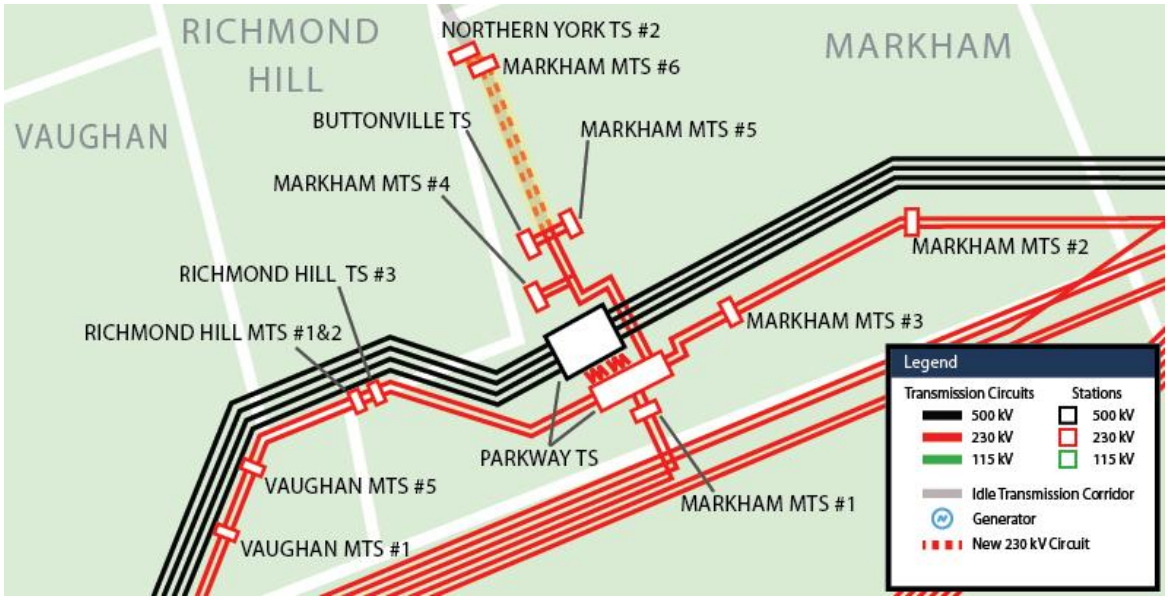
As described in section 6.3.1.2 continued urban expansion throughout northern Markham and Richmond Hill is expected to trigger the need for a new step-down station in around 2034. Actual need date could vary depending on actual demand growth in the area, which is influenced both by new as well as intensified customer demand, but also by the successful uptake of NWA where it can offset peak demand growth. Because the driver for this station is growth in the northern section of these municipalities, and because transmission does not currently extend beyond ~3km from the south of Markham, this station could not be built in a way that allows for efficient or reliable service to customers today. As a result, pursuing the development of this future step-down station will also require a parallel development of new transmission to allow connection closer to anticipated load centres. An existing, idle transmission corridor already exists in a suitable area and could be leveraged to enable this connection. This is explored in section 7.4.2.3, below. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2.3 P45/46 Transmission Extension

As described above, connecting and supplying the future Northern York TS #2 and Markham MTS #6 in the longer term will require extending the existing transmission system a further 7 km (approximately) into northern Markham. An idle transmission corridor already exists and can be repurposed for new infrastructure without requiring new land acquisitions. The existing towers and

conductors, rated for 115 kV, would need to be rebuilt to a 230 kV standard. The location of the idle transmission corridor and the general location of future step-down stations are shown in Figure 24.

Figure 24| P45/46 transmission circuit extension into northern Markham



Alternative connection points for the future Northern York TS #2 and Markham MTS #6 stations would require either developing new transmission rights-of-way to supply the emerging load in northern Markham or locating the new station capacity along the existing transmission, which would be far from the anticipated growth. Neither of these alternatives are preferred to repurposing the idle transmission corridor. New transmission corridors through heavily built-up areas would be significantly more costly and disruptive to the community. Alternatively, locating new step-down stations farther away from the load would require long distance distribution lines and would introduce reliability risks and potential voltage support challenges due to the load density and distance from the transmission supply.

Based on comments received through engagement, there is a strong local preference for deferring the need for new transmission infrastructure in Markham for as long as possible, and for considering less visually intrusive technology types when the transmission is ultimately required.

The need for new transmission is directly linked to the need for new step-down transmission stations to serve Markham, northern Richmond Hill, and the eastern half of Northern York region. Measures that target peak demand reductions in these areas could have deferral benefits pushing the need for these stations and consequential transmission expansion. As a result, it is recommended that NWAs be targeted in this area, with particular focus on Markham, parts of northern Richmond Hill (i.e., in areas not associated with intensification along Highway 407 and Yonge subway extension), Aurora, and Whitchurch-Stouffville. These initiatives could produce net positive economic benefits by deferring infrastructure needs. The combined station development costs, including real estate, are estimated at approximately $120 million, while the minimum transmission cost is estimated at $45.5 million, and costs could be higher depending on the transmission technology type (e.g., monopole towers or undergrounding).

Should the transmission expansion be required to supply growth in northern Markham, there are technology types that can be considered at the time of designing the facilities to reduce the potential visual impact. For example, steel monopole tower designs, although more expensive than lattice tower structures, can be used in urban areas to minimize foundations and leaves more space for secondary uses. These alternative tower types may also be preferred by neighbouring communities due to their less industrial aesthetic. Underground transmission may also be preferred by communities, but undergrounding is generally reserved for cases where overhead facilities are not technically feasible due to their very high costs. Underground transmission cables can be several times more expensive than overhead lines, with the incremental cost related to undergrounding likely borne by the benefitting community. Other trade-offs associated with underground cables are a lower asset life expectancy, and longer and costlier repair and maintenance. Cables are less likely to experience outages due to factors such as weather, animal contact, and vehicular accidents, but may be more prone to impact from overland flooding or drought conditions. Given that this transmission corridor would be supplying radial loads (i.e., no redundant supply from both ends), interruption to customer loads could be significant if a contingency impacted an underground cable. A comparison of overhead and underground technologies for this transmission is provided in Table 9.

Table 9| Estimated cost of ~7km transmission extension along existing Right of Way in Markham

	Life of Asset (Years)	Cost ($M)
Lattice Tower	90-100	45.5
Cable	40-50	175

Decisions for the final technology type of new transmission lines are not typically made until the Environmental Assessment (EA) stage of line design.

7.4.2.4 P45/46 reconductoring to Buttonville

The near-term recommendation to reconductor the limiting section of P45/46 circuits (described in section 7.3.2.3) only considered the need to reconductor the section between Parkway TS and Markham MTS #4. This upgrade would allow for the full loading up to station LTR of Markham MTS #4, Buttonville TS, and future Markham MTS #5. In the longer-term, step-down station needs are expected to trigger the extension of circuits P45/46 and connection of two additional step-down stations: Northern York TS #2 and Markham MTS #6. The collective load of these five step-down stations would exceed both security limits and supply meeting (thermal) capacity of the remaining P45/46 circuits section between present day Markham MTS #4 and Buttonville TS. Options to address security needs are described in section 7.4.2.5, below.

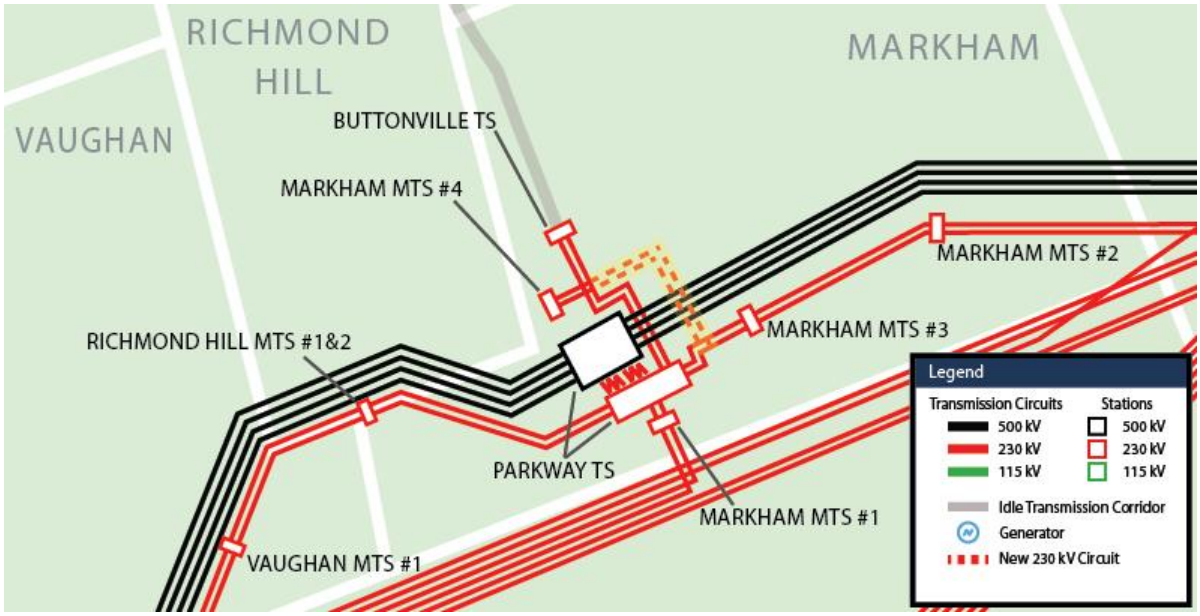
Thermal needs would be triggered when combined load at Buttonville TS, Markham MTS #5, Markham MTS #6, and Northern York TS #2 exceeds approximately 450 MW. These needs can be addressed by reconductoring the remaining ~2.7 km section of P45/46 circuits between Markham MTS #4 and Buttonville TS, with an approximate cost of $9.5 million.

The need date for this reconductoring work is when the collective load of Buttonville TS, Markham MTS #5, Markham MTS #6, and Northern York TS #2 exceeds 450 MW. To ensure that newly connected stations can make full use of their assets, this work should occur no later than the connection of either Markham MTS #6 or Northern York #2 TS, whichever comes first. However, it can often be challenging for facility owners and operators to manage outages required during reconductoring work. As a result, this work may be advanced at Hydro One's discretion, particularly if project efficiencies are identified from pairing this work with the reconductoring of the adjacent Parkway TS to Markham MTS #4 section of P45/46.

7.4.2.5 Markham MTS #4 radial tap

After addressing thermal needs with the reconductoring described above, the connection and loading of longer-term stations to the P45/46 circuits would still cause security needs to emerge when total load exceeds 600 MW. To address security needs, a new radial transmission circuit could be extended from the existing transmission corridor in the south (adjacent to Highway 407), to connect Markham MTS #4, and remove it from the remaining P45/46 circuits. This would increase the LMC of the area by roughly one station worth of load. This is shown conceptually in Figure 25.

Figure 25| Possible Radial Tap of Markham MTS #4



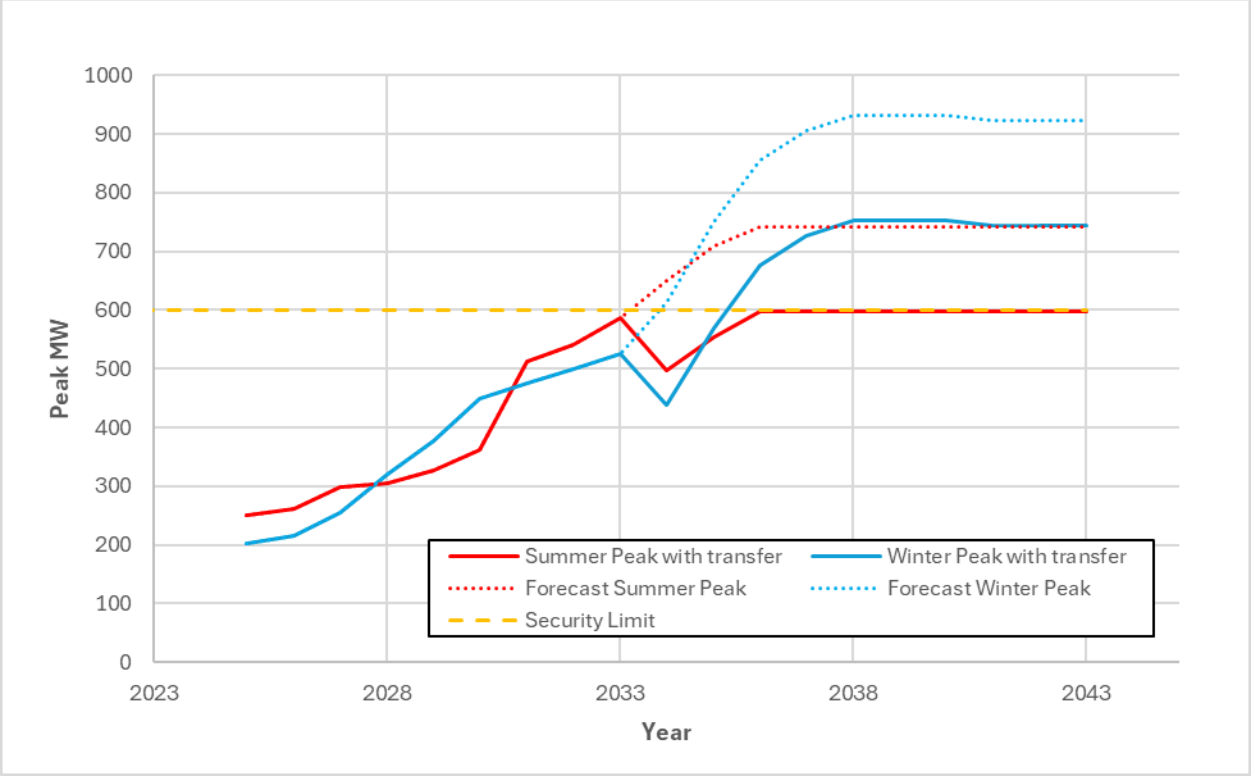
Markham MTS #4 is the preferred station for tapping off with a new transmission connection, as it is located close to alternate transmission points, with potentially as little as 1.5 km of new transmission required. Several potential connection points for this extension exist, including direct connection to Parkway TS, and tapping of the existing C35/36P circuits. The latter option is currently preferred as it would be significantly less costly than a connection within Parkway TS, which would incur additional upgrade costs to existing bulk system infrastructure at the station due to space constraints. The estimated present-day cost of the Markham MTS #4 tap from C35/36P circuits is $9 million. Making a

direct connection within Parkway TS, while offering improved reliability by reducing the number of stations served by a single transmission asset, would likely incur a minimum additional cost of $70 million to upgrade existing Air Insulated Switchgear (AIS) to Gas Insulated Switchgear (GIS). Both candidate transmission connection points can be accommodated within existing transmission corridor right of ways.

It is recommended that this work be undertaken to coincide with the connection of either Markham MTS #6 or Northern York TS #2, whichever is ultimately required first. This will allow LDCs to make full use of connection facilities once they become available. Identification of a preferred connection point for the Markham MTS #4 radial tap should be reevaluated during the next planning cycle, as development work is not expected to be required within the next 5 years. Cost assumptions related to different connection points may change in the interim based on bulk planning outcomes and/or upgrades required for new customer connections. This also provides time to monitor demand growth, and to implement measures aimed at managing the demand growth in order to defer the need for new infrastructure as long as possible.

Figure 26 shows the impact of removing Markham MTS #4 from the P45/46 circuits (notionally shown in year 2034) enables the remaining stations to be loaded up to the forecast summer peak.

Figure 26| P45/46 Circuit Loading



In the event that higher winter peaks begin to emerge in the long term, violations of security criteria are possible, with peaks potentially reaching 740 MW. If forecast winter peaks begin to emerge, NWA may provide a good solution to address periods of time where there is a risk of exceeding security limits, particularly as resources would only be required for short periods of time over the year.

7.4.3 Options to Address Northern York Needs

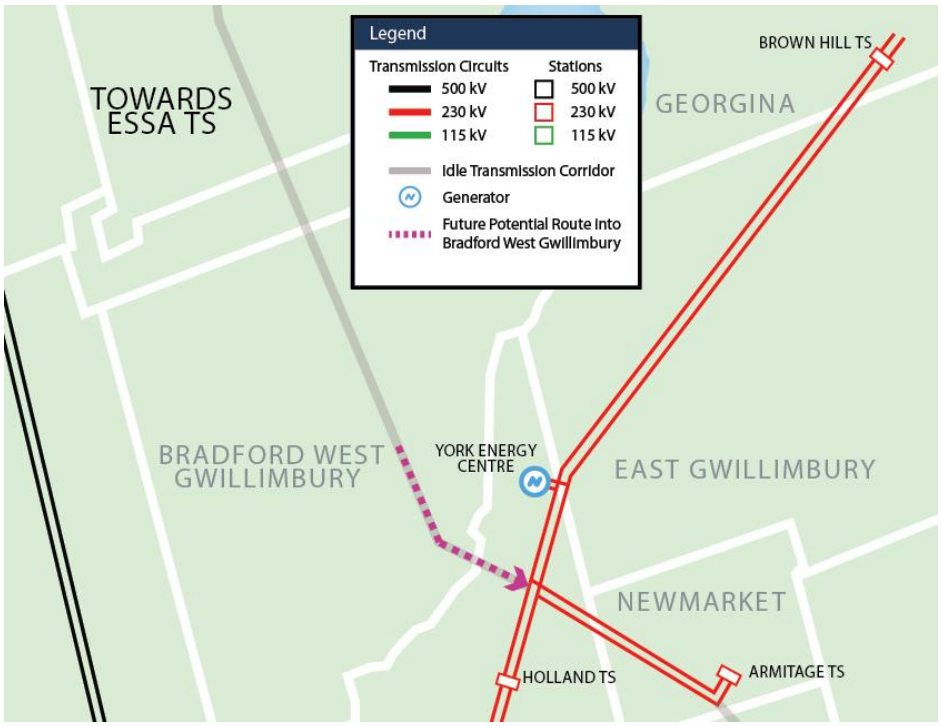
Preferred options to address longer term needs in Northern York will ultimately depend on the location of future Northern York step down stations, and whether YEC is assumed to continue commercial operation after 2035. Potential options are described below, although actions will not need to be taken to advance solutions at this time.

7.4.3.1 Northern York TS #3

As outlined in section 6.3.1.1, by the mid 2030s, growth rates in Northern York are expected to require a new step-down station to serve growing customer demands approximately every 4 years. This could further increase if large loads associated with major customer connections begin to emerge. The general preferred location for Northern York TS #1 and #2 has already been identified based on existing capacity limitations and anticipated high growth areas (the general vicinity of Holland TS and future Markham MTS #6, respectively). The preferred location for Northern York TS #3 is not yet known but would likely be in the general vicinity of Holland Marsh junction, where it would be located to accommodate growth throughout the communities of King, Newmarket, East Gwillimbury, and Bradford West Gwillimbury. This is because these communities are the furthest from the planned location of Northern York TS #2, so, as with Southern York region today, it is reasonable to assume alternating new stations between the east and west sides of the Northern York area.

An existing, idle transmission corridor currently stretches from the Holland Marsh junction, northwest through Bradford-West Gwillimbury, and ultimately through Simcoe County to connect with the existing Barrie TS and planned Innisfil TS (stations are within the South Georgian Bay/Muskoka regional planning area).

Figure 27| Conceptual route along idle corridor between Essa TS and Holland Marsh JCT



Making use of this corridor should be evaluated closer to the Northern York TS #3 need date to determine if the incremental benefit of providing step down capacity closer to load growth centres would offset the increased transmission cost. These benefits could include lower distribution infrastructure costs, lower connection costs for large customers, and higher reliability and power quality depending on the future areas of highest demand growth. Having this station on a separate transmission radial link could also potentially improve future capacity constraints on the remaining network circuits in Northern York (H82/93V and B88/89H), but this would need to be evaluated when actual longer-term supply and demand conditions are better known.

7.4.3.2 York Energy Centre Continued Operation

As described in section 6.3.2.1, the phase out of YEC following its contract expiry in 2035 would introduce a sudden 400 MW shortfall of local capacity in Northern York region. The supply gap would be in addition to organic load growth already defined in the load forecast. Meeting a sudden supply requirement of this magnitude would either require similar sized generation to take its place, or new transmission to bring capacity into he same general area where generation is lost.

In order to replace the existing, single cycle gas supply, a generation option would need to have similar operational characteristics as YEC today. This means the ability to rapidly ramp up operation, adjust generation levels to match local demand levels, and operate continuously throughout periods of peak demand, which can last for several hours in a day, and last several days in a row. Intermittent generation sources, such as solar and wind, would not be suitable alternatives due to significant land requirements to account for lower capacity factors for these generation types. Pairing

with batteries would also pose challenges, as the size of batteries required would need to account for worst expected duration of needs over several years, which would not be economic since these conditions are by definition rare events.

It is important to note the that the local requirements to operate YEC (or a similar sized and technology type resource) are only triggered for short periods of the year. This would include hours where local demand is at its highest, or during planned or emergency system outages. While fully offsetting the need for the full 400 MW of available capacity would be very challenging without significant transmission infrastructure to replace this shortfall, adding additional energy sources, such as a Battery Energy Storage System (BESS), would lower the number of hours of the year in which YEC would be expected to operate.

Local communities have consistently indicated a strong preference for lowering greenhouse gases (GHG) emissions released in the area, where achievable with minimal disruption to the surrounding agricultural land use. Capital Power, the owner of YEC, has recently installed a 132 MW BESS to one of the two yards that YEC operates out of. The existing BESS, while able to lower expected GHG from normal operation, does not have a significant impact on local capacity or reliability needs.

If a second, similarly sized BESS were connected to the B89H circuit (either at YEC, or elsewhere on the circuit section), the combined impact of the two BESS units would improve system reliability performance, as at least one could be assumed in service under all contingencies in which either B88H or B89H remain operable. The reliability benefit for adding a second, identically sized BESS within the B89H corridor would be equivalent to approximately 60 MW of reliable local capacity, after accounting for typical operational profiles of BESS technology.

However, the supply capacity increase from this second BESS would not be sufficient to offset near term needs, nor would it have an impact on longer-term step-down station capacity needs. For that reason, it is not included as a recommendation in this study. A combination of short circuit and congestion issues also currently prevent new local resources, including BESSs, from connecting in this area. However, if these issues are resolved in the longer term, this project, or other similar sized generation projects, could help defer longer term needs in the area while reducing the amount of time YEC could be expected to run in the near term, thereby lowering GHG emissions within the area. This makes it a potentially higher value location for siting BESS technologies within York Region, when considering reliability and environmental factors. These benefits would be unique to generation sources which are dispatchable, non emitting, and able to be connected to the B88/89H (preferably B89H) circuits.

7.4.3.3 New Northern York transmission supply

In the event that YEC is phased out following its contract expiry in 2035, and equivalent generation is not located in the same general area, it would trigger the need for a new transmission circuit to deliver capacity into Northern York. A typical double-circuit 230 kV line can transfer at least 600 MW of power, though design factors can influence total capacity. Planning this type of infrastructure would require consideration of the initial supply point, the termination, and route between these two points. For a supply point, the anticipated and nearby Kleinburg TS would provide an excellent source of bulk power and given it is expected to come into service in the early 2030s, would likely have

more than sufficient capacity for this project. As a termination point, a connection in the same general vicinity as YEC, or at a minimum on the B88/89H circuits would be preferred. This would ensure that new capacity can push against the typically limiting flow away from Kleinburg TS along H82/83V. An ideal connection point would be a new Switching Station (SS), described in the section below, which would link the existing H82/83V circuits with B88/89H, while creating new terminations for the Armitage radial pocket. Having a supply path into this SS would ensure each of the supply points emanating from this station could have a redundant source of supply under multiple configurations and contingencies.

Based on an initial review of the existing corridor between Kleinburg TS and the Holland Marsh area, a new transmission right of way would need to be identified and land acquired to enable this connection. The first section of a proposed corridor could make use of the planned Kleinburg – Kirby transmission link, adjacent to the future Highway 413. Sufficient land is being set aside to enable two double-circuit transmission lines along this route. The first, described in section 7.3.2.2, is expected to be developed in the near term, while the space allocated for the second could be leveraged here. This would allow for a partial new corridor between Kleinburg TS and the approximate intersection of Kirby and Kipling. The remaining ~23km to the Holland Marsh area has an existing transmission line, but there is insufficient land along this corridor to enable a second transmission line. Additionally, there are several points along this corridor where buildings and other geographic features unsuitable for transmission use are immediately adjacent, meaning acquiring new land adjacent to the existing line is either not preferable, or infeasible. As a result, a new route would need to be identified, largely through King township. Given the complexities of siting transmission, namely requiring a linear corridor, with fixed start and end points, and compatible adjacent land uses for the entire route, this could be a costly and disruptive undertaking for the community.

No actions or recommendations are required at this time. However, if YEC is assumed to come out of service in 2035, work should begin no later than 2028 to identify land suitable for a new transmission corridor and initiate development work. Although no site-specific analysis has been undertaken to produce formal cost estimates, typical new corridors of this size, including transmission infrastructure and real estate costs, could be $200-300M.

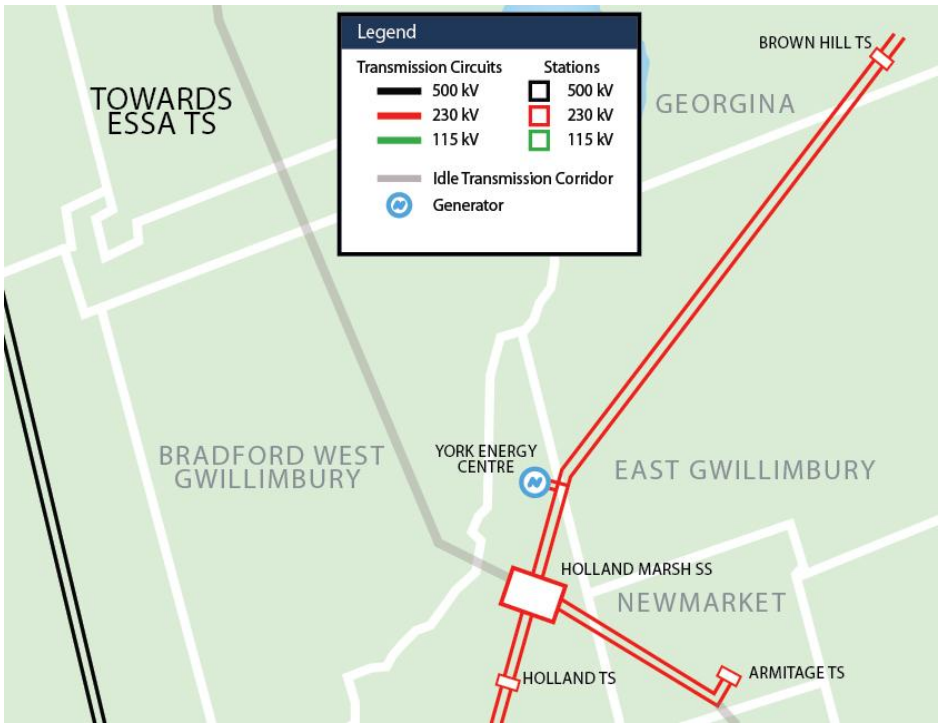
7.4.3.4 Holland Marsh Switching Station

As described in section 7.5.3.1, the connection of a third Northern York TS along the Claireville to Minden corridor will trigger a security need regardless of whether it is connected to the H82/83V or B88/89V circuits. In addition to the security needs triggered, this section of the grid has been cited by operators as posing significant challenges due to the presence of two sets of inline breakers, and a major system resource facility (YEC). Sectionalizing the existing circuits through a Switching Station (SS) would greatly streamline the operational characteristics, while enabling the connection of Northern York TS #3, and eliminate the most limiting breaker failure contingencies currently affecting the area.

A long-term switching station configuration would be positioned at the existing Holland Marsh junction, to allow for separate circuit termination for the existing H82/83V, modified B88/89H circuits (only the section north of the Armitage junction), and a new, separate radial pocket for Armitage TS. Circuit positions should also be made available for the connection of any future radial circuits

required for supply to the Bradford-West Gwillimbury area, and for connection of any new supply transmission line which may be required in the long term, as outlined in Section 7.4.3.3.

Figure 28| Potential future location of Holland Marsh SS



The ultimate configuration of the SS is outside the scope of this study but should be investigated to eliminate the possibility of a common breaker failure triggering simultaneous loss of one H82/83V circuit and one B88/89V circuit. This would eliminate the most limiting breaker failure contingency. If a longer-term connection line into West Gwillimbury is ultimately developed to connect the future Northern York TS #3, an initial preferred switching station arrangement could assume that line terminations are alternated between network lines (B88/89H and H82/83V) and radial lines (Armitage tap, West Gwillimbury Tap).

At this time, the development of a Holland Marsh Switching Station is not required. The current demand forecast suggests that Northern York TS #3, and as a result Holland Marsh SS, would be required in the mid 2030s. However, these assumptions should be revisited during future studies based on actual growth rates, preferred location for future stations, and ultimate connection arrangements. Hydro One has indicated that existing land rights are expected to be sufficient to accommodate this facility when required, with no additional acquisitions required. Switching Stations of this size, including all associated switchgear and breakers, typically cost $200-250 million.

7.4.3.5 Reconductoring H82/83V

As described in section 7.3.2.2, reconductoring of the limiting section of H82/83V between Claireville TS and Vaughan MTS #4 is not a viable option, as the existing corridor is too narrow, and development too close, to allow the work to be completed. However, development north of the proposed Kleinburg-Kirby connection point along H82/83V is significantly less dense. Based on a

review undertaken by Hydro One, reconductoring the remaining section between the Kleinburg-Kirby link and Holland Marsh junction is likely feasible.

Following completion of the YEC station service project and the Kleinburg-Kirby link, additional load meeting capability in Northern York is not expected to be required until an additional step-down station is required (notionally Northern York TS #3), and/or following the potential retirement of YEC.

The benefit provided by this reconductoring would depend on the longer-term configuration of the system, including location of demand, supply, and any new infrastructure such as switching facilities. Where thermal limits along the H82/83V circuits are found to be limiting, reconductoring this section could potentially increase LMC by providing improved capacity into a future Holland Marsh SS.

7.5 Opportunities for Non-Wires Alternatives

7.5.1 Large-scale Non-Wires Alternatives

Transmission-connected resources such as large-scale solar, wind, BESS or a combination of these resources were found not adequate to resolve the supply capacity needs covered in Section 6. This is mainly due to 1) connection restrictions in the area due to short circuit limitations at Claireville TS and congestions on the circuits covered in the needs 2) the large magnitude of land required to meet the supply capacity needs of each region sufficiently to defer wires reinforcements.

Installing large transmission-connected resources also do not resolve the station capacity needs in the region, especially in Northern York and the Markham area where downstream feeders cannot viably connect to the system unless new step-down stations are implemented. It is expected that the near-term recommendations described in Section 7.3.2.2, along with the required bulk upgrades described in Section 8.1, will help enable the connection of some resources by resolving the short circuit limitations of Northern York, but congestion constraints will remain in the area, and short circuit issues remain in Southern York.

7.5.2 Demand Side Management

Incremental eDSM can help manage the demand until the next major grid reinforcement or step-down station would be required to cater to the large supply capacity needs. The table below provides a year over year cumulative breakdown of the incremental eDSM potential available per subregion above and beyond that already captured in the IRRP demand forecast.

Table 10| Estimated Incremental eDSM Potential (Cumulative MW) by Subregion

	Northern York	Kleinburg subsystem	Southern Vaughan-Richmond Hill	Markham and Area
2025	18.4	7.7	10.3	9.9
2026	26.3	10.7	13.3	13.4
2027	44.0	17.6	20.3	23.8
2028	35.1	14.1	16.9	18.0
2029	52.5	20.7	23.3	29.1
2030	60.2	23.5	26.8	34.4
2031	70.3	28.1	35.7	45.3
2032	82.5	33.9	47.8	55.9
2033	92.8	38.9	58.9	66.8
2034	103.1	42.5	68.0	78.2
2035	123.9	46.9	76.8	95.5
2036	112.8	44.5	71.7	86.9
2037	141.4	49.6	80.5	100.5
2038	161.0	52.4	84.9	105.7
2039	177.0	55.2	89.1	113.0
2040	190.9	57.6	92.8	123.0
2041	200.0	59.4	96.1	131.5
2042	**211.6**	**61.5**	**99.3**	**137.4**

8 South and Central Bulk Study

IESO is currently also undertaking a bulk study focused on the Southwestern and Central regions of Ontario, particularly along the Windsor to Hamilton corridor as well as the urban centers in the GTA.

This bulk study is closely linked to the GTA North IRRP and will be key in enabling some of the near-term recommendations discussed above.

Some of the key linkages from the bulk study to this IRRP are as follows:

- Upgrading station (Kleinburg TS) from 230kV to 500kV to support provincial and local needs
- Building an additional circuit from Essa (Barrie) to Kleinburg TS to strengthen electricity flows north/south
- Improving bulk system supply from east GTA towards Parkway TS to help support growth in GTA North
- Determining transmission required to enable decreased bulk system reliance on YEC
- Protecting strategic corridors for future infrastructure to support economic development and community growth

8.1 Bulk Considerations for Enabling the Kleinburg-Kirby Transmission Link

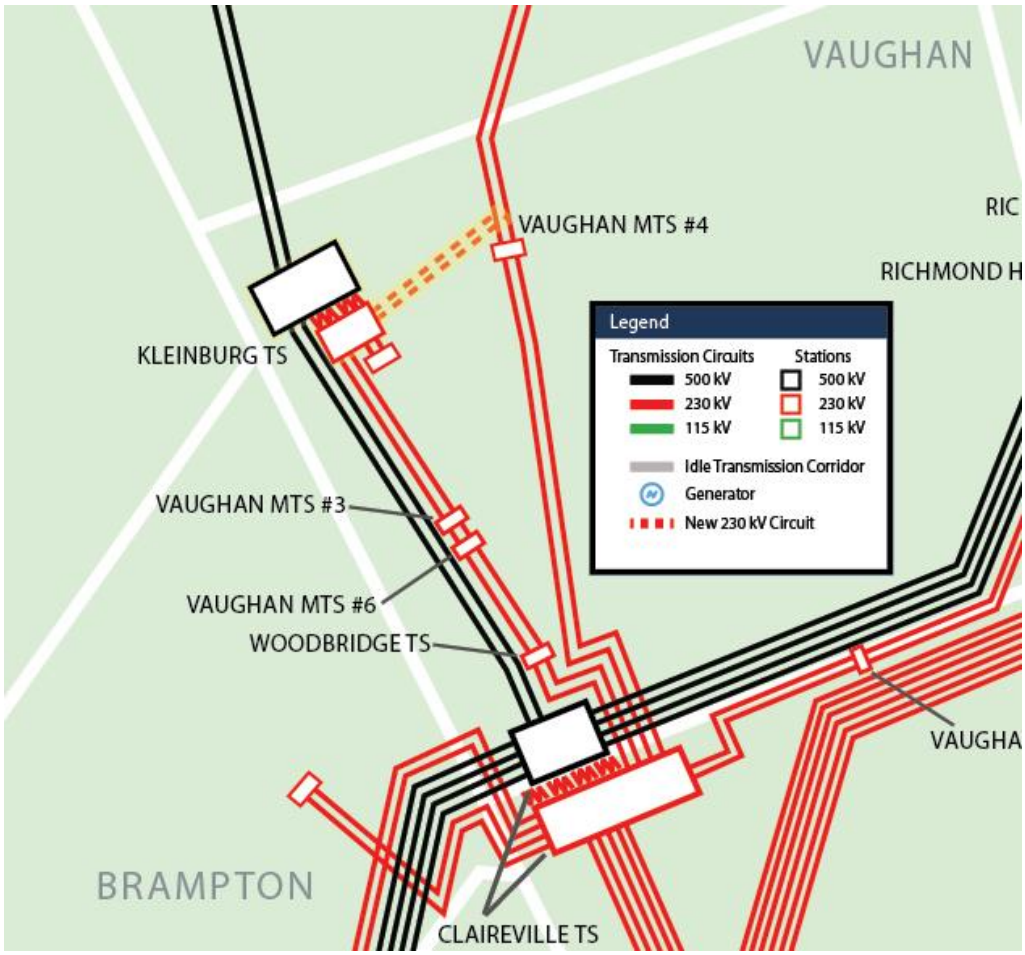
Placing the Kleinburg – Kirby link in service discussed in section 7.3.2.2 will require additional capacity to be available at Kleinburg TS to supply northern York. In the absence of a new supply source, the existing Kleinburg radial tap would become thermally overloaded north of Claireville TS, as the V43/44 circuits would have to carry all existing supply for the local pocket, as well as incremental demand for customers in northern York.

The existing Kleinburg TS, located at the northernmost point of the V43/44 circuits, is currently operated as a step-down station primarily providing distribution supply to customers in Vaughan, Brampton, and Caledon. However, when this site was originally developed, its access to both the regional 230 kV and bulk 500 kV transmission network made it a suitable candidate as a future bulk supply point. Enough land was acquired when developing this station to accommodate additional switching and autotransformer facilities to create a 500kV to 230 kV bulk supply point once required. Based on the current needs for supplying local growth, and broader bulk system benefits identified through a separate bulk planning process, it is recommended that the development of Kleinburg TS as a bulk supply point proceed.

In order to manage higher order contingency scenarios required for the bulk system, three 500 kV to 230 kV autotransformers will initially be required at this site. Space should be set aside to enable the long-term connection of a fourth autotransformer, as a final build out option. Supply to the new autotransformers is to be accomplished through bisecting and re-terminating the existing two 500 kV circuits between Claireville TS and Essa TS. This will require a single 500 kV bus at Kleinburg TS with an initial four 500 kV connection points – two connecting Kleinburg TS to Claireville TS, and two connecting Kleinburg TS to Essa TS.

On the 230 kV yard, space should initially be set aside for six circuit terminations. These would consist of the original two V43/44 circuits, the new double-circuit Kleinburg-Kirby link, and a double-circuit tap to directly supply the existing Kleinburg TS step down station (referred to as Kleinburg DESN hereafter for clarity). Providing a separate connection for the existing Kleinburg DESN would address potential security needs on the Kleinburg radial tap by reducing the amount of capacity supplied by the V43/44 circuits (see section 6.3.3.2). Selecting Kleinburg DESN for direct connection to the 230 kV bus work would minimize connection costs as the station is already located within the facility. In addition to these initial six 230 kV termination points, space should also be set aside for a minimum of four additional positions, to accommodate a potential longer-term need for a new double-circuit 230 kV line into northern York, and a double-circuit 230 kV line spanning westward to supply local demand in northern Brampton and southern Caledon. This latter route would also make use of the planned transmission corridor adjacent to Highway 413. The notional layout of these new facilities is provided below:

Figure 29| Future Kleinburg TS and Kleinburg – Kirby transmission link



This configuration should be considered preliminary at this point and is provided to aid in system evaluation and preliminary site design. Review and further recommendations for the configuration and layout of the Kleinburg TS 500 kV and 230 kV station yards should be carried out by Hydro One as part of the Regional Infrastructure Planning (RIP) process, and final design through the applicable approvals process.

Given that Kleinburg TS is owned and operated by Hydro One today, the development of the Kleinburg TS bulk supply station is not suitable for competitive procurement.

Providing capacity at Kleinburg TS through new local generation, as opposed to creating a new bulk supply point, is not preferred for several reasons.

1. Short circuit levels at Claireville TS are elevated today and will require operational changes at the 230 kV level in order to accommodate additional supply (transmission or generation) at Kleinburg TS.
2. Using a generation source of supply, as opposed to transformers, would require continuous operation and significant load following capability to match local demand. These types of operational requirements are not practical or cost effective for a local system.
3. Transformers are preferred as they provide the benefit to the overall bulk transmission system. Introducing this new supply point in the GTA will provide needed offloading for Claireville TS, enabling growth and the connection of some local resources in the surrounding regions including City of Toronto and Regions of Peel and Halton. while improving long term ability to disperse flows into Essa towards the higher demand centres to the south.

The estimated cost for the development of Kleinburg TS, including all associated switching gear, autotransformers, and reconfiguration of the existing 500 kV system, is approximately $400 M. This station is needed in the near term to accommodate regional growth as well as primarily to serve a bulk system function by managing supply between the existing Claireville TS bulk supply point to the south, and the new supply point to the north, which is better located for accommodating growth throughout northern Halton, Peel, and York regions. The Kleinburg to Kirby link is likewise performing a bulk system function by allowing supply from the new Kleinburg TS to be accessible for regional customers.

Timelines for the implementation of the Kleinburg-Kirby link, and bulk system build out of Kleinburg TS, would ideally align with the proposed in-service date of Northern York TS #1, to ensure infrastructure can be loaded to its full capacity once available. Given typical rates at which new stations are loaded, however, the connection of Northern York TS #1 could be advanced, so long as total loading on the Claireville TS – Brown Hill TS corridor remains under 848 MW, assuming the YEC station service issue has been resolved. This loading level is roughly equivalent to Vaughan MTS #4, Holland TS, and Armitage TS at their full respective LTRs[7], Brown Hill TS loaded at its current summer peak, and the new Northern York TS #1 loaded to 38 MW. Loads of these levels are typical for the first one to two years of a newly in service station. Above this load level, more frequent arming of the existing RAS would be required until the transmission solution has come into service.

8.2 Bringing Bulk Supply from East GTA towards Parkway TS

New generation resources located near Darlington Nuclear Generation stations will become available in early to mid 2030s. The IESO has previously identified a need for a double-circuit going west towards the GTA as an early action to supply the urban centres in the GTA, including the Region of

[7] Inclusive of new Metrolinx loads in Newmarket

York. Parkway TS has been preliminarily selected to be connected to the new double-circuit to reinforce supply into the region while catering for growing demand in the surrounding regions. This option also makes the best of use of available corridor and station real estate in the GTA. It also allows for reconfiguration of existing loads between the key GTA transformer stations, taking short circuit limitations and supply capability into account.

The study will also consider any system reinforcements required to accommodate the new supply downstream of the station in the GTA 230 kV system.

8.3 Additional Essa (Barrie) to Kleinburg TS

In the longer term, larger bulk flows into Essa will also require a third 500 kV line to be built between Essa TS and the proposed Kleinburg TS. This could be triggered from either higher procurement of generation in northern Ontario (such as through expanded hydro development), or the completion of Bruce to Essa transmission upgrades to incorporate expansion at Bruce nuclear GS or large-scale pumped storage between Bruce and Essa zones. This need is based purely on bulk system considerations, and as such timing for the third line will be outside the scope of the GTA North IRRP.

8.4 Decreasing Bulk System Reliance on YEC in the Long Term

As discussed in Section 6.3.2.1, should YEC be phased out following its contract expiry in 2035 or at its eventual retirement at the end of its life cycle, and equivalent generation is not located in the same general area, new transmission infrastructure may be required to cover the capacity shortfall. The bulk study is aimed at studying the impact of the absence of YEC at a wider system level and any potential reinforcements required to adequately supply the region.

8.5 Protecting Strategic Corridors

The IESO is taking early action to identify and protect strategic corridors to enable the long-term infrastructure discussed in the sections above and beyond to enable and support electrification, residential and economic intensification. Three key studies are identified in high-growth areas, including York Region, where land is limited and electricity systems are nearing capacity:

- **Parkway Belt West Corridor**: Exploring future high-voltage transmission lines and transformer stations to support GTA growth and to enable new generation resources.
- **Barrie to Markham Corridor**: Preserving land for a future transmission line to further link Northern and Southern Ontario, to enable growth in Northern Ontario and to supply Southern Ontario with diversified resources.
- **Northwest GTA Corridor**: Refining plans near Highway 413 to support future infrastructure in York, Peel, and Halton.

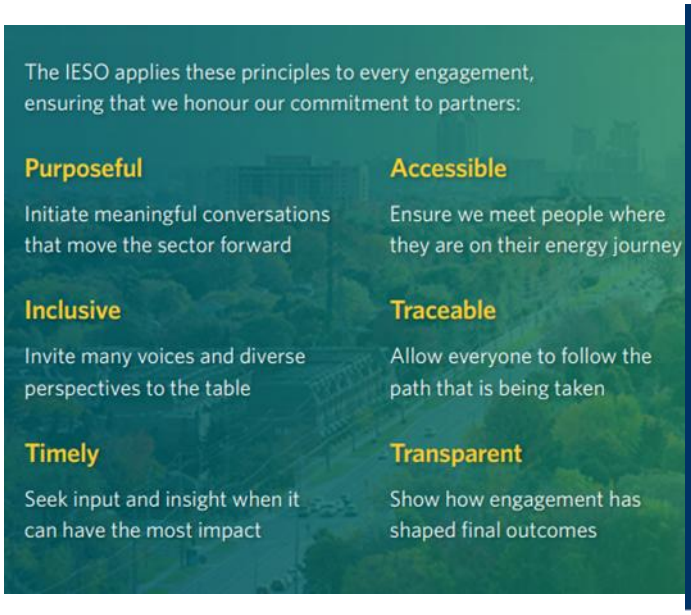
9 Community and Stakeholder Engagement

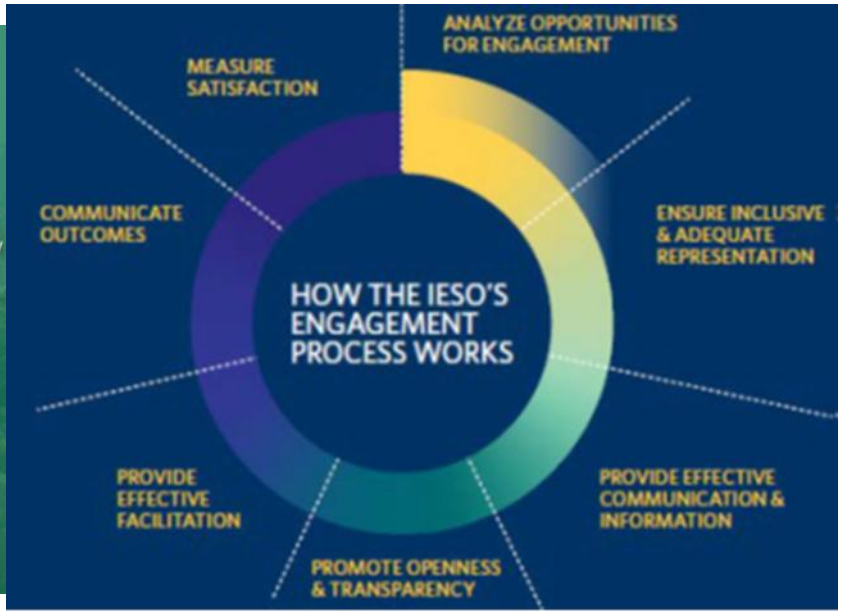
Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the GTA North IRRP.

9.1 Engagement Principles

The IESO's External Relations Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 30| The IESO's Engagement Principles





9.2 Engagement Approach

To ensure that the Plan reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement involved:

- Leveraging the GTA North engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback;

- Encouraging participants to visit the Powering the GTA website, dedicated to exploring electricity needs and solutions across the GTA;
- Timely and targeted discussions with municipalities and letters prepared for Mayors and Councillors to help inform the engagement approach for this planning cycle;
- Hosted a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions; and
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 9.4).

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the GTA North Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the GTA North Scoping Assessment Report finalization. A public webinar was held in September 2023 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in October 2023, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, several targeted outreach meetings then began to involve municipalities in the region to ensure growth and development plans have been accurately captured in the Technical Working Group's draft demand forecast and solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the GTA North Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar. The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during public engagements primarily focused on:

- Significant population growth and economic development projects across the region;
- Aligning infrastructure with community infrastructure development;
- Interest in leveraging existing and local generation;
- Alignment of electricity planning with local priorities, such as community and energy plans; and
- Exploring alternative solutions, such as non-wire options, to meet the area's electricity needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to GTA North Region subscribers, municipalities, and Indigenous communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with the significant forecasted growth and development both within specific municipalities and the region more broadly (e.g. significant population and employment growth shared by the City of Richmond Hill, constrained land use shared by the Cities of Richmond Hill and Markham, and capacity constraints shared by Bradford West Gwillimbury). Another key priority was to understand community perspectives on keeping York Energy Centre (YEC) in service past the 2035 contact expiration, which received general support from municipalities and stakeholders highlighting concerns for the remaining supply gap without the facility. These insights have been valuable to the IESO – as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's GTA North engagement webpage.

9.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on its planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the lower-tier municipalities in York Region to share key developments and to provide an opportunity for municipal feedback on the forecasted regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal and community electricity needs and priorities, establish new relationships, and provide opportunities for ongoing dialogue beyond this IRRP process. Additionally, the IESO led

council outreach that included letters prepared for mayors and councillors, and one-on-one councillor meetings to provide elected officials with updates on electricity planning developments, and to provide an opportunity for discussion.

Through these discussions, valuable feedback was received and incorporated in the final IRRP recommendations, including:

- The Town of Stouffville recommended sharing the methodology on how the demand forecast is calculated, including the different variables that are considered.
- The Township of King, the City of Markham and the City of Richmond Hill expressed the need for early and detailed coordination with municipalities to ensure electricity planning aligns with land use policies and congested municipal right-of-ways (ROWs).
- The City of Markham emphasized their preference for utilizing existing station and transmission infrastructure corridors to avoid expanded or new corridors, reducing impact on development and adjacent communities.
- The City of Richmond Hill, and the Town of Whitchurch-Stouffville requested sharing a layout of the power distribution network and detailed mapping of locations for future infrastructure requirements to understand compatibility.
- The Cities of Richmond Hill, Markham and Vaughan detailed significant population and development growth projections in their cities to ensure it is captured in the demand forecast.
- Station capacity concerns were raised in Bradford West Gwillimbury at their Holland TS, and in the City of Vaughan along the Yonge/Steeles corridor.
- Several municipalities highlighted their energy, and sustainability plans and encouraged consideration for non-wire alternatives as solutions in the IRRP in order to align with their net-zero and decarbonization targets.
- King Township and the City of Markham support keeping YEC in service considering the facility already exists and reduces the need for widespread transmission infrastructure and suggest exploring deep retrofits that align the facility with climate goals.

9.5 Engaging with Indigenous Communities

The IESO remains committed to ongoing, effective dialogue with Indigenous communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in the GTA North (York Region) and provide opportunities for input, the IESO invited Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use to participate in engagement efforts that included webinars and meeting discussions (virtual or in-person).

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions across Ontario.

10 Summary and Conclusion

The York Region Integrated Regional Resource Plan (IRRP) identifies electricity needs across the region over the 20-year planning horizon from 2024 to 2043 and recommends a coordinated set of actions to address these needs in the near term to enable growth in the region and identifies potential options which may be required in the longer term. The IESO will continue to participate in the Technical Working Group during the next phase of planning, the Regional Infrastructure Plan (RIP), to support implementation and ensure alignment with broader system planning.

In the near term, the Technical Working Group recommends immediate action to address station and supply capacity needs in Northern York, Markham, and Richmond Hill. This includes the development of new step-down transformer stations (Northern York TS #1, Markham MTS #5, and Richmond Hill MTS #3), a new 6-7 km transmission line along the future Highway 413 corridor in Vaughan, reconductoring of existing transmission circuits in Markham, and sectionalization devices to address security needs. To improve reliability, operational measures including reconfiguration of York Energy Centre's power supply, and targeted incremental eDSM are also recommended to manage reliability risks and defer longer-term infrastructure needs.

In the medium- to long- term, the Technical Working Group recommends planning for additional step-down transformer stations (Northern York TS #2 and #3, Markham MTS #6, Vaughan MTS #5), and transmission enhancements to ensure these stations can be reliably supplied. This includes extending the existing Markham transmission line approximately 7 km into northern Markham, to enable the connection and supply of new step-down stations to serve customers in the vicinity of northern Markham, northern Richmond Hill, and Whitchurch-Stouffville. Longer-term needs associated with Northern York TS #3 will likely require additional transmission upgrades in Northern York, including, at a minimum, a new switching station in the vicinity of Holland Marsh junction. The potential retirement of York Energy Centre post-2035 has also been identified as a key driver of future supply needs and would likely trigger the development of a comparably size generator, or a new transmission corridor into Northern York, if this supply source is phased out.

The Technical Working Group will continue to monitor regional developments, including electrification trends, large customer connections, and community energy planning. Opportunities to target incremental eDSM and non-wires alternatives will be evaluated to defer infrastructure needs where feasible. The Working Group will meet regularly to track progress, assess changing conditions, and update the plan as needed. Should significant changes in assumptions arise, the IRRP may be amended or a new planning cycle initiated ahead of the standard five-year schedule.

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REGIONAL INFRASTRUCTURE PLAN REPORT

GTA North

Regional Infrastructure Plan Report

GTA North

May 6, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

GTA North Technical Working Group

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Disclaimer

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

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

The cost figures presented are high-level allocations in 2025 dollars and have not been informed by detailed engineering design or development work. Accordingly, these estimates are preliminary in nature, subject to material change, and are intended for options analysis purposes only.

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

Executive Summary

Region	**GTA North** (the "Region")
Lead	Hydro One Networks Inc. ("HONI")
Start Date: November 7, 2025	**End Date:** May 6, 2026

The Regional Infrastructure Plan (RIP) represents the final phase of the Regional Planning Process for the GTA North region. It builds on earlier planning activities, including the Needs Assessment (NA) report published by Hydro One on July 14, 2023, followed by the Scoping Assessment and Integrated Regional Resource Planning (IRRP) reports which were released by the Electricity System Operator (IESO) on October 12, 2023 and on October 10, 2025 respectively.

As the lead transmitter, Hydro One developed the RIP in collaboration with the GTA North Technical Working Group (TWG) for the region and is responsible for publishing the final report. The RIP report consolidates the analysis of options, recommended plans, and preferred wire infrastructure investments identified in earlier planning phases to address the near- and medium-term electricity needs. The load forecast used in this RIP has been adopted from the IRRP report, as no material changes were identified relative to the load forecast submitted during the IRRP Phase. The forecast period covers the 10 years following the completion of IRRP.

The objectives and scope of the RIP are:

- Compile and present a consolidated summary of regional needs and corresponding wires plans to address near and medium-term requirements (2026-2035) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identify any new need(s) that may have emerged over 2026-2035 period.
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.
- Consideration of long-term needs identified in the Toronto IRRP, Bulk system studies or as identified by the TWG.

The major infrastructure investments recommended by the TWG in the GTA North region for the next ten years are given below. A single line diagram with the new investments marked is given Appendix G.

Recommendations

Station/Circuit Name	Recommended Plan	Lead	Planned ISD[1]	Section No.
Asset Renewal Needs				
Woodbridge TS	Transformer (T5) refurbishment	Hydro One	2032	8.1.1
Station Capacity Needs				
Kleinburg TS	Adding Kleinburg TS (T3/T4) 230/44kV DESN	Hydro One	2028	8.2.1.1
Vaughan MTS #6	Build Vaughan MTS #6 230/27.6 kV DESN	Alectra	2027	8.2.1.2
Northern York TS #1	Build Northern York TS #1 230/44kV DESN	Hydro One	2031	8.2.2.1
Northern York TS #3	Build Northern York TS #3 230/44kV DESN	Hydro One	2035	8.2.2.2
Richmond Hill MTS #3	Build Richmond Hill MTS #3 230/27.6kV DESN	Alectra	2030	8.2.3.1
Vaughan MTS #5	Build Vaughan MTS #5 230/27.6kV DESN	Alectra	2033	8.2.3.2
Buttonville TS #2 (Previously referred to as Markham MTS #5)	Build Buttonville TS #2 230/27.6kV DESN	Hydro One	2030	8.2.4.1
Markham MTS #6	Build Markham MTS #6 230/27.6kV DESN	Alectra	2034[2]	8.2.4.2
Northern York TS #2	Build Northern York TS #2 230/44kV DESN	Hydro One	2034[2]	8.2.4.3
Transmission Line Capacity Needs				
P45/P46	Upgrade P45/P46 from Parkway TS to Markham MTS #4	Hydro One	2031	8.3.1.1
P45/P46	Upgrade P45/P46 from Markham MTS #4 to Buttonville TS	Hydro One	2034	8.3.1.2
P45/P46	Extend P45/P46 7 km north from Buttonville TS	Hydro One	2034	8.3.1.3
C35P/C36P	Reconnect Markham MTS #4 to C35P/C36P	Hydro One	To be discussed in the next Regional Planning cycle	8.3.1.4

Station/Circuit Name	Recommended Plan	Lead	Planned ISD[1]	Section No.
System Reliability				
Kleinburg TS	Build Kleinburg to Kirby Transmission Link	Hydro One	2031-2032	8.4.1
Kleinburg TS	Bulk Supply - 500/230 kV Transformer Station[3]	Hydro One	2031-2032	8.4.2
York Energy Centre	York Energy Centre – Station Service Upgrade	IESO/Capital Power	2026 (Current)	8.4.3
Holland Marsh SS	Holland Marsh Switching Station	IESO / Hydro One	TBD[4]	8.4.4
New Northern York Transmission Supply	Reinforce transmission supply to Northern York	IESO / Hydro One	TBD[4]	8.4.5
V71P/V75P	In-line breakers New 230kV inline breakers on V71P/V75P circuits	Hydro One	2030	8.4.6
H82V/H83V & B82H/B83H	Claireville to Minden - Over voltages and Under voltage needs.	IESO / Hydro One	TBD[5]	8.4.7
Section of H82V/H83V from Kirby towards Holland	Add new Circuits/Upgrading H82V/H83V circuits from Kirby Jct. to Holland Marsh.	IESO / Hydro One	TBD[5]	8.4.8
Load Security and Restoration				
V43/V44	Load Security on Kleinburg Radial Tap	Hydro One	2031-2032[6]	8.5.1
V71P/V75P	Load Security and Restoration on V71P/V75P	Hydro One	2030[7]	8.5.3
P45/P46	Load Security and Restoration on Buttonville Corridor (P45/P46)	Hydro One	2034[8]	8.5.4

[1] The in-service dates are tentative and subject to change.

[2] The in-service date for Northern York TS #2 and Markham MTS #6 will be coordinated with the P45/P46 Line Extension Project.

[3] This project has been recommended by the IESO's South and Central bulk system study and is part of bulk system reinforcement.

[4] The need, scope and timing of this work will be further discussed in the next planning cycle.

[5] TWG will continue to monitor status.

[6] This issue will be addressed by the Kleinburg TS 500/230kV Station project.

[7] This issue will be addressed by the V71P/V75P in-line breakers project.

[8] This issue will be addressed by reconnecting Markham MTS #4 to circuits C35P/C36P project.

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1 INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of the Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the GTA North region, preceded by, the publication of Needs Assessment (NA) report in July 14, 2023 by Hydro One, followed by the Scoping Assessment (SA) & Regional Resource Planning (IRRP) which were published in October 12, 2023 and in October 10, 2025 respectively, by the Independent Electricity System Operator (IESO). Typically, an IRRP takes 18 months to complete. However, due to the complex nature of the needs in the region, the IESO requested a six-month extension from the OEB to finalize the plan.

The RIP report includes a common discussion of all the options and recommended plans, and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by GTA North TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDC"), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1.

Table 1: GTA North Region TWG Participants

No.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission)
2	Hydro One Networks Inc. (Distribution)
3	Alectra Utilities Inc.
4	Newmarket-Tay Power Distribution LTD (NT Power)
5	Toronto Hydro
6	Independent Electricity System Operator (IESO)
7	Elexicon Energy

2 OBJECTIVES AND SCOPE OF THE REGIONAL INFRASTRUCTURE PLAN

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

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

The RIP adopted the IRRP provided load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near- and medium- term needs (2026-2035) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2026-2035 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in GTA North IRRP, Bulk system studies or as identified by the TWG, are excluded but briefly touched upon.

2.1 Structure

The rest of the report is organized as follows:

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

3 REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and require longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides an outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all regional needs. If no further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs are:

a) local in nature;
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address

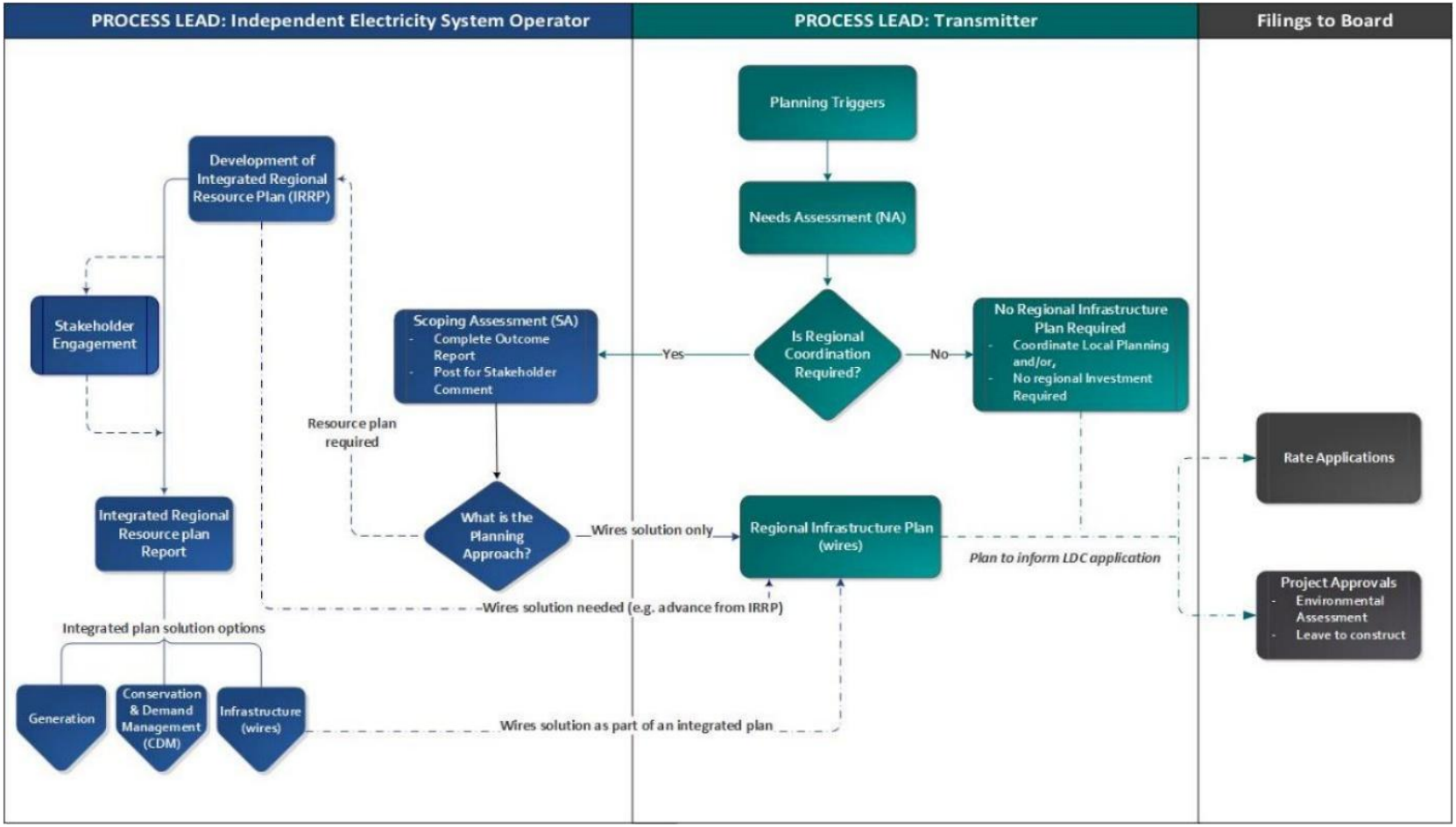
the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter, and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

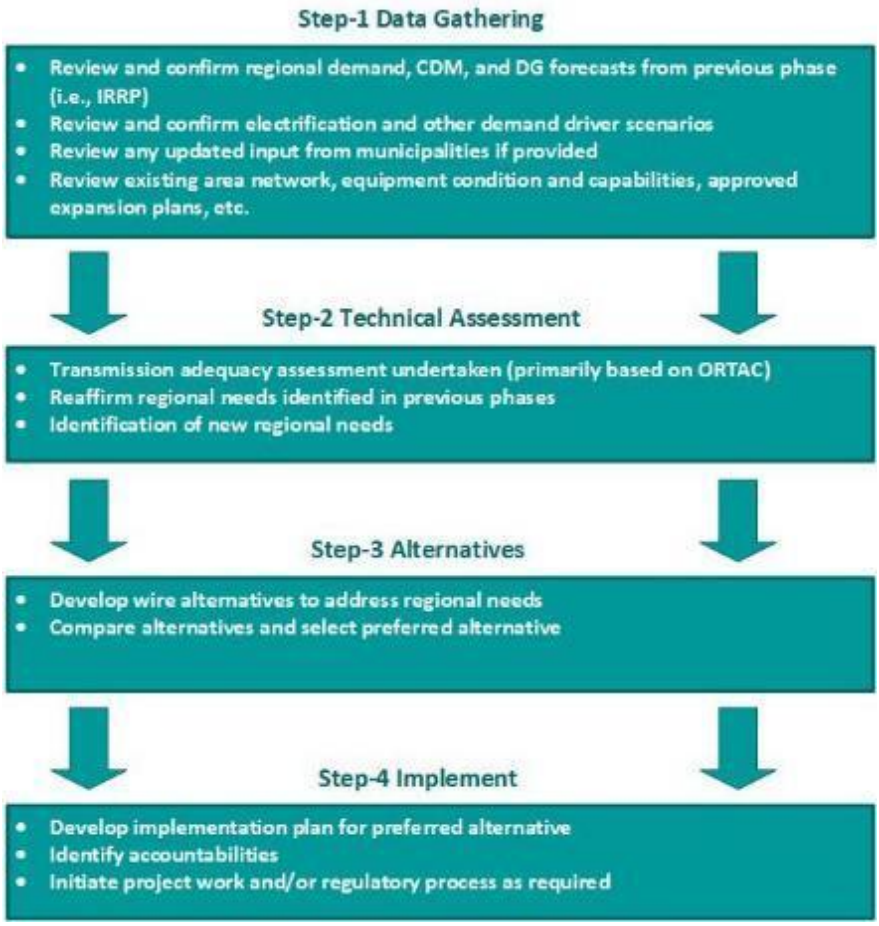
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure 1.

Figure 1: Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure 2: Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1 Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight on the future load growth and was translated into the load forecast through inputs

provided by their respective LDCs. As agreed by TWG members, the load forecast from the IRRP is to be used for this RIP unless material changes in the load forecast are envisaged.

- Review and confirm electrification and other growth scenarios which affect the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2 Technical Assessment:

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

3.2.3 Alternative Development:

The third step is the development of wires options to address needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4 Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiating project work or obtaining permission from the Regulatory Commission, if any.

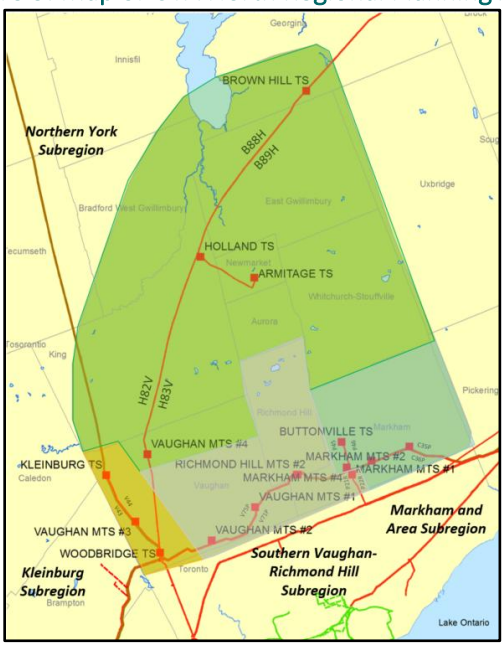
4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

THE GTA NORTH REGION IS COMPRISED OF THE WESTERN AREA, NORTHERN YORK AREA, SOUTHERN VAUGHAN-RICHMOND HILL AREA AND THE MARKHAM AREA. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM SIXTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2025 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 2337 MW.

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

The area has been divided into four sub-regions as shown in Figure 3 and described below:

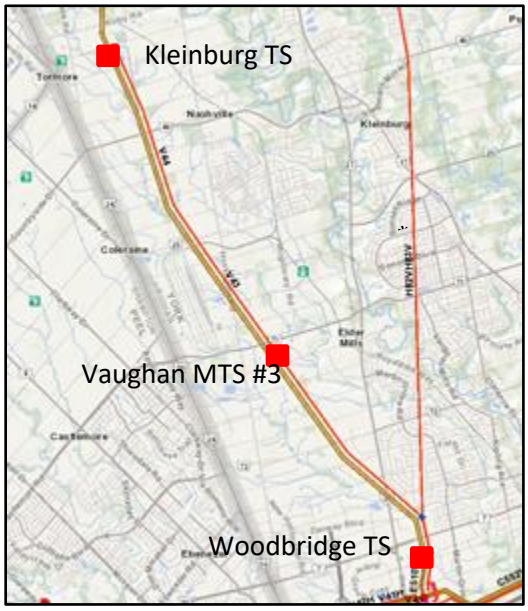
Figure 3: Map of GTA North Regional Planning Area



The **Western Area Subregion** comprises the western portion of the municipality of Vaughan. Electrical supply to the area is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV double circuit line (V43/V44) that supplies three 230 kV transformer stations

(Woodbridge TS, Vaughan MTS#3, Kleinburg TS) stepping down the voltage to 44 kV and 27.6 kV. The Western Sub-region transmission facilities are shown in Figure 4.

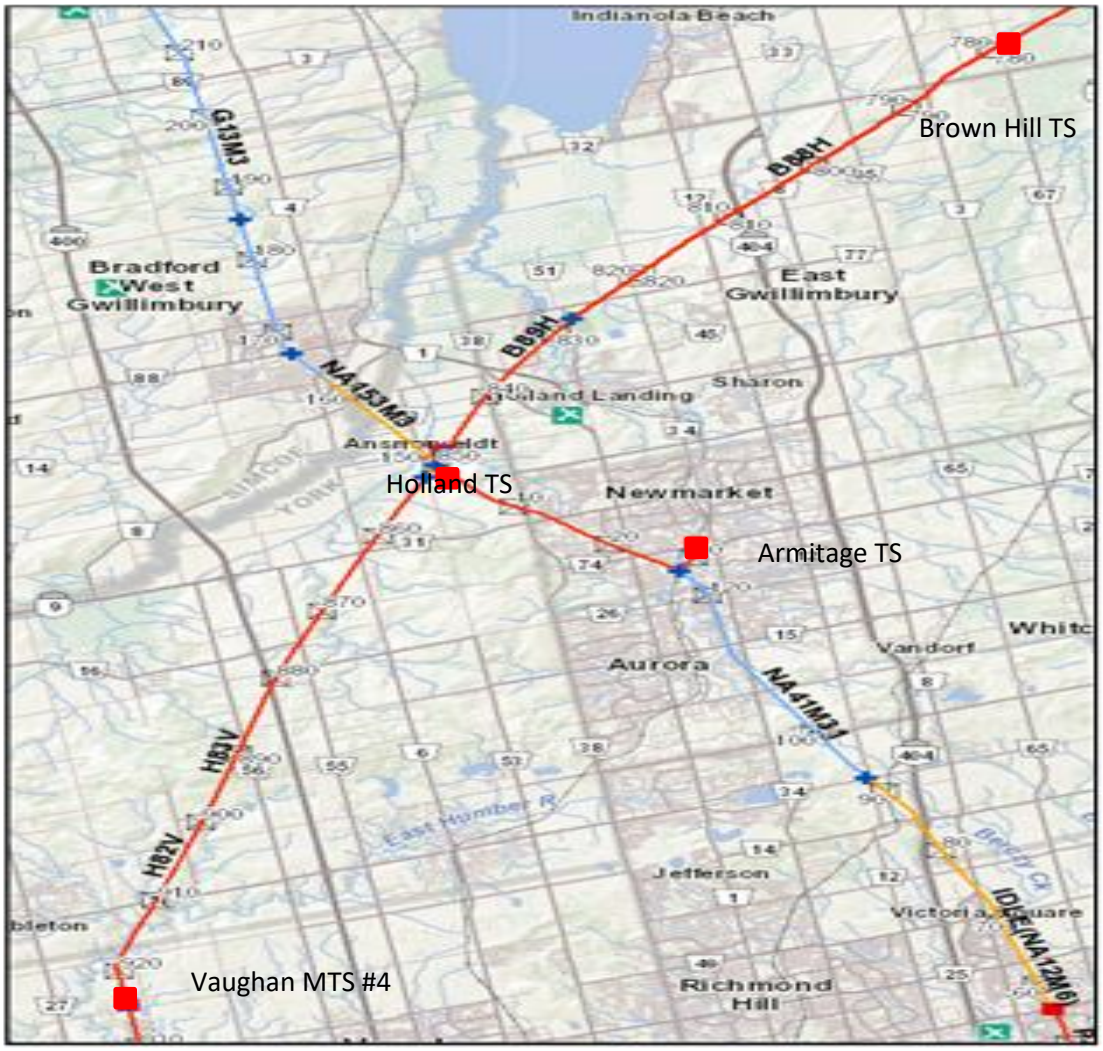
Figure 4: Western Area Subregion



The total 2025 net summer peak demand for three stations was 482 MW. Alectra Utilities is the main LDC that serves the electricity demand for the City of Vaughan. Hydro One Distribution and Toronto Hydro supplies load in the outlying areas of the sub-region. The electricity demand is comprised of residential, commercial, and industrial customers.

The **Northern York Area subregion** covers northern area of the City of Vaughan as well as the Townships of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and includes the Chippewas of Georgina Island. Electricity supply to the sub-region is provided from Claireville TS via a double circuit 230kV transmission corridor extending north to Brownhill TS. The H82V/H83V circuits supply Vaughan MTS #4 and Holland TS along the section between Claireville TS and the Holland Marsh Junction, while the B88H/B89H circuits supply Armitage TS and Brown Hill TS along the section between the Holland Marsh Junction and Brown Hill TS. The York Energy Centre provides a local supply source. The Northern York Area sub-region transmission facilities are shown in Figure 5.

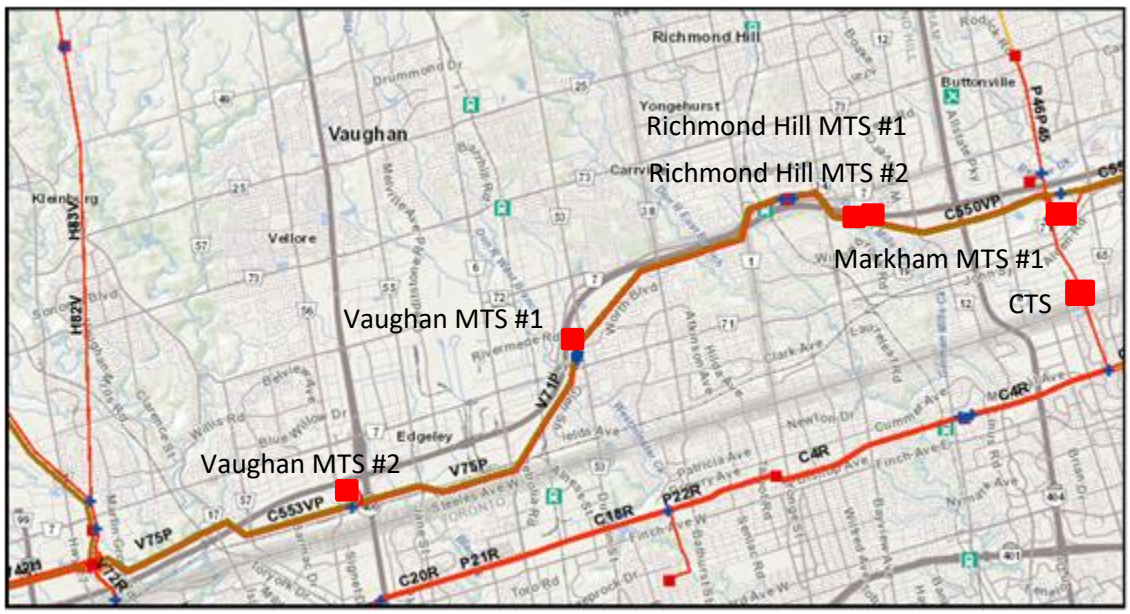
Figure 5: Northern Area Subregion



This area is served by Alectra Utilities, Newmarket-Tay Power Distribution, and Hydro One Distribution. The electricity demand is comprised of residential, commercial, and industrial customers. The total 2025 net summer peak demand for the two stations connected to H82V/H83V circuits was 248 MW and for the two stations connected to B88H/B89H circuits was 360 MW.

The **Southern Vaughan-Richmond Hill Area subregion** encompasses southern parts of the City of Markham, City of Richmond Hill, and the City of Vaughan. The electricity supply to the sub-region is provided through two 230 kV double-circuit transmission corridors: the V71P/V75P circuits supplying Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, and Richmond Hill MTS #2, and the P21R/P22R circuits supplying Markham MTS #1 and one direct transmission connected load customer. The Southern Vaughan-Richmond Hill Area sub-region transmission facilities are shown in Figure 6.

Figure 6: Southern Vaughan - Richmond Hill Area Subregion

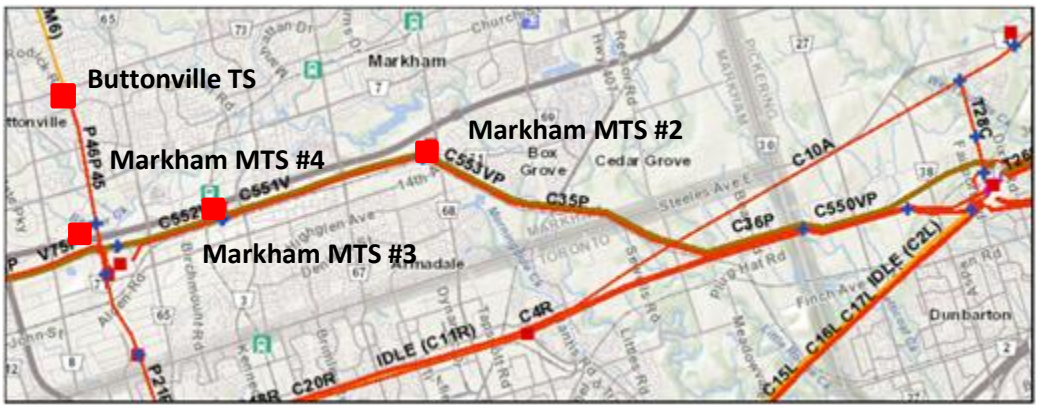


The area is served by Alectra Utilities, and the electricity demand is comprised of residential, commercial, and industrial customers. The total 2025 net summer peak demand for the stations supplied by V71P/V75P and P21R/P22R circuits was 735 MW and 65 MW respectively.

The **Markham Area subregion** encompasses most of the City of Markham. Electricity supply to the Sub-region is provided from Parkway TS by two 230 kV double-circuit transmission corridors, with the P45/P46 circuits supplying Buttonville TS and Markham MTS #4, and the C35P/C36P circuits supplying Markham MTS #2 and Markham MTS #3. The Markham Area sub-region transmission facilities are shown in Figure 7.

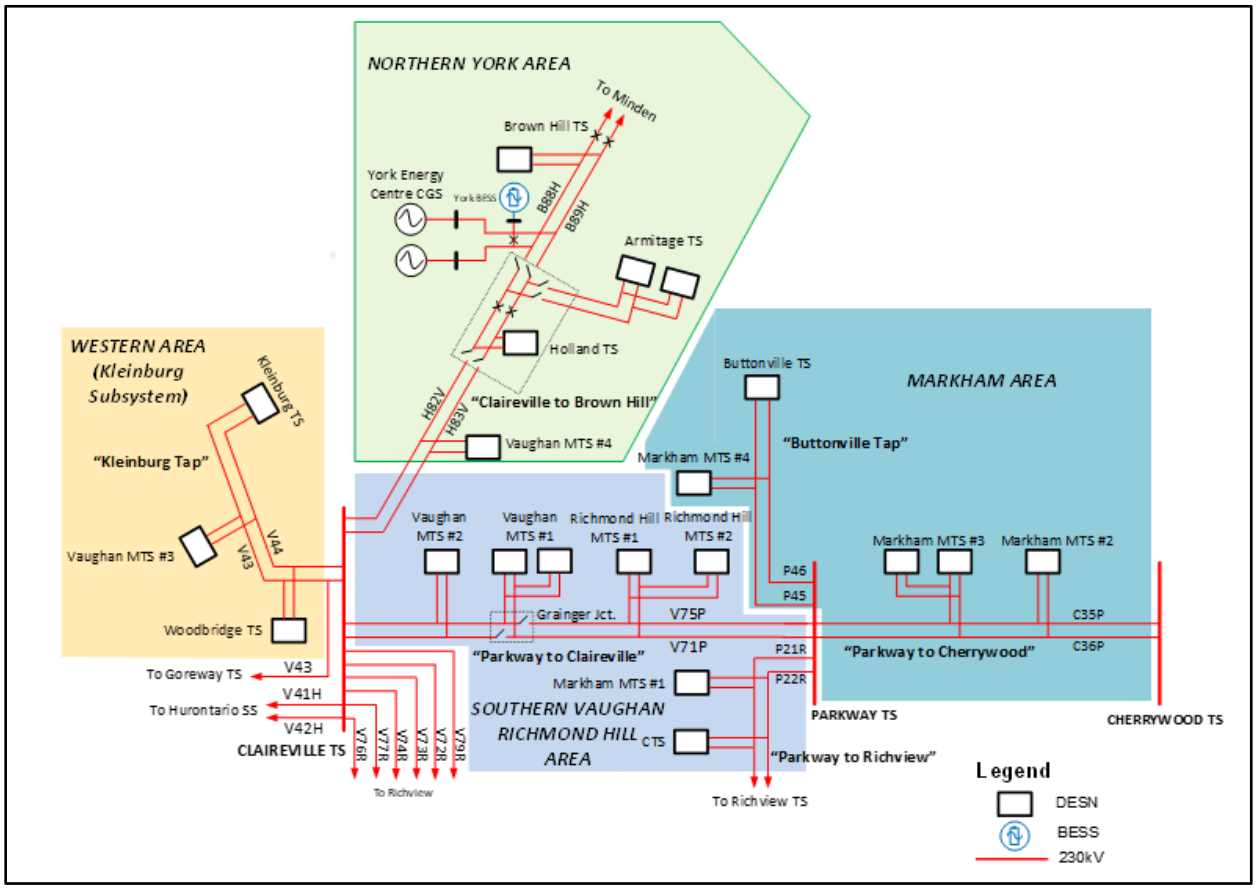
The area is served by Alectra Utilities, and the electricity demand mix is comprised of residential, commercial and industrial uses. The 2025 net summer peak demand for the stations on the P45/P46 circuit was 207 MW and was 267 MW for stations on the C35P/C36P circuit.

Figure 7: Markham Area Subregion



The single line diagram of the Transmission Network of GTA North region is shown in Figure 8 below.

Figure 8: GTA North Region Transmission Area Single Line Diagram



5 TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

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

A summary and brief description of all the projects completed or are currently underway is given below:

5.1 Completed Projects

- Vaughan #4 MTS (2017) – To increase transformation capacity in the City of Vaughan
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the Northern York area.
- Inline switches on the Parkway belt (V71P/V75P) at Grainger Jct. (2018) – to improve reliability for stations in Southern Richmond Hill and Vaughan area.

5.2 Projects initiated and underway.

- Kleinburg TS T3/T4, add two new transformers, and feeder breaker positions (NTD Inservice date) – Increase 44kV transformation capacity at Kleinburg TS
- Vaughan MTS #6: New transformer station – Increase transformation capacity in the City of Vaughan
- Northern York TS #1 (NY-TS#1): New 230/44kV DESN – Increase transformation capacity in Northern York subregion.
- Markham MTS#5/Buttonville TS #2: New 230/27.6kV DESN – Increase transformation capacity in the City of Markham.
- Richmond Hill MTS#3 – New 230/27.6kV DESN - Increase transformation capacity in the City of Richmond Hill

6 LOAD FORECAST AND STUDY ASSUMPTIONS

THIS SECTION PRESENTS THE LOAD FORECAST AND THE STUDY ASSUMPTIONS USED FOR CARRYING OUT THE GTA NORTH REGIONAL PLANNING STUDY.

6.1 Load Forecast

The RIP phase has adopted the load forecast developed during the IRRP which incorporates the impact of the conservation and demand management (CDM), distributed generation (DG) and weather correction factors. The municipalities were contacted as part of IRRP stakeholder engagement process to get their input on future load growth and this has been incorporated into the forecast provided by their respective LDCs. The TWG participants, including representatives from LDC's, the IESO and Hydro One, have reviewed and confirmed the continued use of the IRRP load forecast for this report.

Figure 9 and Figure 10 present the GTA North regional summer and winter net peak load forecasts for the periods 2026 - 2035 and 2036-2043, respectively. Summer peak demand is forecast to grow at an average annual rate of approximately 4.0% between 2026 and 2035, moderating to about 2.0% between 2036 and 2043. Winter peak demand is expected to grow more rapidly due to electrification and is expected to grow at an average growth rate of about 7% between 2026 and 2035 and about 3.85% between 2036 and 2043. The GTA Region is expected to become winter peaking beyond 2030.

Figure 9: GTA North Summer and Winter Net Peak Load Forecast

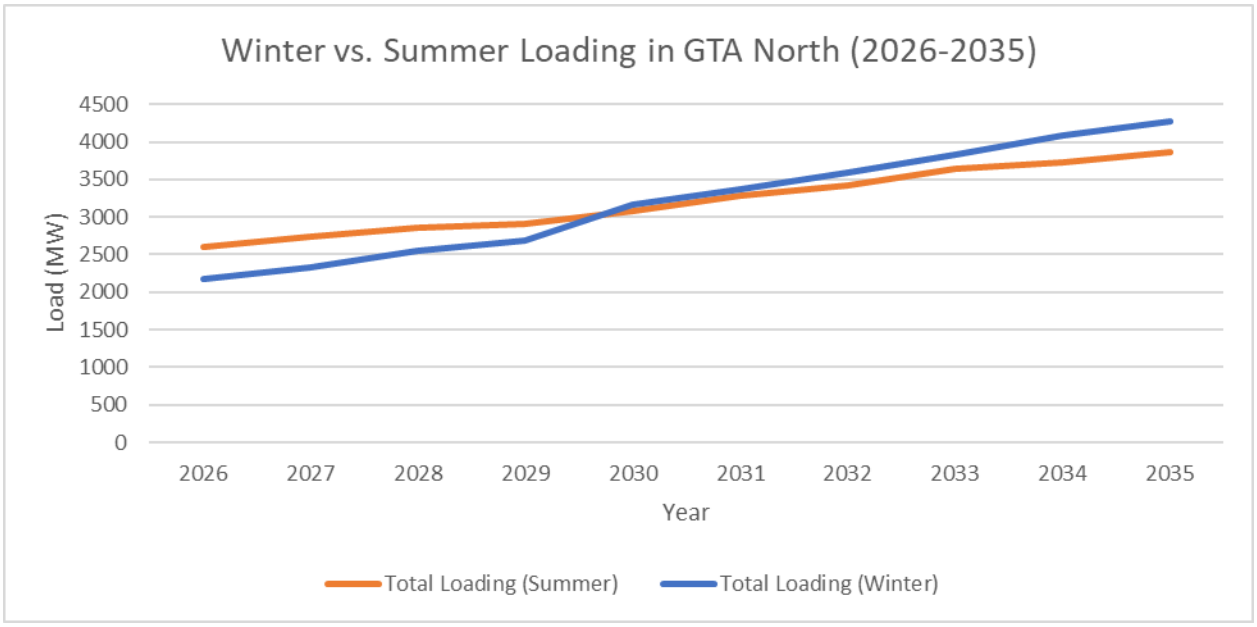
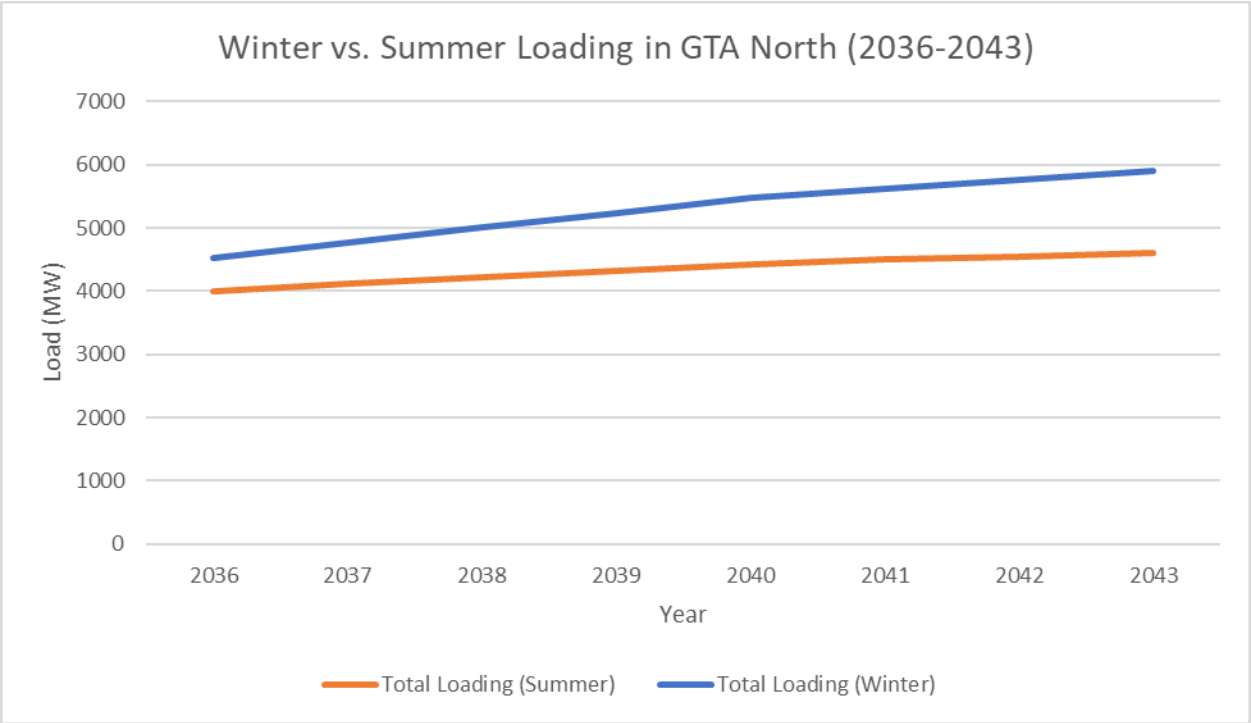


Figure 10: GTA North Summer and Winter Net Peak Load Forecast (2036-2043)



6.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2026-2035.
- While the Region is changing from summer to winter peaking by 2030, summer remains the critical period with respect to line and transformer loadings over the study period of 2026-2035. The assessment is therefore based on summer peak loads.
- Since GTA North stations peak at roughly the same time, the TWG has assumed no difference between the coincident and non-coincident demands, and a single set of load forecast for the RIP purposes has been considered – termed as 'Net Peak Load Forecast'.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks or based on historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using net summer peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations uses non-coincident peak loads.

- All Battery storage projects are assumed to only charge during off-peak hours. Any future charging of these battery storage projects may impact LMC (Load Meeting Capability) of some circuits.
- Adequacy assessment is conducted as per Ontario Resource and Transmission Assessment Criteria (ORTAC).

7 SYSTEM ADEQUACY AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING GTA NORTH REGION OVER THE RIP STUDY PERIOD 2026-2035.

In the current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- GTA North region Third cycle Needs Assessment Report, Completed in September 2022 by Hydro One
- GTA North region Third cycle Scoping Assessment Report, Completed in October 2023 by the IESO
- GTA North region Third cycle Integrated Regional Resource Plan Report, Completed in October 2026 by the IESO

The Technical Working Group identified several regional needs based on the forecasted demand over the near-to-mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections “7.1 to 7.4” and a detailed description and status of plans to meet these needs are given in “Section 8” of this report.

7.1 Asset Renewal Needs for Major HV Transmission Equipment

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The list of major HV transmission equipment requiring replacement in the GTA North region is provided in Table 2 below

Table 2: Major HV Transmission Asset assessed for Replacement in the Region

Station/Circuit	Need Description	Planned ISD
Woodbridge TS	Transformer T5 refurbishment	2032

7.2 Station Capacity Needs

Over the 2026-2035 study period, the RIP assessed the capacity of all the 230kV transformer stations in the GTA North region. Previous NA and IRRP studies identified several stations requiring capacity relief within this timeframe. This RIP confirms those findings and, based on the load forecast, identifies the stations requiring capacity relief as summarized in Table 3. The need date represents the point at which forecast peak demand exceeds the most limiting seasonal (summer) Limited Time ratings.

Table 3: GTA North region Station Capacity Needs in the study period

Sr. No.	Station Name	Station LTR(MW) (Summer)	2026 Loading (MW) (Summer)	Need Date
1	Kleinburg TS	180	214	Current[1]
2	Holland TS	168	169	Current[2]
3	Armitage TS	317	317	Current[2]
4	Brown Hill TS	184	177	2027
5	Richmond Hill MTS #1&#2	254	249	2030[2]
6	Buttonville TS	166	151	2030[2]
7	Vaughan MTS #1	306	301	2033

[1] Work is underway to add a new T3/T4 DESN at Kleinburg TS
[2] Work to provide relief has been initiated

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3 Lines Capacity Needs

The RIP assessed the capacity of all 230kV transmission lines within the GTA North region and confirmed previously identified needs using the transmission lines and confirmed those needs based on the load forecast. Transmission lines requiring capacity relief during the study period are summarized in Table 4 below. The need timeframe represents the point at which the forecast peak demand exceeds the most limiting seasonal (summer) Limited Time Emergency ratings.

Table 4: GTA North region Transmission Line Capacity Needs in the study period

No.	Name of Circuit	Name of Section	Maximum capacity Long Term Emergency (LTE)	Current loading	2035 Loading	Need Date
1	H82V/H83V	Woodbridge Jct. to Vaughan #4 Jct.	1090A	<LTE	> 170%	2030
2	P45/P46	Parkway TS to Markham #4 Jct.	1103A	< LTE	> 120% of LTE	2031
3	P45/P46	Markham #4 Jct. to Buttonville TS	1103A	< LTE	> 150% of LTE	2034

7.4 System Reliability

The RIP reviewed the reliability of the system as per IRRP recommendations provided for the GTA North region. System upgrades required to ensure reliability in the area, and which have been recommended through the GTA North IRRP and South & Central bulk study, are shown in Table 5 below. The need timeframe defines the time when the projects require support from the IESO as part of Bulk system input and need.

Table 5: GTA North region System Reliability Needs in the study period

Station/Circuit	Need Description	Need Date
Kleinburg Kirby Transmission Line K43H/K44H [1]	Provide relief for loading on circuits H82V/H83V	2031-2032
Kleinburg TS – 500/230kV station expansion[2]	Provide additional supply to local area	2031-2032
YEC -Station Service Upgrade	Station Service Upgrade- mitigate load restoration concerns	Immediate
Holland Marsh Switching Station (SS)	Switching station enhances restoration and mitigate load security concerns	TBD[3]
New Transmission Supply corridor	Linking Kleinburg TS or Essa/Barrie to Holland Marsh SS	TBD[3]

[1] Assumed nomenclature for new line.
[2] Bulk system upgrade recommended by South and Central bulk system study.
[3] Option to be reviewed in next planning cycle.

7.5 Load Security and Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

Load Security needs for loss of double circuits lines are listed in Table 6. The needs and the TWG recommendations to address the needs are discussed in more detail in Section 8.5.

Table 6: GTA North region System Reliability Needs in the study period

Circuit	Need Description	Need Date
V43/V44	Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria.	Current[1]
H82V/H83V	Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria.	Current[1]
B88H/B89H	Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria.	Current[1]
V71P/V75P	Loading on this line exceeds the 600 MW limit as per ORTAC security criteria.	Current[1]
P45/P46	Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria.	2030

[1] Current issue

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

8 REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the GTA North Region. These needs include those previously identified in the NA and IRRP for the GTA North Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 7 below:

Table 7: Near/ Mid-term Needs Identified in the Region

Sub-Region	Area/ Station/Circuit	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs				
Western Area	Woodbridge TS	Transformer T5 replacement	2032	8.1.1
Station Capacity Needs				
Western area	Kleinburg TS (T3/T4)	New T3/T4 230/44kV DESN as T1/T2 DESN approaching its supply capacity.	2028	8.2.1.1
	Vaughan MTS #6	New Station 230/27.6kV DESN accommodate Customer	2027	8.2.1.2
Northern York Area	Build Northern York TS #1 230/44kV DESN	To meet forecast load	2031	8.2.2.1
	Build Northern York TS #3 230/44kV DESN	To meet forecast load	2035	8.2.2.2
Southern Vaughan - Richmond Hill Area	Build Richmond Hill MTS #3 230/27.6kV DESN	To meet forecast load	2030	8.2.3.1
	Build Vaughan MTS #5 230/27.6kV DESN	To meet forecast load	2033	8.2.3.2
Markham Area	Build Buttonville TS#2 230/27.6kV DESN	To meet forecast load	2030	8.2.4.1
	Build Markham MTS #6	To meet customer load.	2034	8.2.4.2

Sub-Region	Area/ Station/Circuit	Description of Need	Need Date	RIP Report Section
	230/27.6kV DESN			
	Build Northern York TS #2 230/44kV DESN	To meet customer load.	2034	8.2.4.3
Transmission Line Capacity Needs				
Markham Area- Parkway TS to Buttonville TS	Upgrade P45/P46	Upgrade P45/P46 230kV conductors from Parkway to Markham MTS#4 Junction to accommodate Buttonville TS #2	2031	8.3.1.1
	Upgrade P45/P46	Upgrade P45/P46 230kV conductor from Markham MTS#4 Jct. to Buttonville TS, before connecting either Northern York TS#2 or Markham MTS#6, whichever comes first.	2034	8.3.1.2
	Extend P45/P46	Extend the P45/P46 circuits 7 km north of Buttonville TS along the idle 115kV corridor[2].	2034	8.3.1.3
Markham Area- Parkway TS to Cherrywood TS	Re-terminate Markham MTS#4 from P45/P46 to C35P/C36P	Re-terminate Markham MTS#4 from P45/P46 to C35P/C36P to offset the future loading concerns.	To be discussed in the next Regional Planning cycle	8.3.1.4
System Reliability				
Bulk System- Western and Northern Area sub-systems	Build Kleinburg to Kirby Transmission Link	Supply capability of H82V/H83V- Claireville to Holland Marsh Jct. exceeded.	2031-2032	8.4.1
Bulk System	Kleinburg TS: Build new 500/230 kV station	Provide additional supply to local area[3]	2031-2032	8.4.2

[2] The distance varies depending upon the location of the future Markham MTS#6 and Northern York TS#2 Stations.
[3] Bulk system upgrade recommended by IESO's South and Central bulk system study.

Sub-Region	Area/ Station/Circuit	Description of Need	Need Date	RIP Report Section
Northern Area	York Energy Centre – Station Service Upgrade	Mitigate load security issue for loss of Station service.	2026 (Current)	8.4.3
Bulk System	Build Holland Marsh Switching Station	Reinforce supply to Newmarket and Armitage area	To be discussed in the next planning cycle	8.4.4
Bulk System	New Transmission Supply to Holland Jct	Supply capability of H82V/H83V- Claireville to Holland Marsh Jct. exceeded.	To be discussed in next planning cycle	8.4.5
Southern Vaughan - Richmond Hill Area	Add new 230kV inline breakers on V71P/V75P circuits	Mitigate load security issue	2030	8.4.6
Northern Area	H82V/H83V – B88H/B89H-M6E/M7E	Mitigate Claireville to Minden-Over voltages and Under voltage needs. Thermal Overloads-M6E/M7E	Continue to be monitored -No action except for M6E/M7E thermal overloads	8.4.7
Bulk System	Add/Upgrade Kirby Jct to Holland Marsh Jct (23 km)	Upgrade the limiting section	To be discussed in the next planning cycle	8.4.8
Load Security and Restoration Needs				
Western Area	V43/V44	Mitigate Load Security on Kleinburg Radial Tap	2031-2032	8.5.1
Northern Area	H82V/H83V	Load Restoration from Claireville TS to Holland TS Circuits (H82V/H83V)	No Needs identified	8.5.2.1
Northern Area	B88H/B89H	Monitor Load Security Issue	2035	8.5.2.2
Southern Vaughan - Richmond Hill Area	V71P/V75P	Mitigate Load Security concerns on V71P/V75P	2030	8.5.3
Markham Area	P45/P46	Monitor Load Security concerns on Buttonville Corridor (P45/P46)	2034	8.5.4

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

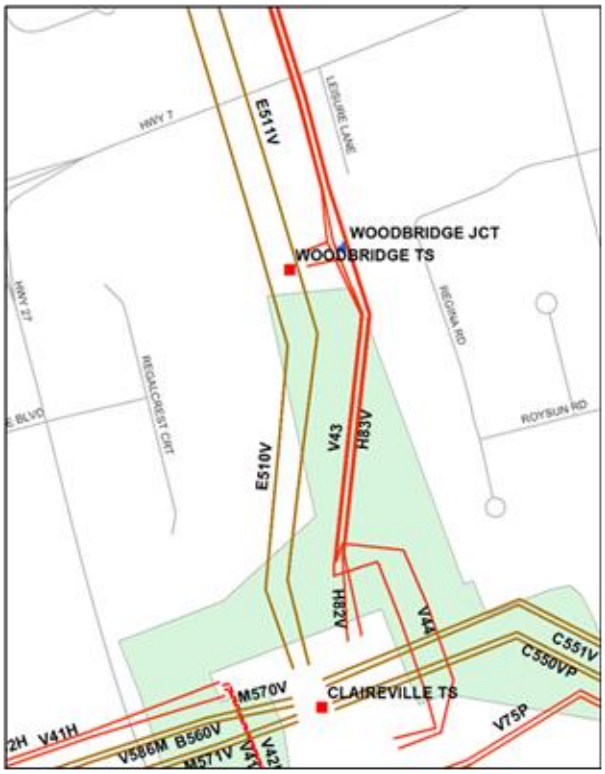
- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

8.1.1 Woodbridge TS: T5 End-of-Life Transformer

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL, having geographic location as shown in Figure 11. The station's 2025 actual peak load was 128 MW. Transformer T5 is currently about 54 years old and is planned for replacement.

Figure 11: Woodbridge TS Project Location



Alternatives and Recommended Plan

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

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

The Working Group has recommended that Hydro One proceed with Alternative 2 and coordinate the replacement plan with affected LDCs. The estimated project cost is to be determined and is work is planned to be completed in 2032.

8.2 Station Capacity Needs

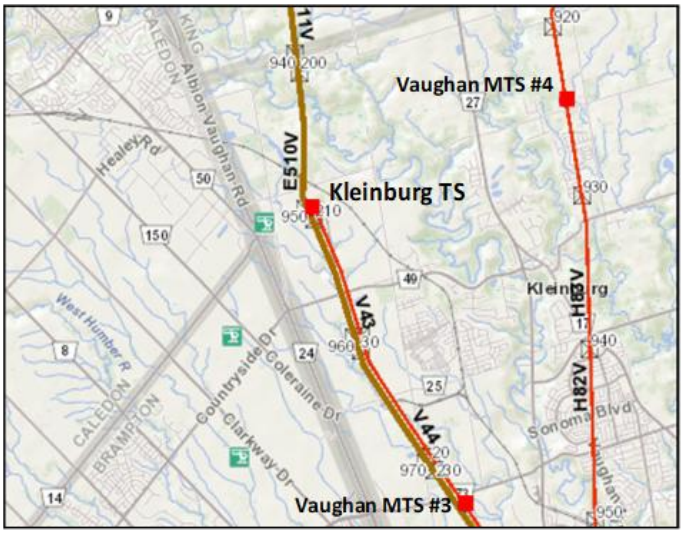
A Station Capacity assessment was performed over the study period 2026-2035 for the 230kV transformer stations in the GTA North region using the net summer peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified during the study period:

8.2.1 Western Sub Region

8.2.1.1 Kleinburg TS T3/T4 Addition

Kleinburg TS in King Township (see Figure 12) consists of two existing dual winding 230/44/27.6 kV transformers T1 and T2. The 44kV winding supplies a 44kV LV yard that serves Hydro One Distribution load. The 27.6kV winding supplies a 27.6kV LV yard that serves both Hydro One Distribution and Alectra load. The station 2025 actual 44kV peak load of 105 MW exceeds the 44kV kV winding rating of 99 MW. Hydro One Distribution has asked for additional 44kV supply capacity to support increased demand in the Caledon area.

Figure 12: Kleinburg TS Project Location



Alternatives and Recommended Plan

The following alternatives were considered to address the increased load demand:

1. **Maintain Status Quo**: Existing transformer T1 and T2 assets and 27.6 kV and 44 kV switchyard configurations at the Kleinberg TS are nearing capacity limits. Not addressing these assets needs will result in Hydro One Distribution not being able to meet its customer connection obligations. Therefore, this option is rejected.
2. **Add two new 75/125 MVA, 230kV/44kV transformers and reconnect the 44kV yard supply from the T1/T2 transformers to the new T3/T4**. Under this option the existing 44kV yard together with the new T3/T4 transformers become a separate 230/44kV DESN increasing the 44kV supply capability to 200 MVA.

The Working Group has recommended that Hydro One proceeds with Alternative 2 and coordinates the replacement plan with affected LDCs. The project estimated cost is around $40M and work is currently underway with a planned completion date of 2028.

8.2.1.2 Vaughan MTS #6 TS (T3/T4) 27.6 kV DESN

Vaughan MTS #6 was identified in the NA as triggered by a dedicated Customer need. Alectra has started building a new station to provide supply to a large customer, having geographic location as shown in Figure 13. The new station will have 2 x 75/125 MVA, 230/27.6kV transformers, and a 27.6kV switchgear building. Alectra has requested that Hydro One build a short underground line tap to supply the new station from the 230kV Claireville TS x Kleinburg TS double circuit line V43/V44.

Figure 13: Vaughan MTS #6 Location



Table 8: Vaughan MTS #6 MW Summer Demand and Forecast Loading on the 230kV Claireville TS x Kleinburg TS line V43/V44

Transformer Station/ Corridor	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Vaughan MTS #6 (28kV)	0	0	30	29	49	48	56	76	92	90
Total Load on V43/V44	522	535	596	607	644	645	656	675	690	687

Table 8 shows the forecast load for Vaughan MTS #6 and the total load connected to the line. There is adequate capacity on the line to supply the loads over the study period.

Feasibility study for the line connection and SIA and CIA for the dedicated customer load have been completed. Hydro One has initiated consultations with Alectra for the design and execution of the Project and planned in-service date for the station is 2027. The project estimated cost is in the range of $55M-$65M.

8.2.2 Northern York Area Sub-Region

8.2.2.1 Northern York TS #1

Additional step-down transformation capacity is needed for the areas supplied by Armitage TS and Holland TS. A new station Northern York TS #1, located south of Holland Marsh Jct., and supplied by the Claireville TS x Holland Marsh Jct. 230 kV circuits H82V/H83V (see Figure 14) is proposed to meet this need. Please refer to Table 9 below for the load forecast and in-service timeline for the Station. While the IRRP had identified the need for the station as immediate, the earliest possible in-service date for the project is 2031.

Figure 14: Northern York TSs #1 and 3

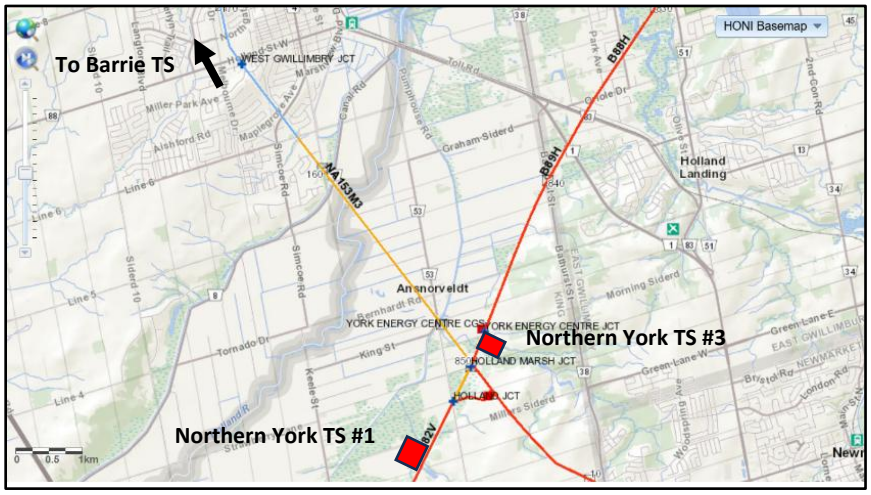


Table 9: Northern York Area MW Summer Demand Forecast

Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Need for Northern York Region TS #1 and #3											
Holland TS	168	169	169	169	169	169	169	169	169	169	169
Armitage TS	317	317	317	317	317	317	317	317	317	317	317
Northern York TS #1	170	0	0	0	0	0	32	65	92	130	170
Northern York TS #3	170	0	0	0	0	0	0	0	0	0	4

Alternatives and Recommended Plan

Status Quo is not an option as not proceeding with this investment will result in Hydro One not meeting the Customer's in-service date. This alternative presents regulatory and customer risks. With this alternative, Hydro One's obligation to connect load customers upon request would not be met.

The Northern York TS #1 station project is currently in the project development phase. Funding has been released for selecting a suitable site for the new station, and preliminary engineering and initial environmental assessment activities have been initiated, including early engagement to inform and seek input from the affected communities and Indigenous groups. The project estimated cost is in the range of $55M-$65M. The planned in-service date is 2031.

8.2.2.2 Northern York TS#3

By the mid-2030s, electricity demand in Northern York is expected to grow to the point that another new transformer station will be required in northern York region by 2035 (please see Table 9 above). The new station Northern York TS #3 will support the forecasted growth at Northen York TS #1 and future growth at Holland TS and Armitage TS area. The location for the Northern York TS #3 has not yet been confirmed. However, based on projected development patterns, the most suitable area would likely be near the Holland Marsh Junction, where it would be well positioned to supply the communities of King, Newmarket, East Gwillimbury, and Bradford West Gwillimbury.

It is anticipated that the station will connect to Holland Marsh Jct. x Brown Hill TS 230kV circuits B88H/B89H. However, additional transmission reinforcements are expected to be required to support this connection.

One option is to reinforce the existing H82V/H3V circuits that connect into Holland Marsh Jct. A second option, see Figure 14 above, is to build a new 230kV double circuit line from Barrie TS to Holland Marsh Jct. utilizing the existing idle transmission corridor that extends from Holland Marsh Jct., northwest through Bradford West Gwillimbury and into Simcoe County, to Barrie TS. Potential advantages of this option include improved voltage performance and system reliability, and and relief of future loading pressure on the core Northern York transmission path (H82/83V). This option is further discussed in Section 8.4.5.

A switching station at Holland Marsh Jct. may also be required at Holland Marsh Jct. to incorporate the new line from Barrie TS (please see Section 8.4.4 for further discussion on Holland Marsh switching station). The TWG will review and finalize the reinforcement options in the next planning cycle

Alternatives and Recommended Plan

As noted above, it is planned to connect the new station to circuits B88H/B89H. Further coordination between Hydro One and the affected LDCs will be required to confirm the preferred station location and connection point through future planning activities. The TWG will monitor the area growth rate, and the timing of the station in-service date of 2035 will be refined based on need.

The capital cost of the new station is currently estimated to be in the range of $55M-$65M. Any required transmission reinforcements and their associated costs will be determined in the next planning cycle, once the scope and configuration of the work have been further defined.

8.2.3 Southern Vaughan -Richmond Hill Area

8.2.3.1 Richmond Hill MTS #3

The Richmond Hill South area is seeing significant growth. The existing stations Richmod TS MTS #1 and MTS #2 are operating at capacity limit and additional transformation capacity is required. Alectra plans to

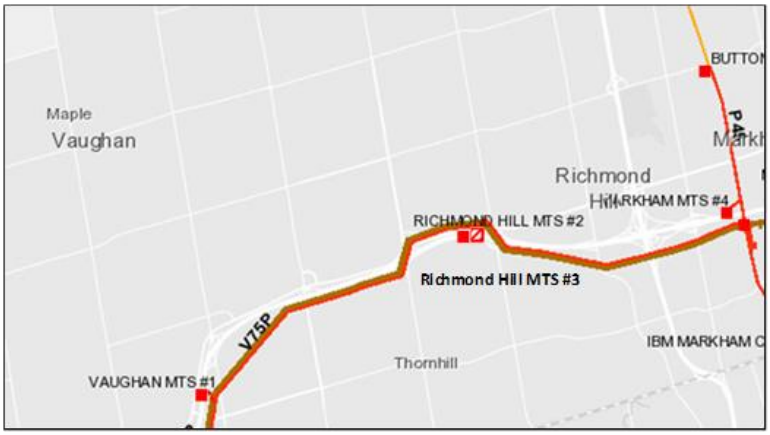
develop a new transformer station Richmond Hill MTS #3 adjacent to the existing Richmond Hill MTS #2 to meet forecast growth. Please see Table 10 below for the area forecast.

Table 10: Richmond Hill Area MW Summer Demand Forecast

Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Richmond Hill MTS #1	153	150	148	153	153	153	153	153	153	153	153
Richmond Hill MTS #2	101	99	98	101	101	101	101	101	101	101	101
Richmond Hill MTS #3	153	0	0	0	0	26	48	61	86	115	129

The proposed station will consist of 2 x 75/125 MVA, 230/27.6kV transformers and a 27.6kV switchyard. Alectra has requested that Hydro One connect the new station to the 230kV Claireville TS x Parkway TS double circuit line V71P/V75P as shown in Figure 15.

Figure 15: Richmond Hill MTS #3 Location



The IRRP has identified load security concerns with the V71P/V75P lines as connected loads exceed the 600 MW limit as per the ORTAC security criteria. The connection of this new station will further increase loading on the line. To connect the station and address the load security need, TWG has recommended the addition of in-line breakers to sectionalize the circuits. The issue is further discussed in the Section 8.4.6 on in-line breakers and Section 8.5.3 on load security assessment

Alternatives and Recommended Plan

The status quo option was eliminated as increasing residential and commercial load growth is driving the need for additional transformation capacity in the area. Accordingly, the TWG recommends proceeding with the development of the new station, with an estimated capital cost of $55M-$65M and a target in-service date of 2030.

8.2.3.2 Vaughan MTS #5

Significant growth is also happening in the Vaughan MTS #1 and Vaughan MTS #2 supply area driven by major commercial and industrial development associated with the Vaughan Metropolitan Center. Both stations operate at capacity limits and additional transformation capacity is required. Please see Table 11 below for the area load forecast.

Table 11: Southern Vaughan Area MW Demand Forecast

Net Summer Peak Demand Forecast- by Station (MW)											
Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Vaughan MTS #1	306	301	300	306	306	306	306	306	306	306	291
Vaughan MTS #2	153	150	149	153	153	153	153	153	153	153	144
Vaughan MTS #5	153	0	0	0	0	0	0	35	99	33	52

Alectra is proposing to build a new station Vaughan MTS #5 consisting of 2x75/125 MVA, 230/27.6kV transformers and a 27.6kV switchyard and connect it to the V71P/V75P circuits west of Yonge Street. While this would further exacerbate the already existing load security issue; the issue will be mitigated through the installation of in-line breakers as discussed in Section 8.4.6 and the associated load Security assessment in Section 8.5.3.

Figure 16: Vaughan MTS #5 Location



Alternatives and Recommended Plan

There are no alternatives to building a new station to meet the area load growth as all area stations are at their limits. The station location as shown in Figure 16 is an assumption and the exact location of the Station is yet to be determined by the LDC.

The Working group has recommended proceeding with the project with the estimated cost in the range of $55M-$65M. The planned in-service date is 2033.

8.2.4 Markham Area

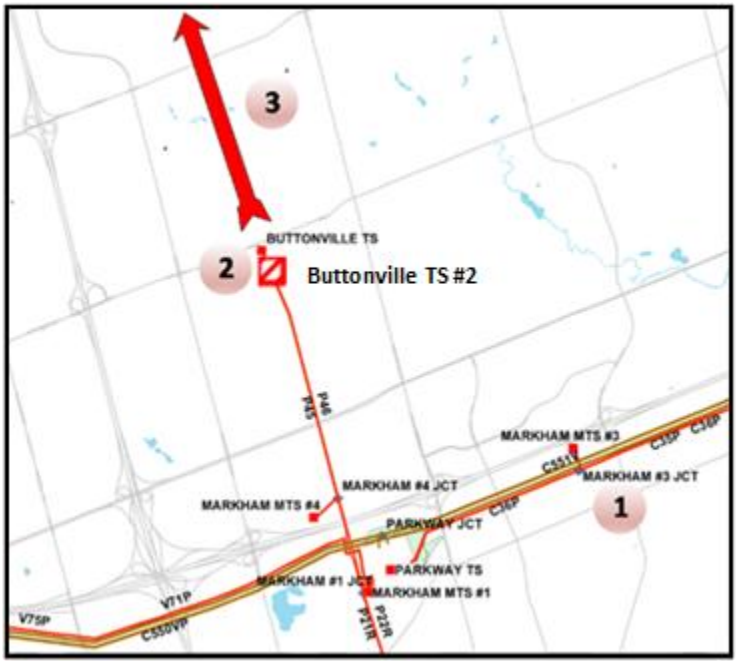
8.2.4.1 Markham MTS #5/Buttonville TS #2

Significant load growth is forecast for the area currently supplied from Buttonville TS and Markham MTS #4 as a result of urban development in the City of Markham. Forecast load is presented below in Table 12 below which shows a need for additional transformation in the area. Alectra proposed building a new Markham MTS #5 station consisting of 2x75/125 MVA, 230/27.6kV transformers and a 27.6kV switchyard supplied from the 230kV circuits P45/P46.

Table 12: Markham Area MW Summer Demand Forecast

Net Summer Peak Demand Forecast- by Station (MW)											
Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Buttonville TS	166	150	150	149	147	146	146	145	145	145	144
Markham MTS #4	153	111	150	153	153	153	153	153	153	153	153
Markham MTS #5	153	0	0	4	27	63	110	144	146	143	143
Markham MTS #6	153	0	0	0	0	0	0	0	0	40	98

Figure 17: Proposed Locations of Markham MTS #5/Buttonville TS #2



Alternatives and Recommended Plan

As shown in Figure 17, three alternative locations for the new Markham MTS #5 were considered:

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

Alternative 2 - Building the station at the existing Buttonville TS and connecting to the P45/P46 circuits: This alternative is closer to the area of anticipated load growth than alternative 1, and lesser distribution infrastructure is required as compared to Alternative 1. A 1.1 km section of the 230kV double circuit line P45/P46 between Parkway TS and the Markham MTS #4 Jct. would need to be uprated.

Alternative 3 - Building the station in north Markham and extending circuits P45/P46 from Buttonville TS to connect the new station: This location is nearest to the area of anticipated load growth. However, it requires rebuilding approximately 6 km of a single circuit 115 kV transmission line as a 230 kV double circuit transmission line. A new station property would also need to be acquired.

Alternative 1 was not considered further due to the high distribution costs. Of the remaining two alternatives, the study team recommends Alternative 2 - building the new station at Buttonville TS. While

the distribution costs are higher under this option compared to Alternative 3, the high costs of extending the transmission line north from Buttonville for Alternative 3 made these two alternatives comparable. Alternative 2 was selected as the preferred option as it also allows the new station to be in service at an earlier date to meet the forecast load requirement.

The TWG has recommended proceeding with the project, with the station capital costs estimated in the range of $55 million to $65 million, and associated line costs estimated at approximately $5 million, as outlined in Section 8.3.1.1. While the identified need date is 2029, the project is expected to be placed in service in 2030. Alectra will be managing the area load till the Station is placed in-service.

8.2.4.2 Markham MTS #6

A second station will be required in the Markham area towards the end of the study period (see Table 12). Alectra's preferred location for this station is about 7 km north of Buttonville TS and would require extending circuits P45/P46 from Buttonville TS to the new station as shown in Figure 18. This option requires replacing approximately 7 km of an idle single circuit 115 kV transmission line with a 230 kV double circuit transmission line.

Figure 18: Proposed Location of Markham MTS #6



Alternatives and Recommended Plan

The status quo option was eliminated. as rising demand driven primarily by increased residential and commercial development necessitates additional transformation capacity. Accordingly, the development of a new station is required. The estimated capital cost of the station is in the range of $55M-$65M,

excluding the cost of associated transmission line work which is discussed separately in Section 8.3.1.3. The planned in-service date for the station is 2034.

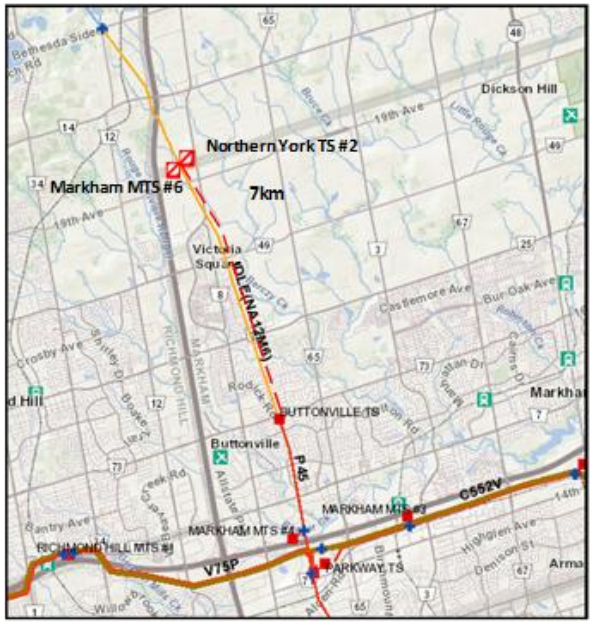
8.2.4.3 Northern York TS #2

Significant load growth is forecast in the eastern portion of Northern York subregion, particularly in Whitchurch-Stouffville. This area currently lacks transmission infrastructure and is primarily served by long distribution feeders, resulting in higher connection costs, and reduced reliability. Hydro One Distribution has identified the need for a new step-down transformer station to meet forecast demand and improve service reliability in this area. The area load forecast is given in Table 13 below.

Table 13: Northern York TS #2 MW Summer Demand Forecast

Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Northern York TS #2	170	0	0	0	0	0	60	99	142	170	170

Figure 19: Proposed Location for Northern York TS #2



Hydro One Distribution preferred location for the station is shown in Figure 19. The station will be slightly north of Markham MTS #6, and it will be supplied from the 230kV line P45/P46 extension from Buttonville TS.

Alternatives and Recommended Plan

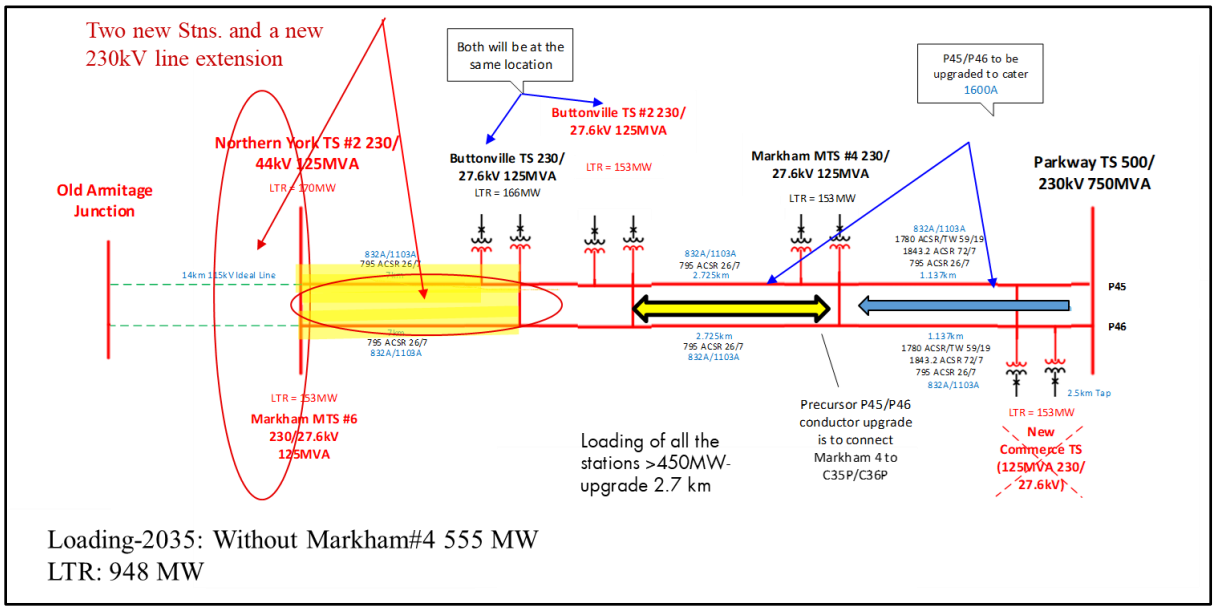
There are no viable alternatives to constructing the new station to address meet the forecast Hydro One Distribution's capacity requirements. The TWG will continue to monitor the load growth and has asked that Hydro One coordinate the station and associate transmission line with the facilities required to connect Markham MTS #6. The estimated project cost for the Station is in the range of $55M-$65M, excluding transmission line costs. Transmission line costs are discussed in Section 8.3.1.3. Given that the earliest possible in-service date for the line is 2034, the station's in-service date will need to be aligned accordingly. In the interim, Hydro One Distribution will manage the area load.

8.3 Line Capacity Needs

8.3.1 Markham Area - Parkway to Buttonville including extension on idle corridor North

Markham area line upgrades, for the recommended projects combined, are shown in the SLD - Figure 20 below displaying each segment length, existing ratings, stations connected including future planned ones and also the preferred circuit upgrade rating[4] for each section.

Figure 20: Future P45/P46 Single Line Diagram



Below are the detailed needs assessments for each of the line segments in Markham area:

[4] Preferred circuit ratings are subject to change as further studies are done.

8.3.1.1 Upgrade from Parkway TS to Markham MTS #4

The connection of the new Buttonville TS #2 to the Parkway TS x Buttonville TS 230kV double circuit line P45/P46 circuits (see Figure 21 below) will increase the loading on this line. Forecast loading, along with applicable long term emergency line rating is given in Table 14.

Figure 21: Parkway TS x Buttonville TS P45/P46 Limiting Section



The transmission capacity is thermally limited by an approximately 1.1 km long section between Parkway TS and Markham #4 Jct. Loading is expected to exceed the rating by 2031. This section will need to be uprated to at least 1600A loading before 2031 to fully supply Buttonville TS #2.

Table 14: MW Loading on the P45/P46 Circuits

P45/P46	Yearly Loading (MW)										
Station	Line Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Markham MTS #4		111	150	153	153	153	153	153	153	153	153
Buttonville TS		150	150	150	149	147	146	146	145	145	145
Buttonville TS #2		0	0	4	27	63	110	144	146	143	143
Northern York TS #2		0	0	0	0	0	60	99	142	170	170
Markham MTS #6		0	0	0	0	0	0	0	0	40	98

Loading – Parkway TS x Markham MTS #4 Jct.	450	261	299	306	327	363	512	542	587	651	708
Loading – Markham MTS #4 to Buttonville TS	450	150	150	153	174	210	316	389	434	498	555

Alternatives and Recommended Plan

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

1. **Increase thermal capability of existing line.** It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying the forecasted load with these circuits.
2. **Reduce loading on the P45/P46 circuits by transferring Markham MTS #4 to the Cherrywood TS x Parkway TS C35P/C36P circuits:** This alternative frees up capacity on the P45/P46 circuits to supply Northern York TS #2 or Markham MTS #6. It requires building a new 1.5 km long 230kV double circuit line from Markham MTS #4 Jct. to the C35P/C36P that is discussed in separate section. This alternative was ruled out until Northern York TS #2 or Markham MTS #6 is needed to be supplied.

The Working Group recommends uprating the line from Parkway TS to Markham MTS #4 Jct. to at least minimum 1600A loading before 2031 to fully supply Buttonville TS #2. A high-level estimate for this work is estimated to be around $5M.

8.3.1.2 Upgrade from Markham MTS #4 to Buttonville TS

The connection of the new Markham MTS #6 or Northern York TS-2, whichever comes earlier, to the Parkway TS x Buttonville TS circuit P45/P46 circuits (see Figure 22 below) will further increase the loading on the Markham MTS #4 Jct. x Buttonville section of the line. The forecast loading along with the long term emergency line rating for this section is also provided in Table 14 and Figure 20 above.

Figure 22: P45/P46 Corridor Line Reinforcement Section



The transmission capacity is thermally limited by an approximately 2.7 km long section between Markham #4 Jut to Buttonville TS. Loading is expected to exceed the rating with the addition of Northern York TS #2 and Markham MTS #6. This section will need to be uprated to at least 1600A prior to connecting these two stations.

Alternatives and Recommended Plan

Maintaining the status quo is not a viable option, as loading levels following the in-service of either Buttonville TS #2 or Northern York TS #2 would exceed the existing long-term emergency (LTE) circuit rating.

The need date[5] for this upgrade is triggered when the combined loading of Buttonville TS, Buttonville TS #2, Markham MTS #6, and Northern York TS #2 exceeds the existing rating of the line which is 1103 A/ 450 MW. Upgrading will be done in conjunction with the new stations' construction schedule with in-service date of 2034. The cost of the project is approximately estimated at $10M.

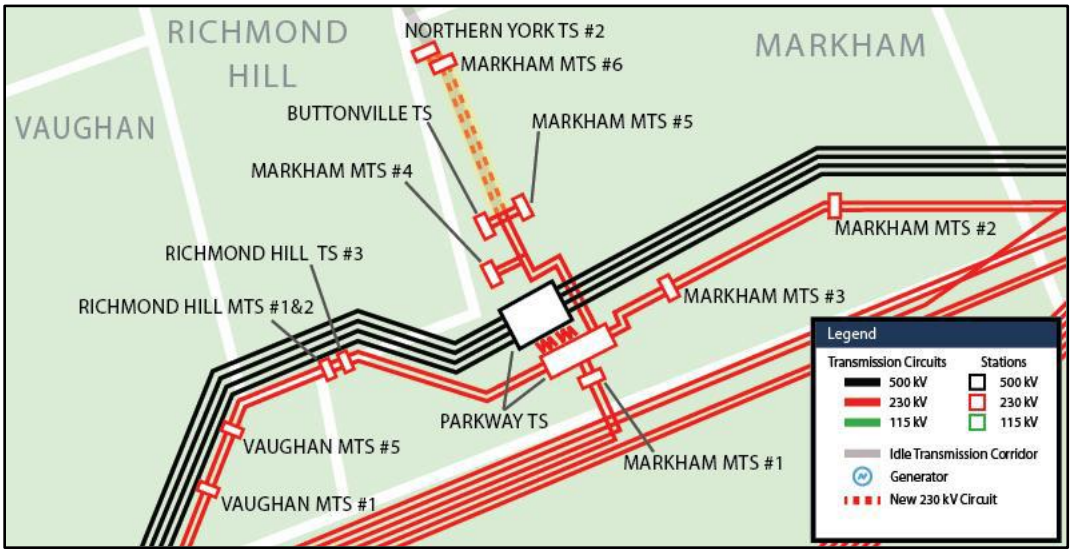
[5] Simultaneously Implementing the two upgrades from Parkway TS to Markham MTS# 4 Jct. and to Buttonville TS concurrently enhance the supply capability of P45/P46. The transmitter may consider uprating these circuits simultaneously to minimize the load at risk during construction-related outages.

8.3.1.3 Extending P45/P46 Circuits - 7 km north from Buttonville TS

The need for extending P45/P46 circuits 7km north of Buttonville TS, on the existing idle corridor, is to be able to supply future Northern York TS #2 and Markham MTS #6 as shown in Figure 23 below.

This work will require rebuilding the existing towers and conductors – which were built to 115kV standards- and ratings, to 230 kV standard. The approximate cost of this work ranges from $50M to $175M depending upon the type of tower structure and overhead conductor or underground cable selection. The cable option is contingent upon the customers' acceptance of the cost, longer outages' duration and expensive repair during contingency with the benefit of aesthetic considerations. The final option for choosing the technology type for the new transmission extension will be dependent upon the outcome of the Environmental Assessment (EA) of the line design.

Figure 23: P45/P46 Circuit extension (Courtesy: IESO)



Alternatives and Recommended Plan

There are essentially no viable alternatives to extending the existing P45/P46 line along the idle corridor. The TWG therefore agreed to extend the line to supply the new stations. The rating of the line extension will be finalized during the next regional planning cycle. The need date is dependent upon the date of either of the two stations' connections. The estimated cost of $50-175M will be refined and revisited during the next planning cycle.

8.3.1.4 Reconnect Markham MTS #4 to C35P/C36P

The need to reconnect Markham MTS #4 from C35P/C46P reduces the loading on the P45/P46 circuits by transferring Markham MTS #4 to the Cherrywood TS x Parkway TS C35P/C36P circuits, hence alleviates

the load security concerns at P45/P46 corridor. It requires building a new 1.5 km long 230kV double circuit line from Markham MTS #4 Jct. to the C35P/C36P.

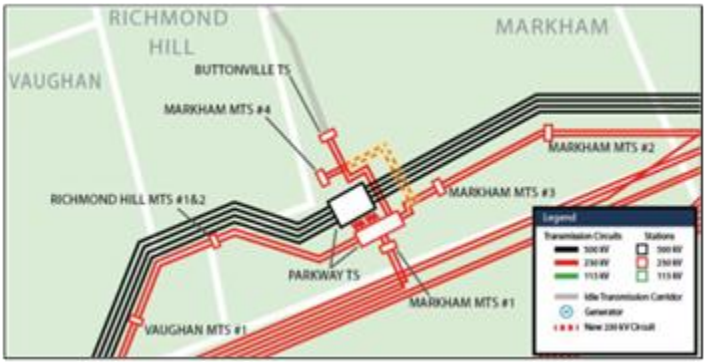
Alternatives and Recommended Plan

1. The status quo of keeping the Markham MTS #4 remain supplied from P45/P4 was not feasible as it will exceed the thermal capacity and ultimately would exacerbate further the already existing load security issues in the long run.

2. Reconnect Markham MTS #4: This alternative frees up capacity on the P45/P46 circuits to accommodate Northern York TS #2 or Markham MTS #6. Several potential connection points are available for this extension, including a direct tie-in at Parkway TS or a tap of the existing C35/36P circuits. The latter is currently the preferred option, as it offers a significantly lower-cost solution. In contrast, establishing a connection within Parkway TS would require extensive upgrades to existing bulk system infrastructure due to space limitations, resulting in substantially higher costs.

The reconnection diagram is shown in Figure 24 below.

Figure 24: Proposed Radial Tap for Markham MTS #4 (Courtesy: IESO)



While working group agreed option 2 was the preferred option, a final decision of the connection will be taken in the next planning cycle. This work will be aligned with the connection of either Markham MTS #6 or Northern York TS #2, whichever is required first, to enable LDCs to fully utilize available connection facilities.

The approximate cost is estimated around $10M.

8.4 System Reliability

8.4.1 Build Kleinburg to Kirby Transmission Link

The Kleinburg–Kirby transmission link is a proposed 230 kV transmission reinforcement designed to increase supply capacity and improve reliability in York Region as electricity demand continues to grow. The project consists of constructing approximately 6 km of new 230 kV transmission line to connect an expanded Kleinburg TS with the H82/83V circuits near Kirby Road, north of Vaughan MTS #4.

The link is intended to relieve loading on the Claireville–Holland Marsh Jct. section of circuit H82V/H83V, which currently carries most of the supply to Northern York Region and is expected to face increasing constraints due to population growth, development activity, and electrification. Establishing this new transmission path would provide an alternative supply route and support the connection and full utilization of future step-down transformer stations required to meet long-term demand.

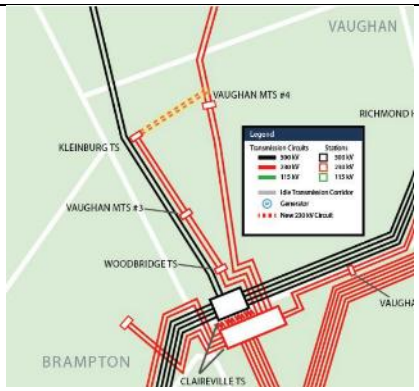
IESO South and Central bulk planning studies have identified the need for adding bulk supply capacity at Kleinburg TS to enable load growth in the area. Because the station is connected to both the regional 230 kV network and is near the provincial 500 kV bulk system, it is well positioned to function as a major supply hub. To accommodate higher power transfers associated with the Kleinburg–Kirby link, additional bulk facilities—such as switching equipment and new autotransformers—are required at Kleinburg TS. These enhancements would add the ability to step down bulk supply and deliver it effectively into the regional system; enable the Kleinburg – Kirby Link and other future supply projects in York and Peel Region. (see Section 8.4.2 for details on the Kleinburg 500/230kV transformer station).

During the regional planning process, several alternatives were evaluated, including reconductoring existing transmission lines to increase thermal capacity, and redeveloping the Buttonville–Armitage corridor to provide additional supply capability into Northern York Region.

While these measures can defer some needs in the near term, studies conclude that additional transmission capacity will still be required to support long-term growth in York Region. As such, the Kleinburg–Kirby link remains a key option.

Together with future upgrades at Kleinburg TS, the Kleinburg–Kirby transmission link is intended to ensure that York Region's electricity system can reliably accommodate future growth, electrification, and new customer connections

Figure 25: The Kleinburg-Kirby Transmission Link (Map & Conceptual SLD)

Proposed Highway 413 - Kleinburg-Kirby Transmission Link	Proposed SLD – Kleinburg-Kirby Transmission Link
	

The IESO has asked Hydro One to proceed with the development work on the project. IESO's March 20, 2026, correspondence to Hydro One regarding the Kleinburg–Kirby 230 kV Transmission Link Project is appended as Appendix F: IESO Letter for Kleinburg-Kirby Transmission Link. The IESO letter confirms the system need, implementation urgency, and the expected project configuration, including the connection between the expanded Kleinburg TS and the H82/83V circuits near Kirby Road. Figure 25 illustrates an approximate transmission line routing along the proposed Highway 413 corridor along with a conceptual single-line diagram of the Kleinburg -Kirby Transmission Link.

The TWG recommends that the proposed Kleinburg–Kirby transmission link be designed to support a minimum LTE rating of 2000A provided that achieving this capacity does not introduce significantly higher additional cost. This higher rating is advisable given the strong likelihood that this section of the network will be utilized in the longer term as part of an independent supply path.

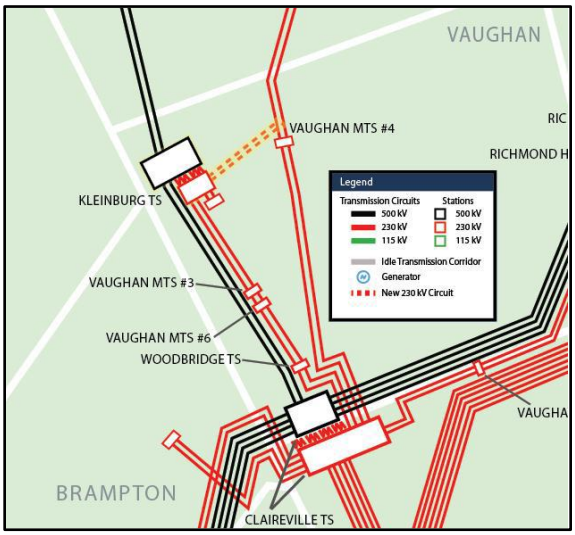
The expected completion date for the Kleinburg -Kirby Transmission corridor is around 2031-2032 with the expected cost range from $40M to $60M.

8.4.2 Bulk Supply – Kleinburg 500/230kV Transformer Station

The in-service of the Kleinburg–Kirby 230kV transmission link will necessitate additional bulk supply capacity at Kleinburg TS to reliably support forecast load growth in Northern York Region. Without a new bulk source, the existing V43/44 radial circuits north of Claireville TS would become thermally constrained as new stations are added and electrification-driven demand materializes. Kleinburg TS was initially envisioned as a 500/230kV station and has access to both the 230kV and 500kV networks. It includes sufficient reserved land and is a suitable and efficient location to advance bulk system capability. The need for the Kleinburg autos has been further described in the South & Central Bulk system study.

Development of Kleinburg TS as a 500/230 transformer station, as shown in Figure 26 below, has been identified as a preferred option to establish a bulk supply node. This would involve integrating the station into the transmission network by building 500kV and 230kV switchyards and installing three 500/230kV autotransformers, with provision for a fourth to accommodate longer-term demand.

Figure 26: Future Kleinburg TS and Kleinburg -Kirby transmission link (Courtesy: IESO)



This expansion would relieve pressure on Claireville TS, improve bulk power flow distribution, and enable effective utilization of the Kleinburg–Kirby link. On the 230kV side, targeted yard expansion would accommodate existing circuits, the new transmission link, and future regional reinforcements, while improving security by reducing reliance on the V43/44 corridor. Detailed configuration and sequencing would be finalized by Hydro One in coordination with IESO once the South and Central Bulk system planning studies are finalized.

Alternative solutions, such as local generation, were assessed but found to be less effective due to short-circuit constraints, operational inefficiencies, and limited bulk system benefits. The estimated capital cost of advancing Kleinburg TS as a bulk supply point is approximately $400 million, representing a cost-effective investment relative to other options. To maximize system benefits, the timing of the bulk expansion should align with the Kleinburg–Kirby link and the in-service date of Northern York TS #1. While early loading of Northern York TS #1 may be possible under constrained conditions, delays in completing the bulk enhancements would increase reliance on remedial action schemes. The working group agreed to initiate the project following the IESO's recommendation on the need, alternatives, and configuration of the Kleinburg autotransformer as part of Central Bulk System Planning with a potential in-service time frame of 2031-2032.

8.4.3 York Energy Centre- Station Service Upgrade

The York Energy Centre (YEC) currently depends on Holland TS for its station service supply. When the H82/83V circuits fail, both Holland TS and YEC lose power, even though YEC's generation path through B88/89H remains unaffected. This forced outage limits the ability to restore load quickly and creates unnecessary capacity and voltage challenges in the local system. Addressing this vulnerability requires a new station service arrangement that allows YEC to stay operational during these contingencies. IRRP suggested possible solutions include adding a second transformer fed from B89H or installing an automatic transfer system that switches between Holland TS and B88H. Fixing this issue would improve local reliability, reduce exposure to load rejection events, and increase system capability by roughly 90 MW without requiring major new transmission infrastructure. Looking ahead, YEC plays a critical role in meeting Northern York's peak demand—about 400 MW.

The working group has considered different alternatives to enhance YEC station service upgrade including adding a second supply via the B89H tap or by implementing an automatic transfer between the Holland TS distribution supply and the existing B88H source during contingencies.

The preferred station service configuration should be determined through a detailed engineering evaluation of technical feasibility and cost.

If YEC retires when its contract expires in 2035, the region would face a large capacity shortfall that cannot be addressed through incremental upgrades alone. Without a comparable replacement (new transmission or new local generation), reliability would significantly decline, and connecting new loads in the area would become severely constrained.

The Working Group concurs that the IESO should formally engage with Capital Power to examine and evaluate potential alternative solutions in the event of a YEC phase-out by 2035, including consideration of a station service upgrade.

8.4.4 Holland Marsh Switching Station

The IRRP has identified the requirement for a Switching Station at the Holland Marsh junction arising from the planned addition of a third Northern York Transformer Station (TS) along the Claireville–Minden transmission corridor. The introduction of this new transformation facility will impose additional system security requirements, irrespective of whether it interconnects with circuits H82/83V or B88/89V. This portion of the transmission network is already operationally complex due to the presence of multiple inline breakers and its interface with the York Energy Centre (YEC).

The establishment of a new Switching Station (SS) at the Holland Marsh junction and sectionalizing the existing circuits at this Holland Marsh location would simplify system operations, facilitate the future integration of Northern York TS #3, and mitigate the most critical breaker failure contingencies that currently constrain system reliability. The proposed configuration would provide dedicated terminations for circuits H82/83V and the modified B88/89H circuits, a new radial supply connection for Armitage TS,

and allowance for future radial circuits serving the Bradford–West Gwillimbury area or other long term transmission developments.

Sufficient existing land rights are available to host the proposed facility, and the estimated capital cost for a switching station of this scale is in the range of $200–250 million. Final design and configuration details for the Switching Station will be addressed in the subsequent regional planning cycle.

The TWG will monitor the area loading and need and timing for Holland Marsh switching station will be reviewed in the next planning cycle.

8.4.5 New Northern York transmission supply option connecting Northern York area

In addition to the Holland Marsh switching station described above, incorporating Northern York TS #3 or any other load request around this area beyond the planned Northern York TS #1 will also require additional supply resources. Options could include new transmission or potentially new generation facilities. One transmission option could be via an existing idle transmission corridor that runs from the Holland Marsh junction northwest through Bradford West Gwillimbury and onward into Simcoe County, connecting to Barrie TS and the planned Innisfil TS.

Utilization of this corridor will be assessed as the need date for Northern York TS #3 approaches to determine whether the benefits of positioning transformation capacity closer to emerging load centers outweigh the incremental transmission costs. Such benefits may include lower distribution system build-out costs, reduced connection costs for large customers, and improved reliability and power quality depending on where demand growth ultimately materializes.

Connecting any future station on a separate radial transmission path from Essa TS, as shown in Figure 27 below may help alleviate future capacity limitations on the Northern York circuits (H82/93V and B88/89H).

Figure 27: Conceptual Corridor route between Essa TS and Holland Marsh JCT (Courtesy: IESO)



An alternative option would be to upgrade the H82V/H83V circuit between Kirby Jct. and Holland Marsh Jct. The TWG will be further evaluating these options in the next planning cycle as longer-term supply and demand conditions become clearer such as YEC continued operation continuity and its Stations Service upgrade.

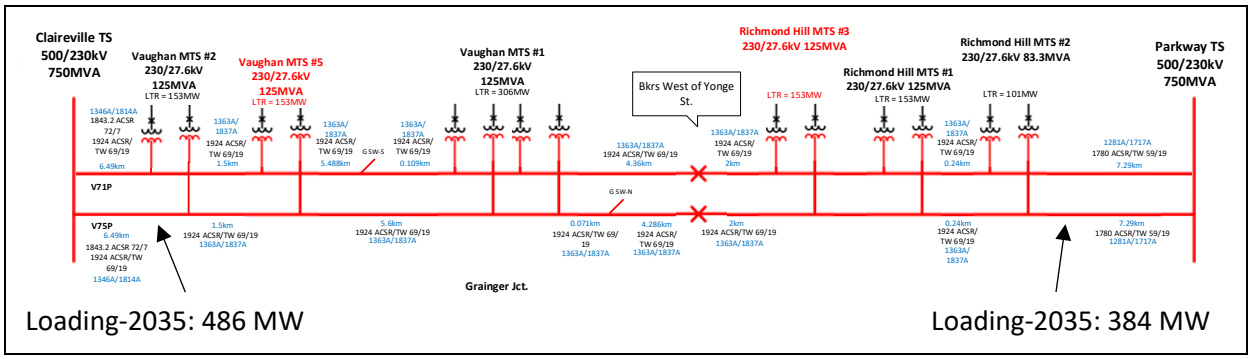
8.4.6 V71P/V75P 230kV in-line Breakers

The GTA north IRRP Study concluded that two in-line breakers are needed across that corridor to facilitate the restoration of load and mitigating the load security concerns to comply with Ontario Resource and Transmission Assessment Criteria (ORTAC). Although, the exact location of the in-line breakers will be determined considering the space availability and load distribution on both sides of breakers as per the table below, the working group has so far determined the location of the inline breakers on west of Yonge Street, between the Vaughan MTS #1 and Richmond Hills MTS #1/Richmond Hill MTS #2 as shown in the map (Figure 28) and single line diagram (Figure 29) below. Existing Grainger Jct. location may be utilized for the in-line breakers.

Figure 28: Approximate Location of V71P/V75P In-line Breakers



Figure 29: V71P/V75P 230kV In-line breakers SLD



The timing of this project's in-service is planned as year 2030 and shall be coordinated simultaneously with the addition of new Richmond Hill MTS #3 connection project. The approximate estimate for the cost is around $30M – $35M and will take around 3-4 years to complete the work. With the installation of in-line breakers, there will be a quick restoration of the load and load security concerns exceeding 600 MW load interruption will be mitigated.

8.4.7 Claireville to Minden - Over voltages and Under voltage needs.

8.4.7.1 Overvoltages

It is appropriate to mention the previously identified overvoltage concerns for YEC Station Service upgrade as the simultaneous loss of B88H and B89H removes Armitage TS, Brown Hill TS, and YEC from service, resulting in a lightly loaded radial supply from Minden TS to Beaverton TS and Lindsay TS. Due to the long circuit lengths and low load conditions, this configuration can lead to unacceptably high voltages. The risk is further exacerbated by capacitor banks at Beaverton and Lindsay TS, which are designed to support voltage under higher load conditions. Although this issue was identified in the previous IRRP too and mitigation measures have not yet been fully implemented. Unacceptable high voltages have not been observed to date. The working group agrees to continue monitoring the overvoltage issue and left open for discussion for the next planning cycle.

8.4.7.2 Undervoltages and M6E/M7E Thermal Overloads

Following the simultaneous loss of H82V and H83V, the subsystem becomes radially supplied from the north via Minden TS on B88/89H. Due to the long circuit lengths - particularly under high load conditions—voltage drops to unacceptable levels. In this configuration, York Energy Centre is unable to provide voltage support, as its station supply from Holland TS is lost. This contingency also results in overloads on sections of the M6E/M7E[6] circuits between Cooper Falls X Orillia along Essa TS and Minden TS corridor, which

[6] This was flagged as an issue for H82/83V outages which also take YEC out of service. Once the YEC station service issue is resolved this should not be a problem for York region at least.

become a primary remaining supply path into Northern York. While the YEC BESS remains in service and provides limited support, it is insufficient to resolve either the voltage issues or the M6E/M7E overloads. This need will be studied under the South Georgian Bay Muskoka IRRP.

8.4.8 Upgrading H82V/H83V circuits from Kirby Jct. to Holland Marsh Jct.

As discussed below, reconductoring the most constrained portion of circuits H82/83V between Claireville TS and Vaughan MTS #4 is not considered feasible due to the limited width of the existing transmission corridor and the close proximity of surrounding development. These physical constraints significantly limit constructability within this section.

North of the proposed Kleinburg–Kirby connection point development along the H82/83V corridor is substantially less dense. Based on a review conducted by Hydro One, reconductoring the portion of H82/83V as shown in Figure 30 between Kirby Jct. and the Holland Marsh junction is expected to be technically feasible.

Figure 30: Section of H82V/H83V from Kirby Jct. to Holland Marsh (23 km)



Following the completion of the York Energy Centre (YEC) station service project as discussed in Section 8.4.3, and the Kleinburg–Kirby Transmission Link, additional load meeting capability in Northern York is not anticipated to be required until a further step-down station is needed (notionally Northern York TS #3) and/or in the event of a potential retirement of YEC.

The degree of benefit provided by reconductoring this northern section of H82/83V would be dependent on the long-term configuration of the transmission system, including the spatial distribution of future demand and supply, as well as the development of any new infrastructure such as switching facilities. Where thermal limitations on the H82/83V circuits become binding, reconductoring this section could

help alleviate those constraints and increase load meeting capability by providing additional capacity into a future Holland Marsh Switching Station as discussed in Section 8.4.4.

Reconductoring the northern portion of H82/83V presents a potential cost-effective means of increasing capacity where corridor constraints are less pronounced and constructability risks are reduced. This option leverages existing infrastructure and rights-of-way, potentially avoiding the need for new corridors. However, its benefits are highly dependent on future system topology, including the timing and location of new step-down stations, changes in load growth patterns, and the availability of complementary infrastructure such as switching stations. As a result, reconductoring should be considered a conditional or enabling measure rather than a standalone solution and will be further discussed further in the next regional planning cycle.

Figure 31: a & b Alternate Route - Section upgrade north of Kirby to Holland Marsh (Courtesy: IESO)

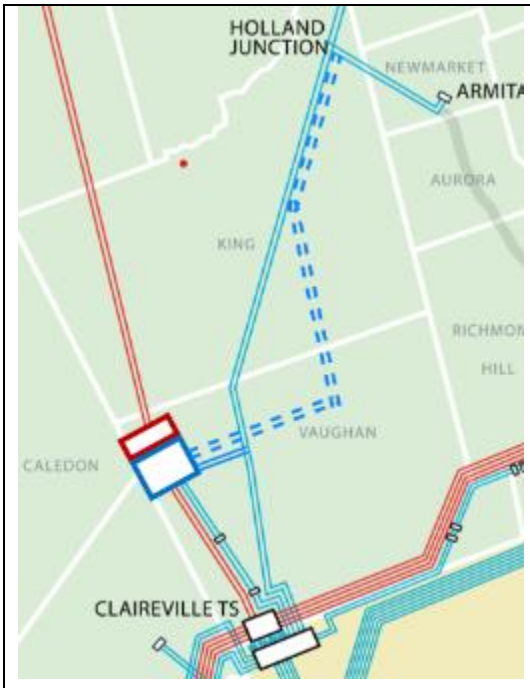


Figure 31-a

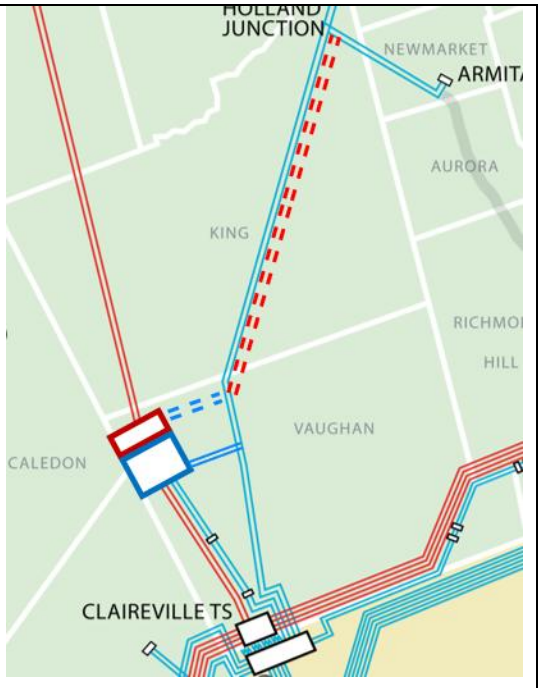


Figure 31-b

Alternatives and Recommended Plan

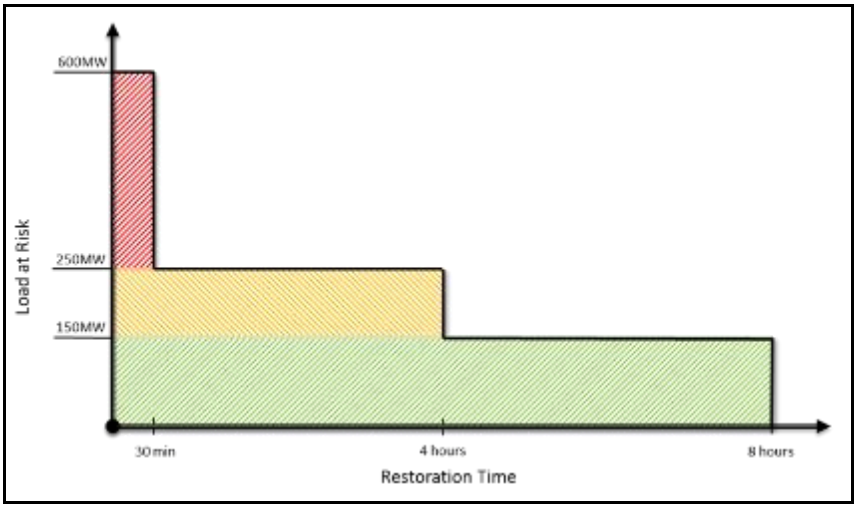
The working group has also considered the alternate route – new 230 kV circuits as shown in Figure 31-a, but not preferred due to the cost, timelines and challenges associated with acquiring new right of way and Environmental Screening. The working group has also explored to run the new line parallel to the existing one as it is easier to widen the existing right of way versus building brand new one as shown in Figure 31-b.

The TWG agreed to examine alternatives in the next regional planning cycle, including reconductoring the H82V/H83V segment north of Kirby Junction or developing a new line parallel to the existing infrastructure and any other options best suited to the needs of the region.

8.5 Load Security and Restoration Needs

Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfer) measures are considered when evaluating restoration capability. The load restoration criteria is defined in ORTAC and summarized in Figure 32.

Figure 32: ORTAC Criteria



8.5.1 Western Area: Load Security and Restoration on Kleinburg Radial Tap (V43/44)

The Kleinburg Radial tap consists of the two 230kV transmission circuits, V43 and V44, which extend northwest from Claireville TS. These circuits currently supply Woodbridge TS, Vaughan MTS #3, and Kleinburg TS, with ongoing development plans for a new step-down facility, Vaughan MTS #6, intended to serve growing commercial demand in the area. Under normal system conditions, the southern portion of this corridor also provides partial supply support to the adjacent Goreway TS in Brampton.

Peak demand within the Kleinburg radial load pocket is projected to exceed 600 MW by summer 2029 as shown in the Table 15 below.

Table 15: Load Security and Restoration on Kleinburg Radial Tap

V43/V44	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Kleinburg tap Load (MW)	522	534	597	607	644	645	656	676	691	687

Load Security

As described in Section 8.4.2, the proposed Kleinburg 500/230 kV Auto Station will address supply capacity and load security requirements in the Western region. By connecting the Kleinburg DESNs directly to the new 230 kV bus, loading on V43/V44 will be reduced to less than 600 MW, improving overall system performance.Load Restoration

Load restoration was assessed for 230kV radial double circuit line V43/V44 supplying the stations. In case of a double circuit outage of the V43/V44 line, not all loads in excess of 250 MW can be restored within 30 minutes, as per the ORTAC restoration criteria. The V43/V44 line is approximately 12 km long with good accessibility by maintenance crews and Hydro One expects all load to be restored within 4 hours with at least one circuit back into service.

Alternatives and Recommendations

The Working Group agreed that no further action is required at this time. However, the need will be reviewed in the next iteration of the regional planning cycle. The historical reliability of these circuits has been good with no coincidence outages of the two circuits; there have only been two direct outages[7] to circuit V43 since 2008 and no direct outages to circuit V44 since 2009. While there are no short-term plans to address this need, the Kleinburg to Kirby option to address supply capacity needs in the long term would also improve the load restoration capability for these circuits.

8.5.2 Northern Area - Load Security and Restoration[8]

8.5.2.1 Northern Area - Load Restoration from Claireville TS to Holland TS circuits (H82V/H83V)

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

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

[8] H1-Dx is assessing limited service territory adjustments at the Holland–Armitage and Brown Hill TS boundary to enhance restoration capability. While large-scale load transfers are constrained, targeted boundary changes could provide near-term flexibility and deliver lasting restoration benefits, maintaining value even after a future station enters service.

Alternatives and Recommendations

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

8.5.2.2 Northern Area- Load Restoration from Holland TS to Brown Hill TS circuits (B88H/B89H)

Load security issues would arise by the year 2035 where load more than 600 MW could be interrupted as shown in Table 16 below, that will be further discussed in the next planning cycle.

Table 16 Load Security Issue on B88H/B89H

Net Summer Load Forecast										
B88H/B89H	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Holland TS- Brown Hill TS (MW)	494	501	501	501	576	576	576	576	589	636

Load restoration was assessed for 230kV circuits B88H/B89H supplying Armitage TS, Northern York TS-1 and Brownhill TS and the customer Load. In case of a double circuit outage of B88H/B89H, not all loads exceeding 250 MW can be restored within 30 minutes per the ORTAC criteria. However, Hydro One expects all loads to be restored within 4 hours with one circuit back in service.

8.5.3 Southern Vaughan -Richmond Hill Area- Load Security and Restoration on V71P/V75P

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. The load security criteria in ORTAC limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.

The load on the corridor already exceeded 600 MW ORTAC Criteria and in the past the transmitter installed in-line switches at Grainger Jct. just outside the Vaughan MTS #1 to mitigate the restoration concerns. But there are existing load security issues that will further exacerbate the load security concerns with the addition of two new transformer stations by 2035. Table 17 below is the summary of the loading on the corridor till 2035.

Table 17: Load Security > 600 MW (V71P/V75P)

Clareville X Parkway	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
V71P/V75P Loading (MW)	700	695	713	713	739	761	809	898	862	870

To address the existing load security issue, working group has recommended the installation of inline breakers as discussed in Section 8.4.6

Load restoration was assessed for 230kV circuits V71P/V75P supplying Vaughan MTS #2, Vaughan MTS #5, Vaughan MTS #1, Richmond Hill MTS #1, Richmond Hill MTS #2, and Richmond Hill MTS #3. In case of a double circuit outage of V71P/V75P, not all loads exceeding 250 MW can be restored within 30 minutes per the ORTAC criteria. However, Hydro One expects all loads to be restored within 4 hours with one circuit back in service.

8.5.4 Markham Area- Load Security and Restoration on Buttonville Corridor (P45/P46)

Load security issues would arise by the year 2034 where load in excess of 600 MW could be interrupted as shown in Table 18 below. Woking group will continue to monitor the load growth in the area and will discuss the potential solutions in the next planning cycle.

Table 18: Load Security on Buttonville Tap (P45/P46)

P45/P46 Corridor	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Load (MW)	261	299	306	327	363	512	542	587	651	708

Following reconductoring of P45/P46 to address thermal constraints; the addition of longer-term stations on the P45/46 circuits would still trigger load security needs once total load exceeds 600 MW. To mitigate this, and as discussed in Section 8.3.1.4, a new radial circuit could be extended from the southern transmission corridor near Highway 407 to supply Markham MTS #4, removing it from P45/46. This would increase area load meeting capability by approximately one station's worth of load and simultaneously mitigating the load security issue on P45/46 corridor as shown in Table 19 below, as no ORTAC > 600 MW load security violation observed till year 2035.

Table 19: Load Security on Buttonville Tap (P45/P46)- after Markham MTS #4 off loading

P45/P46- Corridor	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Load (MW)	150	150	153	174	210	316	389	434	498	555

Load restoration was assessed for 230kV radial double circuit line P45/P46 supplying Markham MTS #4, and Buttonville TS, and in future Buttonville TS #2, Northern York TS #2 and Markham MTS #6 supplying primarily urban communities in Markham Area.

In case of a double circuit outage of the P45/P46 line, not all loads more than 250 MW can be restored within 30 minutes, as per the ORTAC restoration criteria. The P45/P46 line is approximately 4 km long with good accessibility by maintenance crews of Alectra expect all load to be restored within 4 hours with at least one circuit back into service.

9 CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for GTA North region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon [2026-2035] are provided in Table 20 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 20: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M) *
Asset Renewal Needs				
Woodbridge TS	Transformer (T5) refurbishment	Hydro One	2032	TBD
Station Capacity Needs[11]				
Kleinburg TS	Adding Kleinburg TS (T3/T4) — (230/44kV)	Hydro One	2028	$40M
Vaughan MTS #6	Build Vaughan MTS #6 (T3/T4) 27.6 kV DESN	Alectra	2027	$55M-$65M
Northern York TS #1	Build Northern York TS #1 230/44kV DESN	Hydro One	2031	$55M-$65M[12]
Northern York TS #3	Build Northern York TS #3 230/44kV DESN	Hydro One	2035	$55M-$65M
Richmond Hill MTS #3	Build Richmond Hill MTS #3 230/27.6kV DESN	Alectra	2030	$55M-$65M
Vaughan MTS #5	Build Vaughan MTS #5 230/27.6kV DESN	Alectra	2033	$55M-$65M
Buttonville TS #2	Build Buttonville TS #2 230/27.6kV DESN	Hydro One	2030	$55M-$65M

[11] Costs for the new Stations can vary based on location, configuration, layout, environmental issues etc.

[12] Additional cost could incur depending upon the location of the Tx Station and the circuit tap length– overhead / underground required.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M) *
Markham MTS #6	Build Markham MTS #6 230/27.6kV DESN	Alectra	2034	$55M-$65M[13]
Northern York TS #2	Build Northern York TS #2 230/44kV DESN	Hydro One	2034	$55M-$65M[14]
Transmission Line Capacity Needs				
P45/P46	Upgrade P45/P46 from Parkway TS to Markham MTS #4	Hydro One	2031	$5M
P45/P46	Upgrade P45/P46 from Markham MTS #4 to Buttonville TS	Hydro One	2034	$10M
P45/P46	Extend and build P45/P46 Buttonville TS 7km North	Hydro One	2034	$50M
C35P/C36P	Reconnect Markham MTS #4 to C35P/C36P	Hydro One	To be discussed in the next Regional Planning cycle[15]	$9M
System Reliability				
Kleinburg TS	Build Kleinburg to Kirby Transmission Link	Hydro One	2031-2032	$40M - $60M[16]
Kleinburg TS	Bulk Supply - 500/230 kV Transformer Station	Hydro One	2031-2032	$400M
York Energy Centre	York Energy Centre – Station Service Upgrade	Capital Power	2026 (Current)	IESO to coordinate with Capital Power
Holland Marsh SS	Holland Marsh Switching Station	IESO	To be discussed in the next	TBD-Next Planning Cycle

[13] The cost does not include building 230kV line to supply the new TS
[14] The cost does not include building 230kV line to supply the new TS
[15] IRRP recommended that this coincides with connection of Markham#6 or NY-TS2 (whichever is required first)
[16] Refer to Appendix-F for additional reference to the need, recommendation and the cost.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M) *
			Regional Planning cycle	
Essa/Barrie to Holland Marsh	New Northern York Transmission Supply	IESO	To be discussed in the next Regional Planning cycle	TBD-Next Planning Cycle
V71P/V75P	In-line Breakers	Hydro One	2030	$30M-$35M
H82V/H83V-B88H/B89H and M6E/M7E[17]	Claireville to Minden: Over voltages (H82V/H83V); Under voltages (B88H/B89H), and Thermal Needs (M6E)	IESO/Hydro One	TBD/Continued to be monitored	TBD/Continued to be monitored
H82V/H83V	Upgrading the portion of H82V/H83V from Kirby Jct. to Holland Marsh (23km)	IESO /Hydro One	To be discussed next Regional Planning cycle	(To be discussed next Planning Cycle)
Load Security and Restoration				
V43/V44	Load Security on Kleinburg Radial Tap	Hydro One	2031-2032	N/A
H82V/H83V and B88H/B89H	Load Security and Restoration in Northern Area	Hydro One	2031-2032[18]	N/A
H82V/H83V	Load Restoration from Claireville TS to Holland TS Circuits (H82V/H83V)	Hydro One	2031-2032	N/A
B88H/B89H	Load Restoration from Holland TS to Brown Hill TS	Hydro One	2031-2032	N/A

[17] M6E/M7E circuit boundaries are outside of GTA North Region Scope and thermal issues will be dealt by IESO at Bulk level.

[18] YEC Station Service upgrade and Marsh Switching Station would mitigate load restoration and security issue.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M) *
	Circuits (B88H/B89H)			
V71P/V75P	Load Security and Restoration on V71P/V75P	Hydro One	2030	$35M[19]
P45/P46	Load Security and Restoration on Buttonville Corridor (P45/P46)	Hydro One	2034[20]	$9M[21]

* The cost figures presented are high-level allocations in 2025 dollars and have not been informed by detailed engineering design or development work. Accordingly, these estimates are preliminary in nature, subject to material change, and are intended for options analysis purposes only

[19] The $-figure reflects the cost associated with inline breakers at V71P/V75P to mitigate load security issues.
[20] Load Security issue is triggered in year 2034 when LF > 600 MW.
[21] The $-figure reflects the cost associated with Markham MTS#4 re-termination to C35P/C36P

10 REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)
[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)
[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)
[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)
[5] GTA North 3rd Cycle Needs Assessment (NA) Report (issue July 14, 2023)
[6] GTA North 3rd Cycle Scoping Assessment (issue October 12, 2023)
[7] GTA North region Integrated Regional Resource Planning (IRRP) Report (issue October 10, 2025)

11 Appendix A: Net Summer Peak Load Forecast

Table A.1: GTA North region – Net MW Summer Peak Load Forecast

Station	Summer LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Kleinburg TS	180	214	225	249	260	276	275	274	273	272	271
Vaughan MTS #3	153	150	149	153	153	153	153	153	153	153	153
Vaughan MTS #6	153	0	0	30	29	49	48	56	76	92	90
Woodbridge TS	160	158	161	164	165	167	169	173	173	173	173
Western Area (V43/V44) Sub-Total	**646**	**522**	**534**	**597**	**607**	**644**	**645**	**656**	**676**	**691**	**687**
Holland TS	168	169	169	169	169	169	169	169	169	169	169
Northern York TS #1	170	0	0	0	0	0	32	65	92	130	161
Vaughan MTS #4	153	99	138	153	153	153	153	153	153	153	153
H82V/H83V Sub-Total	**474**	**268**	**307**	**322**	**322**	**322**	**354**	**387**	**414**	**452**	**483**
Armitage TS	317	317	317	317	317	317	317	317	317	317	317
Brown Hill TS	184	177	184	184	184	184	184	184	184	184	184
The Customer	75	0	0	0	0	75	75	75	75	75	75
Northern York TS #3	170	0	0	0	0	0	0	0	0	13	60
B88H/B89H Sub-Total	**746**	**494**	**501**	**501**	**501**	**576**	**576**	**576**	**576**	**589**	**636**
Northern York Area Sub-Total	**1220**	**762**	**808**	**823**	**823**	**898**	**930**	**963**	**990**	**1041**	**1119**

Station	Summer LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Richmond Hill MTS #1	153	150	148	153	153	153	153	153	153	153	153
Richmond Hill MTS #2	101	99	98	101	101	101	101	101	101	101	101
Richmond Hill MTS #3	153	0	0	0	0	26	48	61	86	115	129
Vaughan MTS #1	306	301	300	306	306	306	306	306	306	306	291
Vaughan MTS #2	153	150	149	153	153	153	153	153	153	153	144
Vaughan MTS #5	153	0	0	0	0	0	0	35	99	33	52
V71P/V75P Sub-Total	**1019**	**700**	**695**	**713**	**713**	**739**	**761**	**809**	**898**	**862**	**870**
Markham MTS #1	90	81	80	81	81	81	81	81	81	79	79
P21R/P22R Sub-Total	**90**	**81**	**80**	**81**	**81**	**81**	**81**	**81**	**81**	**79**	**79**
Southern York Area Sub-Total	**1109**	**780**	**776**	**794**	**794**	**820**	**842**	**890**	**979**	**941**	**948**
Buttonville TS	166	150	150	149	147	146	146	145	145	145	144
Markham MTS #4	153	111	150	153	153	153	153	153	153	153	153
Buttonville TS #2	153	0	0	4	27	63	110	144	146	143	143
Markham MTS #6	153	0	0	0	0	0	0	0	0	40	98
Northern York TS #2	170	0	0	0	0	0	60	99	142	170	170
P45/P46 Sub-Total	**795**	**261**	**299**	**306**	**327**	**363**	**469**	**542**	**587**	**651**	**708**
Markham MTS #2	101	95	94	101	101	101	101	101	101	101	101
Markham MTS #3	202	190	188	202	202	202	202	202	202	202	202
C35P/C36P Sub-Total	**303**	**285**	**283**	**303**	**303**	**303**	**303**	**303**	**303**	**303**	**303**

Markham Area Sub-Total	**1098**	**546**	**582**	**609**	**630**	**666**	**815**	**845**	**890**	**954**	**1011**

12 Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
2	Kleinburg TS T1/T2 44	230/44	V44/V43
3	Vaughan MTS #3 T1/T2	230/27.6	V44/V43
4	Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
5	Woodbridge TS T3/T5 44	230/44	V44/V43
6	Armitage TS T1/T2	230/44	B88H/B89H
7	Armitage TS T3/T4	230/44	B88H/B89H
8	Brown Hill TS T1/T2	230/44	B88H/B89H
9	Holland TS T1/T2, T3/T4	230/44	H82V/H83V
10	Buttonville TS T3/T4	230/27.6	P45/P46
11	Markham MTS #1 T1/T2	230/27.6	P21R/P22R
12	Markham MTS #2 T1/T2	230/27.6	C35P/C36P
13	Markham MTS #3 T1/T2	230/27.6	C35P/C36P
14	Markham MTS #3 T3/T4	230/27.6	C35P/C36P
15	Markham MTS #4 T1/T2	230/27.6	P45/P46
16	CTS	230/44	P21R/P22R
17	Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
18	Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
19	Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
20	Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
21	Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
22	Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V

13 Appendix C: List of LDC's

No.	Names of LDCs
1	Hydro One Networks Inc. (Transmission)
2	Hydro One Networks Inc. (Distribution)
3	Alectra Utilities Inc.
4	Newmarket-Tay Power Distribution LTD (NT Power)
5	Toronto Hydro
6	Elexicon Energy

14 Appendix D: List of Municipalities in the region

No.	Name of Municipality
1	Aurora
2	Bradford West Gwillimbury
3	East Gwillimbury
4	Georgina
5	King
6	Markham
7	Newmarket
8	Richmond Hill
9	Simcoe County
10	Vaughan
11	Whitchurch-Stouffville

15 Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CA	Customer Application
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere

Acronym	Description
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station
TWG	Technical Working Group
YEC	York Energy Centre

16 Appendix F: IESO Letter for Kleinburg-Kirby Transmission Link

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

March 20, 2026

Robert Reinmuller

Vice President, Transmission System Planning and Large Customer Accounts Hydro One Networks, Inc.

483 Bay Street, TCT 14

Toronto, ON

M5G 2P5

Dear Robert:

Implementation Update for the Kleinburg-Kirby 230 kV Transmission Link

The IESO is providing this letter to Hydro One Networks Inc. (“Hydro One”) in response to

Hydro One’s ongoing development of the GTA North (York Region) Regional Infrastructure Plan (“RIP”). The RIP is expected to include a near-term recommendation to proceed with a new double-circuit 230 kV transmission line, the Kleinburg–Kirby Link (the “Project”), consistent with the recommendations in the 2025 IESO’s GTA North (York Region) Integrated Regional Resource Plan (“IRRP”). The IESO requests that

Hydro One append this letter to the RIP to identify the IESO's recommendations on the Project's scope, timing, and implementation.

The 2025 GTA North (York Region) IRRP was published on October 10th, 2025. Among its recommendations was the development of the Project, to be co-located with the future Highway 413 corridor, to support growing electricity demand in northern York region. The Project will establish a new connection between the existing 230 kV radial transmission system in Kleinburg (at the proposed expanded Kleinburg TS) and the 230 kV transmission system north of Claireville TS, terminating on the existing H82/83V circuits north of Vaughan MTS #4, close to the intersection with Kirby Rd. This new connection is critical for enabling the full loading of the recommended Northern York TS #1 and was recommended in the 2025 GTA North (York Region) IRRP to come in service in 2032.

Following the publication of the 2025 GTA North (York Region) IRRP, the IESO assessed whether the Project was suitable for development under the Transmitter Selection Framework ("TSF"). The IESO has determined that the Project is not a candidate for the TSF for the following reasons:

1. Project scope and cost: The expected cost of the Project is well below the $100 million proposed eligibility criterion for the TSF. Transmission line construction costs for the Project are projected to be approximately $40 million (2025 dollars). While the IESO recognizes that additional project costs due to factors such as land topography, finalized routing and design, land acquisition, community engagement and system integration are possible, the total cost of the Project, inclusive of these factors, is still expected to remain well below $100 million.
2. Development timeline: Meeting the targeted 2032 in-service date is essential to enabling forecast customer growth and connections throughout northern York region, as identified in the 2025 GTA North (York Region) IRRP. The TSF is not anticipated to launch prior to 2027, so using a TSF procurement process could create a material risk of missing the Project's 2032 targeted in-service date.

For these reasons, the IESO recommends that Hydro One proceed with the necessary development work for this Project. This development work should align with the outcomes of the RIP and remain consistent with the IRRP's recommendations and support achieving the targeted 2032 in-service date.

The IESO looks forward to continued collaboration as Hydro One advances this important infrastructure project.

Yours truly,

Gabriel Adam, P.Eng.

Director, Transmission Integration

cc: Ajay Garg, Hydro One

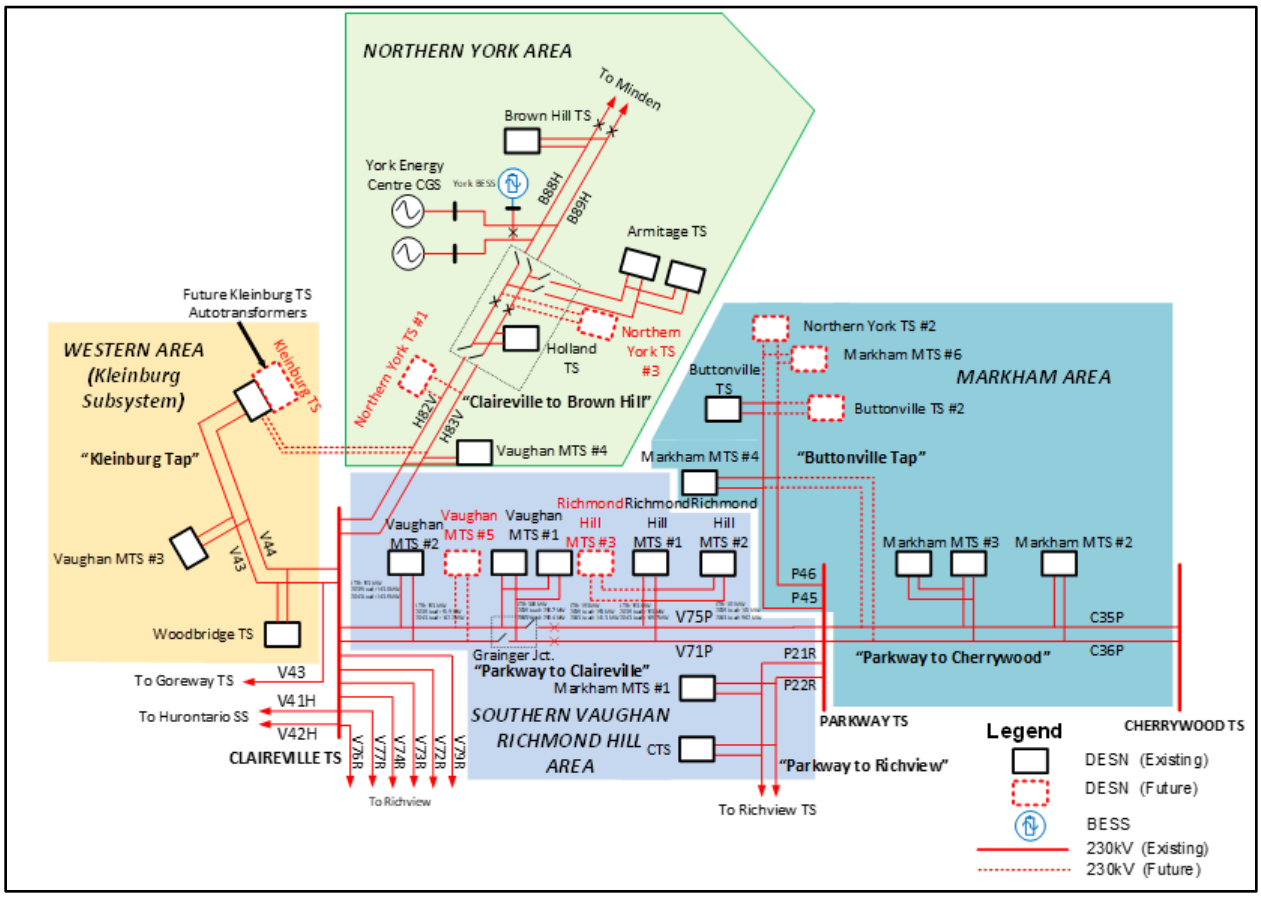
Michael Xavier, Hydro One

Chuck Farmer, IESO

Beverly Nollert, IESO

IESO Records

17 Appendix G: Ultimate SLD for the Needs/ Recommendations RIP (2026-2035)



Greater Toronto Area West (Peel/Halton)

Integrated Regional Resource Plan

July 2021

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Connecting Today.
Powering Tomorrow.

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List of Acronyms

Acronym	Definition
CCAP	Climate Change Action Plan
CCGT	Combined Cycle Gas Turbine
CDM	Conservation and Demand Management
CEP	Community Energy Plan
DER	Distributed Energy Resource
DG	Distributed Generation
ERP	Enabling Resource Program
FETT	Flow East Towards Toronto
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTE	Long-term Emergency (Equipment Rating)
MTO	Ministry of Transportation
NCM	Lithium Nickel Manganese Cobalt Oxide
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
STE	Short-term Emergency (Equipment Rating)
TS	Transformer Station

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Greater Toronto Area West (GTA West) region which included the following members:

Independent Electricity System Operator

Hydro One Networks Inc. (Distribution)

Hydro One Networks Inc. (Transmission)

Alectra Utilities

Burlington Hydro Inc.

Milton Hydro Distribution Inc.

Oakville Hydro Electricity Distribution Inc.

Halton Hills Hydro

The Working Group assessed the reliability of electricity supply to customers in the GTA West Region over a 20-year period beginning in 2019; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The GTA West Working Group members agree with the Integrated Regional Resource Plan (IRRP)'s recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations. The GTA West Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Greater Toronto Area West region (GTA West) over the next 20 years from 2019 to 2038. The GTA West region is located in central Ontario and includes the Regional Municipalities of Halton and Peel. The region includes the area roughly bordered geographically by Highway 27 to the north east, Highway 427 to the south east, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south. The GTA West region comprises the municipalities of Brampton, Caledon, Halton Hills, Mississauga, Milton, Oakville and portions of Burlington.

During discussions with communities, the IESO received feedback that the name "GTA West Regional Planning" was challenging to differentiate from other initiatives underway in the area with a similar naming convention, thus, the region was changed to "Peel/Halton (GTA West) Region" for engagement purposes. Official planning documents continue to adhere to the regulatory name of "GTA West Region".

The GTA West region is summer peaking and, over the last five years, electrical demand has grown on average by 1.3% per year. Electrical supply to the GTA West region is provided through 500/230 kV autotransformers at Trafalgar TS and at Claireville TS and 230 kV transmission lines and step-down transformation facilities as shown in Figure 1.1. The GTA West Region is defined electrically by the 230 kV transmission circuits bounded by Claireville TS, Richview TS and Manby TS to the east and Burlington TS to the west. Local generation in the area includes two gas fired plants: the 1250 MW Goreway Generating Station (GS) in Brampton and the 600 MW Halton Hills GS in Halton Hills.

The region's electricity is delivered by six local distribution companies (LDCs): Hydro One Networks, Alectra Utilities, Burlington Hydro, Milton Hydro Distribution, Oakville Hydro Electricity Distribution, and Halton Hills Hydro. Hydro One Networks is also the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and transmitter.

Development of the GTA West IRRP was initiated in August 2019 following the publication of the Needs Assessment report in May 2019 by Hydro One and the Scoping Assessment Outcome Report in August 2019 by the IESO. The Scoping Assessment identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6
- Alternatives and recommendations for meeting needs are addressed in Section 7
- A summary of engagement to date and moving forward is provided in Section 8; and
- The conclusion is provided in Section 9

Figure 1.1 | Geographical area of the GTA West region with electrical layout



2. The Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) provides recommendations to address the electricity needs of the GTA West region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The GTA West electricity demand forecast projects sustained growth driven by urbanisation and development particularly in the northern areas of the region. Municipalities have also published community energy plans and/or climate change action plans that call for greater electrification which could drive additional upward pressure on the demand forecast.

The IRRP recommendations below are organized under a near-/medium-term plan and a long-term plan. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near future while remaining flexible to new information as electrification, energy efficiency, and development plans evolve.

2.1 Near-/Medium-Term Plan

The near- and medium-term plan is comprised of several recommendations to accommodate load growth, maintain reliability, and optimize end-of-life asset replacement. The recommendations are summarized in Table 2.1 and further discussed below.

Table 2.1 | Summary of Near-/Medium-term Plan for the GTA West Region

Need Description	Recommendation	Lead Responsibility	Required By
After a loss of either H29 or H30, the remaining circuit will exceed its LTE rating	H29/H30 reconductoring	Hydro One	2025
After a loss of V42H and H29, R19TH will exceed its LTE rating. After a loss of V41H and H30, R21TH will exceed its LTE rating	Control actions and/or load rejection scheme	Hydro One	Today

Need Description	Recommendation	Lead Responsibility	Required By
Transformers T3 and T4 at Palermo TS will reach end-of-life	Upsize transformers at end-of-life to the larger 75/125 MVA transformers	Hydro One	2025
Simultaneous loss of both T38B and T39B would result in over 600MW of load being lost by configuration	Further analysis of wires options including circuit sectionalisation and/or reterminating supply stations	Hydro One	2025
30-minute load restoration following V41H/V42H, R19TH/R21TH, and R14T/R17T6 contingencies	Investigate opportunities to enhance distribution load transfer capabilities	LDCs with loads on impacted circuits	Ongoing

2.1.1 H29/H30 Reconductoring

When load at Pleasant TS exceeds approximately 417 MW and one of the H29/30 circuits that supplies Pleasant TS is out of service, there is a potential for overloads on the companion circuit. This need was originally identified in the 2015 Northwest GTA IRRP and upgrading the H29/H30 circuits with conductors of a higher rating was recommended. At the time, the demand forecast was only expected to reach 417 MW in 2033 but the IRRP recognized that this timing could change significantly if higher growth or lower conservation adoption materialized and consequently recommended that the load at Pleasant TS should be monitored and the reconductoring work should be pursued when demand reaches approximately 400 MW.

As discussed in the 2019 GTA West Scoping Assessment report, the role of the current IRRP is to update the implementation timing of this upgrade, not further investigate alternatives to it, given the relatively straightforward scope. The current forecast for Pleasant TS projects demand to reach 417 MW by 2027. However, the observed 2020 summer peak demand was much higher than anticipated and reached 410 MW during a July heat wave. At this time, it is still unclear whether this is an isolated event related to the ongoing COVID-19 pandemic and associated electricity consumption patterns or if this will be an enduring trend. Given that the lead time required to implement the reconductoring work will be at least three years, the IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service date around 2025.

2.1.2 Pleasant TS Control Actions

Post-contingency thermal violations during outage conditions are expected to occur on the R19TH/R21TH circuits leading into Hurontario SS by 2021. This type of contingency is expected to be very infrequent since it only occurs under the confluence of peak load conditions, hot weather, pre--existing forced outage on one element and a subsequent contingency on another. As a result, this need is most economically managed by control actions or load rejection schemes. Alternative options considered are further discussed in Section 7.2.

In the near- to medium-term, the overloads on R19TH/R21TH are expected to exceed their long-term emergency (LTE) but not their short-term emergency (STE) rating. During this period, manual post--contingency control actions such as unloading one of the two transformers at Jim Yarrow TS can provide relief by reducing circuit loading below the LTE rating provided that such actions can be completed within 15 minutes. As load continues to grow, the overloads are expected to exceed STE by 2038 at which point an automatic load rejection scheme at Pleasant TS will be required. The IRRP recommends that the Regional Infrastructure Plan (RIP) led by Hydro One should develop and implement control actions as soon as possible.

2.1.3 Upsizing Palermo TS at End-of-Life

The existing T3 and T4 transformers at Palermo TS will reach end-of-life in 2025. Palermo TS is fully utilized today and there is no remaining capacity for growth. Tremaine TS, a nearby station, is also expected to exceed capacity in 2033.

Refurbishing Palermo TS with larger 75/125 MVA transformers would require significant station reconfiguration. However, Hydro One indicated that the yard itself is in relatively poor condition, had recently been downgraded, and will likely need to be replaced in less than 10 years regardless of the transformer size chosen. Based on planning-level cost estimates, the cost of upsizing Palermo TS when its transformers reach end-of-life in 2025 is substantially more cost-effective than the alternative of refurbishing Palermo TS like-for-like in 2025 followed by subsequent upsizing or building a new station when capacity needs arise in 2033. This financial analysis is further discussed in Section 7.3. The IRRP recommends that the RIP should perform additional analysis to reaffirm the cost estimate and develop an implementation plan for upsizing Palermo TS in 2025.

2.1.4 Further Wires Analysis for T38B/T39B Load Security

The load security need on T38B/T39B was initially documented in the 2015 Northwest GTA IRRP and was expected to materialized between 2024 and 2026. No firm recommendation was made at the time because the need was still approximately 10 years off and future bulk system reinforcements along the Flow East Towards Toronto (FETT) interface may also address the load security need.

The current IRRP forecast reaffirms that the load security need is expected to materialize in 2025. Furthermore, in December 2020, the IESO determined that the most suitable and cost-effective bulk system FETT interface reinforcement are conductor upgrades to the Richview TS x Trafalgar TS 230 kV transmission lines which does not resolve the load security need on T38B/T39B. The FETT interface bulk study is further discussed in Section 4.2.

The IRRP considered the merits of generation, non-wires options and an integrated transmission option, the Hurontario SS x Meadowvale TS transmission reinforcement, that could simultaneously improve bulk system transfer capabilities and help alleviate the load security need on T38B/T39B. Ultimately, wires options such as reterminating Tremaine TS on the companion T36B/T37B circuits or installing breakers at Lantz Junction to sectionalize T38B/T39B are the most suitable and -cost-effective solution at this time. The options analysis is further discussed in Section 7.4.

The IRRP recommends that the RIP should perform detailed analysis to further refine the technical feasibility and costs of these wires options. As part of this work, the RIP should update the near-term load forecast for the stations served on T38B/T39B. The IRRP also recognizes that there may be merit in applying to the IESO for an ORTAC exemption to accept a lower performance level for a few years until future FETT transfer capability needs in the late 2020's are known given the potential integrated nature of the solutions that could address these needs. The IESO will continue to participate in the RIP technical working group to provide advice and input on this matter.

2.1.5 Explore Opportunities to Enhance Distribution Transfer Capabilities

All stations in the GTA West region have dual supply meaning that no load would be lost by configuration for any single contingency. However, there are multiple areas in the GTA West region where major transmission contingencies (such as the simultaneous loss of two elements) would interrupt supply to many customers and where full restoration would be delayed until the transmission contingency has been cleared. The GTA West region is a densely populated and well serviced area so it is assumed that all contingencies can be restored within eight hours consistent with ORTAC load restoration criteria. Most major contingencies have historically been of short duration due to close proximity to staffed maintenance centres. Of the remaining restoration criteria, the 30-minute restoration of all load lost above 250 MW is the most limiting since it relies on remote control actions such as emergency distribution load transfers.

As discussed in the Scoping Assessment, major infrastructure solutions such as new transmission facilities are not generally appropriate since the cost of the solution would exceed the expected benefit to customers. However, restoration needs were kept in scope for this IRRP to evaluate if planned infrastructure solutions for other needs can be modified in ways that maximize restoration capability.

Of the double circuit contingencies where the 30-minute restoration criteria cannot be met, infrastructure solutions for H29/H30 was deemed uneconomic in the previous IRRP due to the high cost and low probability of the contingency occurring while T38B/T39B restoration needs can be significantly improved through the wires options discussed in the previous section for addressing load security.

There remain three double contingencies that are at risk of not meeting 30-minute restoration criteria: V41H/V42H, R19TH/R21TH, and R14T/R17T. At this time, there are no planned infrastructure reinforcements for other needs that can also help improve load restoration on these circuits. However, the IRRP recommends that local distributors, in conjunction with Hydro One where appropriate, investigate opportunities to improve distribution load transfer capability from the stations supplied on these circuits to other nearby stations to maximize restoration capability.

In the long term, future transmission reinforcement projects such as the NW GTA Transmission Corridor can help improve load restoration by providing additional supply points from which northern loads can be restored.

2.2 Long-Term Plan

In addition to the near- and medium-term plan above, there are four items to monitor and develop in the long term.

2.2.1 Monitor Halton Pocket Growth and T38B/T39B Reconductoring

During an outage to Halton Hills GS, post-contingency thermal violations on T38B/T39B are expected to occur by 2031. The thermal violation is on a short 400-meter section of T38B/T39B immediately north of Lantz Junction. This radial portion of T38B/T39B serves the Halton Pocket including Trafalgar DESN, Halton TS, Halton TS #2, Halton MTS, and Meadowvale TS.

Reconductoring the limiting section is the most cost-effective option. The options analysis is further discussed in Section 7.5. Given the timing of the need, no firm recommendation is required at this time. The Working Group will continue to monitor load growth in the Halton Pocket and revisit this need, and its potential alternatives, in the next cycle of regional planning.

2.2.2 Monitor Growth at Cardiff TS and Jim Yarrow TS

Cardiff TS and Jim Yarrow TS are expected to reach capacity in 2029 and 2032, respectively. Given the timing of the need, no firm recommendation is required at this time. The Working Group will continue to monitor load growth and revisit this need in the next cycle of regional planning.

2.2.3 Supporting Community Energy Plans and Monitoring Energy Efficiency and Electrification Trends

Most lower- and upper-tier municipalities in the GTA West region have published community energy plans (CEP) or climate change action plans (CCAP) including the:

- Region of Peel's Climate Change Master Plan,
- Town of Oakville's Community Energy Strategy,
- Town of Caledon Community Climate Change Action Plan,
- Town of Halton Hills' Community Energy Plan,
- City of Brampton Community Energy and Emissions Reduction Plan,
- City of Burlington's Climate Action Plan, and
- City of Mississauga Climate Change Action Plan to name a few.

The scope varies by municipality and plan but the general aim is to promote energy efficiency, improve resiliency, lower greenhouse gas emissions, and invest in the local economy.

While the IRRP seeks to align with these plans where possible, not all of the objectives fall within the scope of the regional planning nor the IESO's mandate. For example, absent of provincial government policy, the IESO is technology agnostic and will generally choose the most economic option that adequately resolves the need and meets applicable reliability standards. Greenhouse gas emissions are considered in the IRRP's options analysis by accounting for the carbon price associated with emitting resources, but the IESO does not have emission reduction targets unless directed by government policy. Furthermore, while regional planning is responsible for ensuring electricity ratepayer value and minimizing electricity costs, the IESO relies on government policy for broader socioeconomic considerations.

There are three CEP and CCAP objectives that the IESO and regional planning can play a role in supporting. First, the IESO recognizes that distributed energy resources (DER) are becoming increasingly prevalent and features prominently in many CEPs and CCAPs. DERs can provide benefits to both customers as well as the distribution and transmission systems. By enabling DERs to provide wholesale services, system costs can be reduced and opportunities for customers and investors can be increased. The IESO's Enabling Resources Program (ERP) will produce a 5-10 year plan to enable resources to provide services they cannot or cannot fully currently provide. The ERP has identified storage, hybrids, and DERs as high-priority opportunities. The IESO is developing a DER roadmap which is expected to be shared with stakeholders in the fall of 2021 to provide clarity on IESO objectives, initiatives, and timing for DER integration. More information can be found on the Distributed Energy Resource Roadmap engagement page.

Second, the Working Group will continue to support and monitor energy efficiency uptake. Conservation expected to be achieved through codes, standards, and program delivery has already been included in the planning forecast as described in Section 5.4. On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 Conservation and Demand Management (CDM) Framework. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensures energy efficiency can continue to play a role in meeting the region's needs. The Working Group will monitor uptake of the CDM framework as well as energy efficiency initiatives in CEPs and assess the impact of these additional savings on the timing of local reliability needs.

Finally, the Working Group will monitor electrification trends and their impact on the demand forecast. The Working Group recognizes that many CEPs and CCAPs are calling for ambitious electrification targets as a means to achieve carbon emission reductions. It is not yet clear how impactful electrification will be to the load forecast in the near-term but it could drive significantly higher demand in the long term that will necessitate new electricity supply into the area. While it is still difficult to establish when firm investments or infrastructure reinforcements will be needed, it is prudent to prepare for a future where electricity demand could potentially be significantly higher than forecast.

The IESO and local distribution companies will continue to participate in local community energy planning initiatives such as the Heritage Heights Community Energy Plan Working Group at the request of municipal staff.

2.2.4 NW GTA Transmission Corridor

While the IRRP has not identified a firm need date for new transmission infrastructure in the northern areas of the region, Halton Hills, Brampton and Caledon are experiencing rapid growth in areas that are increasingly further away from existing transmission infrastructure. As discussed in the previous section, high electrification uptake could also significantly impact electricity demand.

The Ministry of Transportation (MTO) is currently planning for a new 400-series highway in the same approximate area as the anticipated long-term need for new transmission in the region. Provincial policy encourages colocation of linear infrastructure to reduce land use impacts and the IESO and Ministry of Energy are conducting a joint study to ultimately identify a suitable corridor of land that can be preserved for future transmission infrastructure should the need arise. The expectation is that the preferred route for this future transmission corridor will largely align with MTO's highway study area. Although co-location of linear infrastructure provides benefits from a land use perspective, it is important to note that the need associated with future transmission is linked to the size and location of anticipated growth, and not any specific transportation or other infrastructure plan. Protecting land for a future transmission corridor maintains flexibility to accommodate future demand growth in the northern areas beyond what is already captured in the IRRP forecast and mitigates the challenges of needing to build transmission infrastructure through developed land.

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;

3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.2 GTA West and IRRP Development

The process to develop the GTA West IRRP was initiated in August 2019 following the publication of the Needs Assessment report in May 2019 by Hydro One and Scoping Assessment Outcome Report in August 2019 by the IESO.

In October 2020, the IESO wrote to the Ontario Energy Board (OEB) to provide notice of expected delays in completing three ongoing IRRPs including the GTA West IRRP. The additional time to complete the GTA West IRRP provided the IESO the opportunity to align the timing with that of the bulk system plan for the Flow East Toward Toronto (FETT) and further investigate higher than expected actual demand observed at some of the transformers stations within the region in 2020. The IESO estimated that 3-6 months of additional time was required beyond the original completion date of February 8th, 2021.

4. Background and Study Scope

This is the second cycle of regional planning for the GTA West region. In the first cycle of regional planning, the region was divided into two sub-regions: Northwest GTA and Southwest GTA. The Northwest GTA sub-region roughly encompassed the municipalities of Milton, Halton Hills, Caledon and Brampton while the Southwest GTA sub-region encompassed Mississauga, Oakville, and parts of Burlington. Following a Needs Assessment and Scoping Assessment in 2014, an IRRP was initiated for the Northwest GTA sub-region and subsequently published in 2015. The first cycle concluded in 2016 with the publication of a Regional Infrastructure Plan.

The current cycle of regional planning began in 2019 with the publication of the GTA West Needs Assessment Report where a number of needs requiring further regional coordination was identified. The 2019 GTA West Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019.

4.1 Study Scope

This IRRP develops and recommends options to meet the electricity needs of the GTA West Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation and demand management (CDM), distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

The following transmission facilities were included in the scope of this study:

- Step-down transformer stations: Halton TS, Halton Hills MTS, Meadowvale TS, Jim Yarrow MTS, Pleasant TS, Cardiff TS, Bramalea TS, Goreway TS, Tremaine TS, Trafalgar TS, Palermo TS, Glenorchy MTS #1, Churchill Meadows TS, Erindale TS, Tomken TS, Oakville TS #2, Lorne Park TS, Cooksville TS
- Transmission lines: H29/H30, R14T/R17T, R19TH/R21TH, T36B/T37B, T38B/ T39B, V41H/V42H, V43/V44, B15C/B16C, K21C/K23C, R24C

The single line diagram of the GTA West region is shown in Figure 4.1 below. Note that the 500 kV circuits and bulk system transfer capabilities through the region is not within the scope of the IRRP and separately studied in the FETT interface bulk transmission study which is discussed further below in Section 4.2.

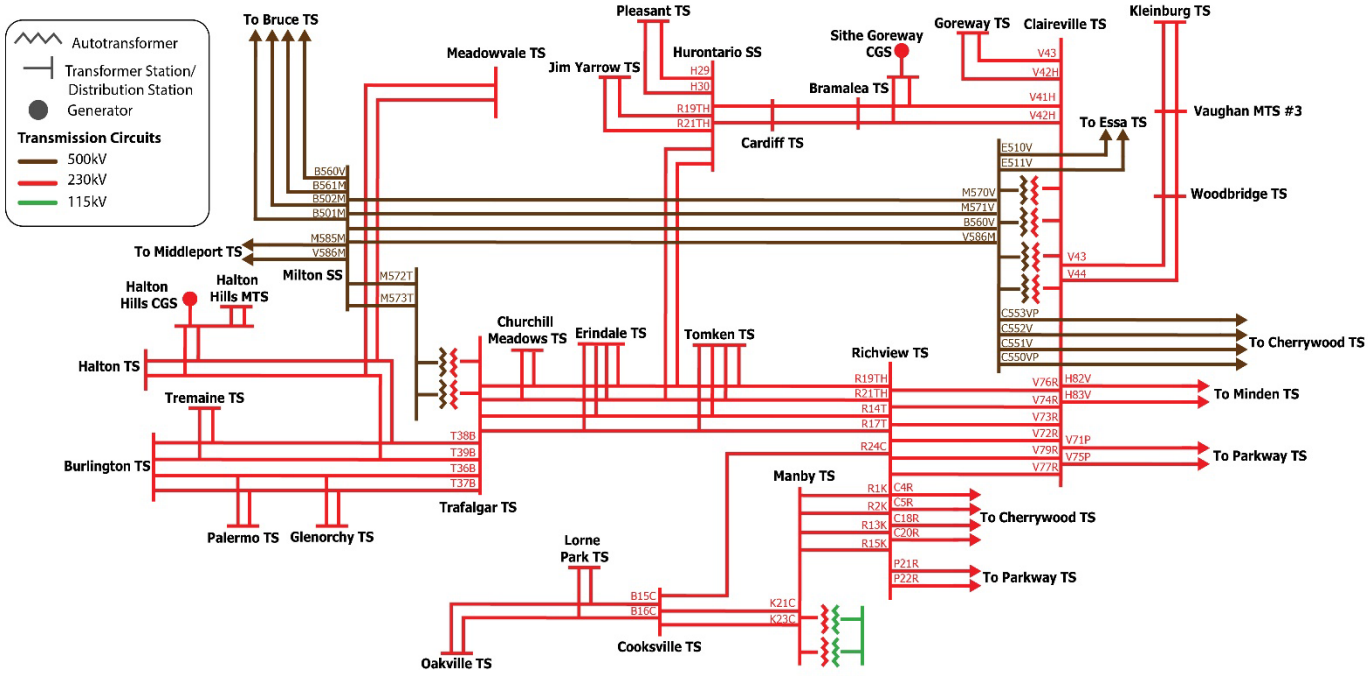


Figure 4.1 | Single Line Diagram of the GTA West Region

The GTA West IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including conservation and demand management;
- Engaging with the community on needs and possible alternatives;

- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

4.2 FETT Interface Bulk Transmission Study

Flow East Towards Toronto (FETT) is a transmission interface that delivers electricity from western to eastern Ontario and consists of three paths: (a) four 500 kV circuits into Claireville TS from the west, (b) four 230 kV circuits between Trafalgar TS and Richview TS, and (c) two 230 kV circuits between Orangeville TS and Essa TS.

Supply capacity in eastern Ontario is expected to decline over the next decade, which contributes to a provincial need for capacity and, because of limits on the transfer capability of the FETT interface, ~2000 MW of that capacity will have to be sited east of the FETT interface by 2026. To reduce the amount of capacity that must be sited in eastern Ontario, the IESO issued a letter in December 2020 recommending that Hydro One proceed with conductor upgrades to the R14T/R17T and R19TH/R21TH circuits between Trafalgar TS and Richview TS as a first stage to increase the FETT transfer capability.

Future FETT interface needs beyond these conductor upgrades are not known at this time and will depend on the future resources acquisition framework and availability of potential resources east of FETT. The IESO will continue participate in the Working Group during the RIP to help ensure recommendations are aligned with the latest bulk system information.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the GTA West Region. It highlights the assumptions made for peak demand forecasts including weather correction and the contribution of CDM and DG. The resulting net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon.

5.1 Historical Demand

Growth within the GTA West region has been steady over the last five years, largely driven by expanding urban boundaries and intensifying urban areas. Figure 5.1 below shows the net actual (as observed at metering point), net median weather corrected (adjusted to reflect median on peak weather conditions), and gross median weather corrected (impact of DG removed) historical demand. The gross median weather corrected electrical demand has grown at an average rate of 1.3% over the past five years, representing an increase of approximately 150 MW for the study area. The peak demand hour for each year occurs in the summer from approximately 3 PM to 7 PM.

Generally speaking, the 2018 gross median weather corrected peak at each station was used as the starting point for the forecast unless adjustments were necessary to remove outliers.

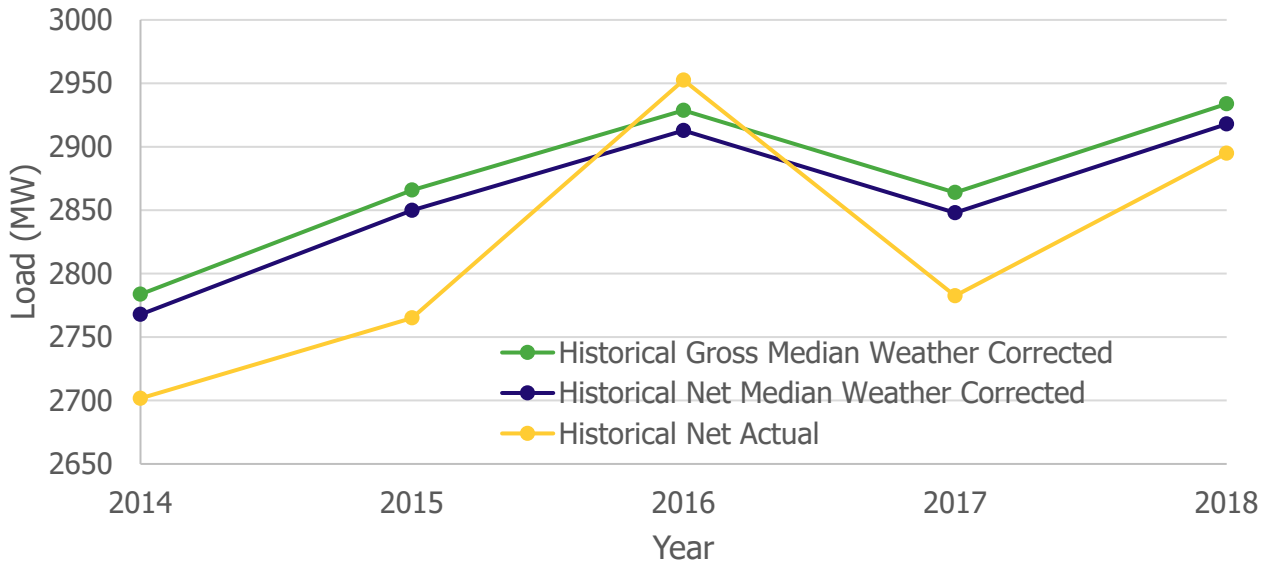


Figure 5.1 | Historical Demand in the GTA West Region

5.2 Demand Forecast Methodology

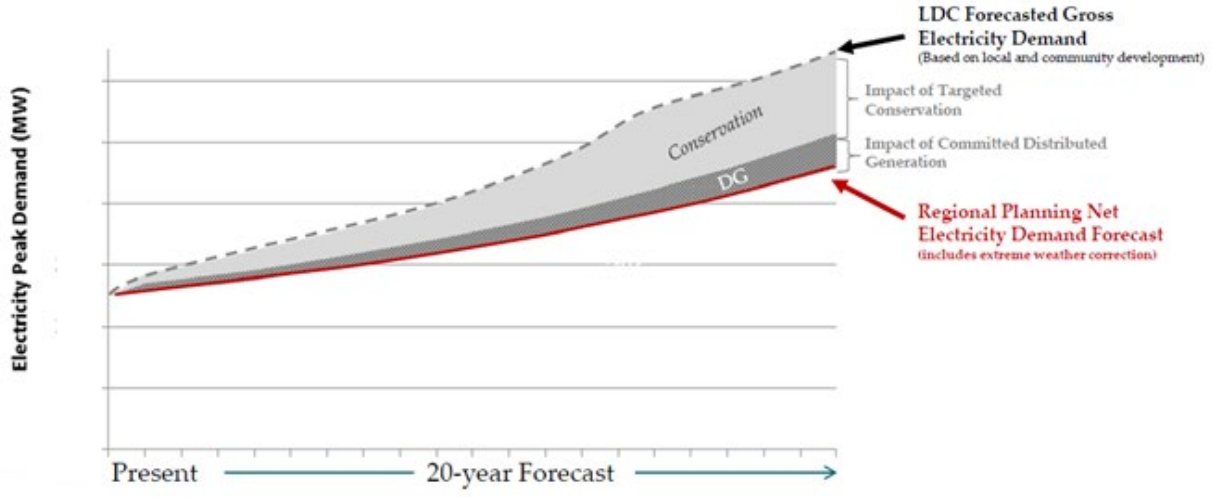


Figure 5.2 | Illustrative Development of Demand Forecast

For the purpose of this IRRP, a 20-year regional peak demand forecast was developed to assess reliability needs for GTA West. The steps taken to perform this are depicted in Figure 5.2. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions and referred to as normal weather, were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs such as FIT and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix B.

5.3 Gross LDC Forecast

Each participating LDC in the GTA West Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development and known connection applications. Most LDCs cited alignment with municipal and regional official plans and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for by the IESO as discussed in Section 5.4 below. The gross LDC forecast assumes median on-peak weather conditions.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants and municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.7. Figure 5.3 below shows the total gross LDC forecast for the GTA West region.

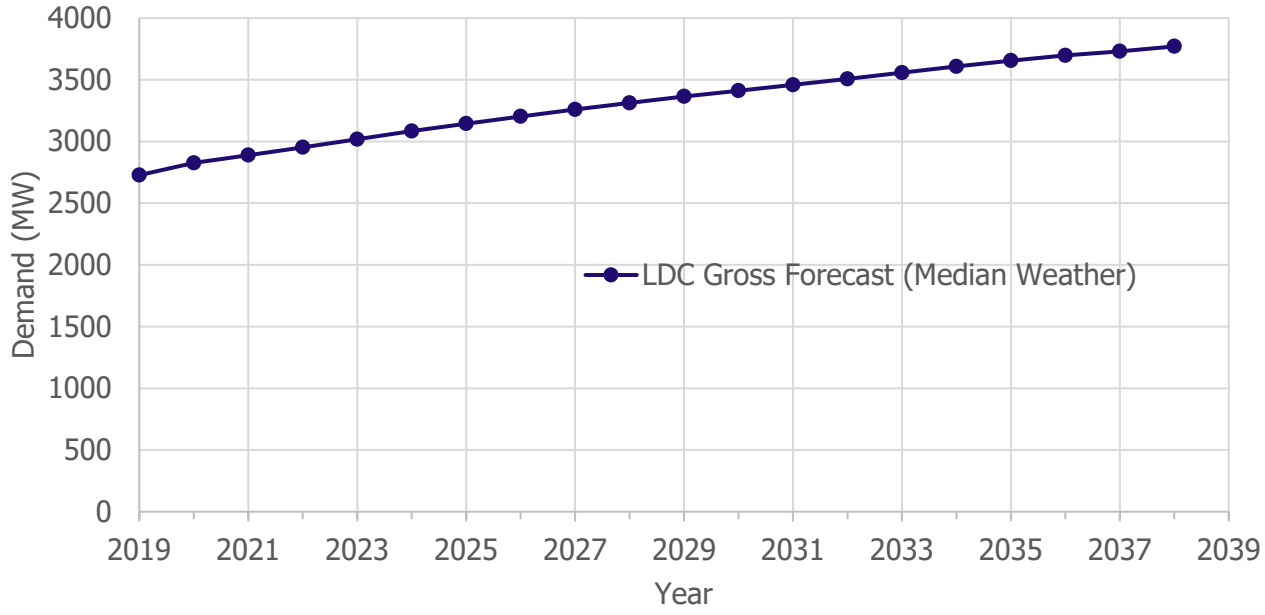


Figure 5.3 | Total Gross LDC Forecast (Median Weather)

5.4 Contribution of Conservation to the Forecast

Conservation and demand management, is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as CDM program-related activities These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers, i.e. residential, commercial and industrial consumers.

The estimates of demand reduction due to program-related activities account for Save on Energy[1] programs, as well as those that will be implemented as part of the 2021-2024 CDM Framework, which started in January 2021. The IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

[1] https://www.saveonenergy.ca/

Figure 5.4 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards and CDM programs) for each of the residential, commercial and industrial consumers. Additional details are provided in Appendix B.8.

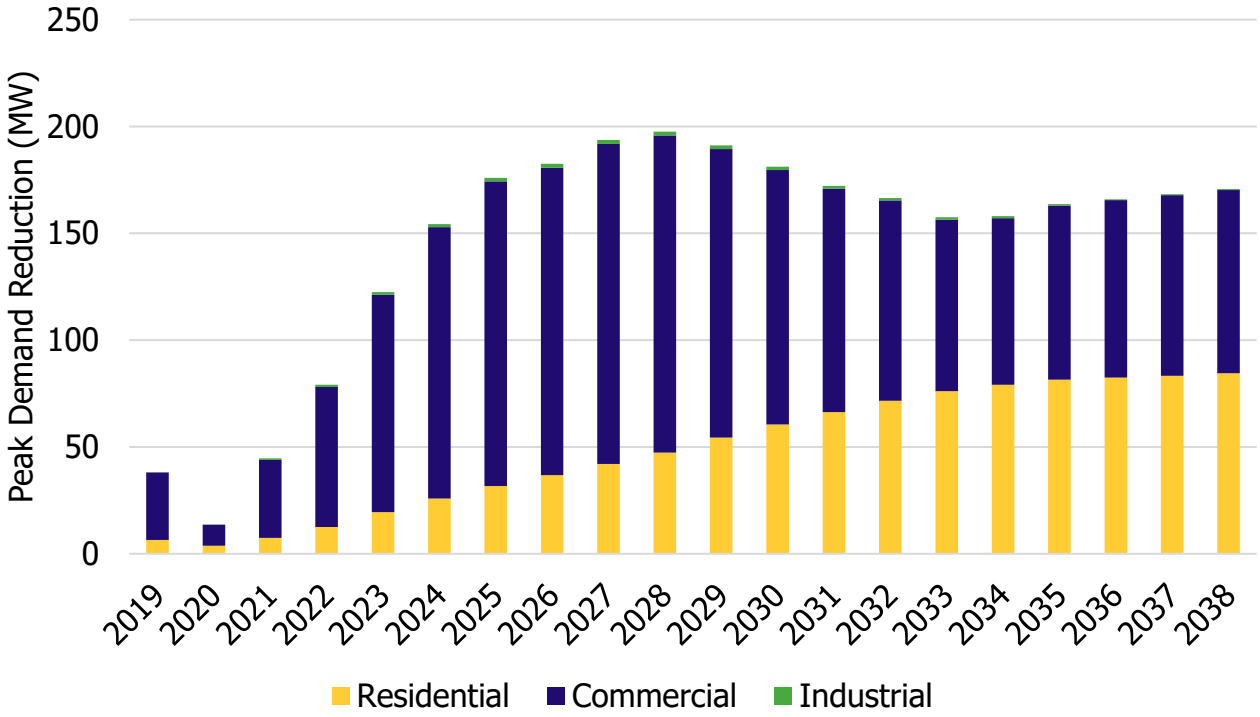


Figure 5.4 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the GTA West Region is also forecast to offset peak-demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B.9.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted DG in the region. Figure 5.5 shows the impact of DG on reducing the demand forecast. In the long term, the contribution of DG is expected to diminish as these contracts expire. Additionally, any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

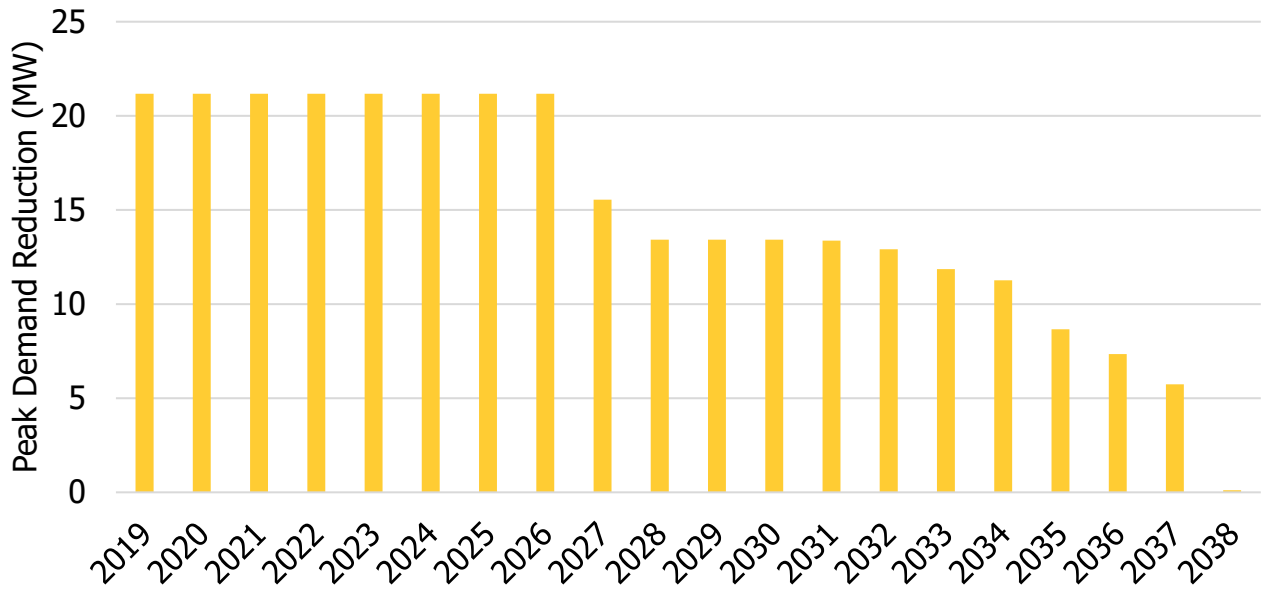


Figure 5.5 | Peak Demand Reduction to Demand Forecast due to DG

5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, as known as the "planning" forecast, is created in two steps. First the gross LDC median weather forecast is adjusted for extreme weather conditions according to the methodology described in Appendix B.1. This results in the gross extreme weather forecast. The net extreme weather forecast is then obtained by adding in the forecast DG and conservation impacts described in Section 5.4 and 5.5 above. Note that this planning forecast is non-coincident meaning that each station in the region is forecast separately at their own peak demand.

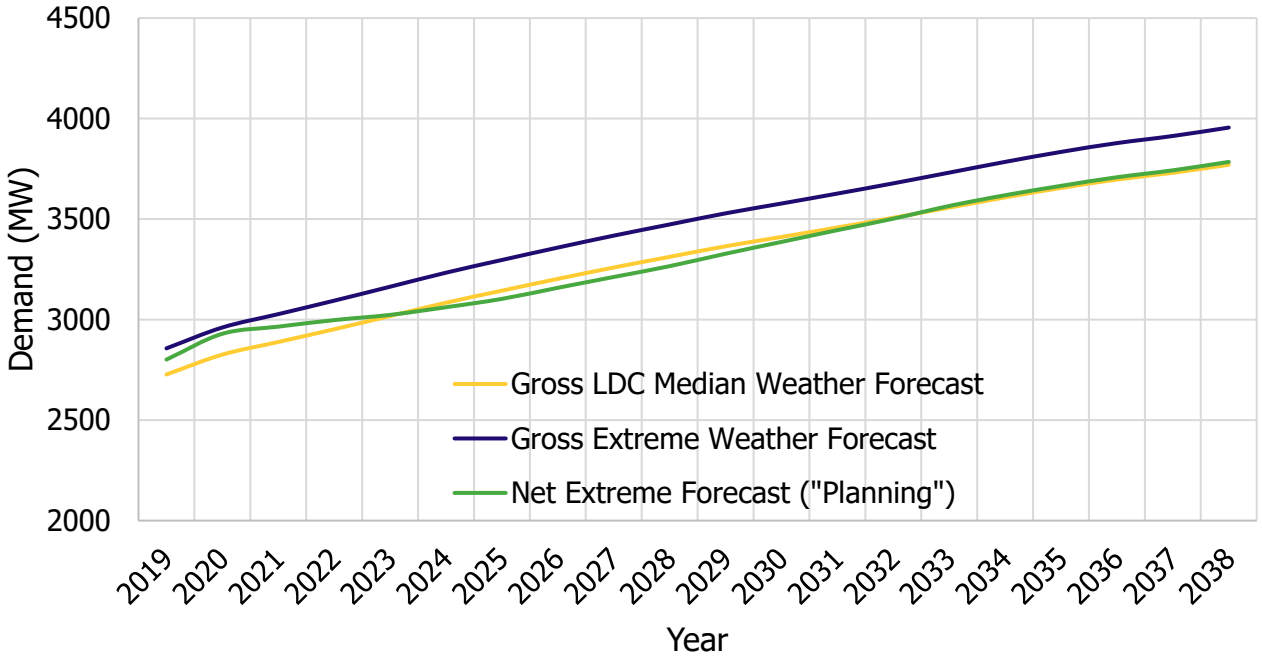


Figure 5.6 | Net Extreme Weather ("Planning") Forecast for the GTA West Region

To determine the need date for needs that are driven by more than one station, the coincident planning forecast for the relevant group of stations are found by applying a coincidence factor. The coincidence factor is based on the contribution of each station to the group's coincident peak over the past five years. The net extreme weather forecast for the GTA West region is shown in Figure 5.6 below.

5.7 Load Profiling

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20 year forecast horizon) for certain stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. As described in Section 7.1, these profiles are used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details including summary tables and hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Further, this data is only used to select suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast (extreme weather, net demand), system capability, the transmitter's identified end-of-life asset replacement plans, and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Working Group identified electricity needs in the near-, medium- and long-term timeframe for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.

- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulations analysis.

- **End-of-life Asset Refurbishment Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results can be found in Appendix C. The needs identified are discussed in Sections 6.2 and 6.3 below.

6.2 Near-/Medium-Term Needs Identified

Table 6.1 below summarizes the near- and medium-term needs identified by this IRRP.

Table 6.1 | Summary of Near and Medium-Term Needs

Need	Need Description	Need Date
H29/H30 Supply Capacity	After a loss of either H29 or H30, the remaining circuit (i.e. H30 or H29) will exceed its LTE rating.	2027[2]
R19TH/R21TH Supply Capacity	After a loss of V42H and H29, R19TH will exceed its LTE rating. After a loss of V41H and H30, R21TH will exceed its LTE rating.	Today
Palermo TS End-of-Life Refurbishment	Transformers T3 and T4 at Palermo TS will reach end-of-life.	2025
T38B/T39B Load Security	Simultaneous loss of both T38B and T39B would result in over 600 MW of load being lost by configuration.	2025
Load Restoration Needs	30-minute restoration of all load lost above 250 MW not achievable with current load transfer capabilities after select N-2 contingencies	Ongoing

[2] Note that the "Required By" date for this need in Section 2.1 is 2025. This reflects the recommendation to advance the H29/H30 work to help mitigate the risk of high than anticipated growth.

6.2.1 Station Capacity Needs

There are no station capacity needs in the near term.

6.2.2 Supply Capacity Needs

6.2.2.1 H29/H30 Supply Capacity Need

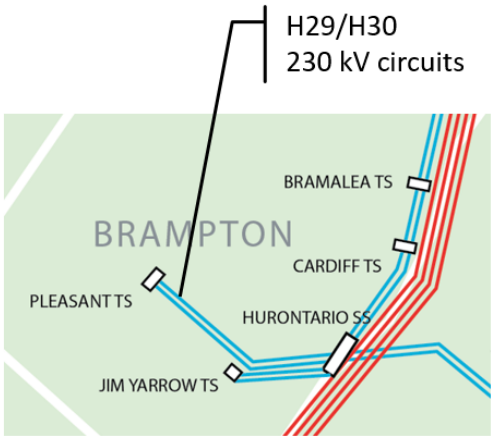


Figure 6.1 | H29/H30 230 kV Circuits

The circuits identified as H29 and H30 form an 8.5 km, 230 kV double-circuit supplying Pleasant TS, as shown in Figure 6.1 above.

According to the demand forecast, this need is expected to exceed the identified LMC of 417 MW by 2027. It is important to note that the 2020 actual peak demand at Pleasant TS reached 410 MW during the July 2020 summer peak. This is shown in Figure 6.2 below. However, it may be too early to conclude if this was an isolated event related to the COVID-19 pandemic or an enduring trend. This need was also identified in the 2015 GTA West IRRP.

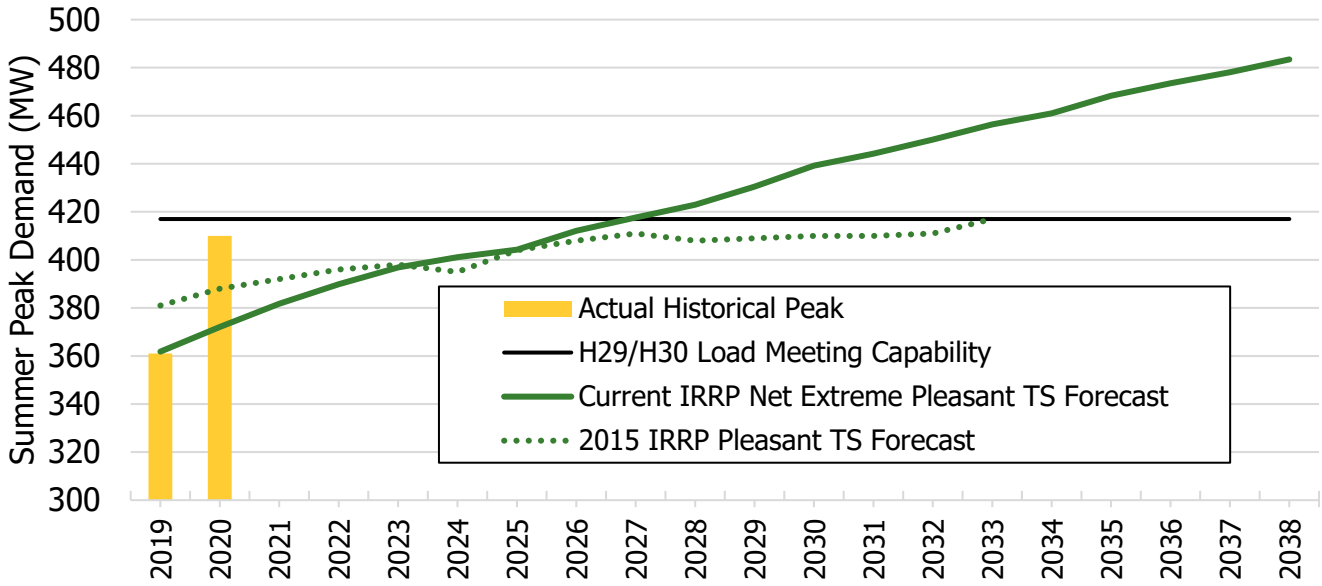


Figure 6.2 | Pleasant TS Historical and Forecast Demand

6.2.2.2 R19TH/R21TH[3] Supply Capacity Need

The circuits R19TH and R21TH form a 230 kV double-circuit from Richview TS to Trafalgar TS. These circuits also extend from Hanlan JCT northward towards Hurontario SS. These circuits provide a supply path to Jim Yarrow MTS, Pleasant TS, Cardiff TS, and Bramalea TS. Figure 6.3 below shows an overview of the area.

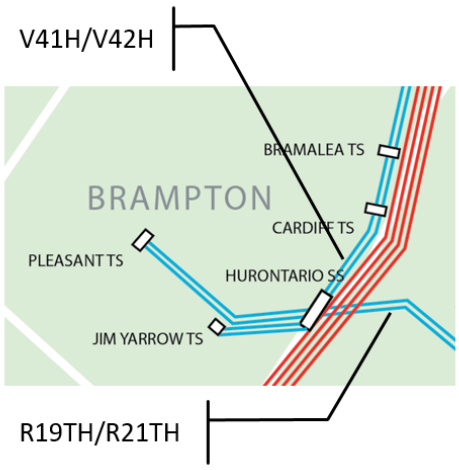


Figure 6.3 | R19TH and R21TH 230 kV Circuits

[3] The limiting sections of R19TH/R21TH referred to here are different from the ones that will be upgraded as the result of the FETT Interface Bulk Transmission Study (Section 4.2).

This need occurs only for specific contingencies during a pre-existing outages (N-1-1 contingency). When V42H is experiencing an outage followed by an H29 contingency, the circuit section of R19TH from Hanlan JCT to Hurontario SS will start to exceed its LTE rating by 2021 and will exceed its STE rating by 2038. The need is primarily driven by growth at Pleasant TS. This is also true for the circuit section of R21TH from Hanlan JCT to Hurontario SS when V41H is experiencing an outage followed by an H30 contingency. The need is illustrated in Figure 6.4 below.

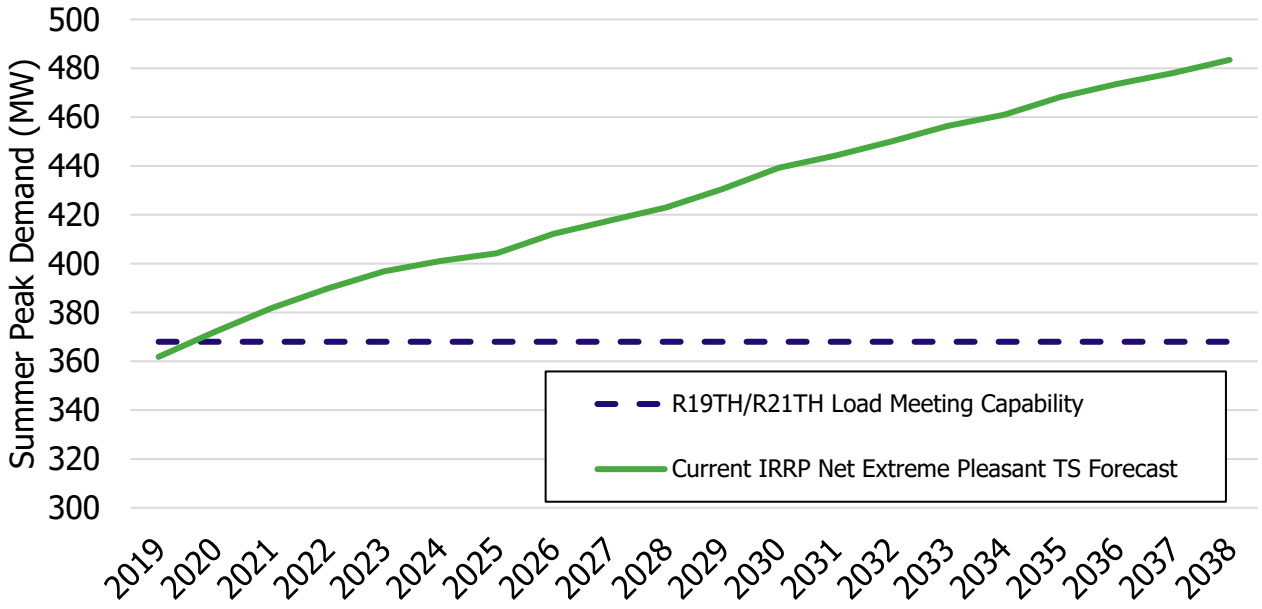


Figure 6.4 | R19TH/R21TH Supply Capacity Need

6.2.3 End-of-Life Refurbishment Needs

6.2.3.1 Palermo TS

Palermo TS is a transformer station that serves load of Burlington Hydro Inc., Milton Hydro Inc. and Oakville Hydro in the municipalities of Burlington, Milton, and Oakville. The transformers at Palermo TS (T3 and T4) are sized up to 83 MVA and will reach end-of-life in 2025.

It is important to note that the nearby Tremaine TS is expected to exceed its station supply capacity limits by 2033 (details of which are found in Section 6.3.2 below). Therefore, it is prudent to consider the needs of Tremaine TS when addressing the end-of-life issues at Palermo TS. Figure 6.5 below shows a geographical overview of Palermo TS and Tremaine TS within the GTA West system.

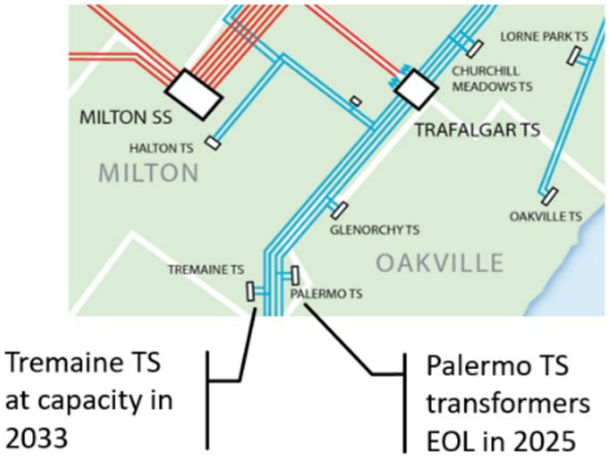


Figure 6.5 | Overview of Palermo TS and Tremaine TS

6.2.4 Load Security

6.2.4.1 T38B/T39B Load Security Need

The circuits designated as T38B/T39B form a 230 kV double-circuit from Burlington TS to Trafalgar TS. These circuits serve numerous transformer stations including Tremaine TS, Trafalgar DESN, Meadowvale TS, Halton TS, Halton #2 TS (future), and Halton Hills MTS. The local 683 MW gas-powered Halton Hills Generating Station also provides power to the province via these two circuits. The area served by this double-circuit is often referred to as the "Halton Pocket". Figure 6.6 provides an overview of the Halton Pocket.

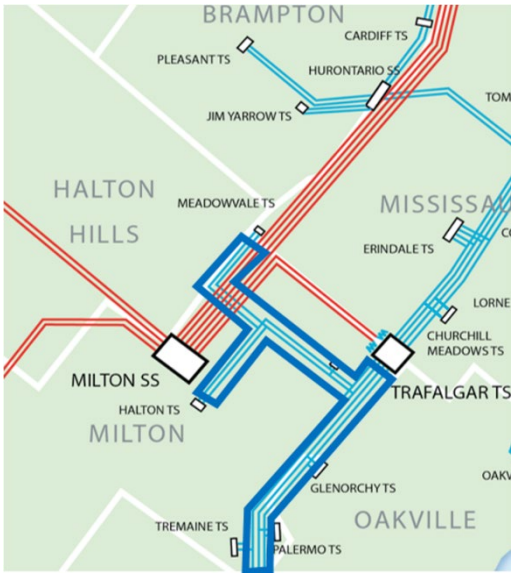


Figure 6.6 | Overview of the Halton Pocket

Starting in 2025, the loss of both T38B and T39B circuits will result in over 600 MW of load being disconnected from the system, and is a violation of Section 7.1 of the ORTAC. This is due to all the aforementioned stations being served solely by these two circuits. The load of at the Halton pocket is expected to grow throughout the study period (i.e. 2020 to 2038). By 2038, it is expected that up to 775 MW of coincident load will be lost following the loss of both these circuits. This is shown in Figure 6.7.

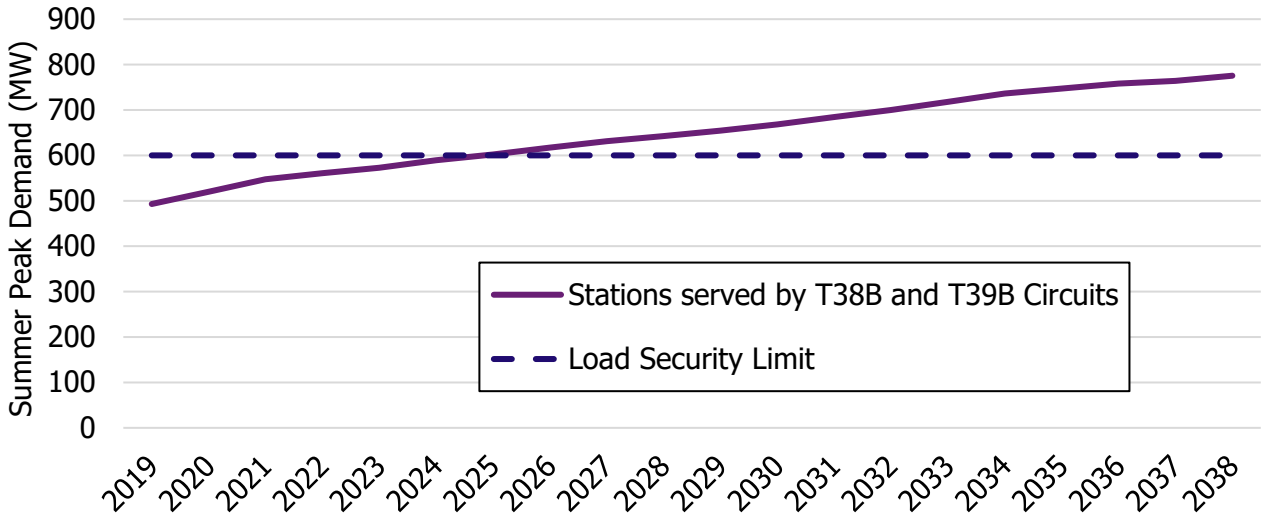


Figure 6.7 | T38B and T39B Load Security Need

6.2.5 Load Restoration

The Needs Assessment and Scoping Assessment reports both identified several load restoration needs in the GTA West Region, as outlined below:

1. Kleinburg Radial Pocket (V43/V44)
2. Halton Radial Pocket (T38B/T39B)
3. Pleasant Radial Pocket (H29/H30)
4. Cardiff/Bramalea Supply (V41H/V42H)
5. West of Cooksville (B15C/B16C)
6. Richview X Trafalgar (R19TH/R21TH)
7. Richview X Trafalgar (R14T/R17T)

For the load restoration needs #1 and #5, it is found that the 4-hour and 8-hour load restoration can be substantially met throughout the forecast. The load serving West of Cooksville and Kleinburg Radial Pocket circuits do not exceed 250 MW throughout the forecast and so the 30-minute requirement does not apply. In addition, need #2 will also be investigated in the RIP in conjunction with the load security need identified above.

In the 2015 GTA West IRRP, addressing the load restoration need #3 (Pleasant Radial Pocket) was ruled out as a cost justification assessment revealed that mitigating solutions were estimated to be significantly costlier to customers in the area than the status quo. This is primarily due to the low probability of the event (loss of H29/H30) occurring and the high cost of building a third supply circuit to Pleasant TS. The 2020 GTA West IRRP takes the same position; it is still not economically prudent to pursue a transmission- or distribution-based solution at this time.

Therefore, for the purposes of this IRRP, the outstanding restoration needs in this IRRP are the Cardiff/Bramalea Supply, and the two Richview x Trafalgar supplies (needs #4, #6, and #7). The 30-minute restoration of all load lost above 250 MW is the most limiting restoration criteria since it relies on remote control actions such as emergency distribution load transfers. 30-minute restoration needs in these pockets existing today and will persist throughout the forecast horizon as demand grows.

6.3 Long-Term Needs Identified

Table 6.2 below summarizes the long-term needs identified by this IRRP:

Table 6.2 | Summary of Long-Term Needs

Need	Need Description	Need Date
Halton Pocket Supply Capacity	Under outage conditions of the local generator, loss of T38B or T39B will lead to the remaining T39B or T38B to exceed its LTE rating	2031
Station Capacity Needs	Cardiff TS, Jim Yarrow MTS, and Tremaine TS are expected to exceed their station capacity limits	2029, 2032, and 2033, respectively
NW GTA Transmission Corridor	There is an anticipated need for future transmission in the GTA West area. This is linked to expected population and employment growth projections.	N/A

6.3.1 Halton Pocket Supply Capacity Need

The load growth at the Halton Pocket is expected to introduce supply capacity needs in the area. Under an outage condition at the Halton Hills Generating Station, the loss of T38B or T39B is expected to cause its remaining companion circuit (i.e. either T39B or T38B, respectively) to exceed its LTE rating. Specifically, this limiting portion of T38B and T39B is a 400-meter section from Lantz JCT to the Trafalgar DESN JCT. This is expected to occur starting in 2031. Figure 6.8 below shows an overview of the limiting section on T38B and T39B. Figure 6.9 shows the limit vs. the forecasted demand in the area.

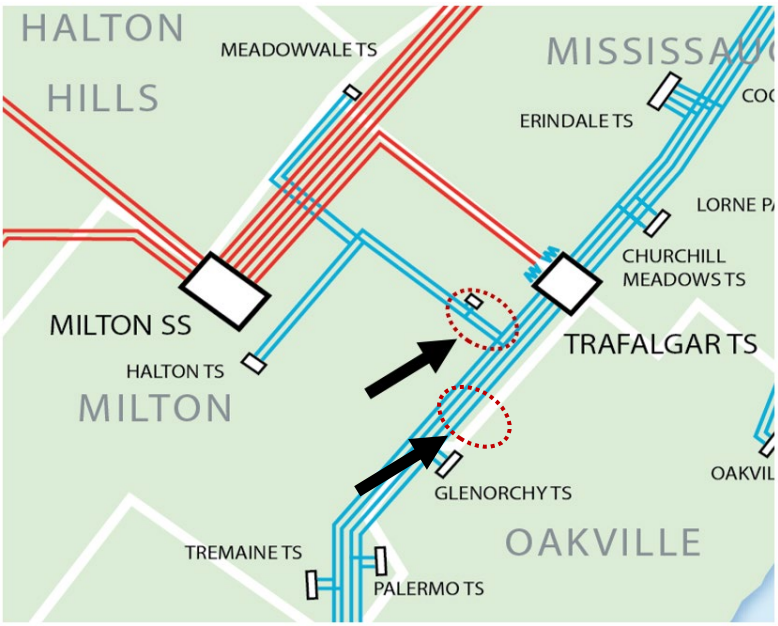


Figure 6.8 | Overview of limiting section on T38B and T39B

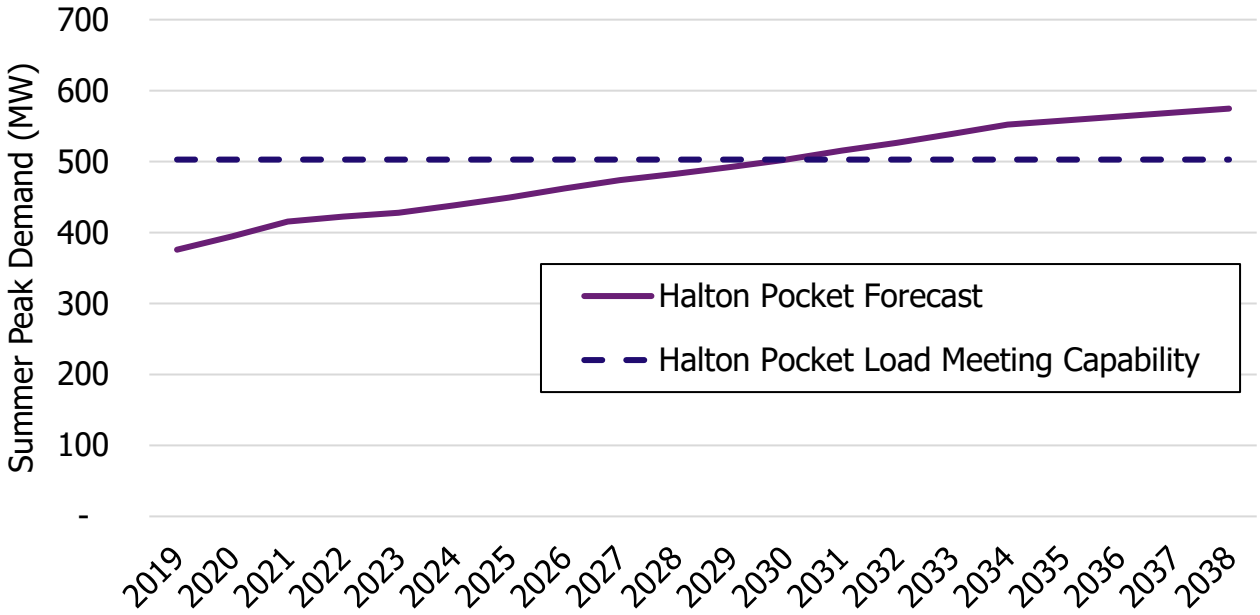


Figure 6.9 | Halton Pocket Supply Capacity Need

6.3.2 Station Capacity Needs

The growth at Cardiff TS is driven mainly by the expansion of a large customer. This expansion was initially slated for mid-2020s but has been put on hold until 2029 due to the effects of the COVID-19 pandemic. Similarly, the growth at Jim Yarrow MTS is primarily driven by load transfers from other stations in Mississauga to Jim Yarrow MTS. However, these load transfers have been delayed to 2032 due to the effects of the COVID-19 pandemic.

The growth at Tremaine TS is expected to exceed station capacity by 2033. A nearby station, Palermo TS, is expected to reach end-of-life by 2025. It is prudent planning practice to consider the needs of both stations when addressing the station capacity needs at Tremaine TS.

7. Plan Options and Recommendations

This section describes the options considered to address system needs in the GTA West region. Section 7.1 to 7.5 documents alternatives to the recommendations described in Section 2 and the rationale for choosing these recommendations. Note that H29/H30 reconductoring is not further discussed here because this recommendation was made in the previous regional planning cycle and this IRRP is only updating the need date. Section 7.6 discusses the Hurontario x Meadowvale transmission option which had the potential to address multiple needs and provide bulk system benefits but was ultimately not selected.

7.1 Options Development and Cost Estimates

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.

- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wires" options and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

Wires options are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc.) of each need. These options are developed through discussions with the Working Group.

To select and size suitable generation and other non-wires options, an hourly load profile is first created as described in Section 5.6. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. These characteristics are shown visually in Appendix D.

The high-level cost estimates for wires options are provided by the transmitter, Hydro One. There is a significant error margin around these estimates as they are only intended to enable comparison between options during the IRRP. As a standard practice, the IRRP performs sensitivity analysis (-25% to +50% costs) to ensure that the recommendations are robust. The Regional Infrastructure Plan (RIP) following the IRRP will perform additional detailed analysis and refine these cost estimates before implementation work begins. The IESO will continue to participate in the Working Group during the RIP and revisit these recommendations if costs estimates differ significantly.

Cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in GTA West are resources with performance and costs on par with simple cycle gas turbines (SCGT) or combined cycle gas turbines (CCGT) generators depending on the relative size of the capacity versus energy requirements. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation. In some cases, energy storage such as lithium nickel manganese cobalt oxide (NMC) batteries are also becoming competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other distributed energy resources which are typically distribution-connected are also considered. The most cost-effective distributed options are typically a combination of smaller-scale storage and demand response. For each of the above options, the system capacity value is "credited" back to arrive at the net cost to meet local reliability needs. This is done to ensure a level playing field comparison between resources that provide capacity and wires options that address the local need but do not provide system capacity benefits.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 Conservation and Demand Management framework are already included in the load forecast as discussed in the Section 5.4. Incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (e.g. on the order of few percent per year). Given the timing, high rate of growth, and MW magnitude of the needs observed, incremental CDM measures are not suitable for the needs identified in this IRRP.

Both the upfront and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs ($/kW-yr) over the lifespan of the asset in question (typically 70 years for transmission infrastructure) for each option. The net present value of these levelized costs are the primarily basis through which options are compared below. Unless stated otherwise, the net present values discussed in the following sections are in 2020 CAD dollars. The list of assumptions made in the economic analysis can be found in Appendix E.

7.2 Alternatives to Pleasant TS Control Actions

Post-contingency thermal violations during outage conditions are expected to occur on the R19TH/R21TH circuits leading into Hurontario SS by 2021. The magnitude of the need is expected to reach 115 MW by 2038. Since this is a post-contingency limitation during pre-existing outage conditions (referred to as an N-1-1 contingency), a load rejection scheme or manual control actions are permitted by ORTAC load security criteria. While a number of stations contribute to this overload, a load rejection scheme at Pleasant TS is most effective to manage this need and is expected to be relatively simple since it is limited to monitoring the immediate circuits (H29/H30) supplying Pleasant TS. As noted in Section 2.1.2, manual control actions are also feasible in the near- to medium-term when overloads exceed long-term emergency (LTE) but not short-term emergency (STE) ratings. For the purpose of comparing the costs of alternative options, this section will assume that a load rejection scheme is installed today at the cost of $5MM.

In most cases where control actions are sufficient to meet the need, other options will typically be orders of magnitude more expensive. Other transmission, generation, and distributed energy resource options do exist and they are included here for completeness. Table 7.1 summarizes the options considered and the net present value of the their levelized costs. A load rejection scheme is the most cost-effective option and the IRRP recommends that the Regional Infrastructure Plan (RIP) led by Hydro One should develop and implement control actions by 2023.

Table 7.1 | Alternatives to Pleasant TS Control Actions and Costs

Option	Cost NPV
Pleasant TS load rejection scheme	$5MM
Install bus at Hurontario SS to maintain dual supply to Pleasant TS during V42 outage/H29 contingency and V41H outage/H30 contingency N-1-1 combinations	$52MM
Local generation portfolio made up of SCGT generation and demand response installed in three phases between today and 2030 as demand increases[4]	$200MM
Distributed energy resource portfolio made up of NMC batteries installed in three phases between today and 2030 as demand increases	$368MM

[4] As discussed in Section 7.1, the cost of new natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation.

7.3 Alternative to Upsizing Palermo TS at End-of-Life

The 83 MVA transformers at Palermo TS (T3 and T4) will reach end-of-life in 2025 and will need to either be replaced either like-for-like or upsized to 75/125 MVA transformers. Today, Palermo TS is able to supply a maximum of 110 MW and is fully loaded with no room for additional growth. Upsizing the transformers and reconfiguring the station will allow Palermo TS to serve approximately 40-50 MW of additional load. Note that the station yard is in relatively poor condition, had recently been de-rated in 2019, and will likely need to be replaced in less than 10 years regardless of the transformer size chosen. The approximately cost of a like-for-like replacement is $30MM. Upsizing will cost approximately $5MM more for a total cost of $35MM. These costs can vary significantly depending on the extent to yard work needed so the IRRP uses $25MM and $35MM for the like-for-like and upsized costs, respectively. This is a more conservative assumption with a higher incremental cost of upsizing.

Tremaine TS, a nearby station 3 km from Palermo TS, can serve a maximum of 190 MW and is forecast to reach capacity in 2033. This is a good opportunity to look at the Palermo TS end-of-life need and Tremaine TS capacity need together and select an optimal refurbishment option to serve regional needs at the lowest cost to ratepayers.

The first option is to refurbish Palermo TS like-for-like in 2025 followed by a subsequent upsizing or new station in 2033 when the capacity need arises. The second option is to upsize Palermo TS at a higher cost when it reaches end-of-life in 2025 and simultaneously resolve the capacity need albeit earlier than necessary. Table 7.2 below summarizes these two options and the associate net present value of the costs. Option 2 is significantly more cost-effective than Option 1 and the IRRP recommends that the RIP should perform additional analysis to reaffirm the cost estimates and develop an implementation plan for upsizing Palermo TS in 2025.

Table 7.2 | Alternatives to Upsizing Palermo TS at End-of-Life and Costs

Option	2025 Action	2033 Action	NPV
Option 1	Refurbish Palermo TS like-for-like - $25MM	Upsize Palermo TS - $35MM	$47MM
Option 2	Upsize Palermo TS - $35MM	None	$32MM

7.4 Alternatives to Local Wires Solutions for T38B/T39B Load Security

Starting in 2025, the loss of both T38B and T39B circuits will result in over 600 MW of load being disconnected from the system, and is a violation of Section 7.1 of the ORTAC. By 2038, it is expected that up to 775 MW of coincident load will be lost following the loss of both these circuits.

The purpose of ORTAC load security criteria is to specify the maximum permitted amount of load lost following recognized contingencies which limits the magnitude of customer interruptions. Installing incremental generation and distributed energy resources are not considered suitable options for addressing the load security need because, while they can reduce the net demand (loading observed on the transmission system), they do not reduce the gross demand (actual electricity consumption) that is interrupted post-contingency. For example, the existing Halton Hills GS has a capacity of 640 MW which is more than the combined coincident peak load of all the stations served on T38B/T39B today. However, in the event of a common tower contingency, all load stations and Halton Hills GS would be interrupted by configuration regardless of the generator's output. The same logic applies to distributed energy resources connected on the distribution system. While it is possible to configure some distributed resources like batteries to provide backup power when grid supply is lost, that is a matter of load restoration rather than load security.

The IRRP considered options to either resupply the Trafalgar DESN at Trafalgar TS or to reconfigure the radial portion of T38B/T39B so that it is supplied directly from Trafalgar TS rather than branching northward at Lantz Junction. This would sectionalize T38B/T39B and reduce the total load lost during double circuit contingencies. These options were ruled out because Trafalgar TS is a gas insulated station with large SF_6 insulated ducts which makes additional connections to the bus impractical. Supplying the Trafalgar DESN or additional circuits would require adding new diameters which would cost on the order of $40MM to $50MM based on previous study estimates.

The IRRP also considered opportunities to align with the FETT bulk study and select a common solution to meeting both regional and bulk system needs simultaneously. This is further discussed in Section 7.6 but ultimately, the most capable and cost-effective solution for addressing bulk system needs at this time, the R14T/R17T/R19TH/R21TH conductor upgrades, will not resolve the T38B/T39B load security need.

The remaining options are local transmission solutions like reterminating supply stations on lighter loaded circuits or installing breakers to sectionalize T38B/T39B. The cost of installing breakers to sectionalize T38B/T39B at Tremaine TS or Lantz Junction is approximately $5MM. For the same cost, Tremaine TS can also be reterminated from T38B/T39B to the companion T36B/T37B circuits since the station sits immediately under the transmission corridor. More detailed wires analysis is needed to refine these cost estimates and further study the technical feasibility of installing breakers or reterminating stations at various points along the circuits. The IRRP recommends that the RIP should carry out detailed wires analysis including updating the near-term demand forecast for the stations served on T38B/T39B. As additional bulk system needs on the FETT interface in the late 2020's become more clear, the IESO will continue to provide input on the Working Group to help ensure that the RIP recommendations are aligned with the latest bulk system information.

7.5 Alternatives to T38B/T39B Reconductoring for Halton Pocket Supply

During an outage to Halton Hills GS, post-contingency thermal violations on T38B/T39B are expected to occur by 2031. The thermal violation is on a short 400-meter section of T38B/T39B immediately north of Lantz Junction. This radial portion of T38B/T39B serves the Halton Pocket including Trafalgar DESN, Halton TS, Halton TS #2, Halton MTS, and Meadowvale TS. By 2038, the coincident demand at these stations will exceed the LMC by approximately 70 MW.

The transmission, utility generation, and distributed energy resource options considered are shown in Table 7.3. Upgrading the conductors on the limiting section of T38B/T39B is the most cost-effective option to meet the supply capacity need in the Halton Pocket. Although load rejection is permitted to account for local generation outages, upgrading T38B/T39B is still cheaper due to the short length of the limiting section. A load rejection scheme would also be more complex to operate and reduce reliability for local customers. Note that if Halton Hills GS were to not continue operation after its contract expiry, load rejection would also no longer be an option. Given the timing of the need, no firm recommendation is required at this time. The Working Group will continue to monitor load growth in the Halton Pocket and revisit this need in the next cycle of regional planning.

Table 7.3 | Alternatives to T38B/T39B Reconductoring and Costs

Option	NPV of Levelized Cost Net of System Capacity Value (if applicable)
Upgrade limiting section of T38B/T39B	<$1MM
Local generation portfolio made up of SCGT generation and demand response installed in two phases between 2030 and 2036 as demand increases[5]	$97MM
Distributed energy resource portfolio made up of NMC batteries installed in two phases between 2030 and 2034 as demand increases	$50MM

7.6 Hurontario SS x Meadowvale TS Transmission Option

The Meadowvale SS x Hurontario TS (MxH) transmission option is a new double 230 kV circuit line from Meadowvale TS to Hurontario SS along the existing transmission corridor. This is an integrated option that has potential benefits for both bulk and regional needs. The MxH option is estimated to cost $47MM. This includes the cost of the 8 km line between Meadowvale TS and Hurontario SS as well as an additional 5 km of transmission between Meadowvale TS and Halton TS to allow for a connection to Milton SS if 500-230 kV autotransformers are installed in the future.

From a regional perspective, the MxH option can address the R19TH/R21TH supply capacity, T38B/T39B load security, and T38B/T39B supply capacity needs. The cost of addressing these needs separately through the recommendations above is $5MM in 2023 (Pleasant TS load rejection scheme), $5MM in 2025 (retermination/sectionalisation for T38B/T39B load security), and $1MM in 2033 (T38B/T39B reconductoring) for a total net present value of $10MM. On regional needs alone, it is more cost-effective to address each need separately rather than together through the MxH option.

[5] As discussed in Section 7.1, the cost of new natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation.

From a bulk perspective, the MxH option introduces a new path along the FETT interface which would improve transfer capability. However, the MxH option alone would not provide sufficient additional transfer capability. The FETT interface is currently thermally limited by the Richview TS x Trafalgar TS circuits. Upgrading the conductors on these circuits (R14T/R17T/R19TH/R21TH) yields an approximately three-fold higher incremental transfer capability increase than the MxH option would provide.

Furthermore, even after discounting the cost of the MxH option by the avoided regional reliability costs, the per MW capability cost of the MxH option is still roughly double that of the Richview TS x Trafalgar TS conductor upgrades. The IESO issued a letter in December 2020 recommending that Hydro One should proceed with conductor upgrades to the R14T/R17T/R19TH/R21TH circuits between Trafalgar TS and Richview TS as a first stage to increase the FETT transfer capability.

Future FETT interface needs beyond these conductor upgrades are not known at this time and will depend on the future resources acquisition framework and availability of potential resources east of FETT. The IESO will continue to participate in the Working Group during the RIP to help ensure recommendations are aligned with the latest bulk system information.

8. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the GTA West IRRP.

8.1 Engagement Principles

The IESO's engagement principles[6] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

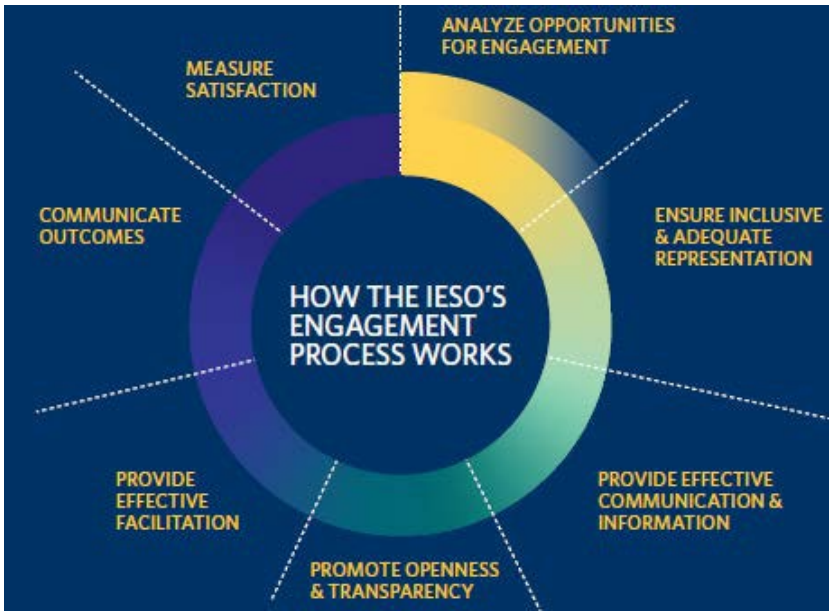


Figure 8.8.1 | The IESO's Engagement Principles

8.2 Creating an Engagement Approach for GTA West (Peel/Halton)

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

[6] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage[7] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Face-to-face meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.4 Bringing Communities to the Table).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, leveraging existing relationships built through the previous planning cycle. This started with the Scoping Assessment Outcome Report for the GTA West region. An invitation to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the GTA West Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to align community energy plans and other planning initiatives in the development of the IRRP, and for the final plan to consider designated land use in the region including a recreational aircraft flying space in the event of any potential infrastructure siting recommendations. Along with a response to the feedback received, the final Scoping Assessment was posted in August 2019 which identified the need for a coordinated regional planning approach done through an IRRP for the GTA West Region.

[7] Regional Electricity Planning - Peel/Halton (GTA West) Region (ieso.ca)

Following the finalization of the Scoping Assessment, outreach then began with targeted municipalities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the GTA West planning region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on key components of the plan. These webinars received strong participation with a cross-representation of stakeholders and community representatives. Written feedback was received as a result during a 21-day comment period following each webinar.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.
2. The defined electricity needs for the region and potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement focused on the following major themes:

- Consideration should be given to local developments and growth plans
- Alignment and coordination is needed with other community planning and projects in the region. Future infrastructure and/or electricity supply should consider the priorities of energy and climate action plans and, in particular, alternative energy systems, renewable generation and electrification
- Incorporate shifting economies into planning assumptions and cost benefit analysis
- Integrated options that provide both local and broader provincial system benefit should be considered
- Consideration should be given to non-wires alternatives as part of the recommended solutions in the IRRP

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to GTA West region subscribers, municipalities and communities as well as the members of the GTA/Central Regional Electricity Network.

Based on the discussions both through the GTA West IRRP engagement initiative and broader network dialogue, there is a clear interest to further discuss the potential for alternative energy solutions as a way to meet local needs particularly as communities shift towards electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts. To that end, ongoing discussions will continue through the IESO's GTA/Central Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities and planning initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Peel/Halton (GTA West) IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement. Meetings were also held to discuss the joint NW GTA Corridor Study underway by the IESO, Ministry of Energy, Northern Development and Mines; coinciding with the Ministry of Transportation's Transportation Corridor Study that is also underway. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

During discussions with communities, the IESO received feedback that the name "GTA West Regional Planning" was challenging to differentiate from other initiatives underway in the area with a similar naming convention, thus, the region was changed to "Peel/Halton (GTA West) Region" for engagement purposes. Official planning documents continue to adhere to the regulatory name of "GTA West Region".

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the GTA West electricity planning region throughout the development of the plan. This includes the communities of Alderville First Nation, Curve Lake First Nation, Haudenosaunee Confederacy Chiefs Council, Hiawatha First Nation, Huron-Wendat, Kawartha Nishnawbe First Nation, Mississaugas of Scugog Island First Nation, Mississauagas of the Credit First Nation, and Six Nations of the Grand River.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

The GTA West IRRP identifies electricity needs in the region over the 20-year period from 2019 to 2038, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

In the near term, the IRRP recommends the implementation of control actions at Pleasant TS to manage overloads during outage conditions, upsizing Palermo TS at end-of-life, and further wires analysis for T38B/T39B load security needs during the Regional Infrastructure Plan. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Working Group monitor growth in the Halton Pocket and at Cardiff TS and Jim Yarrow TS to determine when further reinforcements will be needed. The IESO and the Working Group will also continue to monitor community energy planning and monitor electrification trends. The IESO and the Ministry of Energy will continue the NW GTA Transmission Corridor study to identify a suitable corridor of land that can be preserved for future transmission infrastructure should the need arise.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.



GTA West

REGIONAL INFRASTRUCTURE PLAN

February 23, 2022

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Prepared by:
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With support from:

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Burlington Hydro Electric Inc.
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Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution Inc.

Disclaimer

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

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

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EXECUTIVE SUMMARY

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

The participants of the GTA West Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Alectra Utilities Corporation ("Alectra")
- Burlington Hydro Electric Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the second cycle of the GTA West regional planning (RP) process and it follows the completion of the GTA West Integrated Regional Resource Plan ("IRRP") [1] in August 2021; and the GTA West Needs Assessment ("NA") [2] and Scoping Assessment ("SA") in May 2019 and August 2019, respectively. This RIP provides a consolidated summary of needs and recommended plans for the GTA West Region over a 10-year planning horizon (2021-2031) based on available information. The load forecast for the 2032-2041 period is provided to show the longer term needs and trend. All needs for this long term horizon will be reviewed and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in January 2016 with the publication of the GTA West RIP [3], which provided a description of needs and recommendations of preferred wires plans to address near-term needs. Since the previous planning cycle the following projects have been completed:

- Halton Hills Hydro MTS (completed in 2018)
- Tremaine TS: Add 4 x 27.6 kV feeders (completed in 2020)

The recommended major infrastructure investments including assets replacements in the GTA West Region over the near and medium-term (2021-2031) period are given in Table 1 below, along with their planned in-service date and budgetary estimate for planning purposes.

Table 1. GTA West Region - Recommended Plans over the 2021-2031 Study Period

No.	Investments	I/S Date	Cost[1] ($M)
A	**Increase Capacity**		
1	Palermo TS: Refurbish and Upgrade Transformers T3 and T4 and add new 27.6 kV yard	2026	30
2	Hurontario TS x Pleasant TS: Reconductor circuits H29/H30 with higher ampacity conductor	2027	8
B	**Asset Replacement**		
1	Bramalea TS: Replace Transformers T3 and T4	2028	20
2	Tomken TS: Replace Transformers T1 and T2	2029	49
3	Lorne Park TS: Replace Transformer T2	2030	14

[1] These costs are budgetary estimates for planning purposes unless otherwise specified

A number of potential capacity needs were also identified with the following facilities expected to exceed capacity limits over the medium to long term as listed below. The stations loading will continue to be monitored with medium term needs being managed at the distribution level utilizing capacity at adjacent area stations. All needs will be reviewed in the next regional planning cycle.

Medium Term Capacity Needs 2027 - 2031

- Pleasant TS: T1/T2 DESN – 2027
- Erindale TS: T1/T2 DESN – 2028
- Cardiff TS: T1/T2 DESN – 2029
- Erindale TS: T5/T6 DESN – 2031

Longer Term Capacity Needs 2032 – 2041

- Kleinburg TS: T1/T2 DESN – 2032
- Jim Yarrow MTS: T3/T4 DESN - 2032
- T38B/T39B: Lantz Jct x Trafalgar DESN – 2033
- Goreway TS: T5/T6 DESN - 2034
- Bramalea TS:T3/T4 DESN - 2036
- Tremaine TS: T1T2 DESN - 2039

The GTA West TWG recommends that:

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

The next regional planning cycle for the GTA West Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will start in Q1 2024. However, the next regional planning cycle can be started earlier if required to address any new emerging needs.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The Working Group included members from the following organizations:

- Alectra Utilities Corporation ("Alectra")
- Burlington Hydro Electric Inc.
- Milton Hydro Distribution Inc.
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses the municipalities of Brampton, southern Caledon, Halton Hills, Mississauga, Milton, and Oakville[1]. The region includes the area roughly bordered geographically by Highway 27 to the northeast, Highway 427 to the southeast, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south, as shown in Figure 1-1.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and from the 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and twenty (20) step-down transformer stations. The summer 2021 non-coincident peak load of the region was approximately 3184 MW.

[1] Some parts of the City of Burlington are also supplied from Palermo and Tremaine transformer stations, located in the GTA West region.

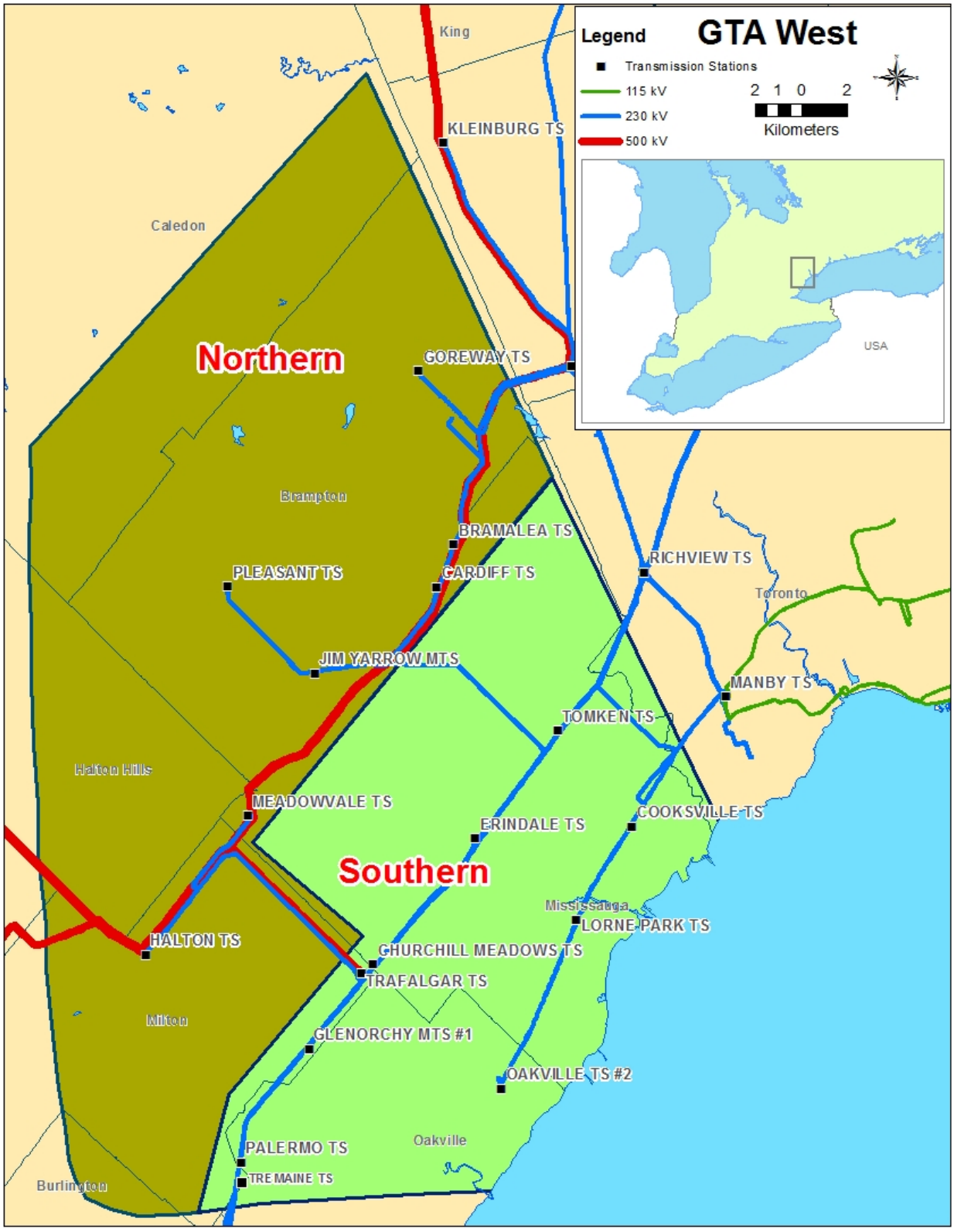


Figure 1-1 GTA West Region Map

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2021-2031) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2021-2031 period and wires plans to address these needs based on new and/or updated information;
- Consideration of long-term needs identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [2] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

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

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

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

[2] also referred to as Needs Screening

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

The RIP phase is the final stage of the regional planning process and involves confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, plan level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

- Planning activities that were already underway in the region prior to the regional planning process taking effect;
- The NA, SA, IRRP and LP phases of regional planning;
- Conducting wires planning as part of the RIP for the region or sub-region;
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

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

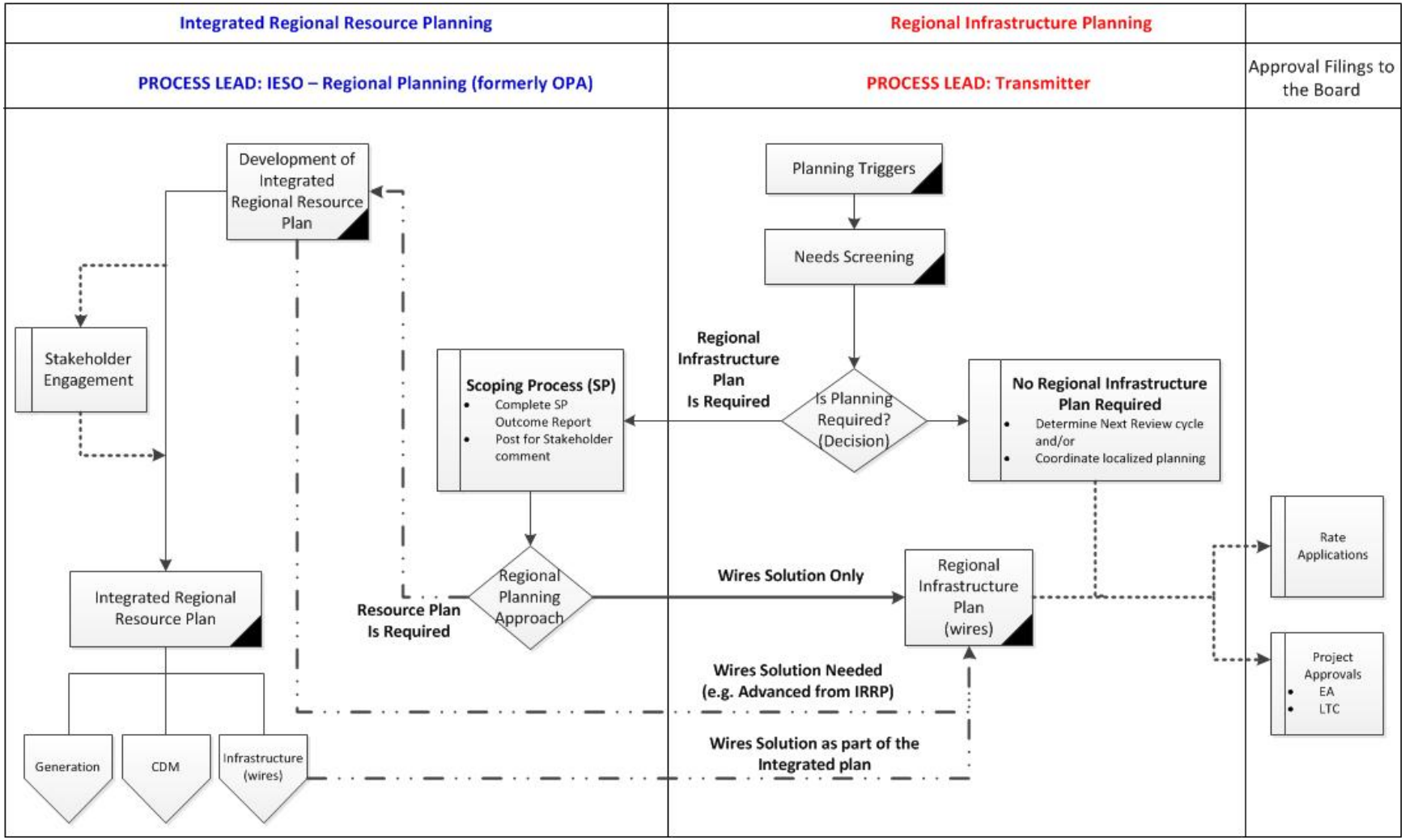


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

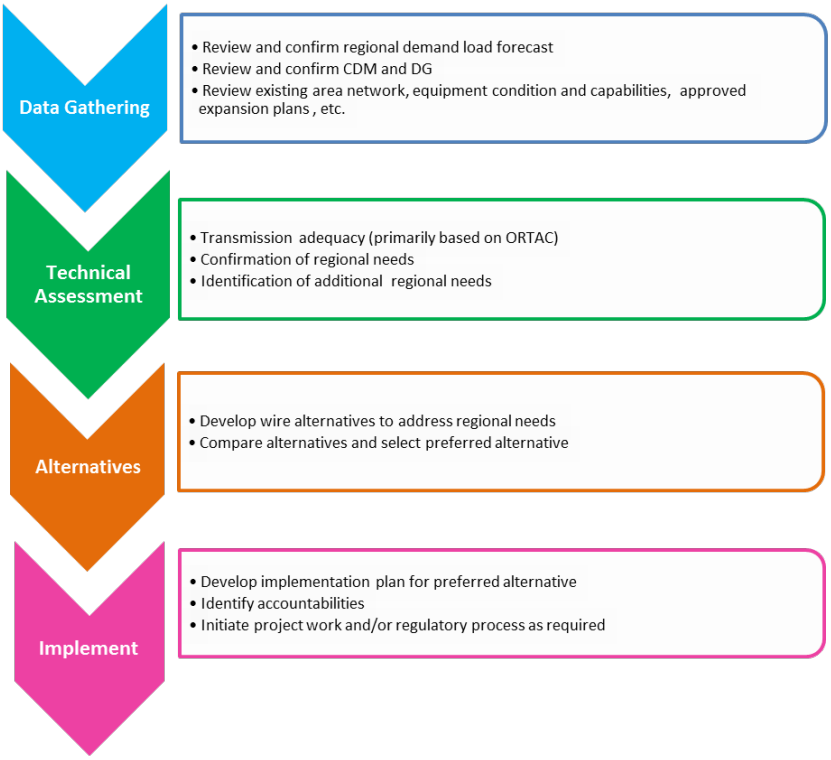


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION COVERS THE REGIONAL MUNICIPALITIES OF HALTON AND PEEL AND INCLUDES THE MUNICIPALITIES OF BRAMPTON, SOUTHERN CALEDON, HALTON HILLS, MISSISSAUGA, MILTON, AND OAKVILLE. THE REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY HIGHWAY 27 TO THE NORTH-EAST, HIGHWAY 427 TO THE SOUTH-EAST, REGIONAL ROAD 25 TO THE WEST, KING STREET TO THE NORTH AND LAKE ONTARIO TO THE SOUTH.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and from the 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and twenty (20) step-down transformer stations (see Appendix A and B for a complete list). The distribution system in this Region is at two voltage levels, 44 kV and 27.6 kV. Local generation in the area include the two gas fired plants, the 1250 MW Sithe Goreway GS in Brampton and the 683 MW Halton Hills GS in Halton Hills.

The Local Distribution Customers (LDC) in the GTA West Region are Alectra Utilities Co., Burlington Hydro Inc., Halton Hills Hydro Inc., Hydro One Networks Inc., Milton Hydro Distribution Inc. and Oakville Hydro Electricity Distribution Inc. A listing of the LDCs along with the associated supply stations is given in Appendix C. The high-voltage system in this Region also provides supply to one direct transmission connected custormer's transformer station. An electrical single line diagram for the GTA West Region facilities is shown in Figure 3-1.

Kleinburg TS is located near Bolton, Ontario and has been part of the GTA North regional planning process. However, majority of the Kleinburg TS transformational capacity is being used to supply communities located into GTA West region. Due to this reason, the Kleinburg TS has been included as part of the GTA West Regional Planning process as well.

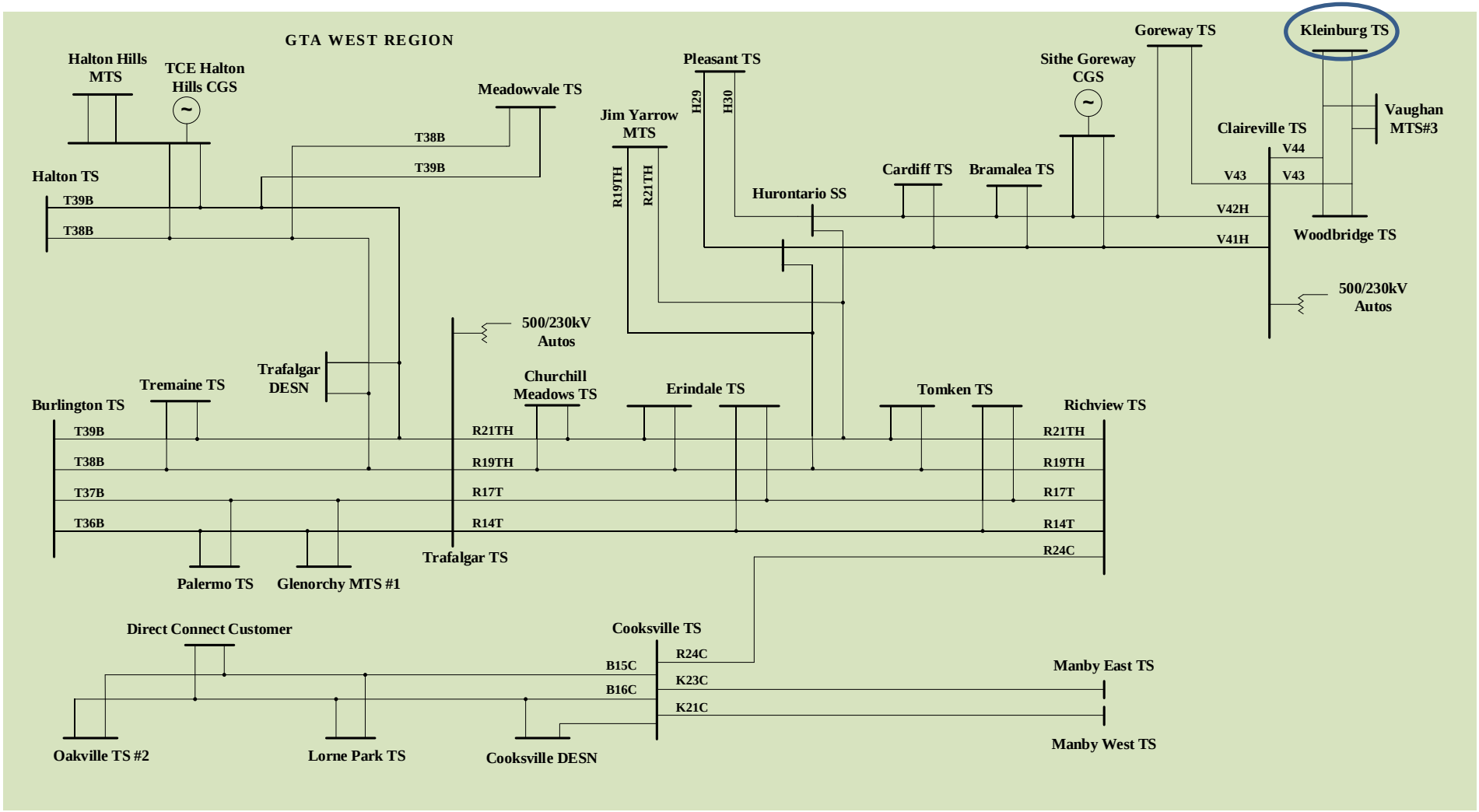


Figure 3-1 GTA West Region Single Line Diagram

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

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE GTA WEST REGION.

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

- Churchill Meadows TS (2010) – built a new step down transformer station consisting of two 75/125 MVA transformers in Mississauga supplied from 230 kV circuits R19TH and R21TH. This station provided additional load meeting capability to meet Alectra Inc. requirements.
- Hurontario SS and underground cable work (2010) - built a new switching station Hurontario SS, 4.2 km of double circuit 230 kV Line from Hurontario SS to Cardiff TS and 3.3 km of underground cable from Hurontario SS to Jim Yarrow MTS. The new switching station and associated line work connects the R19T/R21T circuits and the V42/V43H circuits to provide relief and improved reliability to Pleasant TS and Jim Yarrow MTS.
- Halton Hills GS (2010) – connected a new 683 MW gas-fired combined cycle generation station in Halton Hills connected to 230 kV circuits T38B and T39B. This generation station provided necessary local power to supply the GTA West Region.
- Glenorchy MTS#1 (2011) – connected new Oakville Hydro-owned Glenorchy MTS to 230 kV circuits T36B and T37B. This station provided additional load meeting capability to meet Oakville Hydro requirements
- Tremaine TS (2012) – built a new step down transformer station consisting of two 75/125 MVA transformers in Burlington supplied from 230 kV circuits T38B and T39B. This station provided additional load meeting capability to meet Burlington Hydro and Milton Hydro requirements.
- Richview TS x Trafalgar TS 230 kV Line Upgrade (Currently Underway) – The two 230 kV double circuits lines R14T/R17T and R19TH/T21TH between Richview TS and Trafalgar TS are being upgraded to provide additional bulk power transfer capability. The planned in-service date is Q2 2026.
- In addition to Hydro One, Halton Hills Hydro has also built the new Halton Hills Hydro MTS in 2019. This is a 230/28kV station with two 50/83MVA transformers and is connected to the 230 kV bus of the Halton Hills GS. This station has provided load meeting capability to supply Halton Hills Hydro loads.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA West Region is expected to grow at an average rate of approximately 1.6% annually from 2021 to 2031, and 1.2% annually from 2031 to 2041. The growth rate varies across the region ranging from 1.4% in the Central Mississauga area to 2.4% in the West Oakville /Milton/Halton Hills area.

Figure 5-1 shows the GTA West Region extreme summer weather net load forecast from 2021 to 2041. The forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the 20 step-down transformer stations. The regional non-coincident peak load is forecast to increase from approximately 3184 MW in 2021 to 4212 MW in 2041. Non-coincident forecast for the individual stations in the region is available in Appendix D, and is used to determine any need for station capacity relief.

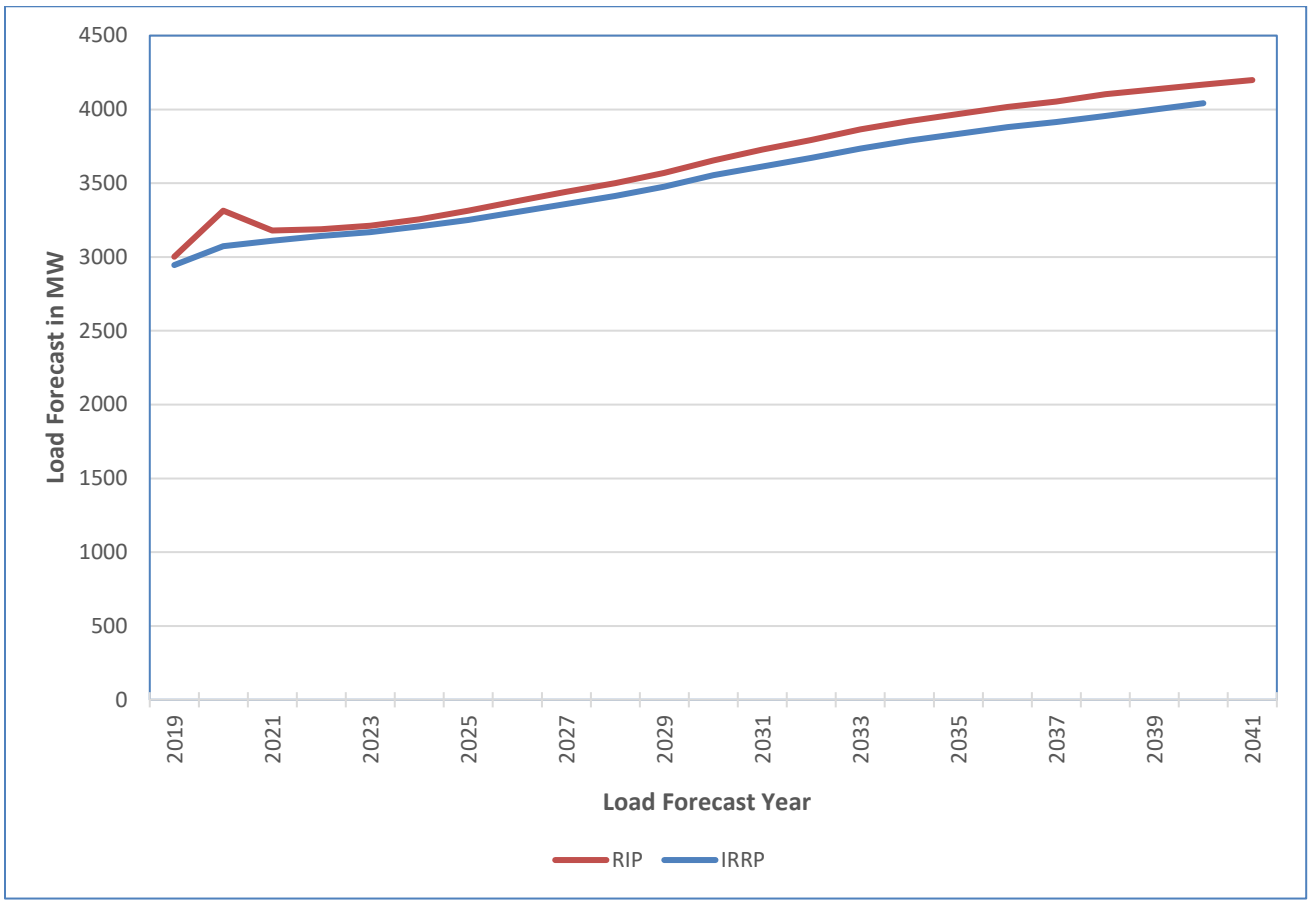


Figure 5-1 GTA West Region Non–Coincident Net Summer Peak Load Forecast

The regional non-coincident load forecast was developed by projecting the 2021 summer peak loads corrected for extreme weather, using the area stations growth rates as per the July 2021 IESO GTA West IRRP with

subsequent additional load forecast information provided by Alectra and Milton Hydro[3]. The IRRP forecast is shown for comparison. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used to update the stations forecast in this report are provided in the GTA West IRRP [3] and are not repeated in this report.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2021-2031. However, a longer term forecast up to 2041 is provided to identify long-term needs and align with the IESO GTA West IRRP.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using peak loads in the area.

[3] As a result of the need to refurbish Palermo TS and the decision to upgrade the station transformers (see Section 7.1), Milton Hydro plan to increase the loading on Palermo TS and have reduced their forecast for Halton TS.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2021-2031 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are inputs to this RIP. These assessments are:

1) GTA West Region Needs Assessment (NA) Report, May 9, 2019
2) GTA West Region Scoping Assessment (SA) Report, August 8, 2019
3) GTA West (Peel Halton) Integrated Regional Resource Plan (IRRP) and Appendices, July 2021

The NA and IRRP reports identified a number of needs as a result of the forecasted load demand and condition of major high voltage transmission assets. This section reviews the adequacy of the transmission lines and stations in the GTA West Region based on the updated regional load forecast provided in Appendix D. Sections 6.1 to 6.2 present the results of this review. Asset replacement needs identified in the previous NA report are discussed in Section 6.3 of this report. Load security and load restoration needs are discussed in Section 6.4.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the GTA West Region with the exception of the Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system. The 230 kV circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as the local area loads.

6.1.1 500/230 kV Transformation Facilities

Bulk power supply to the GTA West Region is provided by 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS, Richview TS and Manby TS. Additional support is provided from the 230 kV generation facilities at Halton Hills GS and Sithe Goreway GS. Both Claireville TS and Trafalgar TS are expected to require relief in the 2030s.

6.1.2 230 kV Transmission Circuits

The 230kV circuits in the region are as follows (please refer to Figure 3-1):

1. Claireville TS to Hurontario SS (230 kV Circuits V41H, V42H, V43) – Supply Bramalea TS, Cardiff TS, and Goreway TS
2. Hurontario SS to Pleasant TS (230 kV Circuits H29, H30) – Supply Pleasant TS

3. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine TS
4. Trafalgar TS to Halton TS (Radial Tap from 230 kV Circuits T38B, T39B) – Supply Trafalgar DESN, Meadowvale TS and Halton TS
5. Richview TS to Trafalgar TS (230 kV Circuits R14T, R17T) – Supply Erindale TS and Tomken TS
6. Richview TS to Trafalgar TS, with tap to Hurontario SS (230 kV Circuits R19TH, R21TH) – Supply Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, and Tomken TS
7. Richview TS and Manby TS to Cooksville TS (230 kV Circuits R24C, K21C, K23C, B15C, B16C) – Supply Cooksville DESN, Ford Oakville CTS, Lorne Park TS, and Oakville TS #2.

The Richview TS x Trafalgar TS 230 kV circuits, R14T/R17T and R19TH/R21TH, are part of the "Flow East toward Toronto" interface ("FETT") and the flow on these circuits is expected to increase as a result of the change in generation resource following the retirement of the Pickering Nuclear Generating Station in 2025. As the result, these circuits need to be upgraded. OEB Leave to Construct ("Section 92") approvals have been obtained for the project and work is underway on reconductoring these circuits with new conductors that have a 2000A summer continuous rating. The planned in-service date for the project is Q2 2026.

Other line sections expected to exceed their ratings during the study period are listed in Table 6-1 below.

Table 6-1 GTA West Region - Lines Sections Exceeding ratings

No.	Line	Section	Contingency	Line Rating MW	Year Line Rating exceeded
1	H29/H30	Hurontario SS x Pleasant TS	N-1[1]	419	2027
2	T38B/T39B	Lantz Jct x Trafalgar DESN	N-1[1]	535	2033
3	R19TH/R21TH	Hanlan Jct x Hurontario TS	N-1-1[2,3]	416	2021

[1] Loss of one circuit of the double circuit line
[2] R19TH is overloaded when H29 and V42H are out of service
[3] R21TH is overloaded when H30 and V41H are out of service

The planned solutions to address these needs are discussed further in Section 7 of the report.

6.2 Step-Down Transformation Facilities

There are a total of twenty (20) step-down transformer stations in the GTA West Region as listed in Table 6-2. Nineteen (19) supply electricity to LDCs and one is a transmission connected industrial customer station. Of the nineteen stations, three (3) are owned and operated by the LDCs.

The stations summer peak load forecast is given in Appendix D Table D-1.

Table 6-2 GTA West Region - Step-Down Transformer Stations

Bramalea TS	Glenorchy MTS#1	Kleinburg TS	Pleasant TS
Cardiff TS	Goreway TS	Lorne Park TS	Tomken TS
Churchill Meadows TS	Halton Hills MTS	Meadowvale TS	Trafalgar TS
Cooksville TS	Halton TS	Oakville TS #2	Tremaine TS
Erindale TS	Jim Yarrow MTS	Palermo TS	Customer #1 CTS

This RIP reviewed the step-down transformation capacity for the stations within the GTA West Region. The NA and IRRP studies had previously indicated that a second Halton TS DESN would be required by summer 2022. Subsequent to those studies, and as part of the discussions for this RIP, Milton Hydro provided a revised load forecast with new load being supplied from Glenorchy MTS #1, Halton Hills MTS, and Palermo TS. As a result of this update,the need for the second Halton TS DESN has been deferred to 2033. Based on the load forecast, the following stations would require capacity relief during the 2021-2031 study period as shown in Table 6-3 below. The need timeframe defines the time when the peak load forecast exceeds the DESN's Summer 10-day LTR.

Table 6-3 GTA West Region - Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2021 Loading (MW)	Need Date
Palermo TS: T1/T2 DESN refurbishment	110	124	2027
Pleasant TS: T1/T2 DESN	148	138	2027
Erindale TS: T1/T2 DESN	181	142	2028
Cardiff TS: T1/T2 DESN	113	103	2029
Erindale: T5/T6 DESN	185	142	2031

Further, based on the load forecast, the stations requiring relief beyond 2031 are listed below:

- Jim Yarrow MTS: T3/T4 DESN – 2032
- Kleinburg TS: T1/T2 DESN – 2032
- Goreway TS: T5/T6 DESN – 2034
- Bramalea TS: T3/T4 DESN – 2036
- Tremaine TS: T1/T2 DESN – 2039

6.3 Asset Replacement Needs for Major High Voltage (HV) Transmission Equipment

A number of Hydro One facilities in the GTA West Region will require replacement over the 2021-2031 study period. These needs are determined by asset condition based on a range of considerations such as equipment deterioration, technical obsolescence due to outdated design, lack of spare parts availability or manufacturer support, and/or potential health and safety hazards.

Asset replacement work is planned over the study period at area transformer stations listed in Table 6-4. Palermo TS work is discussed in Section 7.1. Details for the remaining stations are provided in Section 7.5.

Table 6-4 GTA West Region - Planned Replacement Work

No.	Station	Planned I/S Date
1	Palermo TS	2026
2	Bramalea TS	2028
3	Tomken TS	2029
4	Lorne Park TS	2030

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. For load security ORTAC requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interruped in excess of 250 MW must be restored within 30 minutes.

6.4.1 T38B/T39B Load Security

The 2021 IRRP had identified that the loading on the double circuit 230kV line T38B/T39B corridor was forecast to exceed the 600 MW limit by 2025. However, as mentioned in Sections 5 and 6.2, Milton Hydro plan to increase loading on Palermo TS and have updated the forecast for Halton TS. As a result, the loading on T38B/T39B circuits has been reduced. The current revised forecast (See Table 6-5) indicates that the non-coincident connected load on the T38B/T39B circuits will exceed the 600 MW limit by 2030.

Table 6-5 GTA West Region – Load connected to 230kV double circuit line T38B/T39B

Circuit	Limit MW	Act.	Forecast - Connected Load (MW)										
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2041
T38B/T39B	600	523	516	529	555	566	580	578	584	598	**613**	631	843

This load security need is further discussed in section 7.6

6.4.2 Load Restoration

Load restoration needs in the Region were previously identified in the NA, SA and IRRP. These were again reviewed by the Working Group in the RIP. The lines, stations served and the loads at the end of the study period on the lines in the Region are given in Table 6-6 below:

Table 6-6 GTA West Region – Load Connected to Various Transmission Lines

No.	Lines/ Circuits	Connected Stations	Line Length (km)	Year 2031 Connected Load (MW)	Load subject to 30 minute criteria (MW)
1	B15/B16	Lorne Park TS, Oakville #2 TS	12.5	278	28
2	H29/H30	Pleasant TS	8.5	459	209
3	R14T/R17T	Erindale TS (T1/T2) & (T3/T4), Tomken T1/T2	21.7	479	229
4	R19TH/ R21TH	Churchill Meadows TS, Erindale TS (T5/T6), Tomken TS (T3/T4), Jim Yarrow TS	33.3	583	333
5	T36B/T37B	Palermo TS, Glenorchy MTS#1	24.5	272	22
6	T38B/T39B[1]	Tremaine TS, Trafalgar DESN, Halton TS, Meadowvale TS and Halton Hills MTS	42.7	631	381
7	V41H/V42H	Bramalea TS, Cardiff TS	17/26.3[2]	435	185
8	V42H/V43	Goreway TS	17/21.4[2]	269	19
9	V43/V44	Woodbridge TS, Vaughan MTS#3, Kleinburg TS[3]	21.4/12[2]	498	248

[1] Trafalgar DESN, Halton TS, Meadowvale TS and Halton Hills TS are on a radial tap connected to the T38B/T39B line.

[2] Tap length for the two circuits are different

[3]Vaughan MTS#3 and Woodbridge TS are also supplied from the V43/V44 line and loads are taken from the 2020 GTA North RIP report.

The Table shows that all lines in the Region have connected load greater than 250MW. For lines 1, 5, 8 the load in excess of 250MW is small and transfers can be managed at the distribution levels. For all other lines, the load in excess of 250MW cannot be restored within 30 minutes. However, all lines are short; reliability of the lines is good and the incidents of overlapping outages very rare. The lines are located in the GTA, with good accessibility for maintenance crews and Hydro One expects all loads to be restored within 4 hours with at least one circuit back into service.

Any mitigation measure to meet the 30 minute restoration requires building new lines and/or installing additional switching facilities. The work will be extremely expensive and have substantial environmental and public impact. Given the past reliability performance and expectation to restore the load within 4 hours, the TWG does not recommend any further action.

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION..

The electrical infrastructure needs for the GTA West Region are summarized in Table 7-1. These needs include those previously identified in the GTA West NA and IRRP as well as those resulting from the adequacy assessment carried out as part of this RIP report. The details of the project/plan to address these needs are provided in Sections 7.1 through 7.7.

Table 7-1 GTA West Region – Identified Near, Medium-Term and Long Term Needs

Section	Facilities	Need	Timing
7.1	Palermo TS	Transformers T3 and T4 replacement. Milton Hydro capacity requirements	2026
7.2	H29/H30: Hurontario TS x Pleasant TS	Line upgrade required to supply Pleasant TS	2027
7.3	R19TH/R21H	Overload under certain outage conditions	Existing
7.4	Pleasant TS: T1/T2 DESN	Load exceeding DESN capacity	2027
7.4	Erindale TS: T1/T2 DESN	Load exceeding DESN capacity	2028
7.4	Cardiff TS: T1/T2 DESN	Load exceeding DESN capacity	2029
7.4	Kleinburg TS: T1/T2 DESN	Load exceeding DESN capacity	2030
7.4	Erindale: T5/T6 DESN	Load exceeding DESN capacity	2031
7.5	Bramalea TS	Transformer T3 and T4 replacement	2028
7.5	Tomken TS	Transformers T1 and T2 replacement	2029
7.5	Lorne Park TS	Transformer T2 replacement	2030
7.6	Load Security	T38B/T39 Loading	2030
7.7	Load Restoration	ORTAC 30 minutes restoration criteria not met.	---[1]
7.8	Longer Term Needs	Capacity Exceeded Lines - T38B/T39B: Lantz Jct x Trafalgar DESN Stations - Jim Yarrow MTS: T3/T4 DESN Kleinburg TS: T1/T2 (27.6kV) DESN Goreway TS: T5/T6 DESN Bramalea TS:T3/T4 DESN Tremaine TS: T1T2 DESN	 2033 2032 2032 2034 2036 2039

[1]No action is planned. Please see sections 6.4.2 and 7.7.

7.1 Palermo TS: T3/T4 Replacement and Milton Hydro Capacity Requirements

7.1.1 Description

Palermo TS is a 230/27.6 kV transformer station that facilitates load delivery to Burlington Hydro Inc., Milton Hydro Inc. and Oakville Hydro customers in the cities of Burlington, Milton and Oakville, respectively (see Figure 7-1). Peak station demand was about 124 MW in summer 2021 as compared to the station 10 day LTR of 110 MW.

The transformers, T3 and T4, at Palermo TS are over 50 years old and based on asset condition assessment require replacement in the near-term. The current plan is to replace these transformers by Q4 2026.

Palermo TS is currently a “restricted station” due to short circuit constraints and new DER resources cannot connect to feeders from the station.

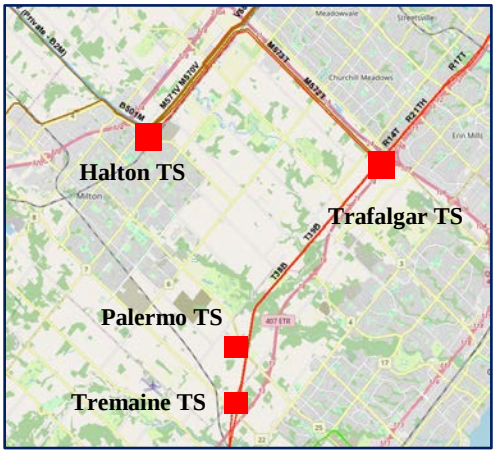


Figure 7-1 Palermo TS

The earlier NA and IRRP reports had identified the need for adding a second DESN at Halton TS by 2022 and that the loading on Tremaine TS would be exceeded by 2033. The IRRP had also identified upsizing the Palermo TS transformers as a more cost effective alternative to replacing the transformer like for like. As part of this RIP, Milton Hydro reviewed their load forecast and now plan to utilize the increased capacity at Palermo TS, thereby deferring the need for a second DESN at Halton TS to 2033. The Palermo TS upgrade also defers the need for providing relief for Tremaine TS to 2039. The Palermo TS forecast is given below in Table 7-2 and reflects the revised loading provided by Milton Hydro and assumes that Burlington Hydro and Oakville Hydro existing load on Palermo TS remains constant.

Table 7-2 Palermo TS Load Forecast

Station	LTR (MW)	Act.	Load Forecast										
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2041
Palermo TS	110/180[1]	124	115	113	113	112	112	129	133	134	135	137	155

[1]The station existing LTR is 110 MW. With new 75/125MVA transformers the LTR will increase to 180 MW.

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Palermo TS T3/T4 replacement need as well as meet future demand requirements:

- **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One’s obligation to provide reliable supply to the customers.

- **Alternative 2 – Replace T3/T4 with similar type and size equipment as per current standard:** Under this alternative the existing T3/T4 transformers at Palermo TS will be replaced with new 50/83 MVA, 230/27.6 kV transformers. This alternative would address the need and maintain reliable supply to the customers in the area. It would not however, provide additional capacity to meet the future load growth as per the load forecast. It would also not allow additional DER resources to connect to the station since the short circuit constraints will remain due to the lower impedances of the 50/83MVA transformers.
- **Alternative 3 – Replace T3/T4 with larger size 230/27.6 kV, 75/125MVA transformers:** This alternative would require replacing the existing T3/T4 transformers with larger size transformers. Since the new transformers will be dual-winding transformers, the existing low voltage switchyard will need to be modified and additional feeders added to utilize the increased capacity. The modified station will have dual 27.6 kV buses with reduced fault current level and station capacity will increase from current 110 MW to 180 MW. This alternative will thus provide additional capacity to meet future load growth and the reduced fault current will permit DER resources to connect to the station.

The TWG recommends Alternative 3 as the preferred and cost effective alternative for addressing the need and taking "right-sizing" into consideration. It provides capacity to meet future load growth, removes the restriction on DER to connect to the station, maintains reliable supply to the customers in the area while increasing system resiliency and flexibility. While the incremental cost difference between the 50/83MVA and the 75/125MVA transformers is small (<$1M), planning estimates for the LV yard expansion and additional feeder positions are between $7-10M.

7.2 230 kV Circuits H29/H30 Conductor Upgrade

7.2.1 Description

Pleasant TS is located in Brampton and has two 230/27.6 kV DESNs and one 230/44kV DESN. The station is supplied by the 230 kV double circuit line H29/H30 from Hurontario SS (see Figure 7-2). The station serves Alectra – Brampton loads. The summer 2021 peak station load was about 383 MW.

The existing conductor used for 230 kV circuits H29/H30 going to Pleasant TS is 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). This rating limits the maximum load-carrying capacity to approximately 419 MW of load at Pleasant TS. As mentioned in Table 6.1 the line flows are forecast to exceed line rating by summer 2027.

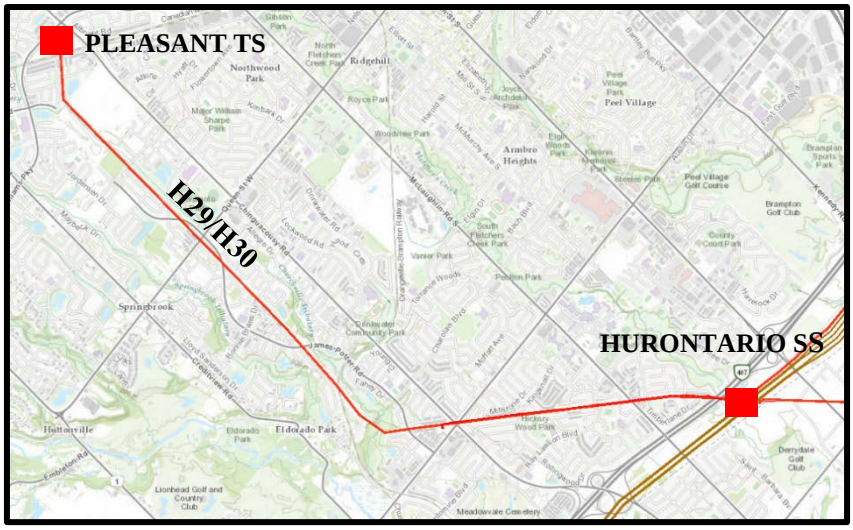


Figure 7-2 Radial Circuits of H29/H30 Supplying Pleasant TS

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address upgrading of the H29/H30 line:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not provide adequate transmission capacity to supply the load demand at Pleasant TS.
2. **Alternative 2 – Upgrade Line conductor:** This alternative covers upgrading the line by replacing the existing conductor with a conductor with a higher current rating.

Other alternatives such as building a second 230 kV line to Pleasant TS or transferring load away from Pleasant TS were considered and ruled out as impractical and not cost effective.

The TWG recommends Alternative 2 as the technically preferred and cost effective alternative for reinforcing the supply to Pleasant TS. Hydro One will consider transmission losses while selecting the conductor. OEB approval under Section 92 of the Electricity Act will be required. The estimated cost of the project is about $8M.

7.3 230 kV Circuits R19TH/R21TH - Overload under certain outage conditions

7.3.1 Description

The loads at Jim Yarrow MTS and Pleasant TS are supported by the 230 kV line V41H/V42H from Claireville and the R19TH/R21TH line as shown in Figure 7-3, Under certain outage conditions all loads at Pleasant TS and half the load on Jim Yarrow MTS can end up on one of the R19TH or the R21TH section between Hanlan Jct and Hurontario SS.

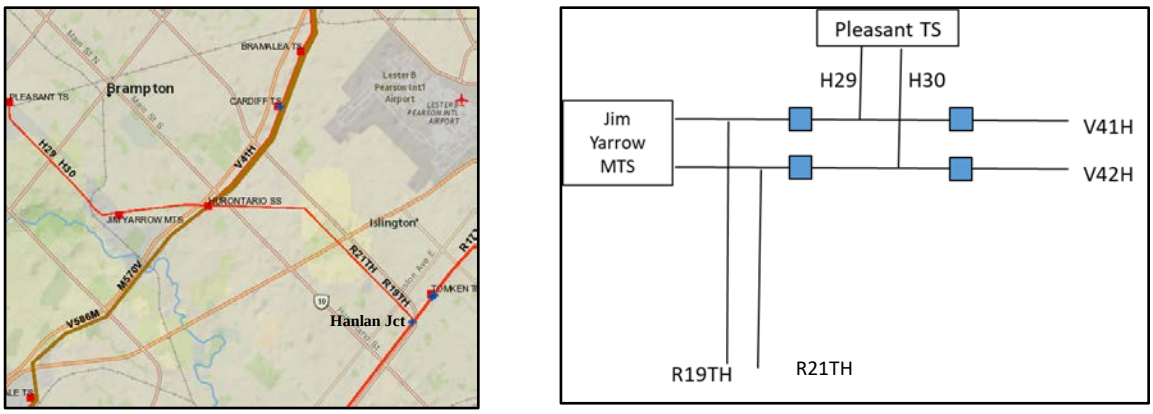


Figure 7-3 Supply to Jim Yarrow MTS and Pleasant TS

The two outage scenarios are:

- R19TH overloaded for overlapping outages of V41H and H30 (V41H out of service and H30 lost or H30 out of service and V41H lost).
- R21TH overloaded for overlapping outages of V42H and H29) (V42H out of service and H29 lost or H29 out of service and V42H lost).

7.3.2 Alternatives and Recommendation

The IRRP had considered a number of alternatives to address this issue ranging from a local load rejection scheme at Pleasant TS to reinforcing the supply to Hurontario SS.

Following discussions with IESO and Hydro One Operating groups, given the fact that the possibility of the overlapping outages is rare, manual operator action can be taken to relieve the line overloads and will be adequate over the near to medium-term (till 2030). Hydro One has implemented an operating procedure under which Jim Yarrow MTS load is transferred to R21TH if V41H or H30 are out of service pre-contingency and to R19TH if V42H or H29 are out of service pre-contingency.

The TWG recommends that the loading on the R19TH/R21TH and the performance of the manual scheme be monitored. The timing (currently forecast to be around 2030) and the preferred option alternative for the LR scheme will be reviewed in the next planning cycle.

7.4 Station Capacity - DESN Stations Exceeding LTR

As discussed in Section 6.2 the loading on five DESN stations – Palermo TS T3/T4, Erindale TS T1/T2, Pleasant TS T1/T2, Cardiff TS T1/T2, Erindale T5/T6 - is expected to exceed station LTR during the 2021-2031 study period. Palermo TS has been discussed in Section 7.1. The remaining stations are discussed here.

All these remaining DESNs supply Alectra utilities load. Erindale TS and Cardiff TS supply load in Mississauga and Pleasant TS supplies load in Brampton (Figure 7-4). The stations forecast loads and need dates are given in Table 7-3 below.

Table 7-3 Forecast Loads on DESNs Overloaded during Plan Period

Station	LTR MW	Act.	Load Forecast											Need Date
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2041	
Pleasant TS T1/T2 DESN	148	138	142	147	147	147	148	149	150	151	152	154	162	**2027**
Erindale TS T1/T2 DESN	181	142	147	151	156	162	168	175	182	190	192	195	211	**2028**
Cardiff TS T1/T2 DESN	114	103	102	100	99	102	106	110	114	119	120	121	128	**2029**
Erindale TS T5/T6 DESN	195	142	141	139	137	145	153	163	172	182	193	196	230	**2031**

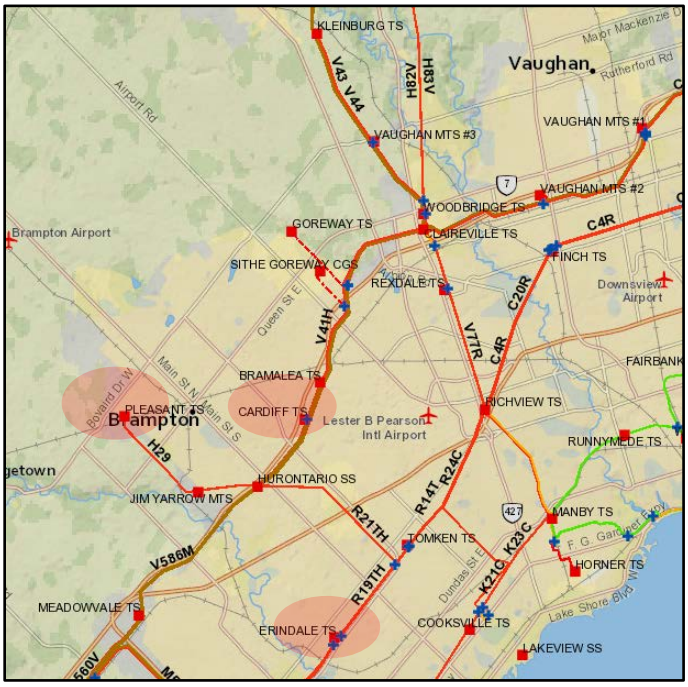


Figure 7-4 GTA West Region - Pleasant TS, Cardiff TS and Erindale TS

Options for providing the required relief for Erindale TS T1/T2 DESN were previously investigated in 2015 Local Planning Report for Erindale TS [4]. As discussed in the 2019 GTA West Region NA Report [2], this need is being managed by Alectra and no transmission upgrades are required.

The loading issues at the Pleasant TS T1/T2 DESN, Cardiff TS T1/T2 DESN, and the Erindale TS T5/T6 DESN are similar to those of Erindale T1/T2 DESN. The TWG recommends that these loading issues be managed at the Distribution level in the near term and it will be reviewing the station loadings in the next regional planning cycle.

7.5 Asset Replacement for Major HV Transmission Equipment

As discussed in Section 6.3, Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at a number of GTA West Region Hydro One stations – Palermo TS, Bramalea TS, Tomken TS and Lorne Park TS –. Palermo TS T3/T4 replacement is discussed in section 7.1.

Details of thework at the remaining stations along with their planned in-service year are given in Table 7-4 below:

Table 7-4 GTA West Region – Asset Replacement Plans

No.	Station	Planned work	In-service year(1)
1	Bramalea TS	The work includes replacement of the 230/44kV, 50/83MVA transformers, T3 and T4 with larger size 230/44kV, 75/125MVA units.	2028
2	Tomken TS	The work includes like-for-like replacement of 230/44 kV, 75/125 MVA transformers T1 and T2.	2029
3	Lorne Park TS	The work includes like-for-like replacement of 230/27.6 kV, 50/83MVA transformer T2.	2030

(1) The planned in-service year is tentative and is subject to change

The above asset replacement plans have taken “right sizing” into consideration. Based on the load forecast, Bramalea TS T3/T4 transformers will be replaced with larger size 75/125MVA units as the load forecast indicates that increased capacity would be required by 2036. The Lorne Park TS T2 transformer is planned to be replaced with “like-for-like” 50/83MVA units and Tomken TS T1/T2 transformers will be replaced with “like-for-like” 75/125MVA units (which is the largest standard size for these transformers).

The TWG recommends that Hydro One proceed with the above work to ensure that the system meet reliability criteria and supply to customers is not affected.

7.6 Load Security – 230 kV circuits T38B/T39B

7.6.1 Load Security

As discussed in Section 6.4.1 loads connected to the 230 kV circuits T38B/T39B will exceed the 600 MW by summer 2030. The circuit T38B/T39B will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted by configuration.

7.6.2 Alternatives and Recommendations

There were a number of alternatives suggested in the IRRP to ensure compliance with the ORTAC load security criteria. These included sectionalizing the T38B/ T39B circuits using breakers or re-terminating the stations to reduce loads connected to the T38B/T39B circuits. However, as per the current forecast, load is not expected to exceed 600 MW till summer 2030 due to the lower than expected load at Halton TS and Milton Hydro supplying some of the projected area load from the upsized Palermo TS.

The TWG recommends that Hydro One continue to monitor the load and that it wll review the the need the next regional planning cycle.

7.7 Load Restoration

Load restoration following outages was discussed in Section 6.4.2 As mentioned, there are a number of lines that do not meet the IESO criteria of the restoration of all load above 250 MW in 30 minutes.

However, given the high cost for mitigation measures, the low probability of the event happening and the ability to restore load within 4 hours, the TWG agrees that no further action is required.

7.8 Long Term Considerations

7.8.1 Capacity needs for 2032-2041

A number of capacity needs were identified in Section 6 over the longer term. These are summarized here.

1. Line capacity – Loading on a small 300m section of the T38B/T39B line, between Lantz Jct and Trafalgar DESN, will exceed the line rating by 2033.
2. Station Capacity – The following stations are expected to require relief:

    - Jim Yarrow MTS: T3/T4 DESN - 2032
    - Kleinburg TS: T1/T2 (27.6 kV) - 2032
    - Goreway TS: T5/T6 DESN - 2034
    - Bramalea TS: T3/T4 DESN – 2036[4]
    - Tremaine TS: T1/T2 DESN - 2039

The TWG will be reviewing these needs in the next regional planning cycle.

7.8.2 Long-Term Growth & NWGTA Electricity Corridor Need

The 2015 GTA West RIP had indicated the need for a new transmission corridor connecting Milton TS in the west to Kleinburg TS in the east. The corridor was proposed to provide the necessary transmission infrastructure required to support the load growth expected in the in northern part of the GTA West region as a result of the Provincial Government growth plans.

The Ministry of Energy and the Independent Electricity System Operator (IESO) have been working on the proposal to identify and protect a corridor of land for the future transmission corridor [5]

The TWG supports the initiative for the development of the new corridor as it will be essential to meet the future area growth. The progress of corridor development will be reviewed in the next regional planning cycle.

[4] This need will be addressed by the planned replacement of Bramalea TS T3 and T4 230/44kV, 50/83MVA transformers in 2028 with larger size 75/125MVA units.

8. CONCLUSIONS

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

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near and medium-term planning horizon (2021-2031) are provided in Table 8-1 below, along with their planned in-service dates and budgetary estimates for planning purposes.

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

No.	Need	Recommended Action Plan	Lead	Timing	Budgetary Estimates[1]
1	Palermo TS: Transformers T3 and T4 replacement. Also increased capacity required for Milton Hydro	Replace existing transformers with larger 75/125MVA units and modify/upgrade existing LV switchyard	Hydro One	2026	$30M
2	Relief required for H29/H30 line supplying Pleasant TS	Reconductor line to meet expected load demand	Hydro One	2027	$8M
3	Section of R19TH/R21H overloaded under certain outage conditions	Review Mitigation[2]	Hydro One	2030	TBD[3]
4	Station loading exceeds LTR • Pleasant TS: T1/T2 DESN • Erindale TS: T1/T2 DESN • Cardiff TS: T1/T2 DESN • Erindale: T5/T6 DESN	Balance load between DESNs	Alectra/ Hydro One	 2027 2028 2029 2031	TBD[3]
5	Asset Replacement: • Bramalea TS • Tomken TS • Lorne Park TS	Refurbish/replace major high voltage transmission equipment	Hydro One	 2028 2030 2030	 $20M $49M $14M
6	T38B/T39 Loading exceed load security criteria	Review Mitigation[2]	Hydro One	2030	TBD[3]

[1] Excludes cost for distribution infrastructure.

[2] The IRRP had proposed alternatives for mitigation. The alternatives and project timing will be reviewed and finalized in the next regional planning cycle.

[3] TBD – To be determined. The costs will depend on the alternative selected and therefore are not available at this time.

The GTA West TWG recommends that:

- Hydro One and LDCs to continue with the implementation of infrastructure investments listed in Table 8-1.
- All the other identified needs/options will be further reviewed by the TWG in the next regional planning cycle.

The next regional planning cycle for the GTA West Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will start in Q1 2024. If a need(s) emerges before this time, the next regional planning cycle can be started earlier to address the need(s).

9. REFERENCES

[1] GTA West Integrated Regional Resource Plan, July 2021

[2] Needs Assessment Report GTA West, May 2019

[3] GTA West Regional Infrastructure Plan - January 25, 2016

[4] Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief, July, 2015

[5] Proposal for NWGTA Transmission Corridor - Revised Study November 18, 2020

APPENDIX A. GTA WEST REGION - STATIONS

Station (DESN)	Voltage (kV)	Supply Circuits
Bramalea TS T1/T2	230/27.6	V41H/V42H
Bramalea TS T3/T4	230/44	V41H/V42H
Bramalea TS T5/T6	230/27.6	V41H/V42H
Cardiff TS T1/T2	230/27.6	V41H/V42H
Churchill Meadows TS T1/T2	230/44	R19TH / R21TH
Cooksville TS T1/T2	230/27.6	B16C/K21C
Cooksville TS T3/T4	230/27.6	B16C/K21C
Erindale TS T1/T2	230/27.6	R14T / R17T
Erindale TS T3/T4	230/44	R14T / R17T
Erindale TS T5/T6	230/44	R19TH / R21TH
Glenorchy MTS#1	230/27.6	T36B / T37B
Goreway TS (T1/T2, T5/T6)	230/27.6	V42H / V43
Goreway TS T5/T6	230/27.6	V42H / V43
Goreway TS T4	230/44	V43
Jim Yarrow MTS T1/T2	230/27.6	R19TH / R21TH
Halton Hills Hydro MTS	230/27.6	T38B/T39B
Halton TS T3/T4	230/27.6	T38B/T39B
Kleinburg TS T1/T2	230/27.6	V43/V44
Kleinburg TS T1/T2	230/44	V43/V44
Lorne Park TS T1/T2	230/27.6	B15C / B16C
Meadowvale TS T1/T2	230/27.6	T38B / T39B
Oakville TS # 2 T1/T2	230/27.6	B15C / B16C
Oakville TS # 2 T5/T6	230/27.6	B15C / B16C
Palermo TS T3/T4	230/27.6	T36B / T37B
Pleasant TS T1/T2	230/44	H29 / H30
Pleasant TS T5/T6	230/27.6	H29 / H30
Pleasant TS T7/T8	230/27.6	H29 / H30
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Trafalgar TS T1/T2	230/27.6	T38B/T39B
Tremaine TS T1/T2	230/27.6	T38B/T39B

APPENDIX B. GTA WEST REGION - TRANSMISSION LINES

No.	Circuit ID	From Station	To Station	Voltage (kV)
1	H29/H30	Hurontario SS	Pleasant TS	230
2	R14T/R17T	Richview TS	Trafalgar TS	230
3	R19TH/R21TH	Richview TS	Trafalgar TS/ Hurontario SS	230
4	T36B/T37B	Trafalgar TS	Burlington TS	230
5	T38B/ T39B	Trafalgar TS	Burlington TS	230
6	V41H/V42H	Claireville TS	Hurontario SS	230
7	V43/V44	Claireville TS	Kleinburg TS	230
8	B15C/B16C	Cooksville TS	Oakville TS	230
9	K21C/K23C	Manby TS	Cooksville TS	230
10	R24C	Richview TS	Cooksville TS	230

APPENDIX C. GTA WEST REGION - DISTRIBUTORS

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Bramalea TS	Tx / Dx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Kleinburg TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS#2	Dx
	Pleasant TS	Tx
	Tomken TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Burlington Hydro	Palermo TS	Tx
	Tremaine TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Halton Hills Hydro Inc.	Halton TS	Tx / Dx
	Halton Hills MTS	Tx
	Pleasant TS	Dx
Distributor Name	**Station Name**	**Connection Type**
Hydro One Networks Inc.	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Milton Hydro	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS#1	Tx
	Oakville TS#2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

APPENDIX D. GTA WEST REGION - STATIONS LOAD FORECAST

GTA West Non-Coincident Station Load Forecast (MW)

Station	DESN ID	Bus ID	LTR (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Bramalea TS	**T1/T2**	BY (27.6 kV)	185	103	128	97	96	98	101	101	101	102	103	105	107	108	109	111	112	113	114	114	115	116	116	117
	T3/T4	JQ (44kV)	106	110	95	103	102	101	100	100	100	99	100	101	102	103	104	105	106	106	107	108	108	109	110	110
	T5/T6	EZ (44kV)	159	92	86	98	101	100	99	99	100	100	100	101	102	102	103	104	105	105	106	106	106	107	107	107
Bramalea TS Total			450	305	309	297	299	299	300	299	300	301	303	307	310	313	316	320	322	324	326	328	330	331	333	335
Cardiff TS	**T1/T2**	BQ (27.6 kV)	114	102	89	103	102	100	99	102	106	110	114	119	120	121	122	124	124	125	125	126	126	127	127	128
Churchill Meadows TS	**T1/T2**	BY (44kV)	173	107	110	106	105	103	102	101	101	101	101	102	104	105	107	108	109	110	111	112	113	114	115	116
Cooksville TS	**T1/T2**	EZ (27.6kV)	120	47	44	51	50	49	53	56	58	62	66	67	68	69	70	71	72	72	73	73	74	74	75	76
	T3/T4	JQ (27.6 kV)	120	60	63	59	59	62	66	70	72	72	72	72	73	74	75	76	77	78	78	79	80	80	81	81
Cooksville TS Total			239	107	107	110	109	112	119	126	130	134	138	140	141	143	145	147	149	150	151	152	153	155	156	157
Erindale TS	**T5/T6**	BJ (44kV)	195	116	154	142	141	139	137	145	153	163	172	182	193	196	198	201	203	205	206	217	227	228	229	230
	T1/T2	EQ (27.6 kV)	181	153	178	142	147	151	156	162	168	175	182	190	192	195	197	200	202	203	205	207	208	209	210	211
	T3/T4	ZY (44kV)	193	129	156	139	141	142	144	143	143	144	144	146	147	150	152	154	155	157	158	159	161	162	163	164
Erindale TS Total			569	398	488	424	429	432	438	449	464	483	498	518	532	540	547	554	560	565	569	582	596	599	602	605
Glenorchy MTS #1	**T1/T2**	JQ (27.6 kV)	153	55	62	74	95	103	106	113	118	123	127	129	132	134	137	99	102	104	106	105	105	105	105	105
Goreway TS	**T1/T2**	JQ (27.6 kV)	184	60	73	53	54	58	61	65	69	72	75	78	79	81	82	84	85	86	87	88	88	89	90	91
	T4	M36 (44kV)	78	27	26	22	21	20	19	19	19	19	19	19	20	20	20	21	21	21	21	21	21	21	21	22
	T5/T6	BY (27.6 kV)	173	160	173	153	152	152	152	153	155	157	159	162	165	168	170	173	174	175	176	177	178	178	179	180
Goreway TS Total			435	247	272	228	228	230	233	237	243	248	253	259	264	269	273	277	279	282	284	285	287	288	290	292
Halton Hills MTS	**T1/T2**	(27.6	83	8	3	18	18	18	30	33	38	30	35	43	54	66	79	45	52	52	52	53	53	53	53	54
Halton TS	**T3/T4**	JQ (27.6 kV)	186	160	151	153	144	150	155	158	161	161	160	163	163	163	163	164	164	163	163	164	164	163	163	163
Halton TS#2	**T1/T2**	(blank)	180	0	0	0	0	0	0	0	0	0	0	0	0	0	0	89	97	107	116	125	136	148	160	174
Jim Yarrow MTS	**T1/T2**	AB (28kV)	157	124	138	135	135	133	134	137	140	143	146	149	153	156	159	162	163	164	166	166	167	168	168	169
Kleinburg TS	**T1/T2**	JQ (44kV)	99	84	89	83	83	83	82	83	83	83	84	84	83	83	84	84	84	83	85	85	85	85	85	85
	T1/T2	BY (27.6 kV)	97	60	65	59	58	59	68	80	80	80	80	80	80	79	99	99	99	100	100	100	100	100	100	100
Kleinburg TS Total			196	144	154	142	141	142	151	163	163	163	164	164	163	163	183	182	182	183	184	184	184	184	184	184

Station	DESN ID	Bus ID	LTR (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Lorne Park TS	T1/T2	BJ (27.6 kV)	137	78	109	83	87	89	89	88	88	88	88	89	90	91	93	94	95	96	96	97	98	99	99	100
Meadowvale TS	T1/T2	EZ (44kV)	181	112	152	119	118	121	124	128	132	136	136	137	138	140	142	144	145	146	148	149	150	151	152	154
Oakville TS #2	T1/T2	EZ (27.6 kV)	175	139	145	160	159	157	155	155	154	154	154	155	156	156	157	158	158	158	159	159	159	160	160	160
Palermo TS	T3/T4	BY (27.6 kV)	180	113	129	125	115	113	113	112	112	129	133	134	135	137	139	141	142	144	146	147	149	151	153	155
Pleasant TS	T1/T2	JQ (44K)	148	113	128	138	142	147	147	147	148	149	150	151	152	154	155	156	157	159	160	160	161	161	162	163
	T5/T6	BY, EZ (27.6 kV)	181	165	182	154	154	154	154	155	156	156	157	158	160	161	162	163	164	165	166	167	168	168	169	170
	T7/T8	FV (27.6 kV)	188	89	128	90	90	90	95	102	110	117	124	130	137	144	150	157	159	161	163	164	165	166	166	168
Pleasant TS Total			517	367	438	383	387	391	396	404	413	422	431	440	449	459	468	477	481	485	489	491	493	495	497	500
Tomken TS	T1/T2	BY (44kV)	164	162	111	129	128	126	124	123	123	123	123	125	126	135	144	153	154	155	157	158	159	160	162	163
	T3/T4	EZ (44kV)	183	105	130	127	126	124	122	121	121	121	121	123	124	126	128	129	137	146	154	155	156	157	159	160
Tomken TS Total			347	267	241	257	253	249	247	245	245	244	245	247	251	261	271	282	292	301	310	313	315	318	320	323
Trafalgar TS	T1/T2	BY (27.6 kV)	124	68	76	107	106	105	104	103	103	103	103	103	103	103	103	104	104	103	103	103	103	103	103	103
Tremaine TS	T1/T2	BY (27.6 kV)	189	71	112	126	130	136	142	144	146	148	150	152	155	159	163	168	173	178	183	183	189	192	196	196
Customer #1 CTS	T1/T2	BY (27.6 kV)	83	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Total			4868	3002	3314	3184	3188	3213	3266	3327	3388	3450	3510	3578	3643	3710	3796	3866	3923	3972	4018	4056	4101	4137	4174	4212

Notes:

- Load forecast is based on the IESO July 2021 IRRP forecast and adjusted for input provided by Alectra, Milton Hydro and Hydro One Distribution..
- Halton TS# 2 is assumed to be in service in 2033

APPENDIX E. LIST OF ACRONYMS

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



NEEDS ASSESSMENT REPORT

Greater Toronto Area West

August 30, 2024

Needs Assessment Report

Greater Toronto Area (GTA) West Region

August 30, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: GTA West Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Toronto Area West and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the Needs Assessment phase and b) require further assessment and regional coordination. The results reported in this Need Assessment are based on the input and information provided by the Technical Working Group (the "TWG") for this region at the time. Updates may be made based on best available information throughout the planning process.

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

Executive Summary

REGION	Greater Toronto Area West (GTA West) Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE:	May 3, 2024	**END DATE:**	August 30, 2024

1. INTRODUCTION

The second Regional Planning cycle for the GTA West Region was completed in February 2022 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report). This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered for the GTA West Region on May 3rd, 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTW West Region NA includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA West Region includes the area roughly bordered by Highway 27 to the northeast, Highway 427 to the southeast, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south. The Region area comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville and portions of Burlington.

5. INPUTS/DATA

The TWG comprises of representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the Region regarding capacity needs, reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy

b) System reliability needs and operational concerns

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs discussed in the GTW West second cycle RIP have been addressed or updated:

- R19TH/R21TH overload under specific N-1-1 contingencies at peak load condition: A Key Operation Point ("KOP") procedure has been implemented in Hydro One control room to manage the N-1-1 post contingency thermal overload.
- Erindale T1/T2 DESN load will exceed station LTR by 2028: New forecast suggests the need will trigger in 2030. The TWG recommends this need is addressed with further regional planning coordination in conjunction with other capacity needs in Mississauga.
- Cardiff TS load will exceed station LTR by 2029: New forecast suggests the need will trigger in 2030. The TWG recommends this need is addressed with further regional planning coordination in conjunction with other capacity needs in Mississauga.
- Pleasant T1/T2 DESN capacity will be exceeded in 2027: Transformer replacement with standard LTR will provide sufficient capacity for forecasted loads.
- Erindale T5/T6 DESN load will exceed station LTR by 2031: New load forecast in this NA suggests the need will trigger beyond 2033.
- Lorne Park T2 replacement: Planned in service beyond 2033
- Bramalea T3/T4 replacement: Planned in service beyond 2033
- Tomken T1/T2 replacement: Planned in service beyond 2033
- T38B/T39B loads will exceed 600MW load security criteria in 2030: New load forecast suggests the threshold will be reached in 2029.

The following needs and projects discussed in the GTA West second cycle RIP are currently underway:

- Circuits H29/H30 reconductoring: planned in service in Q2, 2028.
- Palermo TS transformer replacement with larger capacity units: planned in service in Q4, 2027.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Halton T3/T4 (27.6kV)
- Pleasant T5/T6 (27.6kV)

b) Station Capacity

- Halton TS (27.6kV)
- Bramalea T1/T2 DESN (27.6kV)
- Cooksville T1/T2 DESN and T3/T4 DESN (all 27.6kV)
- Pleasant T5/T6 DESN (27.6kV)

- Jim Yarrow T1/T2 (27.6kV)
- Goreway T5/T6 DESN (27.6kV).
- Bramalea T3/T4 DESN (44kV)
- Lorne Park T1/T2 DESN (27.6kV)

c) Transmission Line Capacity

- No new transmission Line Capacity need identified

d) System Reliability, Operation and Load Restoration

- Trafalgar 230kV bus over-voltage issue under light load condition as reported by IESO.

e) Transmission System Reinforcement

- Major transmission expansion in Milton area will be needed to accommodate increasing new load connection requests including large transmission-connected data centers. Existing 230kV facilities, especially the radial section of T38B/T39B from Trafalgar TS, do not have sufficient capacity to supply the new demand and may not be simply addressed by reconductoring. In addition, T38B/T39B corridor will exceed the load security limit of 600MW in this NA timeframe

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and new station capacity needs. These needs will be assessed again during the next phases of this Regional Planning cycle

No.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Halton TS LTR	2026	2026	2029
2	Cardiff TS LTR	2030	2028	2032
3	Erindale T1/T2 LTR	2030	2027	2032
4	Bramalea T1/T2 LTR	2031	2030	Beyond 2033
5	Bramalea T3/T4 LTR*	2024	2024	2024
6	Lorne Park LTR*	2031	2030	Beyond 2033
7	Cooksville T1/T2 LTR	2030	2030	Beyond 2033

8	Cooksville T3/T4 LTR	2030	2029	Beyond 2033
9	Pleasant T1/T2 LTR*	2027	2026	Beyond 2033
10	Pleasant T5/T6 LTR	2026	2025	2027
11	Jim Yarrow T1/T2 LTR	2030	2028	Beyond 2033
12	Goreway T5/T6 LTR	2026	2025	2026
Additional capacity needs under high growth scenario				
13	Meadowvale TS LTR	Beyond 2033	2029	
14	Palermo TS LTR	Beyond 2033	2029	
15	Tremaine TS LTR	Beyond 2033	2029	
16	Tomken T1/T2 LTR	Beyond 2033	2031	
* The need can be addressed by transformer renewal with higher LTR specification				

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

a) Integrated transmission reinforcement plan in Milton area to accommodate new transmission and distribution connected loads including large data centers. A reinforcement plan should also help to manage T38B/T39B load security. The TWG recommends further regional coordination to address the capacity constraints. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing such plan.

b) Accommodation of loads growth beyond LTR at Halton TS with a new 230/27.6kV Halton #2 station

c) Accommodation of load growth beyond LTRs at Bramalea T1/T2, Erindale T1/T2 and Cardiff TS in Mississauga area

d) Accommodation of load growth beyond LTRs at Cooksville T1/T2 and Cooksville T3/T4 in Mississauga area

e) Accommodation of load growth beyond LTRs at Pleasant T5/T6 and Jim Yarrow T1/T2 in Brampton area

f) Accommodation of load growth beyond LTRs at Goreway T5/T6 and Bramalea T1/T2 in Brampton area.

II. Needs that do not require further regional coordination

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

a) Accommodation of load growth at Pleasant T1/T2 through transformer renewals with standard LTR specification
b) Accommodation of load growth at Bramalea T3/T4 through transformer renewals with upsized rating
c) Accommodation of load growth at Lorne Park T1/T2 through T2 renewal with standard LTR specification (T1 has sufficient LTR).

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities Co.
- Milton Hydro Distribution Inc.
- Halton Hills Hydro Inc.
- Oakville Hydro Electricity Distribution Inc.
- Burlington Hydro Inc.
- Hydro One Networks Inc. (Distribution)

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1. Introduction

The second cycle of the Regional Planning process for the GTA West Region was completed in February 2022 with the publication of the Regional Infrastructure Plan ("RIP") Report [1] - (RIP link). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the GTA West Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is shown in Figure 1 below.

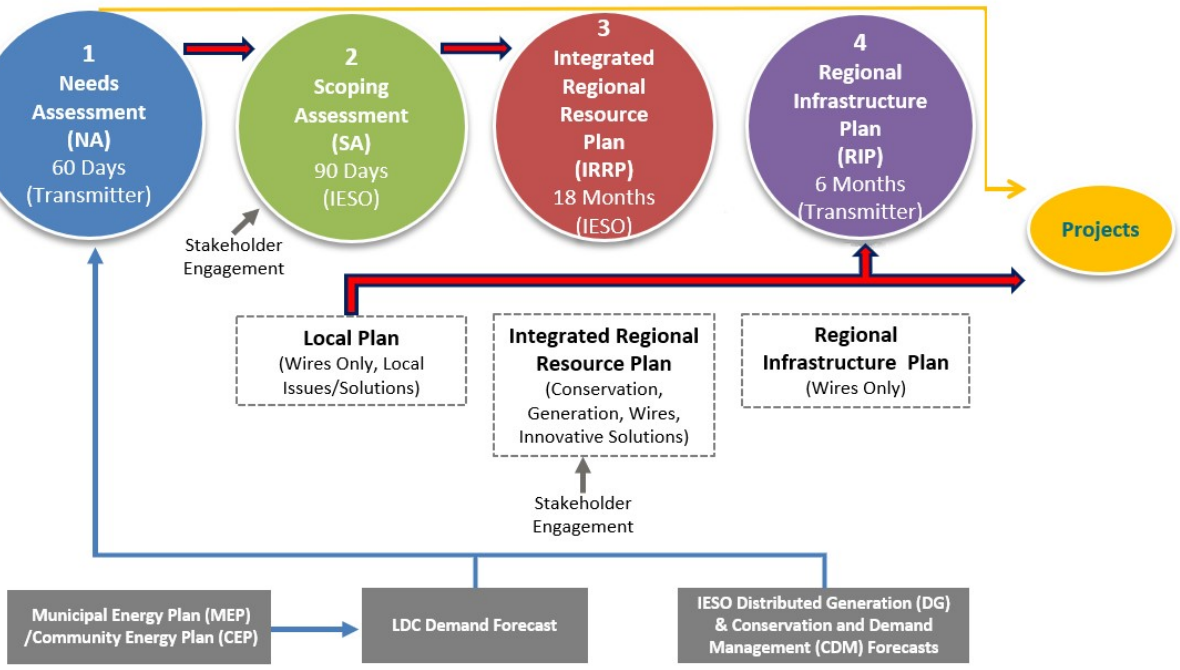


Figure 1: Regional Planning Process

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

Table 1: GTA West Region TWG Participants

No.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission) - (Lead Transmitter)
2	Hydro One Networks Inc. (Distribution)
3	Independent Electricity System Operator
4	Alectra Utilities Co.
5	Burlington Hydro Inc.
6	Milton Hydro Distribution Inc.
7	Halton Hills Hydro Inc.
8	Oakville Hydro Electricity Distribution Inc.

2. Regional Issue/Trigger

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the third Regional Planning cycle was triggered for the GTA West Region.

3. Scope of Needs Assessment

The scope of this NA covers the GTA West region and includes:

- Review and update needs and plans identified in the previous cycle RIP,
- Identify any new needs resulting from this assessment,
- Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan, and
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is 10 years.

4. Regional Description and Connection Configuration

The GTA West Region includes the area roughly bordered geographically by Highway 27 to the northeast, Highway 427 to the southeast, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south. The GTA West Region area comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville and portions of Burlington.

The geographical boundaries of the Region are shown in Figure 2.



Figure 2: Map of GTA West Regional Planning Area

Electrically the GTA West Region is bounded by Richview TS to Manby TS 230 kV circuits on the east, Richview TS to Trafalgar TS to Burlington TS 230 kV circuits on the north and Manby TS to Cooksville TS to Oakville TS 230 kV circuits on the south. The distribution system in this Region is at two voltage levels, 44 kV and 27.6 kV. Local generation in the area include the two gas fired plants, the 1196MVA Goreway CGS in Brampton and the 755MVA TCE CGS in Halton Hills.

The Local Distribution Customers (LDC) in the Region include Burlington Hydro Inc., Alectra Utilities Co., Halton Hills Hydro Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc. and Oakville Hydro Electricity Distribution Inc. The high-voltage system in this Region also provides supply to one customer owned transformer station. An electrical single line diagram for the GTA West Region facilities is shown in Figure 3.

The circuits and stations of the area are summarized in Table 2 below:

Table 2: Transmission Station and Circuits in the GTA West Region

230kV circuits	Transformer Stations	Generation Stations
H29/H30 R14T/R17T R19TH/R21TH T36B/T37B T38B/ T39B V41H/V42H V43 B15C/B16C K21C/K23C, R24C	Bramalea TS Cardiff TS Churchill Meadows TS Claireville TS[1] Cooksville TS Erindale TS CTS-1 Glenorchy MTS Goreway TS Halton TS Halton Hills MTS Jim Yarrow MTS Lorne Park TS Meadowvale TS Oakville TS Palermo TS Pleasant TS Richview TS Tomken TS Trafalgar TS[1] Tremaine TS (Hurontario SS)	Sithe Goreway CGS, 787MW[2]/1196MVA TCE Halton Hills CGS, 526MW[3]/755MVA

1: 500kV Stations with Autotransformers installed

2: At 35°C ambient temperature. Generation capacity will increase by 40MW under IESO's Expedited Long-term RFP

3: At 35°C ambient temperature. Generation capacity will increase by 29MW under IESO's Expedited Long-term RFP

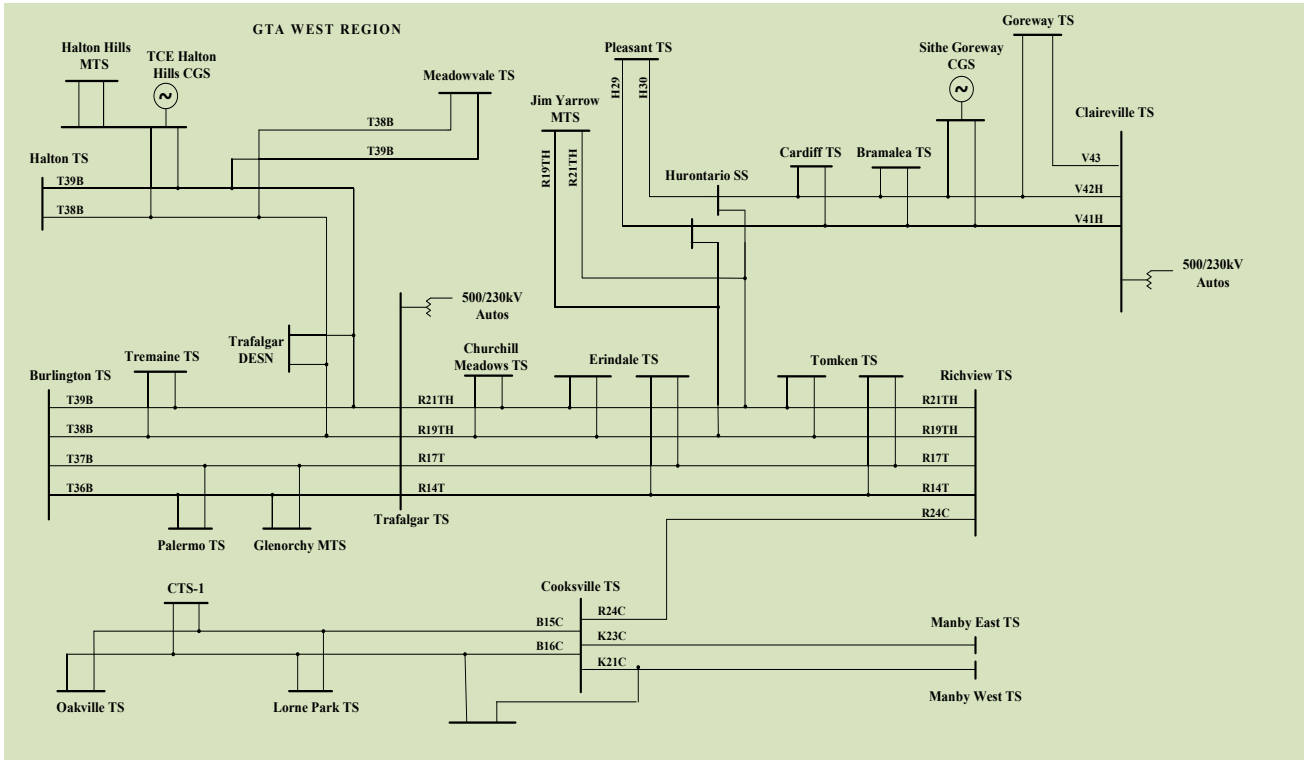


Figure 3: GTA West Transmission Single Line Diagram

5. Inputs and Data

TWG participants, including representatives from LDCs, IESO, and Hydro One provided input for the GTA West NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022 [2]. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the followings:

- GTA West 10-year summer and winter load forecast for all supply stations inclusive of the inputs provided by the municipalities listed in Appendix E
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement or refurbishment
- Planned transmission and distribution investments that are relevant to Regional Planning for the GTA West
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. Assessment Methodology

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy
- System reliability and operational considerations
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"
- Load forecast data requested from industrial customers in the region
- Summer peak load condition. Three load forecasts were developed, i.e. normal growth scenario, high and low growth scenario. The high and low growth load forecasts are developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, government policies, higher than expected EV charging trend during peak load conditions, etc.

The following assumptions are made in this report:

- The study period for this Needs Assessment is 2024-2033.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC) [3].

6.2 Information Gathering Process

6.2.1 Load forecast

The LDCs provided their summer and winter load forecast for all the stations supplying their loads in the GTA West region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Region. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point

the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Region is given in Appendix A.

6.2.2 Sensitivity analysis

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3 Asset renewal needs for major HV equipment

A list is generated for major HV transmission equipment planned or identified to be replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4 System reliability and operational issues

Relevant information regarding system reliability and operational issues in the region as feedback is provided by the IESO during the NA phase.

7. Needs

This section describes new needs identified in the Region and updates on previously identified needs since the completion of previous regional planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates:

- Palermo T3/T4 replacement with larger capacity units: project is in progress with planned in service in Q4, 2027.
- Tomken T1/T2 replacement: expected in service date is updated as Q4, 2035.
- Lorne Park T2 replacement: expected in service date is updated as Q4, 2034.
- Bramalea T3/T4 replacement with larger capacity units: expected in service date is updated as Q2, 2040.
- Pleasant T1/T2 capacity need: will plan to replace T1/T2 with standard LTR rating, in service date is to be determined.
- Erindale T5/T6 capacity need: updated load forecast suggests the need is beyond 2033.
- Circuit H29/H30 capacity need: reconductoring to higher capacity is in progress, expected in service date is Q2, 2028.
- R19TH/R21TH post-contingency overload under specific N-1-1 scenarios: operational KOP has been implemented in Hydro One control room.
- T38B/T39B Lantz Junction to Trafalgar DESN (~200m) post-contingency overload: being re-evaluated since more new load connection requests are received, this could be included an integrated transmission reinforcement plan in the area.

All new near and midterm needs that are discussed as a part of this report are summarized in Table 3. Note the planned in-service year for the projects is tentative and is subject to change.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Halton T3/T4 end-of-life replacement	Planned in service Q4, 2035	N/A	Sec. 7.1
Pleasant T5/T6 End-of-life replacement	Planned in service Q3, 2037	N/A	Se. 7.1

Station Capacity Needs			
Halton TS Forecasted demand will exceeds LTR in 2026.	Plan Halton TS #2 to accommodate new load.	Sec. 6.2	Sec. 7.2.1
Bramalea T1/T2 Forecasted demand will exceed LTR in 2031	Plan Mississauga and Brampton areas to accommodate new load	N/A	Sec.7.2.2
Erindale T1/T2 Forecasted demand will exceed LTR in 2030.	Plan area to accommodate new load	Sec. 6.2, 7.4	Sec. 7.2.4
Cardiff T1/T2 Forecasted demand will exceed LTR in 2030.	Plan area to accommodate new load	Sec. 6.2, 7.4	Sec. 7.2.5
Lorne Park T1/T2 Forecasted demand will exceed LTR in 2031	Replace Lorne Park T2 with standard LTR	N/A	Sec. 7.2.6
Cooksville T1/T2, T3/T4 Forecasted demand will exceed LTR in 2030	Plan area to accommodate new load	N/A	Sec. 7.2.7
Pleasant T5/T6 Forecasted demand will exceed LTR in 2026	Plan area to accommodate new load	N/A	Sec. 7.2.9
Jim Yarrow T1/T2 Forecasted demand will exceed LTR in 2030.	Plan area to accommodate new load	Sec. 7.8.1	Sec. 7.2.10
Goreway T5/T6 Forecasted demand will exceed LTR in 2026.	Plan area to accommodate new load	Sec. 6.2	Sec. 7.2.11
System Reliability, Operation and Load restoration Needs			
T38B/T39B load security and restoration	Consolidate with Milton area transmission reinforcement need and assess further in next phase of regional planning	Sec. 7.6	Sec. 7.4
Trafalgar 230kV high voltage control under light load condition	IESO and Hydro One operations coordinate to assess solutions	N/A	Sec. 7.4
Transmission System Reinforcement Needs			
Milton area reinforcement for load supply and security	Develop an integrated transmission system reinforcement plan in further regional planning phases to address substantial new load connection requests in Milton area	N/A	Sec. 7.5

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Region. The complete list of planned major HV transmission equipment requiring replacement is provided in Table 4. Only Palermo T3/T4 will be put in service in next 10 years according to Hydro One's recent investment planning. Note the in service year is subject to change as the asset renewal planning is a dynamic process.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors
- Technical obsolescence due to outdated design
- Lack of spare parts availability or manufacturer support and/or
- Potential health and safety hazards.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230 load serving step down transformers
- 230kV breakers where:
  replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

In the list of Table 4, Halton T3/T4 and Pleasant T5/T6 transformers are newly identified asset for replacement but the in-service dates will be outside of this NA window based on recent Hydro One investment planning outcome. It is expected that Lorne Park TS capacity will increase once T2 is replaced

with standard LTR specification (sec. 7.2.6). Bramalea T3/T4 may also be replaced with larger capacity to address the capacity issue (sec. 7.2.3).

Table 4: Major HV Transmission Asset Assessed for Replacement in the Region in Next 10 Years

Station/Circuit	Need Description	Planned ISD
Palermo T3/T4	Built in 1969, applied in 1970, replacement with upsized units	2027
Assets planned for replacement post 2033		
Halton T3/T4	Built in 1989, applied in 1990	Beyond 2033
Pleasant T5/T6	Built in 1988, applied in 1991	Beyond 2033
Lorne Park T2	Built in 1974, applied in 1975	Beyond 2033
Tomken T1/T2	Built and applied in 1970	Beyond 2033
Bramalea T3/T4	Built in 1970, applied in 1983	Beyond 2033

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV Transforming stations in the Region using the summer peak load forecasts. Based on the results, the identified station capacity needs are flagged in Table 5. Comparing with the recommendations in RIP 2022 [1], Bramalea T1/T2, Cooksville T1/T2, T3/T4 and Pleasant T5/T6 are newly identified needs in this NA period. Previously identified capacity need of Erindale T5/T6 in [1] has been updated to post 2033.

Table 5: Stations with Capacity Need

TS	LTR (MW)	Load Forecast (MW)									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Halton T3/T4	195	154.0	179.1	**215.9**	234.4	231.3	250.2	264.2	266.5	268.8	273.5
Bramalea T1/T2	193	134.7	139.5	144.6	149.9	156.4	170.2	182.7	**205.3**	228.8	252.8
Bramalea T3/T4	111	**113.6**	115.1	114.6	119.1	122.7	126.0	126.4	127.3	128.8	130.4
Bramalea T5/T6	169	103.4	103.4	105.0	107.7	111.4	114.9	118.5	118.9	119.8	122.7
Erindale T1/T2	180	166.6	169.2	174.4	180.0	179.8	179.2	**184.5**	193.5	199.2	215.4
Erindale T3/T4	190	156.8	163.0	164.6	166.3	167.3	166.9	166.7	167.3	169.3	181.0
Erindale T5/T6	194	132.9	134.8	135.7	136.2	137.8	139.2	140.6	142.7	145.3	147.9
Cardiff T1/T2	113	109.3	110.8	111.6	111.9	113.3	113.2	**115.6**	118.5	121.8	125.1
Lorne Park T1/T2	144	104.4	105.8	111.2	116.1	122.0	128.2	136.9	**146.1**	152.3	151.8
Cooksville T1/T2	117	50.7	51.4	51.8	51.9	64.1	78.3	**123.9**	152.5	171.4	204.9
Cooksville T3/T4	117	40.2	40.8	41.1	51.2	67.9	87.4	**130.4**	150.3	168.6	202.9
Pleasant T1/T2	155	122.7	131.9	147.1	**156.3**	158.2	158.8	158.9	159.7	161.1	162.8
Pleasant T5/T6	187	181.8	186.2	**191.6**	197.1	203.6	209.2	216.0	223.3	231.9	241.3
Pleasant T7/T8	183	108.0	111.3	115.2	119.3	124.0	128.2	133.1	138.4	144.5	151.1
Jim Yarrow T1/T2	157	134.3	137.6	141.5	145.6	150.4	154.6	**159.6**	165.0	171.3	178.3
Goreway T5/T6	181	177.6	181.9	**187.1**	192.5	198.9	204.4	211.0	218.2	226.6	235.8
Goreway T1/T2	180	74.4	77.3	80.7	84.3	88.4	92.1	96.3	100.8	105.9	111.4

7.2.1 Halton TS

Halton TS (27.6kV) supplies loads from Milton Hydro and Halton Hills Hydro. Milton Hydro forecasts rapid load growth at Halton TS in next three years, while Halton Hills Hydro load forecast remain flat in next 10 years. By end of this assessment cycle, Milton Hydro forecasts nearly 80MW loads beyond Halton TS LTR need to be served from other supplies. As the LTR at Halton TS cannot be increased through standard transformer replacement, a new station Halton TS #2 as previously suggested in [1,6] could be appropriate to address the need. In near term, Milton Hydro plans to use Oakville Hydro's Glenorchy MTS and upsized Palermo TS to meet the increasing demand before Halton TS #2 is available. The TWG recommends that the capacity need at Halton TS be investigated further through the regional planning process in conjunction with Milton area load supply planning (sec. 7.5).

7.2.2 Bramalea T1/T2

Bramalea TS has three DESNs as shown in Table 5, supplying Alectra's loads in Mississauga and Brampton. T1/T2 is the only 27.6kV DESN in Bramalea. The forecasted load at T1/T2 is expected to exceed its LTR in 2031. As Erindale T1/T2 (27.6kV) and Cardiff TS (27.6kV) in Mississauga will have similar capacity need (7.2.4 and 7.2.5 below) in medium term, the TWG acknowledges that a new station might be one option and recommends further regional coordination to address this need.

7.2.3 Bramalea TS T3/T4

Bramalea T3/T4 (44kV) are 83.3MVA CGE units built in 1970. Operating data shows the actual peak load at T3/T4 has slightly exceeded summer LTR and the load will grow at moderate rate near 2%. The issue can be addressed by replacing the transformers with higher rating such as standard 125MVA units. At interim, Alectra may balance the 44kV load with Bramalea T5/T6 DESN that can accommodate extra load. The TWG acknowledges load rebalance and transformer replacement could address the issue.

7.2.4 Erindale TS T1/T2

Erindale TS has three DESNs as shown in Table 5, all supplying Alectra's loads. T1/T2 is the only 27.6kV DESN in Erindale. The forecasted load will exceed T1/T2 LTR in 2030. The TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.5 Cardiff TS

Cardiff T1/T2 (27.6kV) serves Alectra's loads with two 83.3MVA transformers built in 2004. The LTRs of the transformers are further limited by its MVGIS breakers. Load forecast suggests the station will be overloaded by 2030. Since it is impractical to upsize the transformers and MVGIS still in good condition, the TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.6 Lorne Park TS

Lorne Park T1/T2 (27.6kV) serves Alectra loads only. The LTR of the station is determined by T2 (built in 1974) that has lower overloading capability than T1 (built in 2008). The forecast shows that Lorne Park TS load will exceed T2 LTR in 2031 and further growth is moderate. The TWG acknowledges that T2 replacement with standard LTR should be one option to address the issue.

7.2.7 Cooksville TS

Cooksville TS (27.6kV) has two DESNs, T1/T2 and T3/T4, supplying Alectra's loads only. All the transformers are 83.3MVA units built in 2013. Alectra forecasts significant load growth at Cooksville after 2028 as shown in Table 5. Lakeview Village, Rangeview, Dixie Mall conversion, Trillium Hospital new building, Water and Wastewater Treatment Plants expansion are examples of the new need to be served. The load growth rates will peak at 60% for T1/T2 DESN and 50% for T3/T4 DESN in 2030. As a result, the LTRs at both DESNs will be exceeded in 2030. Considering the existing transformers are still young and the T1/T2 27.6kV yard was just rebuilt in 2014, the TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.8 Pleasant TS T1/T2

Pleasant TS has three DESNs. T1/T2 DESN (44kV) supplies loads from Alectra, Hydro One Distribution and Halton Hills Hydro. Combined load forecasts from the three LDCs suggest moderate LTR violation after 2027 as shown in Table 5. T1/T2 are Westinghouse 125MVA units built in 1975 and their LTRs are lower than today's standard (above 180MVA). The TWG recommends this issue is addressed by regular transformer end-of-life renewal with standard LTR specifications.

7.2.9 Pleasant T5/T6

Pleasant T5/T6 (27.6kV) supplies Alectra load only. The DESN is heavily loaded at present. Alectra's load forecast suggests steady annual growth rate near 5% throughout the assessment period and the DESN LTR will be exceeded as early as 2026. As another 27.6kV station adjacent to Pleasant, Jim Yarrow MTS (sec. 7.2.10) also forecasts its LTR will be exceeded during this NA timeframe, the TWG acknowledges that a new station might be one option and recommends that further regional coordination take place to address this need.

7.2.10 Jim Yarrow T1/T2

Jim Yarrow MTS is an Alectra-owned station built in 2004. The load at the MTS is forecasted to grow at approximately 4.4% annually and its LTR will be exceeded in 2030. Since adjacent Pleasant TS is also expected to reach full capacity in this assessment period, the TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.11 Goreway T5/T6

Goreway TS has two 27.6kV DESNs T1/T2, T5/T6 and one 44kV supply from T4, all supplying Alectra load. The forecasted demand at T5/T6 DESN will exceed LTR in 2026 and keep growing at approximately 4% per year. As Alectra forecasts additional new Brampton loads beyond Bramalea T1/T2 capacity, the TWG acknowledges that a new station in the area may be appropriate and recommends that further regional coordination takes place to address this need. In near term, available capacity from Goreway T1/T2 could be utilized to meet the load growth need in the area.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such

as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV Transmission line circuits in the Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, there is no new transmission line capacity need other than identified in the second cycle RIP [1].

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The system should also meet load security and load restoration criteria as defined in ORTAC [3]. Based on input from the IESO and LDCs, the following operational issues are identified:

- The new load forecast suggests T38B/T39B corridor will exceed load security limit of 600MW [3] in 2029. Table 6 shows load growth of all double-circuit corridors in the Region (assuming the new Halton TS #2 will still tap to T38B/T39B in 2030). The TWG recommends further regional coordination to address the T38B/T39B load security issue. All other double circuits corridors will not have more than 600MW net loads in the assessment window.

- All double-circuit corridor loads will exceed 250MW in this assessment timeframe. The ORTAC [3] requires the amount of load interruption in excess of 250MW must be restored within 30 minutes (and within 4 hours for load loss more than 150MW). The TWG surveyed transmission load interruption performance data from 2014 to 2024 for the Region. The results show that delivery points supplied by the circuits in Table 6 did not log load loss of more than 250MW for longer than 30 minutes, or loss of more than 150MW for longer than 4 hours in the 10 years. Based on past performance data, the TWG would not recommends capital investment for load restoration at this point. Hydro One shall proactively monitor load restoration data and identify opportunities to reduce risk of prolonged load restoration.

Table 6 Double-circuit Corridor Load

Circuits	Loads served by the double circuits (MW)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
T38B/T39B	444.8	492.1	558.6	570.3	588.3	**606.9**	676.2	688.6	703.7	721.2
T36B/T37B	231.6	236.1	241.2	247.5	299.1	283.0	294.5	304.8	314.7	327.6
R14T/R17T	449.9	459.0	466.2	474.7	483.9	483.7	484.2	486.4	491.8	502.7
R19TH/R21TH	456.5	463.2	470.1	476.3	487.4	505.6	510.1	515.4	520.1	526.0
H29/H30	395.0	411.0	431.6	444.1	450.2	454.6	459.2	464.8	471.7	479.3
B15C/B16C	220.1	224.0	230.1	235.8	242.7	249.6	257.9	268.6	277.7	282.1
V41H/V42H	371.7	378.2	383.7	393.8	405.7	421.8	436.9	459.0	482.8	496.6

- IESO reports high voltage at Trafalgar 230kV bus under light load conditions. Hydro One and IESO operation departments are coordinating to assess alternatives including Trafalgar TS Autotransformer tap changer position adjustment.

7.5 Transmission System Reinforcement Needs

Milton area transmission reinforcement:

In addition to the rapid organic load growth forecasted in T38B/T39B corridor, multiple proponents have requested to connect large-scale loads in Milton area, especially in proximity to Milton SS. Majority of the requests are large data centers with combined capacity exceeding 1000MW. It is not feasible for the existing 230kV transmission infrastructure in Milton area to accommodate such sizeable loads. Due to the scale and complexity of such connections, the TWG recommends further regional coordination to address the capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.

8. Sensitivity Analysis

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the GTA West region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The impact of sensitivity analysis for the high and low growth scenario is shown in Table 7. The additional capacity needs identified towards the end of the study period will be assessed again during the next phases of the Regional Planning cycle.

Table 7: Impact of Sensitivity Analysis on Capacity Needs in the Region

No.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Halton TS LTR	2026	2026	2029
2	Cardiff TS LTR	2030	2028	2032
3	Erinddale T1/T2 LTR	2030	2027	2032
4	Bramalea T1/T2 LTR	2031	2030	Beyond 2033
5	Bramalea T3/T4 LTR*	2024	2024	2024
6	Lorne Park LTR*	2031	2030	Beyond 2033
7	Cooksville T1/T2 LTR	2030	2030	Beyond 2033
8	Cooksville T3/T4 LTR	2030	2029	Beyond 2033
9	Pleasant T1/T2 LTR*	2027	2026	Beyond 2033
10	Pleasant T5/T6 LTR	2026	2025	2027
11	Jim Yarrow T1/T2 LTR	2030	2028	Beyond 2033
12	Goreway T5/T6 LTR	2026	2025	2027
Additional capacity needs under high growth scenario				
13	Meadowvale TS LTR	Beyond 2033	2029	
14	Palermo TS LTR	Beyond 2033	2029	
15	Tremaine TS LTR	Beyond 2033	2029	
16	Tomken T1/T2 LTR	Beyond 2033	2031	
* The need can be addressed by transformer renewal with standard rating specification				

9. Conclusion and Recommendation

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs not Requiring Further Regional Coordination

No.	Need	Recommendation
1	Bramalea T3/T4 DESN LTR violation	Replace T3/T4 with higher rating during transformer renewal. Balance T3/T4 load with Bramalea T5/T6 as interim solution.
2	Pleasant T1/T2 DESN moderate LTR violation	Replace T1/T2 with standard LTR.
3	Lorne Park T1/T2 DESN moderate LTR violation	Replace T2 with standard LTR.

Table 9: Needs Requiring Further Regional Coordination

No.	Need
1	Transmission reinforcement at Milton area to accommodate large load connection requests including data centers and manage load security
2	Accommodate Halton TS load growth beyond LTRs
3	Accommodate Mississauga 27.6 kV load growth beyond LTRs at Cardiff T1/T2, Bramalea T1/T2 and Erindale T1/T2
4	Accommodate Mississauga 27.6kV load growth beyond LTRs at Cooksville T1/T2 and T3/T4
5	Accommodate Brampton 27.6 kV load growth beyond LTRs at Pleasant T5/T6 and Jim Yarrow T1/T2
6	Accommodate Brampton 27.6kV load growth beyond LTRs at Goreway T5/T6 and Bramalea T1/T2

List of LDC(s) to be involved in further regional planning activities:

- Alectra Utilities Co.
- Milton Hydro Distribution Inc.
- Halton Hills Hydro Inc.
- Oakville Hydro Electricity Distribution Inc.
- Burlington Hydro Inc.
- Hydro One Networks Inc. (Distribution)

10. References

[1] Hydro One, RIP Report GTA West 2022 (hydroone.com) (issue February 23, 2022)

[2] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[3] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[4] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[5] Ontario Energy Board, Distribution System Code (issue July 14, 2000 rev. March 27, 2024)

[6] Independent Electricity System Operator, IRRP Report GTA West 2021.

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: GTA West Region – Non-coincident Normal Growth Net Load Forecast

Station	LTR (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea T1/T2	193	134.7	139.5	144.6	149.9	156.4	170.2	182.7	**193.1**	**193.1**	**193.1**
Bramalea T3/T4	111[1]	**113.6**	115.1	114.6	119.1	122.7	126.0	126.4	127.3	128.8	130.4
Bramalea T5/T6	169	103.4	103.4	105.0	107.7	111.4	114.9	118.5	118.9	119.8	122.7
Bramalea Total	473	351.8	358.0	364.2	376.7	390.6	411.0	427.6	439.4	441.6	446.2
Cardiff	113	109.3	110.8	111.6	111.9	113.3	113.2	**113.2**	**113.2**	**113.2**	**113.2**
Erindale T1/T2	180	166.6	169.2	174.4	180.0	179.8	179.2	**180.3**	**180.3**	**180.3**	**180.3**
Erindale T3/T4	190	156.8	163.0	164.6	166.3	167.3	166.9	166.7	167.3	169.3	181.0
Erindale T5/T6	194	132.9	134.8	135.7	136.2	137.8	139.2	140.6	142.7	145.3	147.9
Erindale Total	564	456.3	467.0	474.8	482.5	484.8	485.2	487.6	490.3	495.0	509.2
Churchill Meadows	168	99.8	101.1	101.9	102.2	103.4	104.9	106.1	107.9	110.0	112.2
Cooksville T1/T2	117	50.7	51.4	51.8	51.9	64.1	78.3	**117.0**	**117.0**	**117.0**	**117.0**
Cooksville T3/T4	117	40.2	40.8	41.1	51.2	67.9	87.4	**116.6**	**116.6**	**116.6**	**116.6**
Cooksville Total	234	90.9	92.2	92.9	103.1	132.0	165.6	233.6	233.7	233.6	233.7
New gross loads to be served in Mississauga								21	71	165	277
CTS-1	75	20.0	21.5	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Glenorchy MTS	153	115.9	120.7	125.5	131.9	138.0	116.8	120.0	126.2	133.3	140.0
Goreway T1/T2	180	74.4	77.3	80.7	84.3	88.4	92.1	96.3	100.8	105.9	111.4
Goreway T5/T6	181	177.6	181.9	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**
Goreway T4	73	26.9	27.0	27.2	27.3	27.6	27.7	27.9	28.3	28.8	29.3
Goreway Total	434	278.9	286.3	289.8	293.1	297.3	301.2	305.7	310.5	315.9	322.0
Halton TS	195	154.0	179.1	**195.2**	**195.2**	**195.1**	**195.1**	**195.1**	**195.1**	**195.1**	**195.1**
New Halton #2 (Gross)	187[2]	0	0	0	0	0	0	70.5	73.3	76.0	81.1
Halton Hills MTS	102	4.0	6.4	6.4	12.7	16.4	22.4	26.0	29.6	33.2	36.9
Jim Yarrow MTS	157	134.3	137.6	141.5	145.6	150.4	154.6	**157.0**	**157.0**	**157.0**	**157.0**
Lorne Park TS	144[1]	104.4	105.8	111.2	116.1	122.0	128.2	136.9	**146.1**	152.3	151.8
Meadowvale	188	125.1	127.5	140.3	141.2	154.5	166.3	170.3	173.8	178.7	182.6
Oakville	172	126.8	128.6	130.2	132.3	134.9	137.3	138.7	142.3	146.9	152.3
Palermo	187[3]	118.0	118.5	119.7	121.0	168.2	173.5	183.1	188.2	**191.8**	198.9
Pleasant T1/T2	155[1]	122.7	131.9	147.1	**156.3**	158.2	158.8	158.9	159.7	161.1	162.8
Pleasant T5/T6	187	181.8	186.2	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**
Pleasant T7/T8	183	108.0	111.3	115.2	119.3	124.0	128.2	133.1	138.4	144.5	151.1
Pleasant Total	525[4]	412.5	429.4	449.5	462.8	469.6	474.3	479.2	485.3	492.9	501.0
New gross loads to be served in Brampton		0	0	0	0	0	0	32	46	124	159
Tomken T1/T2	165	150.8	151.8	152.7	154.3	156.7	157.6	159.0	161.1	164.8	165.3
Tomken T3/T4	192	118.3	118.9	120.5	122.2	126.4	129.2	131.3	133.1	133.4	134.8
Tomken Total	357	269.2	270.6	273.1	276.5	283.2	286.8	290.3	294.2	298.2	300.1
Trafalgar DESN	123	88.7	90.4	92.1	94.5	96.9	99.1	99.7	101.6	103.7	105.9
Tremaine	185	113.4	132.4	157.0	159.7	160.9	162.1	163.9	166.4	170.2	174.9
Total		3166	3277	3392	3474	3624	3710	3917	4032	4229	4379
Note	1. Capacity can be increased by transformer renewal with higher LTR 2. Assumption based on typical station, final LTR will be determined after the station is built 3. Assumption for upsized transformers, final LTR will be determined after transformers are delivered 4. Presently limited to 419 MW by upstream transmission lines H29/H30										

Table A.2 GTA West Region – Coincident Normal Growth Net Load Forecast

Station	LTR (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea T1/T2	193	109.2	113.0	117.2	121.5	126.8	138.0	148.1	166.5	185.5	193.0
Bramalea T3/T4	111	94.2	95.4	95.0	98.8	101.7	104.4	104.8	105.6	106.8	108.1
Bramalea T5/T6	169	66.9	66.9	67.9	69.7	72.1	74.3	76.7	76.9	77.5	79.4
Bramalea Total	473	270.3	275.4	280.1	289.9	300.6	316.7	329.6	349.0	369.7	380.5
Cardiff	113	101.4	102.8	103.5	103.9	105.1	105.1	107.3	110.0	113.0	116.1
Erindale T1/T2	180	157.6	160.1	165.1	170.3	170.1	169.6	174.6	183.1	188.5	203.8
Erindale T3/T4	190	143.1	148.8	150.2	151.8	152.7	152.3	152.1	152.7	154.6	165.2
Erindale T5/T6	194	122.4	124.1	125.0	125.4	126.9	128.1	129.5	131.4	133.7	136.2
Erindale Total	564	423.2	433.0	440.3	447.5	449.6	450.0	456.2	467.2	476.8	505.2
Churchill Meadows	168	98.5	99.8	100.5	100.8	102.1	103.5	104.7	106.5	108.6	110.7
Cooksville T1/T2	117	47.5	48.2	48.5	48.7	60.1	73.4	116.2	143.0	160.7	192.1
Cooksville T3/T4	117	39.5	40.0	40.3	50.2	66.6	85.8	128.0	147.5	165.5	199.2
Cooksville Total	234	87.0	88.2	88.9	98.9	126.7	159.2	244.2	290.5	326.2	391.3
CTS-1	75	20.0	21.5	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Glenorchy MTS	153	114.6	118.5	122.6	127.6	132.3	111.0	112.9	118.2	124.4	130.3
Goreway T1/T2	180	70.1	72.9	76.1	79.5	83.4	86.8	90.8	95.0	99.8	105.1
Goreway T5/T6	181	176.2	180.5	185.7	191.0	197.3	202.8	209.3	216.4	224.8	233.9
Goreway T4	73	23.0	23.1	23.2	23.3	23.5	23.7	23.9	24.2	24.6	25.0
Goreway Total	434	269.3	276.5	285.0	293.8	304.2	313.3	324.0	335.6	349.2	363.9
Halton TS & #2	195	141.6	164.6	195.3	195.3	195.3	195.3	255.7	257.8	259.8	264.0
Halton Hills MTS	102	4.0	6.3	6.3	12.2	15.7	21.3	24.4	27.7	31.0	34.3
Jim Yarrow MTS	157	128.6	131.7	135.5	139.4	143.9	148.0	152.7	157.9	164.0	170.6
Lorne Park TS	144	85.9	87.1	91.5	95.6	100.4	105.5	112.7	120.2	125.3	124.9
Meadowvale	188	103.3	105.2	115.7	116.5	127.5	137.2	140.5	143.4	147.4	150.6
Oakville	172	114.4	116.0	117.4	119.4	121.7	123.8	125.1	128.4	132.5	137.4
Palermo	187	117.0	117.5	118.7	119.9	166.7	172.0	181.5	186.6	190.2	197.2
Pleasant T1/T2	155	115.6	124.2	138.5	147.2	149.0	149.5	149.6	150.4	151.7	153.3
Pleasant T5/T6	187	180.1	184.5	189.8	195.3	201.7	207.3	214.0	221.3	229.8	239.1
Pleasant T7/T8	183	99.3	102.3	105.9	109.6	114.0	117.9	122.4	127.2	132.8	138.8
Pleasant Total	525	395.0	411.0	434.2	452.1	464.7	474.7	486.0	498.9	514.3	531.3
Tomken T1/T2	165	149.1	150.1	150.9	152.6	155.0	155.8	157.2	159.3	162.9	163.5
Tomken T3/T4	192	107.2	107.7	109.1	110.7	114.5	117.0	118.9	120.5	120.8	122.1
Tomken Total	357	256.3	257.7	260.0	263.2	269.5	272.8	276.1	279.8	283.8	285.6
Trafalgar DESN	123	86.8	88.4	90.1	92.5	94.8	97.0	97.6	99.4	101.5	103.7
Tremaine	185	109.3	127.5	151.2	153.8	155.0	156.1	157.9	160.3	163.9	168.5
Total		2926	3029	3159	3244	3398	3484	3711	3859	4004	4188

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station		Voltage (kV)	Supply Circuits
1	Bramalea TS (Alectra)	T1/T2	230/27.6	V41H/V42H
		T3/T4	230/44	
		T5/T6	230/44	
2	Cardiff TS (Alectra)	T1/T2	230/27.6	V41H/V42H
3	Churchill Meadows TS (Alectra)	T1/T2	230/44	R19TH / R21TH
4	Cooksville TS (Alectra)	T1/T2	230/27.6	B16C/K21C
		T3/T4	230/27.6	
5	Erindale TS (Alectra)	T1/T2	230/27.6	R14T / R17T
		T3/T4	230/44	
		T5/T6	230/44	R19TH / R21TH
6	CTS-1	T1/T2	230/27.6	B15C / B16C
7	Glenorchy MTS (Oakville Hydro)	T1/T2	230/27.6	T36B / T37B
8	Goreway TS (Alectra)	T1/T2	230/27.6	V42H / V43
		T5/T6	230/27.6	
		T4	230/44	V43
9	Jim Yarrow MTS (Alectra)	T1/T2	230/27.6	R19TH / R21TH
10	Halton Hills MTS (Halton Hills Hydro)	T4/T5	230/27.6	T38B/T39B
11	Halton TS (Milton Hydro, Halton Hills Hydro)	T3/T4	230/27.6	T38B/T39B
12	Lorne Park TS (Alectra)	T1/T2	230/27.6	B15C / B16C
13	Meadowvale TS (Alectra)	T1/T2	230/44	T38B / T39B
14	Oakville TS (Alectra, Oakville Hydro)	T5/T6	230/27.6	B15C / B16C
15	Palermo TS (Oakville Hydro, Milton Hydro, Burlington Hydro)	T3/T4	230/27.6	T36B / T37B
16	Pleasant TS (Alectra, HONI, Halton Hills Hydro)	T1/T2	230/44	H29 / H30
		T5/T6	230/27.6	
		T7/T8	230/27.6	
17	Tomken TS (Alectra)	T1/T2	230/44	R14T/R17T
		T3/T4	230/44	R19TH/R21TH
18	Trafalgar DESN (Oakville Hydro)	T1/T2	230/27.6	T38B/T39B
19	Tremaine TS (Milton Hydro, Burlington Hydro)	T1/T2	230/27.6	T38B/T39B

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	**Hurontario SS***, Pleasant TS	H29/H30	230
2	**Richview TS*, Trafalgar TS*,** Tomken TS, Erindale TS	R14T/R17T	230
3	**Richview TS*, Trafalgar TS*, Hurontario SS*,** Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, Tomken TS	R19TH/R21TH	230
4	**Trafalgar TS*, Burlington TS*,** Palermo TS, Glenorchy MTS,	T36B/T37B	230
5	**Trafalgar TS*, Burlington TS*,** Tremaine TS, Trafalgar DESN, Meadowvale TD, Halton TS, **TCE Halton Hills CGS***, Halton Hills MTS	T38B/ T39B	230
6	**Claireville TS* Hurontario SS***, Cardiff TS, Bramalea TS, **Sithe Goreway CGS*,** Goreway TS	V41H/V42H	230
7	**Cooksville TS*,** Lorne Park TS, CTS-1, Oakville TS	B15C/B16C	230
8	**Manby TS*, Cooksville TS***	K21C/K23C	230
9	**Claireville TS*,** Goreway TS	V43	230
10	**Richview TS*, Cooksville TS***	R24C	230
*: terminal stations, others are stations tapped to the circuits			

Appendix D: List of LDC's

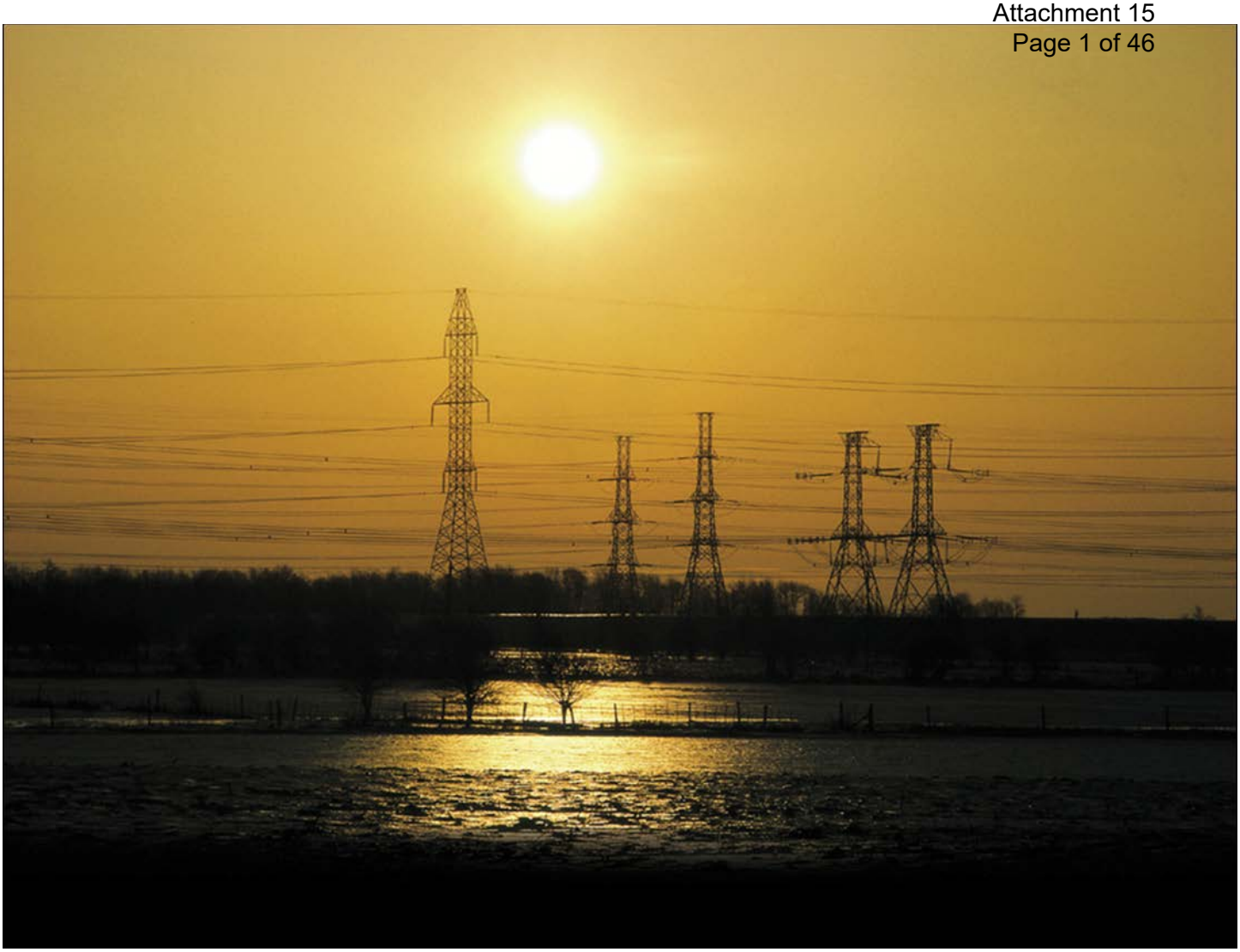
No.	Name of LDC
1	Alectra Utilities Co.
2	Burlington Hydro Inc.
3	Halton Hills Hydro Inc.
4	Milton Hydro Distribution Inc.
5	Oakville Hydro Electricity Distribution Inc.
6	Hydro One Networks Inc. (Distribution)

Appendix E: List of Municipalities in the region

No.	Name of Municipality
1	Brampton
2	Burlington
3	Caledon
4	Halton Hills
5	Milton
6	Mississauga
7	Oakville

Appendix F: Acronyms

Acronym	Description
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
KOP	Key Operating Point
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LP	Local Plan
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
MVGIS	Medium Voltage Gas Insulated Switchgear
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SS	Switching Station
TS	Transformer Station



Kitchener-Waterloo-Cambridge-Guelph Regional Infrastructure Plan

December 10, 2021

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Prepared and supported by:

Company
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Alectra Utilities Corporation
Centre Wellington Hydro Ltd.
Energy+ Inc.
Halton Hills Hydro Inc.
Hydro One Networks Inc. (Distribution)
Kitchener-Wilmot Hydro Inc.
Milton Hydro Distribution Inc.
Waterloo North Hydro Inc.
Wellington North Power Inc.

Disclaimer

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

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

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Executive Summary

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

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

- Alectra Utilities Corporation ("Alectra")
- Centre Wellington Hydro Ltd. ("CWH")
- Energy + Inc. ("Energy+")
- Halton Hills Hydro Inc. ("HHH")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Kitchener Wilmot Hydro Inc.("KWH")
- Milton Hydro Distribution Inc. ("MHD")
- Waterloo North Hydro Inc. ("WNH")
- Wellington North Power Inc. ("WNP")

In the first cycle of the Regional Planning (RP) process for the KWCG Region, an Integrated Regional Resource Plan ("IRRP") was published in April 2015. The first cycle of RP process was completed in December 2015 [1] with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous IRRP and RIP reports as well as new replacement/ refurbishment needs identified in the KWCG Region, the 2nd Regional Planning cycle was triggered for the KWCG region in Q4 2018.

This RIP is the final phase of the second cycle of Kitchener Waterloo Cambridge Guelph (KWCG) regional planning process, which follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") in April 2021 [2][3] and the KWCG Region Needs Assessment ("NA") in December 2018 [4]. This RIP provides a consolidated summary of the needs and recommended plans for KWCG Region over the planning horizon (1 – 20 years) based on available information.

It discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway.

The following needs identified in the first regional planning cycle have been addressed:

Needs	Needs Details
115kV System Supply Capacity	GATR Project Two new 230/115kV autotransformers at Cedar TS to reinforce supply to both 115kV sub-systems in the region.
230kV Load Restoration Needs	GATR Project Two new 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system.
	Galt Junction Two new 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system.
Station Short Circuit Capacity	Arlen MTS Install 13.8 kV series reactors to mitigate LV bus short circuit levels.

Other projects completed in the region since the completion of first regional planning cycle are listed below:

Stations Refurbishment Project	
Campbell TS	Transformers T1 and T2 Replacement
Detweiler TS	AC Station Service and Component Replacement
Detweiler TS	230 /115 kV Auto Transformers T2 and T4 Replacement
D7F / D9F	115 kV Tower Refurbishment – Tower 157 near Freeport SS
D6V / D7V	230 kV Lines Refurbishment between Fergus TS and Campbell TS

The major infrastructure investments recommended for the KWCG Region over the near and mid-term planning horizon are provided in the Table 1 below, are all end of life needs along with their planned in-service date and budgetary estimates for planning purpose.

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

Stations / Lines Project	Details	Timeframe	High Level Cost ($M)[1]
Hanlon TS	Transformers T1 and T2 Replacement	2022-2023	17.8
Kitchener MTS #5	Transformers T9 and T10 Replacement	2023-2024	7.5
Scheifele MTS	Transformers T1 and T2 Replacement	2025-2026	-
B5C/B6C	115KV Lines Refurbishment, refurbishing section from Burlington TS to a CTS	2025-2026	16.8
Preston TS	Transformers T3 and T4 Replacement	2026-2027	22.9
Cedar TS	Transformers T7 and T8 Replacement	2026-2027	23.7
Fergus TS	Transformers T3 and T4 Replacement	2028-2029	30.0
Galt TS	Breakers and Component Replacement	2028-2029	12.0
Campbell TS	Breakers and Component Replacement	2028-2029	18.1

The Study Team recommends that:

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

[1] Budgetary estimates

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1. Introduction

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE KITCHENER WATERLOO CAMBRIDGE GUELPH (KWCG) REGION BETWEEN 2021 AND 2041.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Hydro One, Alectra Utilities ("Alectra"), Centre Wellington Hydro Ltd., Energy+ Inc., Halton Hills Hydro Inc., Hydro One Networks Inc. (Distribution), the Independent Electricity System Operator ("IESO"), Kitchener-Wilmot Hydro Inc., Milton Hydro Distribution Inc., Waterloo North Hydro Inc. and Wellington North Power Inc., in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013 [5].

The Kitchener, Waterloo, Cambridge and Guelph (KWCG) region is located to the west of the Greater Toronto area in southwestern Ontario. The KWCG Region includes the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The approximate boundaries of the KWCG Region are shown below in Figure 1-1.

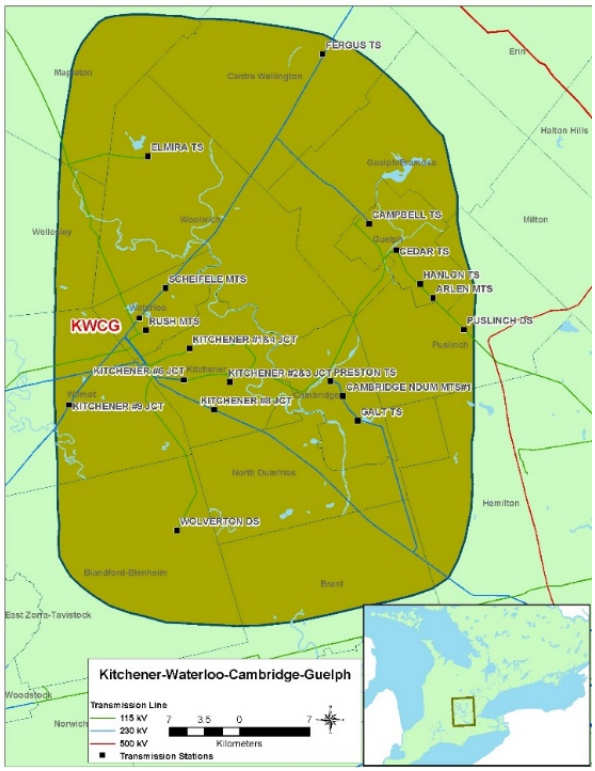


FIGURE 1-1: KWCG REGION MAP

1.1. Objectives and Scope

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

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2. Structure

The rest of the report is organized as follows:

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

2. Regional Planning Process

2.1. Overview

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

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

2.2. Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[2] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[2] Also referred to as Needs Screening

The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

The RIP phase is the fourth and final phase of the regional planning process and involves discussion of previously identified needs and plans, identification of any new needs that may have emerged since the start of the planning cycle, and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

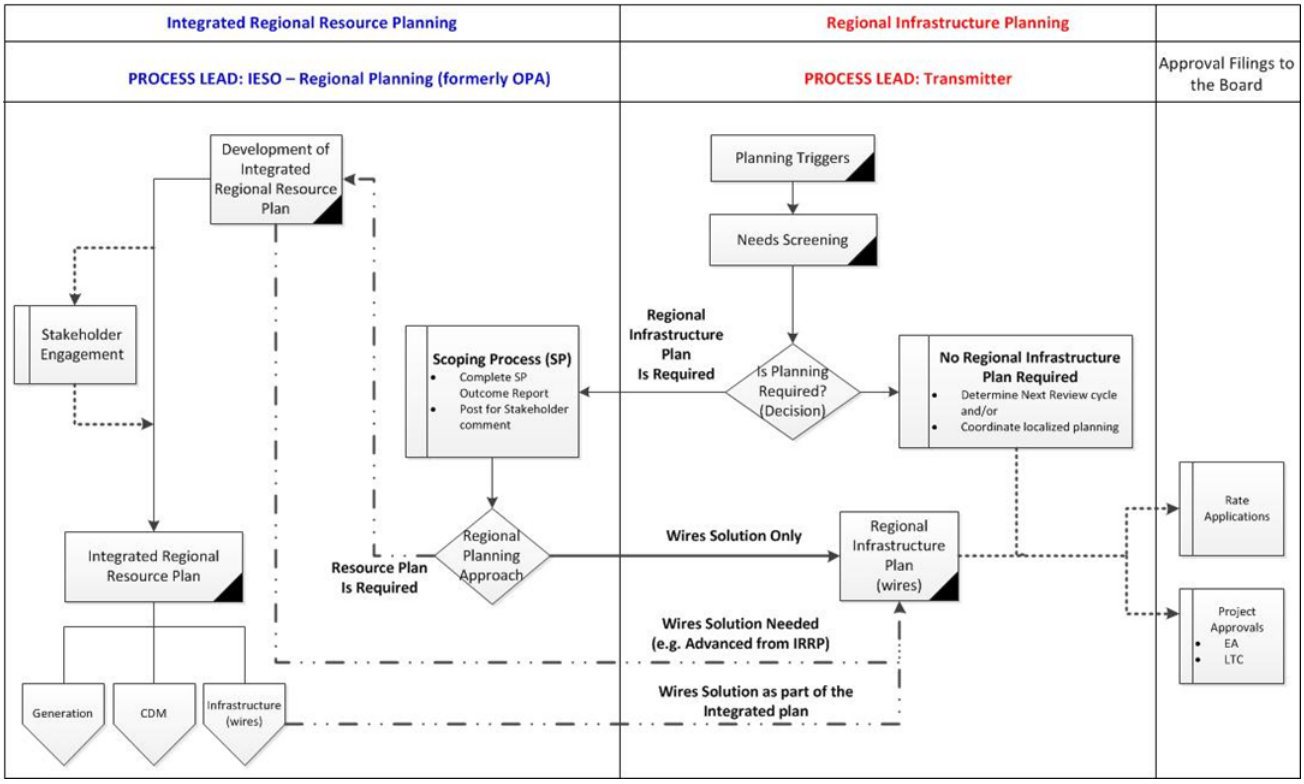


FIGURE 2-2: REGIONAL PLANNING PROCESS FLOWCHART

2.3. RIP Methodology

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

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

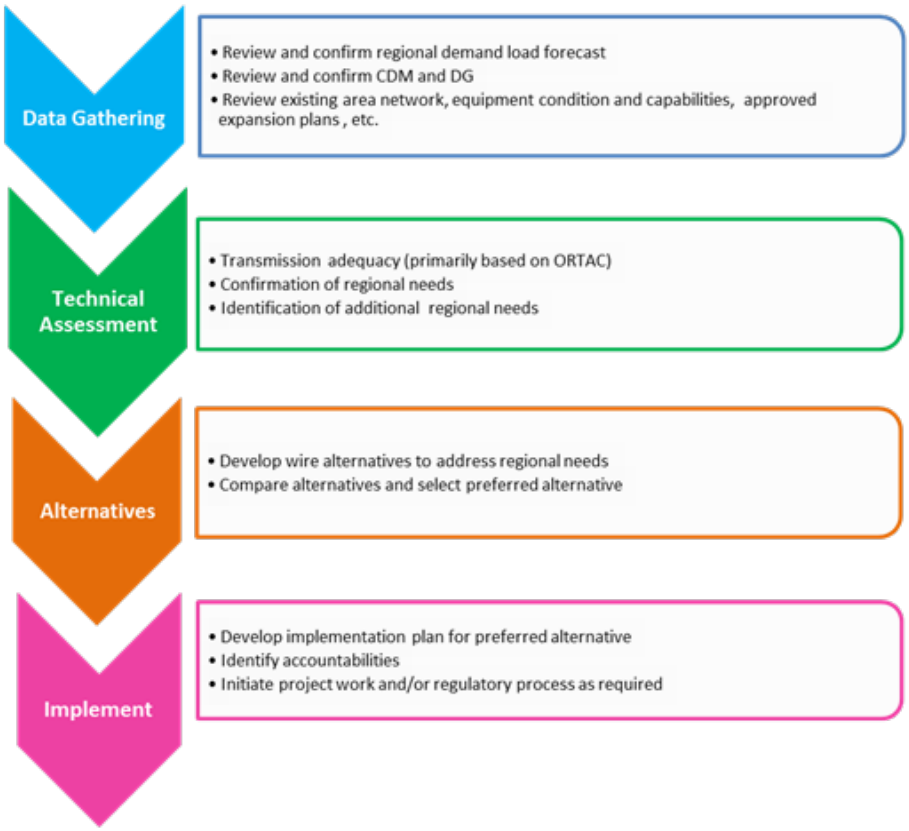


FIGURE 2-3: RIP METHODOLOGY

3. Regional Characteristics

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One transformer stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. Electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively, at these stations. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by twenty-four (24) step-down transformer stations.

A single line diagram showing the electrical facilities of the KWCG Region is provided in Figure 3-1, which illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system.

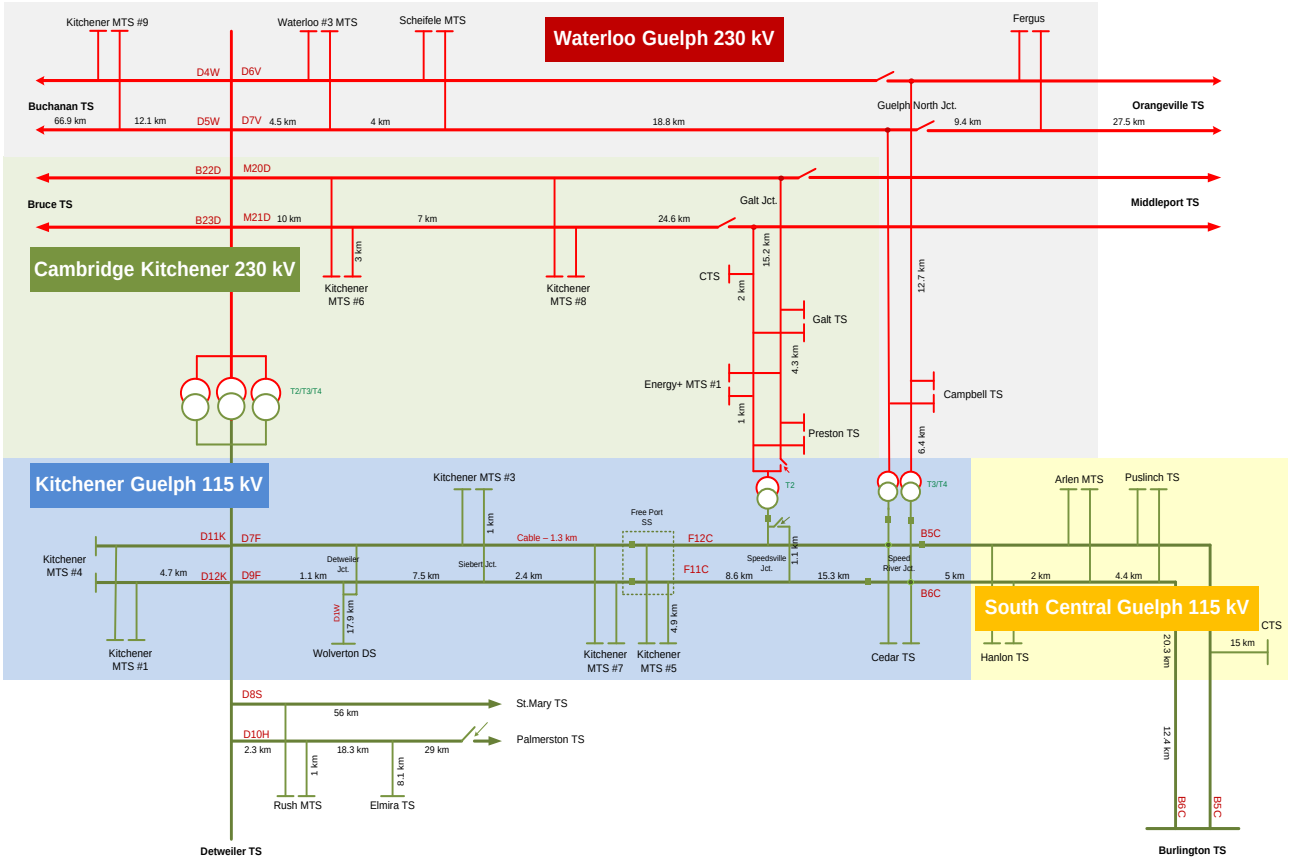


FIGURE 3-4: SINGLE LINE DIAGRAM OF THE KWCG REGION'S TRANSMISSION NETWORK

The twenty-four (24) KWCG's transformer stations can be grouped into six electrical (four major) zones based on their HV supply network:

1. **Waterloo-Guelph 230 kV Area:** The transformer stations in this area are supplied by Detweiler TS 230kV. This area includes transformer stations connected to the 230 kV circuits between Detweiler TS and Orangeville TS D6V/D7V, serving customers in the KWCG area. Below are the transformer stations in Waterloo-Guelph 230 kV area.
    - Campbell TS
    - Fergus TS
    - Scheifele MTS
    - Waterloo North MTS# 3

2. **Cambridge-Kitchener 230 kV Area:** The transformer stations in this area are supplied by Detweiler TS 230kV. This area includes transformer stations connected to the 230 kV circuits between Detweiler TS and Middleport TS M20D/M21D, serving customers in the KWCG area. Below are the transformer stations in Cambridge-Kitchener 230 kV area.
    - Energy + MTS# 1
    - Galt TS
    - Preston TS
    - Kitchener MTS# 6
    - Kitchener MTS# 8
    - CTS# 1

3. **Kitchener-Buchanan 230 kV Area:** The transformer stations in this area are supplied by Detweiler TS 230kV. This area includes transformer stations connected to the 230 kV circuits between Detweiler TS and Buchanan TS. This area has only one transformer station.
    - Kitchener MTS# 9.

4. **Kitchener-Elmira 115 kV Area:** This area covers the north-western part of the KWCG area which is supplied by the Detweiler TS 230/115 kV autotransformers. The transformer stations in this area are:
    - Elmira TS
    - Rush MTS

5. **Kitchener-Guelph 115 kV Area:** This area covers the Kitchener area and northern Guelph area, which is supplied by the Detweiler TS 230/115 kV autotransformers. The transformer stations in this area are:
    - Cedar TS
    - Kitchener MTS# 1
    - Kitchener MTS# 3
    - Wolverton DS
    - Kitchener MTS# 4
    - Kitchener MTS# 5

- Kitchener MTS# 7

6. **South-Central Guelph 115 kV Area:** This area covers the southern part of Guelph, which is supplied by the Burlington TS 230/115 kV autotransformers. The transformer stations in this area are:
    - Arlen MTS
    - Puslinch DS
    - Hanlon TS
    - CTS# 2

4. Transmission Facilities/ Projects Completed and/or Underway Over the Last Ten Years

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

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below. These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For distribution voltage level transformation capacity needs:

- Arlen MTS connected in 2011

For reactive and voltage support needs:

- 230 kV SVC (+350 MVAr @ 250 kV) installed at Detweiler TS in 2011[3]
- 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For 230 kV transmission circuit capacity needs:

- 230 kV M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For 115 kV transmission circuit capacity and 230 kV load restoration needs:

- Guelph Area Transmission Reinforcement (GATR) project in 2016 that includes:
  - extension the 230kV circuits D6V/D7V to Cedar TS;
  - two new 250 MVA, 230/115kV autotransformers at Cedar TS;
  - And two 230 kV in-line switches at Guelph North Junction on circuits D6V/D7V.

  This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system.

- Two new additional 230kV in-line switches on M20D/M21D circuits installed at Galt Junction in 2017 to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system

For station short circuit capacity needs:

[3] Two SVCs were installed for the contingency support in the South-western Ontario

- 13.8 kV series reactors were installed to mitigate short circuit levels at Arlen MTS. This project was identified in the last RIP phase.

For end of life needs addressed:

- Galt TS T7 and T8 Transformers Replacement
- Campbell TS T1 and T2 Transformers Replacement
- Detweiler TS AC Station Service and Component Replacement
- D7F / D9F 115 kV Tower Refurbishment, Tower 157 near Freeport SS
- D6V / D7V 230 kV Lines Refurbishment between Fergus TS and Campbell TS
- Detweiler TS 250 MVA 230/115 kV T2 and T4 autotransformers replaced

5. Load Forecast and Study Assumptions

5.1. Load Forecast

The electricity demand in the KWCG Region is anticipated to grow by about 10% over the next ten years. Figure 5-1 shows the KWCG Region's planning load forecast (summer net, coincident extreme weather corrected peak) developed during this RIP phase.

This RIP load forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity.

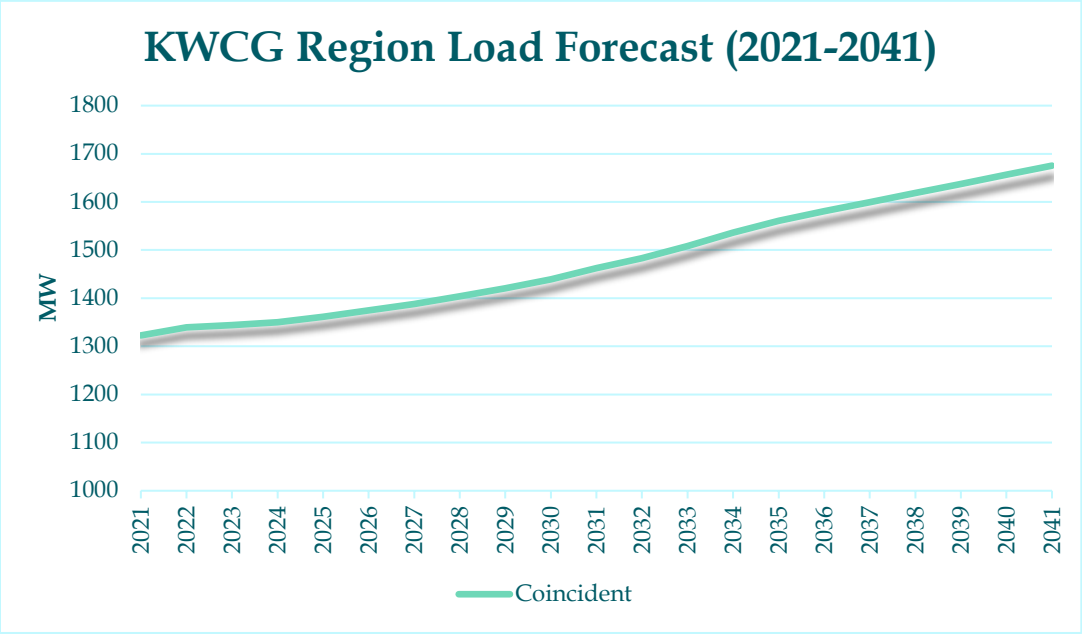


FIGURE 5-5: KWCG REGION LOAD FORECAST

The regional-coincident load forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. The Region's peak summer load is forecasted to increase from 1323 MW in 2021 to 1462 MW by 2031.

The load forecast for KWCG RIP is provided in Appendix D. This load forecast is based upon the 2020 actual loads and the load forecast prepared by the IESO for the recently completed IRRP. The NA and the IRRP used the 2018 actual loads as the base. More than two years have passed since then and though 2020 seems to be unusual year in light of the COVID-19 pandemic; with all the applicable adjustments and the comparisons with 2018, 2019 and 2021 actual loads, it made sense to base the load forecast on 2020 actual station loads.

This approach was reviewed and accepted by the Study Team during the RIP phase. During the data gathering, some LDCs provided a revised load forecast while the other confirmed no changes to their load forecasts provided earlier to the IESO for the IRRP during the current

Regional Planning cycle. The IESO also updated the CDM and DG targets for the preparation of this RIP load forecast. The load forecast for this RIP was prepared by adjusting the actual 2020 summer peak loads applying an extreme weather correction factor and then applying growth rates derived from the LDCs' forecast. This forecast was further adjusted taking into account the impact of CDM and DGs provided by the IESO. Further details regarding the CDM and connected DG are provided in reference [2] [3]. The load forecast prepared for this RIP is slightly lower than the one prepared by the IESO for the purpose of IRRP but is in the same order of magnitude. The change in the load forecast due to the factors listed above has resulted in the shifting or elimination of previously identified needs, along with the emergence of new needs close to the end of the study period.

5.2. Study Assumptions

The following assumptions are made in this report.

- The study period for the RIP assessments is 2021-2041.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC) [6].

6. Adequacy of Existing Facilities

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE KWCG REGION OVER THE PLANNING PERIOD (2021-2041).

During this regional planning cycle three (3) separate assessments have been completed for the KWCG Region. The findings of these studies are the inputs to this Regional Infrastructure Plan (RIP). These assessments are:

- 2018 KWCG Region Needs Assessment ("NA") Report
- 2019 KWCG Region Scoping Assessment ("SA") Report
- 2021 KWCG Integrated Regional Resource Plan ("IRRP") Report

The NA and IRRP reports identified a number of needs to meet the forecasted load demands and assets approaching end of life (EOL). This section provides a review of the adequacy of the transmission lines and stations in the KWCG Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D from a loading perspective. Sections 6.1 to 6.6 present the results of this review. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report.

6.1. 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (please refer to Figure 3-1):

a) Detweiler TS to Orangeville TS 230 kV circuits D6V and D7V
   - supplies Fergus TS, Campbell TS, Waterloo North MTS# 3 and Scheifele MTS

b) Detweiler TS to Middleport TS 230 kV circuits M20D and M21D
   - supplies Kitchener MTS# 6, Kitchener MTS# 8, Energy + MTS# 1, Galt TS, Preston TS and Customer # 1 CTS

c) Detweiler TS to Buchanan TS 230 kV circuits D4W and D5W
   - supplies Kitchener MTS# 9

The RIP review of the current load forecast shows that based on the forecasted station loadings, all the above three (3) 230 kV transmission lines are expected to be adequate over the study period.

6.2. 230/115 kV Autotransformer Facilities

Bulk power supply to the KWCG Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

a) Two 500/230 kV autotransformers at Middleport TS
b) Four 230/115 kV autotransformers at Burlington TS
c) Three 230/115 kV autotransformers at Detweiler TS
d) Two 230/115 kV autotransformers at Cedar TS
e) One 230/115 kV autotransformer at Preston TS

Middleport autotransformers are part of the south-western Ontario bulk supply system and will be studied separately under Middleport bulk planning studies for a more comprehensive understanding of the bulk system needs. However for the purpose of KWCG regional planning needs, these auto-transformer facilities are adequate over the study period.

Burlington TS autotransformers supply the South-Central Guelph 115 area that in turn supply Arlen MTS, Hanlon TS, Customer# 2 CTS and Puslinch DS. The Burlington TS autotransformer facilities are adequate over the study period.

Detweiler TS, Preston TS and Cedar TS autotransformers supply the Kitchener-Guelph 115 kV area that in turn supply Cedar TS, Kitchener MTS #1, Kitchener MTS #3, Kitchener MTS #4, Kitchener MTS #5, Kitchener MTS #7, Elmira TS, Rush MTS and Wolverton DS. The transformation facilities are adequate over the study period.

Note that the Preston TS autotransformer and the 115 kV Kitchener Guelph supply system may not have adequate supply capacity due to its inherent limitation of 115 kV supply system to address the load restoration concerns beyond the study period in case of the simultaneous loss of both the 230 kV circuits, M20D and M21D.

6.3. 115 kV Transmission Facilities

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. The 115 kV transmission facilities can be divided into five main corridors summarized below.

a) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F
    - supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
b) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C
    - supplies Kitchener MTS #5 and Cedar T1/T2 transformers
c) Burlington TS to Cedar TS 115 kV transmission circuits B5C/B6C
    - supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
d) Detweiler TS 115 kV radial transmission circuit D11K/ D12K

- supplies Kitchener MTS #1 and Kitchener MTS #4

e) Detweiler TS to Seaforth TS / Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points

- supplies Rush MTS and Elmira TS (D10H only)

In the near and mid-term, all the 115 kV circuits are adequate and no supply capacity needs are identified under loss of one element. A marginal overloading was identified during the IRRP phase on B5C under the outage scenario of B6C and a subsequent loss of F12C. This marginal overloading can be managed by coordinated outage planning.

In the long term, near the end of the study period, the section of 115 kV D10H circuit between Detweiler TS and tap to Rush MTS may slightly be overloaded following the loss of companion D8S circuit under a peak load scenario. This is a need in the long term and will be revisited in the next planning cycle.

6.4. Step-Down Transformer Station Facilities

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected customer transformer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

The stations summer peak non-coincident load forecast is given in Table D-1 of Appendix D.

TABLE 6-1: KWCG STEP-DOWN EXISTING TRANSFORMER STATIONS

230 kV		115 kV	
Campbell TS	Preston TS	Arlen MTS	Kitchener MTS #5
Energy + MTS # 1	Scheifele MTS	Cedar TS	Kitchener MTS #7
Fergus TS	Waterloo North MTS# 3	Elmira TS	Puslinch DS
Galt TS	CTS# 1	Hanlon TS	Rush MTS
Kitchener MTS # 6		Kitchener MTS# 1	Wolverton DS
Kitchener MTS # 8		Kitchener MTS# 3	CTS # 2
Kitchener MTS # 9		Kitchener MTS # 4	

As a part of RIP assessment, the step-down transformation station capacity was reviewed considering the non-coincident load forecast. Accordingly, the following step down transformation capacity needs are identified. The need timeframe defines the time when the peak load forecast first approaches the station's summer 10 day LTR:

TABLE 6-2: KWCG STEP-DOWN TRANSFORMER STATIONS SUPPLY CAPACITY NEEDS

Stations	Need Timeframe
Kitchener MTS # 5	2028
Cedar TS (T7/T8)	2030
Kitchener MTS # 8 T15/T16	2033
Energy + MTS # 1	2036
Campbell TS (T1/T2)	2038
Preston TS	2038
Arlen MTS	2040
Scheifele MTS	2041
Elmira TS	2041
Waterloo North MTS # 3	2041

6.5. System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

After the in-service of the Guelph Area Transmission Reinforcement project that included the installation of two new 230/115kV autotransformers at Cedar TS, two new 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system and two new 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system; it is expected that all loads can be restored within 8 hours in the KWCG Region over the study period.

A simultaneous loss of M20D and M21D will result in the loss of up to 375 MW of load, by 2041, in the Cambridge area. Up to 150 MW of this load must be restored within 30 minutes as required by ORTAC. This is within the capability of the system and, so, no load restoration concern has been identified in this RIP. However, the Study Team agrees to monitor the load in the region for any new developments to ascertain that load restoration concern are identified ahead of time. Note that the Preston TS autotransformer and the 115 kV Kitchener Guelph supply system may not be adequate due to its inherent limitations to address the load restoration concerns beyond the study period in case of the simultaneous loss of both 230 kV circuits, M20D/M21D.

6.6. Station Short Circuit Capacities [2][3]

The regional planning process identified a need to examine short circuit levels at all the stations in the region as they pertain to LDC equipment ratings as well as to generation or storage resources connection challenges. The particular concerns raised at the time of initiation of this second cycle of the regional planning for the region have since been satisfactorily resolved. However, the Study Team recognizes the importance of a holistic system planning approach, which includes analysis related to short circuit levels.

Distribution system short circuit levels, as measured at the low-voltage (LV) bus of transmission connected transformer stations, are subject to change due to two main driving factors: changes in upstream impedance and changes in amount and type of DERs connected to the station. Changes in upstream impedance typically result from transmission system changes, such as network expansion or reconfiguration or changes in transformer impedance at the time of transformer replacement.

The upstream impedance generally has minimal impact on the station LV actual short circuit level because of the dominant effect of the station transformers impedance. However, changes in the amount and type of DERs connected to a LV bus of a station, unlike changes in upstream impedance, have a significant and direct impact on the station's LV short circuit level.

While equipment which limits the available short circuit capacity on the LV side of a transformer station may have options to be upgraded with higher rated equipment, the Study Team is cognizant that there is an effective practical limit to this rating established by in Appendix 2 of the Transmission System Code. Distribution systems components, including equipment owned by end-use customers, in Ontario, is designed, manufactured, and applied to this standard, which effectively is:

- 500 MVA @ 13.8 kV
- 800 MVA @ 27.6 kV
- 1500 MVA @ 44 kV

The amount of DER that can be connected to a station LV bus is thus limited by the above-mentioned short circuit level requirements. Some stations may have a smaller value due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered. Hence, in examining the rated short circuit capacity of LV station components, the Study Team used lowest equipment rating, or TSC rating, whichever is lower in identifying stations that are at or approaching short circuit capacity limits.

Appendix E lists all stations in the KWCG region where new DER connection is restricted due to the LV short circuit level being extremely high, that is approximately equal to or greater than 90% of the equipment ratings or the TSC ratings capacity. The information presented in this table is obtained with consideration of known generation connections as of March 2021 and is subject to change primarily due to new DER connections.

The appropriate LDC should be consulted for up-to-date short circuit information and feasibility of connecting new DER.

6.7. Longer Term Outlook

While the RIP was focused on the 2021-2041 period, the Study Team has also looked at longer-term electricity sector scenarios and uncertain load growth possibilities within the study period under certain pockets within the KWCG region. Following two subsections describes two such items that requires longer-term insight for the regional needs.

6.7.1. Other Planning Considerations in the KWCG Region

Municipalities in KWCG region have developed their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities are planning for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local battery storage systems to reduce cost and for improved reliability of electricity supply. The implementation timelines, as suggested in these plans, starts in longer term just near the end of the study period and requires greater attention in the next regional planning cycle.

Note that community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends reviewing the community energy plans in the next regional planning cycle.

There are situations where behind the meter battery storage cannot be connected due to technical constraints. The LDCs in this region and Hydro One, outside the regional planning forum, can undertake the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

In parallel and within the Conservation and Demand Management initiatives, communities are also working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community.

6.7.2. Uncertain Load Growths

There are some load growth possibilities in pockets of the region where, due to lack of confirmed status of development projects or uncertainty with connection point, were not included in the load forecast. These load growth triggers will be closely monitored and reviewed for further analysis in the next regional planning cycle:

- Metrolinx electrification project: Metrolinx is electrifying its rail lines and planning a traction power substation (TPSS). The amount of traction load is insignificant but has a very sensitive and peculiar characteristics that makes it troublesome for other customers in a weaker system. The connection point of TPSS is not yet finalized and therefore has a higher uncertainty.
- East Side Lands: Energy + is expecting load growth in its east side lands and are planning Energy + MTS # 2 to meet the increased load demand which has not materialized yet. Similarly, Waterloo North Hydro is also anticipating load growth in

the east side lands near Scheifele TS and are planning WNH MTS # 4 to cater the new load growth and some existing loads currently supplied from Scheifele TS. In addition, Hydro One is carrying out end of life like for like replacement of transformers at Preston TS in the 2026-2027 timeframe that will impart additional supply capacity to the station due to the alleviation of an inherent equipment limitation. This incremental capacity to be available in 2026 at Preston TS would be examined to determine if it is technically and economically feasible, meeting power quality requirements, to service both Energy+ and Waterloo North Hydro's East Side Lands development and surrounding areas under normal and/or contingency situations. These needs along with increased station capacity, therefore, will be revisited in the next regional planning cycle for optimal solution, hoping to have more clarity on the development projects in the pocket by then.

- Development of other projects such as Data Centers and Light Rail Transit from Kitchener to Cambridge will be monitored and assessed in the next regional planning cycle.

7. Regional Needs and Plans

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE KWCG REGION IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE, SCOPING ASSESSMENT AND THE IRRP; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid-to long-term (beyond 5 years) planning horizon. This includes long-term needs associated with sustainment plans and the supply capacity needs. The long term needs will be assessed in the next regional planning cycle.

The near-term and mid to long-term electrical infrastructure needs in the Region are summarized below in Table 7.1 and Table 7.2, respectively. The details of the project / plan are discussed further in sections 7.1 and 7.2.

TABLE 7-3: IDENTIFIED NEAR AND MID-TERM NEEDS IN KWCG REGION

No.	Needs	Project / Need Timeframe	Section
1	Hanlon TS: EOL T1/T2 Supply Transformers Replacement	2022-2023	7.2
2	Kitchener MTS #5: EOL T9/T10 Supply Transformers Replacement	2023-2024	7.2
3	Scheifele MTS: EOL T1/T2 Supply Transformers Replacement	2025-2026	7.3
4	115 kV B5C/ B6C**:** EOL Burlington TS to Westover CTS Line Sections Refurbishment	2025-2026	7.2
5	Preston TS: EOL T3/T4 Supply Transformers Replacement	2026-2027	7.3
6	Cedar TS: EOL T7/T8 Supply Transformers Replacement	2026-2027	7.3

TABLE 7-4: IDENTIFIED LONG-TERM NEEDS IN KWCG REGION

No.	Needs	Timing	Section
1	Fergus TS: EOL T3/T4 Supply Transformers Replacement	2028-2029	7.3
2	Galt TS: EOL Breakers and other component Replacement	2028-2029	7.3
3	Campbell TS: EOL three (3) Breakers and other component Replacement	2028-2029	7.3
4	Kitchener MTS # 8 (T15/T16): Station Supply Capacity	2033	7.4
5	Energy + MTS # 1: Station Supply Capacity	2036	7.4
6	Campbell TS (T1/T2): Station Supply Capacity	2038	7.4

7	Arlen MTS: Station Supply Capacity	2040	7.4
8	Elmira TS: Station Supply Capacity	2041	7.4
9	Waterloo North MTS # 3: Station Supply Capacity	2041	7.4

7.1. Deteriorating Infrastructure, Optimization Opportunities and Replacement Plan of Major Equipment

7.1.1. Deteriorating Infrastructure

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission lines requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life (EOL) assessment, which includes right sizing, for the above high voltage equipment typically includes consideration of the following options:

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

Accordingly, following major high voltage equipment has been identified as approaching its end of life, based on current condition information, over the next 10 years.

TABLE 7-5: DETERIORATING INFRASTRUCTURE, EOL NEEDS IN KWCG REGION

Stations / Lines Project	Details	Timeframe	High Level Cost[4] ($M)
Hanlon TS	T1/ T2 Transformer Replacement	2022-2023	17.8
Kitchener MTS #5	T9/ T10 Transformer Replacement	2023-2024	7.5
Scheifele MTS	T1/ T2 Transformer Replacement	2025-2026	-
B5C/B6C	Refurbishing 115kV line section from Burlington TS to Enbridge Westover CTS	2025-2026	16.8
Preston TS	T3/ T4 Transformer Replacement	2026-2027	22.9
Cedar TS	T7/ T8 Transformer Replacement	2026-2027	23.7
Fergus TS	T3/ T4 Transformer Replacement	2028-2029	30.0
Galt TS	Breakers and Other Component Replacement	2028-2029	12.0
Campbell TS	Breakers and Other Component Replacement	2028-2029	18.1

Maintaining status quo is not an option for any of the end of life autotransformers, station transformers or line sections due to risk of equipment failure, and would result in increased maintenance cost and prolonged customer outages and interruptions. Replacing “like-for-like” with nonstandard transformers would result in complexity with failures, difficulty with spares management strategies and with unique installation requirements. Nonstandard equipment also poses serious safety risk for employees under normal and emergency situations.

No other lines or HV station equipment in the KWCG region than listed above, have been identified for major replacement/refurbishment at this time.

7.1.2. Optimization Opportunities and Replacement Plans

For stations in the Cambridge-Guelph sub region, an analysis of the current distribution situation that includes under-utilized dedicated feeder capacities, determined that there are not enough spare feeder positions and capacity at HONI and Alectra stations to reallocate DESN loads in the sub-system without significant distribution system and neighboring station upgrades.

Similar is the situation with Kitchener-Waterloo sub region and therefore there are little or no significant optimization opportunities present at this time.

[4] Budgetary estimates

Hence, the Study Team recommends that the LDCs undertakes replacement of their end-of-life high voltage equipment as planned with standard size units, being technically and economical most suitable solution.

7.2. Needs in Near-Term (Projects in Execution)

The following end-of-life refurbishment needs are under execution. These needs were identified in the earlier phases of this 2nd cycle of regional planning.

7.2.1.115 kV B5C/ B6C Line Sections

The 115 kV B5C/B6C circuits consist of about 45 km of double circuit line and 15 km of single circuit line supplying South-Central Guelph 115 kV loads. About 12 km of double circuit line section from Burlington TS to Harper's Jct. and about 15 km B5C 115 kV line tap from Harper's Jct. to a Westover Jct. requires refurbishment.

Not refurbishing these line sections would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

The refurbishment of the 27 km 115 kV B5C/B6C line sections from Burlington TS to a CTS is currently under execution and the work is planned to be completed by the end of year 2025. The delay in the in-service is attributed to a hold on project due to outage concerns with a customer.

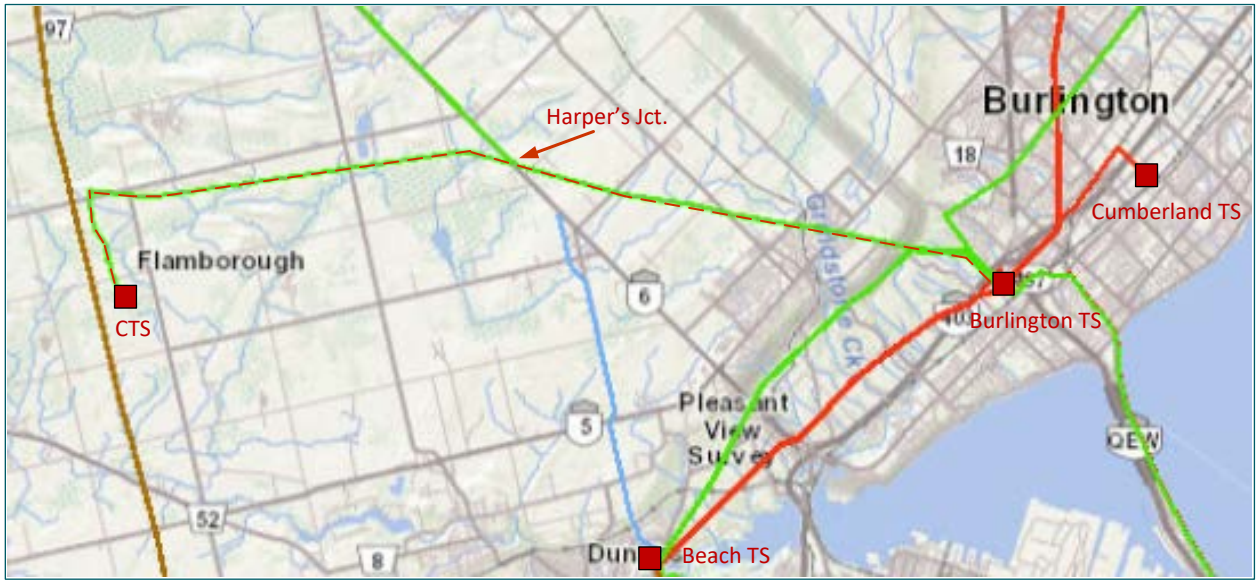


FIGURE 7-6: BURLINGTON TS TO HARPER'S JCT. TO CTS

7.2.2. Hanlon TS T1/T2 Transformer

Hanlon TS is located south of the city of Guelph supplying Alectra loads. Hanlon TS is a single T1/T2 DESN station of 33 MVA nonstandard transformers having a LTR of 48 MVA (43 MW @ 0.9 PF). This station is currently supplying about 27.5 MW of peak load. The loads at Hanlon TS are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T1/T2 transformers were built in 1955-56 and have been identified as EOL due to poor condition requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

There are no nearby supply stations to Hanlon TS with surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2022-2023.

7.2.3. Kitchener MTS #5 T9/T10 Transformers

Kitchener MTS #5 is located in the city of Kitchener supplying Kitchener-Wilmot Hydro Inc. loads. Kitchener MTS #5 is a 115/ 13.8 kV single T9/T10 DESN station of 83 MVA nonstandard transformers having a LTR of 89 MVA (80 MW @ 0.9 PF), currently supplying 67 MW of peak load. The loads at Kitchener MTS #5 are currently forecasted to grow at about 15% over the entire study period and approaches the supply capacity of this station by 2028.

Both the T9/T10 transformers at this station have been identified as approaching end of life requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Kitchener MTS #5 having surplus capacity where this station's loads can be transferred. The Study Team recommends replacing the T9/T10 nonstandard transformers with standard units of similar or greater size, that can provide higher LTR for station capacity to be sufficient beyond study period, is the preferred option. Kitchener-Wilmot Hydro Inc. and Hydro One will coordinate the replacement plan of these transformers. The replacement of the EOL equipment is expected to be completed by 2023-2024.

7.3. Needs in Near, Mid and Long Term

The following end-of-life refurbishment needs have been identified in this regional planning cycle:

7.3.1. Scheifele MTS – T1/ T2 Transformers

Scheifele MTS is located in the city of Waterloo supplying Waterloo North Hydro Inc. loads. Scheifele MTS has four 230/13.8 kV transformers T1 and T2 of 69 MVA (LTR), and T3 and T4 of 110 MVA (LTR) currently supplying 145 MW of peak loads. The load at this station is forecasted to remain almost flat over the entire study period. The total supply capacity of Scheifele MTS is 161 MW expected to be sufficient over the study period, except marginal overloading in 2041.

The T1/T2 transformers based on their age have been identified by Waterloo North Hydro Inc. as approaching end of life potentially requiring replacement in the 2025- 2026 timeframe. Waterloo North Hydro will be monitoring the condition of these transformers to assess their replacement need. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Scheifele MTS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Waterloo North Hydro continue monitoring the condition of these T1/T2 transformers at Scheifele MTS and if required, proceed with replacement plan otherwise this need may be reassessed in the next regional planning cycle.

7.3.2. Cedar TS – T7/ T8 Transformers

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar TS has two 115/13.8 kV DESN units T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 67 MW and 36 MW of peak loads respectively. The loads at both Cedar TS DESNs are currently forecasted to grow at an average of about four percent (4%) over the entire study period. The supply capacity of T7/T8 may approach its LTR by year 2030 while that of T1/T2 is expected to be sufficient over the study period.

The T7/T8 DESN 38 MVA nonstandard transformers were built in 1958 and have been identified for replacement due to poor condition. The T1/T2 transformers are relatively newer and were built in early 1990s. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Cedar TS having surplus capacity where this station's loads can be transferred therefore the Study Team recommends replacing the nonstandard transformers with standard units of 42 MVA in 2026-2027 timeframe, which will impart sufficient capacity (higher LTR) to the station over the study period.

7.3.3. Preston TS T3/T4 Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Energy+ loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available i.e. 125 MVA (113 MW @ 0.9 PF). This station is currently supplying about 92 MW of peak load. The loads at Preston TS are currently forecasted to peak at about 120 MW during the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1968. Condition assessment has identified that both T3/T4 transformers at EOL, requiring replacement. At this time none of other HV/LV equipment at this station has been identified as EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Preston TS having spare supply capacity where this station's loads can be transferred. The Study Team recommends replacing the existing 125 MVA 230/ 27.6 kV T3/T4 transformers at Preston

TS with 125 MVA standard units. This will also result in an increased supplying capacity at Preston TS due to the alleviation of an inherent equipment limitation, required to meet the future Energy+ needs in the Cambridge distribution area. This incremental capacity may be available for Waterloo North Hydro's East-Side-Lands development as deemed technically and economically feasible, meeting power quality requirements. The replacement plan for the equipment will be developed by Hydro One and coordinated with the affected LDC and/or customers and it is expected to be completed by 2026-2027.

7.3.4. Fergus TS T3/T4 Transformers

Fergus TS is located in the township of Fergus supplying various loads LDCs in the KWCG region. Fergus TS has two 230/ 44 kV transformers T3 and T4 of 75/100/125 MVA, currently supplying 90 MW of peak loads. The load at this station is forecasted to grow at about 20 percent over the entire study period. The total supply capacity of Fergus TS is 154 MW expected to be more than adequate over the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1972. Condition assessment has identified that both T3/T4 transformers and the feeder breakers are at their EOL requiring replacement.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Fergus TS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Hydro One continue monitoring the condition of these T3/T4 transformers and other components at Fergus TS and if required proceed with the replacement plan by 2028-2029 or otherwise this need may be reassessed in the next regional planning cycle.

7.3.5. Galt TS Breakers and Components

Galt TS is located in the city of Cambridge supplying Energy + loads in the KWCG region. Galt TS has two 230/ 28-28 kV transformers T7 and T8 of 75/100/125 MVA, currently supplying 112 MW of peak loads. The load at this station is forecasted to grow at about 20 percent over the entire study period. The total supply capacity of Galt TS is 169 MW, expected to be more than adequate over the study period.

The T7/T8 transformers were replaced in 2010 and 2012 respectively to technical issue with the transformers. The breakers and other component at the station are almost 50 years old. Condition assessment has identified that these components are at EOL, requiring replacement.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Galt TS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Hydro One continue monitoring the condition of these EOL components at Galt TS and if required proceed with the replacement plan by 2028-2029 or otherwise this need may be reassessed in the next regional planning cycle.

7.3.6. Campbell TS (T1/T2) Breakers

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/ 13.8 kV DESNs T1/T2 and T3/T4, both 100 MVA transformers. The loads on these two DESNs are currently supplying about 89 MW and 47 MW respectively and their loads are forecasted to grow at about 9 percent by the end of study period.

Two feeder breakers and a tie breaker for T1/T2 DESN are deemed to be end of life and requires replacement. Replacing these three breakers will impart additional 5 to 7 MW of capacity to the DESN, help mitigating the marginal station supply capacity concern at the end of the study period. The Study Team recommends implementing replacement plan by 2028-2029.

7.4. Mid and Long Term Supply Capacity Needs

When the station capacities were reviewed considering the net peak load forecast, below listed ten (10) stations were identified to approach their 10 day LTR. The last four stations were found to approach their 10 day LTR just at the end of the study period of this second regional planning cycle.

TABLE 7-4: KWCG STEP-DOWN TRANSFORMER STATIONS SUPPLY CAPACITY NEEDS

Stations	Need Timeframe
Kitchener MTS #5	2028
Cedar TS (T7/T8)	2030
Kitchener MTS #8 T15/T16	2033
Energy + MTS # 1	2036
Campbell TS (T1/T2)	2038
Preston TS	2038
Arlen MTS	2040
Scheifele MTS	2041
Elmira TS	2041
Waterloo North MTS # 3	2041

The deteriorating infrastructure replacement plans at Kitchener MTS # 5 (T9/T10), Scheifele MTS, Preston TS and Cedar TS (T7/T8) will help mitigate the station supply capacity needs of these stations over and beyond the study period. The Study Team recommends to review other long term station supply capacity needs in the next regional planning cycle.

8. Conclusions and Next Steps

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

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

TABLE 8-6: RECOMMENDED PLANS IN KWCG REGION OVER THE NEXT 10 YEARS

Stations / Lines Project	Details	Timeframe	High Level Cost[5] ($M)
Hanlon TS	Transformers T1 and T2 Replacement	2022-2023	17.8
Kitchener MTS #5	Transformers T9 and T10 Replacement	2023-2024	7.5
Scheifele MTS	Transformers T1 and T2 Replacement	2025-2026	-
B5C/B6C	115KV Lines Refurbishment, refurbishing section from Burlington TS to Enbridge Westover CTS	2025-2026	16.8
Preston TS	Transformers T3 and T4 Replacement	2026-2027	22.9
Cedar TS	Transformers T7 and T8 Replacement	2026-2027	23.7
Fergus TS	Transformers T3 and T4 Replacement	2028-2029	30.0
Galt TS	End of life Breakers and Other Component Replacement	2028-2029	12.0
Campbell TS	End of life Breakers and Other Component Replacement	2028-2029	18.1

The Study Team recommends that:

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

[5] Budgetary estimates

References

[1] KWCG Region Regional Infrastructure Plan (2015)
[2] KWCG Integrated Regional Resource Plan (2021)
[3] KWCG Integrated Regional Resource Plan - Appendices (2021)
[4] KWCG Region Needs Assessment (2018)
[5] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
[6] Ontario Resource and Transmission Assessment Criteria

Appendix A. Stations in the KWCG Region

Station*	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Energy + MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5C/B6C
Arlen MTS	115 kV	B5C/B6C
Hanlon TS	115 kV	B5C/B6C
Cedar TS (T8/T7)	115 kV	B5C/B6C
Customer #2 CTS	115 kV	B5C
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

*All MTSs are LDC owned stations

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5C/B6C	115 kV
Detweiler TS – Kitchener MTS # 4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Fergus TS	Dx
Alectra Utilities Corporation	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Energy + Inc.	Energy + MTS# 1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Region Load Forecast

TABLE D1: KWCG NET NON-COINCIDENT LOAD FORECAST

Transformer Station	Station Capacity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Arlen MTS	45	26	27	27	28	29	30	30	31	32	33	34	35	36	38	39	40	41	42	44	45	46
Campbell TS (T1/T2)	94	86	86	86	86	86	86	86	86	87	87	88	90	91	92	92	93	94	94	95	95	96
Campbell TS (T3/T4)	56	46	46	46	45	45	46	46	46	46	46	47	47	48	48	48	49	49	49	50	50	50
Cedar TS (T1/T2)	103	93	94	94	95	96	96	97	97	98	99	99	99	100	100	100	101	101	101	101	101	102
Cedar TS (T7/T8)	40	30	32	34	35	37	38	38	39	40	40	41	41	41	41	41	42	42	42	42	42	43
Elmira TS	55	34	35	35	35	36	36	37	38	38	39	40	41	42	49	50	51	52	53	54	55	56
EnergyInc(Cam) MTS#1	102	86	87	87	87	87	88	89	90	91	93	94	96	97	99	101	103	104	106	107	108	110
Fergus TS	154	88	91	91	91	92	92	93	94	94	95	98	99	103	104	106	108	108	109	110	111	111
Galt TS	169	112	113	113	114	115	116	117	118	120	122	124	125	127	129	132	134	136	137	139	141	143
Hanlon TS	43	27	28	28	28	29	29	29	30	30	31	31	32	32	33	33	34	34	35	36	36	37
Kitchener MTS # 1	54	33	34	34	34	35	35	36	36	37	38	38	39	40	41	41	42	43	43	44	45	45
Kitchener MTS # 3	108	55	55	55	56	56	57	57	58	59	59	60	61	62	63	64	65	66	67	67	68	69
Kitchener MTS # 4	90	54	55	55	55	55	56	56	56	57	58	58	59	60	61	61	62	63	63	64	64	65
Kitchener MTS#5	80	77	77	77	78	78	78	79	80	80	81	82	83	84	85	86	87	88	88	89	90	91
Kitchener MTS#6	90	72	73	73	73	74	74	75	76	76	77	78	79	80	81	82	83	83	84	85	86	87
Kitchener MTS#7	54	34	34	34	34	35	35	35	36	36	37	38	38	39	40	40	41	41	42	42	43	43
Kitchener MTS#8	54	37	38	40	41	42	44	45	47	48	50	51	53	55	56	58	60	61	63	64	66	68
Kitchener MTS#9	90	32	33	33	33	33	33	34	34	34	35	35	36	36	37	38	38	39	40	40	41	41
Preston TS	113	90	92	93	93	94	95	96	97	99	100	102	103	105	107	109	110	112	114	115	117	118
Puslinch DS	56	31	32	32	32	32	32	33	33	34	34	34	35	35	36	36	37	37	38	38	39	39
Rush MTS	68	52	52	52	52	52	52	53	53	54	54	58	58	59	60	60	61	61	62	63	63	64
Scheifele MTS	161	140	140	140	140	141	142	143	144	145	147	145	147	149	150	152	154	155	157	158	160	161
Waterloo North MTS 3	77	51	53	53	54	54	55	56	57	59	60	61	62	64	65	67	68	70	71	73	74	76
Wolverton DS	54	12	13	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	14
CTS Total	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total	**-**	**1409**	**1428**	**1433**	**1441**	**1453**	**1467**	**1482**	**1498**	**1516**	**1536**	**1560**	**1581**	**1607**	**1636**	**1662**	**1682**	**1702**	**1722**	**1742**	**1762**	**1782**

TABLE D2: KWCG NET COINCIDENT LOAD FORECAST

Transformer Station	Station Capacity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Arlen MTS	45	26	26	27	27	28	29	30	31	32	32	33	34	36	37	38	39	40	41	43	44	45
Campbell TS (T1/T2)	94	81	81	80	80	80	80	81	81	81	82	82	84	85	86	87	87	88	88	89	89	90
Campbell TS (T3/T4)	56	42	42	42	41	41	42	42	42	42	42	43	43	44	44	44	45	45	45	45	46	46
Cedar TS (T1/T2)	103	76	77	77	77	78	79	79	79	80	80	81	81	81	82	82	82	82	83	83	83	83
Cedar TS (T7/T8)	40	27	29	30	31	33	34	34	35	35	36	36	36	36	37	37	37	37	37	38	38	38
Elmira TS	55	33	34	34	35	35	36	36	37	38	38	39	40	41	48	49	50	51	52	53	54	55
Energylnc(Cam) MTS#1	102	86	86	86	86	87	88	89	90	91	92	94	95	97	98	100	102	103	105	106	108	109
Fergus TS	154	87	89	90	90	90	91	91	92	93	94	96	97	101	103	105	106	107	107	108	109	110
Galt TS	169	112	113	113	114	115	116	117	118	120	122	124	125	127	129	132	134	136	137	139	141	143
Hanlon TS	43	25	26	26	26	26	26	27	27	28	28	29	29	30	30	31	31	32	32	33	33	34
Kitchener MTS # 1	54	33	34	34	34	35	35	36	36	37	38	38	39	40	41	41	42	43	43	44	45	45
Kitchener MTS # 3	108	53	53	53	53	54	54	55	56	56	57	58	59	60	61	62	63	63	64	65	65	66
Kitchener MTS # 4	90	54	55	55	55	55	56	56	56	57	58	58	59	60	61	61	62	63	63	64	64	65
Kitchener MTS#5	80	73	74	74	74	74	74	75	76	76	77	78	79	80	80	82	83	83	84	85	85	86
Kitchener MTS#6	90	66	67	67	67	67	68	68	69	70	70	71	72	73	74	75	76	76	77	78	78	79
Kitchener MTS#7	54	34	34	34	34	35	35	35	36	36	37	38	38	39	40	40	41	41	42	42	43	43
Kitchener MTS#8	54	37	38	39	40	42	43	45	46	48	49	51	52	54	56	57	59	61	62	64	65	67
Kitchener MTS#9	90	32	32	32	32	33	33	33	34	34	34	35	35	36	37	37	38	38	39	40	40	41
Preston TS	113	74	76	76	76	77	77	78	79	80	81	83	84	85	87	89	90	91	93	94	95	97
Puslinch DS	56	29	30	30	30	30	30	31	31	32	32	32	33	33	34	34	35	35	35	36	36	37
Rush MTS	68	49	49	49	49	50	50	50	51	51	52	55	56	56	57	57	58	58	59	60	60	61
Scheifele MTS	161	122	122	122	122	122	123	124	125	126	127	126	128	129	131	133	134	135	137	138	139	141
Waterloo North MTS 3	77	50	51	52	52	53	54	55	56	57	58	60	61	63	64	65	67	68	70	71	72	74
Wolverton DS	54	12	13	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	14
CTS Total	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total	**-**	**1323**	**1340**	**1344**	**1350**	**1361**	**1375**	**1388**	**1404**	**1421**	**1439**	**1462**	**1483**	**1508**	**1536**	**1561**	**1581**	**1599**	**1619**	**1637**	**1657**	**1675**

Appendix E. Stations with Extremely High Short Circuit Level*

Station	Bus	Owner	Nominal Voltage (kV)	Short Circuit Capacity** (MVA)	Short Circuit Level (MVA)
Campbell TS	EZ	Hydro One	13.8	443	437
Kitchener MTS # 1	B1B2	Kitchener-Wilmot Hydro	13.8	468	447
Kitchener MTS # 3	B51B61	Kitchener-Wilmot Hydro	13.8	468	436
	B52B62	Kitchener-Wilmot Hydro	13.8	468	474***
Kitchener MTS # 4	B71B81	Kitchener-Wilmot Hydro	13.8	468	466
	B72B82	Kitchener-Wilmot Hydro	13.8	468	467
Kitchener MTS # 5	B91B101	Kitchener-Wilmot Hydro	13.8	468	415
	B92B102	Kitchener-Wilmot Hydro	13.8	468	415
Kitchener MTS # 6	B111B121	Kitchener-Wilmot Hydro	13.8	468	459
	B112B122	Kitchener-Wilmot Hydro	13.8	468	459
Kitchener MTS # 7	B13B14	Kitchener-Wilmot Hydro	13.8	468	446
Rush MTS	B1B2	Waterloo North Hydro	13.8	467	441
Scheifele MTS A	BY	Waterloo North Hydro	13.8	500	455
Scheifele MTS B	QT	Waterloo North Hydro	13.8	500	454

*** Data provided in this table are valid as of March 2021. For up-to-date information, contact LDCs.**

**** Capacities smaller than TSC requirement are due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered.**

***** To be replaced.**

Appendix F. List of Acronyms

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



NEEDS ASSESSMENT REPORT

KWCG

[Date: April 09, 2024]

Needs Assessment Report

Final

KWCG

[Date: April 09, 2024]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: KWCG Technical Working Group



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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the KWCG region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region. Updates may be made based on best available information throughout the planning process.

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

Executive Summary

REGION	**KWCG** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: December 11, 2024	**END DATE:** April 09, 2024

1. INTRODUCTION

The 2nd Regional Planning cycle for the KWCG Region was completed in December, 2021 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the 3rd cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in December 2023 for the KWCG Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the KWCG Region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is ten (10) years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2022 non-coincident regional loads were about 1436 MW.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the KWCG Region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of municipal energy plan(MEPs) and/or Community Energy plans (CEPs) where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and operational concerns;

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs and projects discussed in the 2nd cycle RIP report for KWCG region have been completed:

- Hanlon TS Transformers T1/ T2 Replacement (2022).

The following needs and projects discussed in the 2nd cycle RIP report for KWCG region are currently underway:

- **Burlington TS to CTS 1 Line Section:** The refurbishment of 115 kV B6C/ B6C line section from Burlington TS to Harper's Junction was completed in 2019. The refurbishment of line tap section from Harper's Junction to CTS1

is progressing slowly due to outage availability from the customer. This refurbishment work is currently forecasted to be completed in Q3/ Q4 2025 timeframe.

- **Kitchener MTS #5 – T9/T10 Transformers Replacement**: The existing 83 MVA T9/ T10 transformers are planned to be replaced with new 100 MVA units. This work is currently forecasted to be completed by Q1 2025.
- **Preston TS - T3/T4 Transformer Replacement:** Condition assessment of T3/ T4 transformers have identified these units for replacement. These units are currently planned to be replaced by the end of 2027 with similar Hydro One standard units. This replacement will also remove the existing supply capacity constraint due to a technical limitation in the existing units. The new LTR will be 180 MW

The remaining needs and projects discussed in the 2nd cycle RIP report for KWCG region are as follows:

- **Scheifele MTS - T1/T2 and T3/T4 Transformer Replacement**: These four (T1/T2/T3/T4) transformers are expected to approach end of life over the next 10 year horizon and are planned for replacement by Enova Power Corp. Enova Power Corp will continue monitoring the condition of these transformers with its maintenance program. The expected year of replacement is between 2029-2033.
- **Cedar TS - T7/ T8 Transformer Replacement**: Replacing the existing non-standard T7/T8 transformers with Hydro One standard units of higher capacity. Based on latest condition assessment of these units. These units are to be replaced beyond the study period (10 years) of this report. However, this transformer replacement may need to be advanced due to capacity needs.
- **Campbell TS - Breakers and Component replacement:** Replace breakers deemed to be approaching expected service life. This work is planned to be completed by 2032.
- **Fergus TS – T3/T4 Transformer Replacement:** Hydro One will continue monitoring the condition of these T3/T4 transformers and other components at Fergus TS. Hydro One will proceed with the replacement plan, if required. Otherwise, this need will be reassessed in the next regional planning cycle.
- **Galt TS – Breakers and Component Replacement:** Hydro One will continue monitoring the condition of these components at Galt TS and proceed with the replacement plan as required.

II. Newly identified needs in the region

Based on the new and updated information, a summary of the results of this Needs Assessment is provided below:

a. Asset Renewal for Major HV Transmission Equipment

- No new Asset Renewal Needs

b. Transformation Capacity

- The supply capacity needs at Preston TS, Energy + MTS, Cedar T7/T8 and Campbell TS (T3/T4) have been identified in the near term while the needs at Cedar TS T1/T2 DESN, Cedar T7/T8 DESN, Kitchner MTS #7, Waterloo MTS, and Rush MTS have been identified in the middle term.

c. Transmission System Capacity

- During the study period. Post contingency overload violations were observed on 230 kV M20D/M21D and 115 kV D11K/ D12K circuits for the loss of companion circuits.

d. System Reliability, Operation and Load restoration

- During the study period, post contingency voltage violations were observed on 230 kV M20D/M21D for the loss of companion circuits.
- Load restoration violations on 230 kV D6V/D7V circuits in the long term and system security and load restoration violation on the M21D/M20D circuit in the mid term and near term respectively, for a single tower contingency.

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and/or new station/line capacity needs: These needs will be assessed again during the next phases of this Regional Planning cycle.

Sr. no	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Preston TS - Capacity need	2026	2026	2029
2	Galt TS- Capacity need	Reaches capacity in 2032	2030	Long term
3	Energy Inc MTS - Capacity need	2023	2023	2023
4	Rush MTS - Capacity need	2030	2029	Long term
5	Waterloo North MTS #3 - Capacity need	2030	2030	Long term
6	Campbell TS (T3/T4)- Capacity need	2026	2025	2030
7	Cedar TS (T7/T8)- Capacity need	Immediate	Immediate	Immediate
8	Cedar TS (T1/T2)- Capacity need	2031	2029	Long term
9	Kitchener #7	2031	2030	Long term
10	M20D/M21D Transmission Circuit Supply	2026	2024	2026
11	D11K/D12K- Transmission Circuit Supply	2032	2030	Long term

12	D10H - Transmission Circuit Supply	Long term	2030	Long term
13	M20D/M21D Load Security	2032	2028	Long term
14	M20D/M21D Restoration Needs	2025	2023	2025
15	D6V/D7V Restoration Needs	Long term	2030	Long term
16	Voltage change violation on M20D/M21D	2026	2025	2026

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. These needs are as follows:

a. Transmission System Capacity

- M20D/M21D post contingency violation (Galt Jct x Cambridge #1 Jct)- Near term
- D11K/D12K post contingency violation (Detweiler x Kitchener #1 & 4 Jct) – Mid Term

b. System Reliability, Operation and Load restoration

- System security violation on the M21D/M20D circuit in the Mid term
- Load restoration for M20D/M21D – Near term
- Voltage violations on M20D or M21D due to outage on companion circuit -Near term

c. Transformation Capacity Needs

- Preston TS (T3/T4) – Near term
- Energy Inc MTS (T1/T2) – Near term

Transmission system capacity and restoration needs are likely to trigger system reinforcement needs in the KWCG region.

II. Needs that do not require further regional coordination

These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

a. Transformation Capacity Needs

- Campbell TS (T3/T4) – Mid term
- Cedar TS (T1/T2) – Mid term
- Kitchener MTS #7 (T14/T13) – Mid term
- Cedar (T7/T8) – Near term
- Rush MTS – Mid term
- Waterloo North MTS #3 - Mid term

List of LDC(s) to be involved in further regional planning activities:

- Grandbridge Energy
- Enova Power Corp

List of LDC(s) which are not required to be involved in further regional planning phases:

- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power

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1. INTRODUCTION

The second cycle of the Regional Planning process for the KWCG Region was completed in [December 10, 2021] with the publication of the Regional Infrastructure Plan ("RIP") Report The RIP report included a common discussion of all the options and recommended plans and preferred plans for wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the KWCG Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is given below in Figure 1 below.

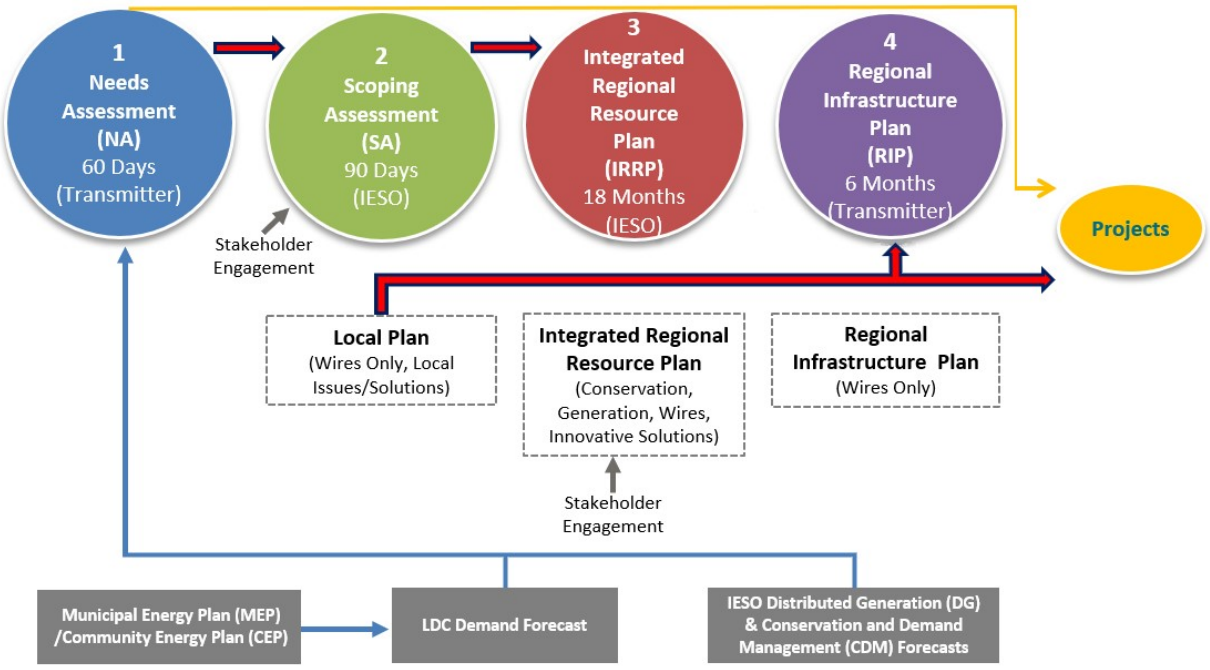


Figure 1: Regional Planning Process

This report was prepared by the KWCG Technical Working Group("TWG"), led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One,

the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 1.

Table 1: KWCG Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator ("IESO")
3	Enova Power Corp.
4	Alectra Inc.
5	Grandbridge energy
6	Centre Wellington
7	Wellington North
8	Halton Hills Hydro Inc.
9	Hydro One Networks Inc. (Distribution)

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the KWCG region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the KWCG region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,

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

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The accumulative summer 2022 non-coincident loads were about 1477 MW. The approximate boundaries of the KWCG Region are shown below in Figure 1.

The main sources of electricity into the KWCG Region are from five Hydro One stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV levels, respectively. Electricity is then delivered to the end users of LDCs and transmission connected industrial customers through 26 (supply transformer stations) step-down transformer stations. Figure 2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. The single line diagram of the KWCG region is shown in Figure 3 below.

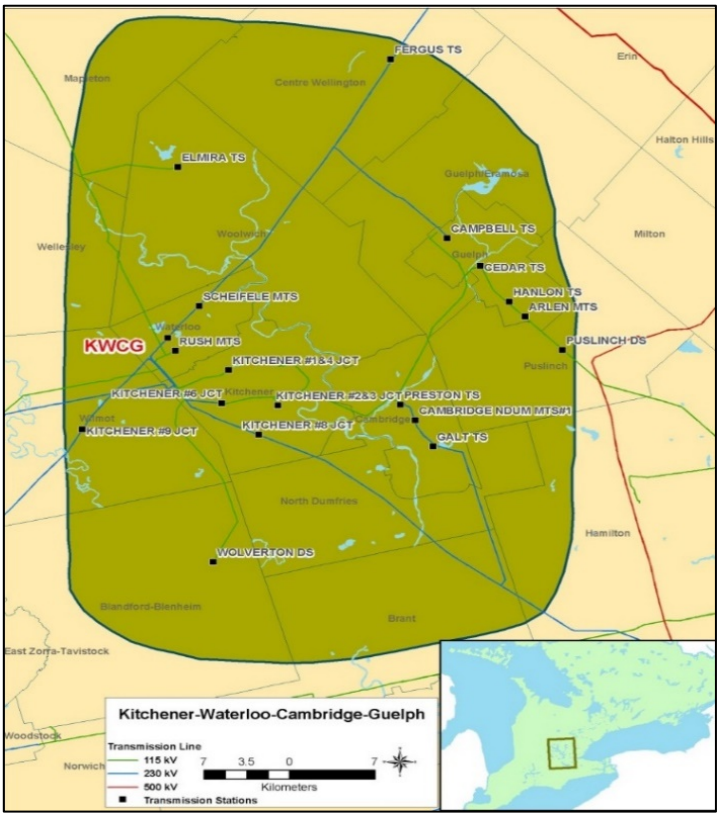


Figure 2: Map of KWCG Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the KWCG Region

115Kv circuits	230Kv circuits	Hydro One Transformer Stations	Generation Stations
B5C/B6C D7F/D9F F12C/F11C D11K/D12K D8S D10K	D4W/D5W D6V/D7V B22D/B23D M20D/M21D	*Detweiler TS , Fergus TS, *Cedar TS, Campbell TS, Galt TS, Elmira TS, Hanlon TS, Scheifele MTS, Waterloo North MTS#3, Energy MTS#1, Kitchener MTS #1, Kitchener MTS#3, Kitchener MTS#4, Kitchener MTS#5, Kitchener MTS#6, Kitchener MTS#7, Kitchener MTS#8, Kitchener MTS#9, Rush MTS, Wolverton DS, Puslinch DS, CTS 1, CTS 2, Preston TS*.	N/A

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of KWCG region is shown in Figure 3 below.

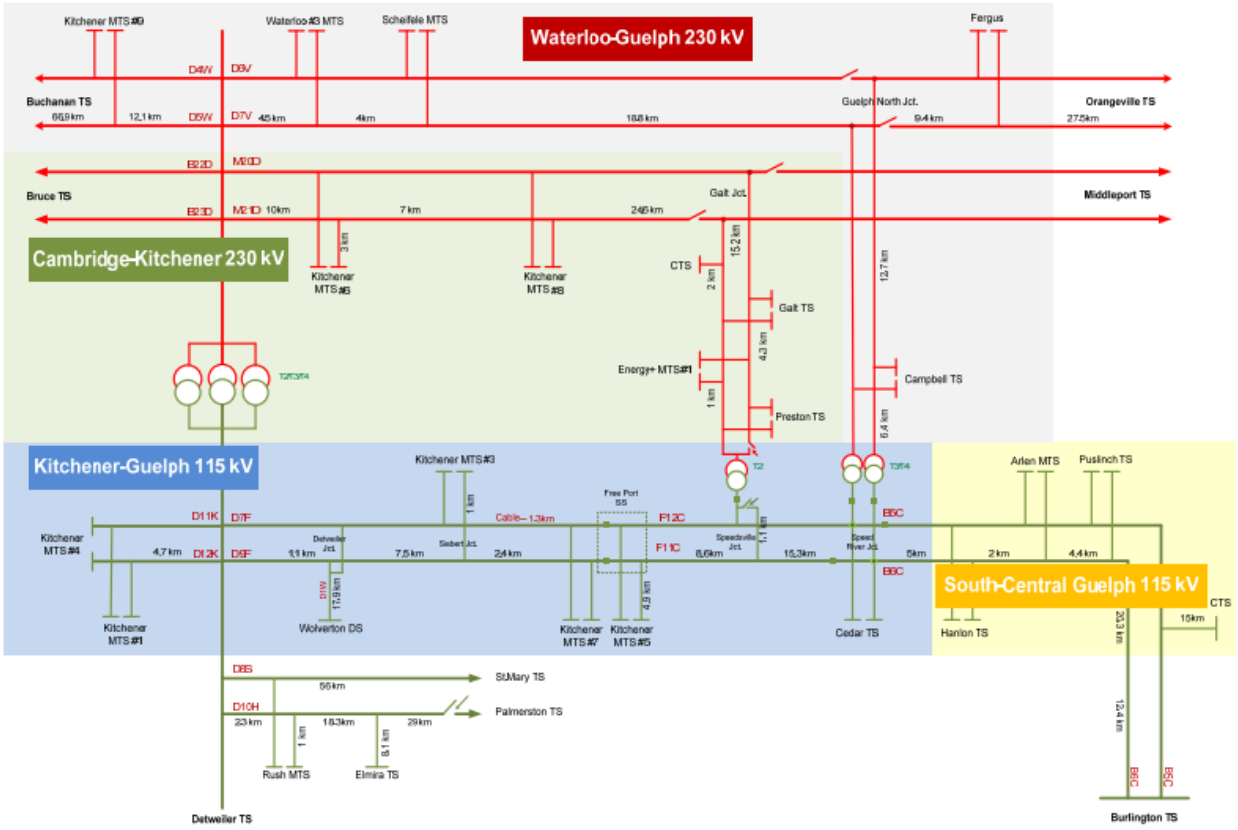


Figure 3: KWCG Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the KWCG NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called “Load Forecast Guideline for Ontario” in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC’s load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- KWCG 10-year Load Forecast for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs),
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the KWCG.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing”; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on Summer peak loads. Three load forecasts were developed i.e. Normal Growth scenario, High & low Growth scenario. The High and low Growth scenario load forecast was developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher-than-expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2023-2032.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.

- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering process

6.2.1. Load forecast:

The LDCs provided their load forecast for all the stations supplying their loads in the KWCG region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the KWCG region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2022 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity for the contracted projects only provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the KWCG region is given in Appendix A.

A very few of the stations have winter peaks marginally higher than summer peaks. The higher winter transformer and line ratings are adequate to accommodate the marginally higher loads. Therefore, only the Summer Assessment was carried out.

Alectra recently advised the TWG that a revised forecast, to better account for their community's decarbonization activities, will soon be available. This updated forecast will be included in later stages of the regional planning process and may impact the area's overall needs and/or may require the creation of a regional winter forecast.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

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

6.2.3. Asset renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1; and

6.2.4. System Reliability and Operational Issues:

- Palmerston-to-Detweiler transfer during Hanover bank outages:
  With current load forecast, this issue does not exist.

TWG members identified the following bulk system issues in the KWCG region to be discussed outside of the RP process:

- Detweiler TS configuration and operating instruction asking for multiple equipment to be out of service during contingency
- Detweiler TS Station Service Auto-Transfer Issues
- Palmerston-to-Detweiler transfer during Hanover bank outages.

7. NEEDS

This section describes emerging new needs identified in the KWCG Region and/or updates on the previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

- Hanlon T1/T2 transformer replacement was completed in 2022.
- Kitchener MTS #5 project is currently underway, existing 83MVA transformers to be replaced by 100MVA units. The planned in-service date is Q3 2024 for T10 and Q1 2025 for T9.
- Preston TS: Project for like-for-like replacement of transformers T3/T4 is underway. The planned in-service date is 2027.
- B5C/B6C 115kV line section refurbishment: The Burlington TS to Harper junction line refurbishment was completed in 2019. The refurbishment of line tap from Harper junction to CTS-1 is progressing slowly due to outage availability from customer. Expected completion date is Q3/Q4 2025.
- Galt TS: The asset condition assessment identified breakers and other components needs to be replaced in long-term. Hydro One will continue to monitor the condition of these components and if required, proceed with the replacement plan.
- Campbell TS: Two feeder breakers and a bus tie breaker for T1/T2 DESN were identified for replacement. The planned in-service date is 2032.

- Scheifele MTS T1/T2/T3/T4 Transformer replacement: These four (T1/T2/T3/T4) transformers are expected to approach end of life over the next 10-year horizon and are planned for replacement by Enova Power Corp. The expected year of replacement is between 2029-2033.

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

All near, and mid-term needs that were discussed as a part of this report are summarized in table 3 below.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cedar TS	T7/T8 Transformers Replacement	7.3.2	7.1.1
Fergus TS	T3/T4 Transformers Replacement	7.3.4	7.1.2
Galt TS	Breakers and Component Replacement	7.3.5	7.1.4
Campbell TS	Breakers and Component Replacement	7.3.6	7.1.3
Station Capacity Needs			
Preston TS	Preston T3/T4 is forecasted to exceed its supply capacity during the study period (beyond the anticipated LTR of the new transformers)	N/A	7.2.1
Energy Inc MTS	The load at Energy Inc MTS is forecasted to exceed its supply capacity in the near term.	N/A	7.2.2
Campbell TS (T3/T4)	The load at Campbell TS (T3/T4) is forecasted to exceed its supply capacity in the near term.	N/A	7.2.3
Cedar TS	Load demand at both Cedar TS T1/T2 and T7/T8 DESNs is forecasted to exceed supply capacities in the mid and near term respectively.	N/A	7.2.4
Kitchener MTS#7	The load at Kitchener MTS#7 is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.5

Waterloo North MTS #3	The load at Waterloo North MTS#3 is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.6
Rush MTS	The load at Rush MTS is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.7
Transmission Line Capacity Needs			
M20D/M21D	The 230 kV M20D/M21D circuits supply transformer stations connected between Detweiler TS and Middleport TS. Loading violations were observed on M20D/ M21D circuits starting 2026 on the sections between Galt Jct. and Cambridge Jct. .	N/A	7.3.1
D11K/D12K	D11K/D12K supplies Enova Power Corp stations, Kitchener MTS#1 and Kitchener MTS#4. Loading violations were observed on these circuits for the loss of companion circuit in the mid-term.	N/A	7.3.2
D10H	The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads at Rush MTS, Elmira TS and Palmerston TS with a normally open motorized switch just south of Palmerston TS. During the outage of 115 kV D8S circuit, loading violations were observed on a section of 115 kV D10H circuit in the long term.	N/A	7.3.3
System Reliability, Operation and Load restoration Needs			
M20D/ M21D	For the loss of two elements M20D/M21D on the 230 kV system, the load interrupted by configuration will exceed 600MW based on the peak coincident load, resulting in violation of ORTAC security criteria in the mid-term.	N/A	7.4.1
M20D/M21D	Load restoration violations observed on the M20D/M21D 230 kV circuits	N/A	7.4.1
D6V/ D7V	Marginal load restoration violations were observed for D6V/D7V 230 kV circuits	N/A	7.4.2
Voltage Performance			

M20D/M21D	Several voltage violations were observed in the near term.	N/A	7.4.3

7.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One and TWG has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the **KWCG** Region. The complete list of major HV transmission equipment requiring replacement in the **KWCG** Region is provided in table 4 in this section. Hydro One and Enova Power Corp are the Transmission Asset Owners (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The Asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region over the next 10 years

Station/Circuit	Need Description	Planned ISD
Kitchener MTS #5	The existing T10 & T9 83 MVA transformers to be replaced by 100 MVA units	T10-2024 T9-2025
Preston TS	Replacement of existing T3 & T4 transformers with similar size units.	2027
B5C/B6C	Refurbishment of B5C/B6C line between Burlington TS to CTS1.	2025
Scheifele MTS	The existing four transformers are expected to approach end of service life over the next 10 years Horizon	2029-2033

7.1.1 Cedar TS (T7/T8)

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar T7/T8 is a 115/13.8 kV DESN station with an LTR of 44 MVA (40 MW @ 0.9 PF), and 40 MW of peak load in 2022. Hydro One will continue to monitor the condition of these transformers. Based on asset condition assessment, T7/T8 are expected to reach end of life beyond the 10-year planning horizon. The station capacity need at this station is discussed in Section 7.2.4 of this report.

7.1.2 Fergus TS (T3/T4)

Fergus TS is a 230 kV/ 44 kV single DESN station having two 125 MVA transformers located in the township of Fergus having a supply capacity of 154 MW and supplying 94 MW of loads. The supply capacity of this station is forecasted to be sufficient over the study period and beyond. Based on asset condition assessment, T7/T8 are expected to reach end of life beyond the 10-year planning horizon.

The TWG recommended Hydro One to keep monitoring the condition of these transformers. No further regional planning coordination is required at this time.

7.1.3 Campbell TS (T1/T2) Breakers and Components

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/13.8 kV DESNs T1/T2 and T3/T4, having supply capacities of 94 MW and 56 MW respectively. The loads on these two DESNs are currently supplying about 86 MW and 47 MW of loads respectively.

In the previous regional planning RIP report, two feeder breakers and a bus tie breaker for T1/T2 DESN were identified for replacement. Based on asset condition assessment, the equipment at this station are

expected to reach end of life within 10 year planning horizon. No further regional coordination is required at this time.

7.1.4 Galt TS Breakers and Components

Galt TS is located in the city of Cambridge supplying Energy + loads in the KWCG region. Galt TS has two 230/ 28-28 kV transformers T7 and T8 of 75/100/125 MVA, currently supplying 115 MW of peak loads. The total supply capacity of Galt TS is 169 MW, expected to be more than adequate over the study period.

The T7/T8 transformers were replaced in 2010 and 2012 respectively due to technical issues with the transformers. The breakers and other component at the station are almost 50 years old. Condition assessment has identified that these older components to be replaced in the long term.

The station cannot be downsized or eliminated because there is no nearby supply station/s having surplus supply capacity for transferring loads. Hydro One will continue monitoring the condition of these components at Galt TS and if required proceed with the replacement plan as required.

7.2 Station Capacity Needs

A 'Station Capacity' assessment was performed over the study period 2023-2032 for the 230kV and 115kV Transforming stations in the KWCG Region using the non-coincident summer peak load forecasts provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Preston TS Supply Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Grandbridge energy loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available. This station is currently supplying loads to its supply capacity. The non-coincident loads at Preston TS are currently forecasted to reach 242 MW[2] by the end of study period. The replacement of these station supply transformers is underway and forecasted to be completed by Q2 of 2027. Upon completion, the new station LTR is expected to be in the range of 180 MW. The Preston TS loads are currently forecasted to reach this new supply capacity in the in-service timeframe of these new transformers. A near-term solution is required to address this need. The TWG recommends to further review this need in next regional planning phases.

[2] Note: Due to the load limit on M20D/M21D imposed by ORTAC's load security criteria, the coincident peak loading on M20D/M21D is limited to 600 MW forecasted to exceed in 2032.

7.2.2 Energy MTS#1

Energy + MTS#1 is located in the city of Cambridge supplying Grandbridge Energy loads in the KWCG region. This station has an LTR of 102 MW and forecasted to exceed its supply capacity near the end of the study period. The loading at this station will be monitored by Grandbridge Energy and this need will be further assessed in the next regional planning phase. Grandbridge Energy is working on measures to transfer load within the distribution system to Galt TS to address near term loading concerns. Hydro One and Grandbridge will continue to monitor load levels.

7.2.3 Campbell TS Transformer

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/13.8 kV DESNs units supplying through T1/T2 and T3/T4 transformers, having supply capacities of 94 MW and 56 MW respectively. These two Campbell TS DESNs are currently supplying about 81 MW and 45 MW of loads respectively and their combined loads at Campbell TS are forecasted to exceed the total station supply capacity close to the end of the study period.

Alectra to propose measures to address capacity needs at this station, if required. Hydro One and Alectra will continue to monitor load levels. The TWG recommends that no further regional coordination is required at this time.

7.2.4 Cedar T1/T2 and T7/T8

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar TS has two 115/13.8 kV DESN stations T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 82 MW and 40 MW of peak loads respectively. The total load of both DESNs is forecasted to exceed its supply capacity in the near term.

Alectra to propose measures to address this capacity needs, if required. Hydro One and Alectra to continue monitoring load levels. The TWG recommends that no further regional coordination is required at this time.

7.2.5 Kitchener MTS #7

Kitchener MTS #7 is located in the city of Kitchener supplying Enova Power Corp loads. Kitchener MTS #7 is a 115/ 13.8 kV single T13/T14 DESN station having 50 MVA transformers and a LTR of 60 MVA (54 MW @ 0.9 PF). This station is currently supplying 37 MW of peak load. The loads at Kitchener MTS #7 are currently forecasted to grow approaching its supply capacity near the end of the study period.

Enova Power Corp to monitor the loading on this station and manage any overloading through load transfers, if required. The TWG recommends that no further regional coordination is required at this time.

7.2.6 Waterloo North MTS #3

Waterloo North MTS#3 is located in the city of Waterloo supplying Enova Power Corp. Waterloo North MTS#3 is a 230/27.6 kV single T1/T2 DESN station having an LTR of 85MVA. This station is currently supplying 48 MW of peak load. The loads at Waterloo North MTS#3 is currently forecasted to grow approaching its supply capacity near the end of the study period. Enova Power Corp to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term. The TWG recommends that no further regional coordination is required at this time.

7.2.7 Rush MTS

Rush MTS is located in the city of Waterloo supplying Enova Power Corp loads. Rush MTS is a 115/ 13.8 kV single T1/T2 DESN station having an LTR of 68 MW. This station is currently supplying 50 MW of peak load. The loads at Rush MTS is currently forecasted to grow approaching its supply capacity near the end of the study period. Enova Power Corp to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term. The TWG recommends that no further regional coordination is required at this time and will be reviewed in next regional planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2023-2032 for the 230kV and 115kV Transmission line circuits in the KWCG Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 M20D/M21D – 230 kV – Transmission Circuit Supply

The M20D/M21D is a 230kV double circuit line about 58 km long, supplying the following stations:

- Kitchener MTS #6
- Kitchener MTS #8
- Galt TS
- Preston TS
- Energy + Inc.
- A Customer CTS

For the loss of one of the M20D or M21D 230 kV circuits, the loading on the Galt JCT to Cambridge JCT section exceeds its rating starting in 2026 (Summer load forecast). The TWG recommends to further review this need in next regional planning phases.

7.3.2 D11K/D12K

D11K/D12K is a 115 kV line supplying Enova Power Corp stations of Kitchener MTS#1 and Kitchener MTS#4. With the current load forecast on the above stations, these D11K and D12K 115 kV circuits will be experiencing overloading for the loss of companion circuits by the end of the study period (2032). The TWG recommends to further review this need in next regional planning phases.

7.3.3 D10H

The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads to Rush MTS and Elmira TS. The D10H circuit has a normally open point just south of Palmerston TS through a motorized disconnect switch for emergency supply to Palmerston TS. The northern section of D10H is supplied from Hanover TS radially supplying Palmerston TS loads. The southern section of D10H is supplied through Detweiler TS radially supplying Enova Power Corp's 34 MW of Elmira TS peak loads. D10H also supplies Rush MTS which has a dual supply through 115 kV D8S circuit from Detweiler TS. For any outage of 115 kV D8S circuit. The D10H line section between Detweiler and Leong Jct is approaching its supply capacity close to the end of the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2023-2032 to cater this need**.** Based on the results, some system reliability, operating and restoring issues have been identified for this Region.

7.4.1 M20D/M21D Load Security and Restoration Needs

As per the load security criteria (ORTAC Section 7.1), with one element out of service, planned load curtailment or load rejection is permissible only to account for local generation outages; and not more than 150MW of load may be interrupted by configuration, planned load curtailment or rejection. With two elements out of service, not more than 600 MW of load may be interrupted by configuration, planned load curtailment or rejection.

As per the load restoration criteria (ORTAC Section 7.2), interrupted load must be restored within the following timelines:

- Load above 250 MW, within 30 minutes;
- Load above 150 MW, within 4 hours; and
- All load, within 8 hours.

For the loss of double 230kV circuits (M20D/M21D), a total peak coincident load of 638 MW will be interrupted in 2032 by configuration which violates ORTAC load security criteria since not more than 600 MW of load may be interrupted by configuration.

With respect to load restoration, a total of 638 MW (2032 forecast) will be interrupted by configuration, of which, 388 MW needs to be restored within 30 mins as per ORTAC criteria. For a double line fault on Galt Jct. to Preston TS section, only 210 MW (out of the 388MW required to be restored) of that load is restorable. Kitchener MTS#6 and MTS#8 load can be restored via Galt Jct in-line switches and approximately 100 MW of load can be restored at Preston TS. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period. The TWG recommends to further review this need in next regional planning phases.

7.4.2 D6V/D7V Restorations Needs.

By year 2032, the total peak coincident forecasted load connected to D6V/D7V is 517 MW. Loss of this double circuit line (Tower Contingency) would result in the loss of all 517 MW which is below the ORTAC load security limit. To restore load to these stations, the 230 kV in-line switches will be utilized to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion. Non-restorable load within 30

minutes is estimated to be about 256 MW. Hence, the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time, and the loading levels will be monitored.

7.4.3 Voltage Performance

M20D or M21D post contingency voltage change exceeds the 10% pre-tap and 5% post-tap limits on the low voltage side at Preston TS and Energy + Inc MTS within the near-term coincident forecast. The post contingency voltages also drop beyond the allowable voltage range. The situation is further worsened in the subsequent years.

In the midterm, the voltage change limits on the high side of Preston TS, Galt TS and Energy + Inc MTS are violated for the post-contingency loss of M20D or M21D circuits. Voltage also drops below the allowable voltage range. The TWG recommends to further review this need in next regional planning phases.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the KWCG region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by applying -50% growth to the annual growth rate on the extreme summer corrected Normal Growth net load forecasts.

The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Preston TS- Capacity need	2026	2026	2029
2	Galt TS- Capacity need	Reaches capacity in 2032	2030	Long term
3	Energy Inc MTS - Capacity need	2023	2023	2023
4	Rush MTS - Capacity need	2030	2029	Long term
5	Waterloo North MTS #3 - Capacity need	2030	2030	Long term
6	Campbell TS (T3/T4)- Capacity need	2026	2025	2030
7	Cedar TS (T7/T8)- Capacity need	2024	2024	2024
8	Cedar TS (T1/T2)- 115kV- Capacity need	2031	2029	Long term
9	Kitchener MTS#7	2031	2030	Long term
10	M20D/M21D Transmission Circuit Supply	2026	2024	2026
11	D11K/D12K- Transmission Circuit Supply	2032	2030	Long term
12	D10H - Transmission Circuit Supply	Long term	2030	Long term
13	M20D/M21D Load Security	2032	2028	Long term
14	M20D/M21D Restoration Needs	2025	2023	2025
15	D6V/D7V Restoration Needs	Long term	2030	Long term
16	Voltage change violation on M20D/M21D	2026	2025	2026

The sensitivity analysis identified the additional capacity needs towards the end of the study period and advanced the triggering date of all the needs. These needs will be assessed again during the next phases of this Regional Planning cycle.

The 2022 forecast from last year's RIP aligns with the actual 2022 loading. Therefore, the high growth scenario can be discounted for now, and monitoring the load growth is recommended.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 7: Needs which do not require regional coordination

Sr.no.	Need	Recommendation
1	Campbell TS (T3/T4) Station Capacity	LDC to propose measures to address capacity needs, if required, Hydro One and Alectra to continue to monitor load levels.
2	Cedar TS (T1/T2) Station Capacity	LDC to propose measures to address capacity needs, if required, Hydro One and Alectra to continue to monitor load levels.
3	Kitchener MTS #7 Station Capacity	LDC to monitor load levels and manage any overloading through load transfers.
4	Cedar TS (T7/T8) Station Capacity	LDC to propose measures to address capacity needs, if required. Hydro One and Alectra to continue to monitor load levels. Advancing and upsizing Cedar transformers is also being considered as an option
5	Waterloo North MTS #3 Station Capacity	LDC to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term.
6	Rush MTS Station Capacity	LDC to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term.

Table 8: Needs which require further regional coordination

Sr.no.	Need	Recommendation
1	Preston TS Station Capacity	To be further assessed in the next RP phases. Hydro One and Grandbridge Energy to keep monitoring load levels
2	Energy Inc MTS Station Capacity	To be further assessed in the next RP phases. Grandbridge Energy to monitor load levels

3	Overload - M20D/M21D post contingency capacity violation (Galt Jct x Cambridge #1 Jct)-	To be further assessed in the next RP phases.
4	System security violation - M21D/M20D 230 kV circuits	To be further assessed in the next RP phases.
5	Voltage violations – On 230 kV M20D or M21D circuit for loss of companion circuit.	To be further assessed in the next RP phases.
6	Load restorations -M20D or M21D due to single tower outage	To be further assessed in the next RP phases.
7	Overload - D11K/D12K 115 kV circuits experience post contingency violation (Detweiler TS x Kitchener MTS#1 & #4 Jct.)	To be further assessed in the next phases. Enova Power Corp to explore load transfers between their stations. H1 and Enova Power Corp to monitor load levels.

List of LDC(s) to be involved in further regional planning activities:

- Grandbridge Energy
- Enova Power Corp.

List of LDC(s) which are not required to be involved in further regional planning phases: (if any)

- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: KWCG Region – Non-Coincident- Normal Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	35.1	34.2	17.8	20.1	21.8	22.6	23.8	24.6	26.0	27.3	28.6
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.3	89.1	88.8	89.2	89.2	89.5	90.0	91.0
Campbell TS (T3/T4)	56.3	45.7	46.9	54.2	56.2	56.7	56.8	57.3	57.6	58.1	58.7	59.3
Cedar TS (T1/T2)	103.3	82.5	89.0	90.7	92.0	94.8	95.8	97.6	99.1	101.3	103.5	105.4
Cedar TS (T7/T8)	39.9	40.7	45.0	46.8	48.3	50.6	51.2	52.1	52.9	54.0	55.1	56.0
Elmira TS	55.0	36.7	33.8	33.9	34.0	34.2	34.2	36.4	36.5	36.7	37.0	37.3
Energy Inc(Cam) MTS#1	101.7	115.2	125.5	130.5	135.6	141.3	146.3	152.5	158.5	164.9	172.4	179.7
Fergus TS	153.5	91.0	93.9	95.9	98.6	101.9	104.9	108.3	110.7	113.5	117.7	120.0
Galt TS	169.4	113.6	117.0	121.9	126.7	132.1	136.7	142.5	148.1	154.6	161.5	168.4
Hanlon TS	42.9	25.7	27.9	28.7	29.2	30.1	30.8	31.7	32.4	33.6	34.7	36.2
Kitchener MTS # 1	54.0	26.1	27.5	28.9	30.2	31.7	34.2	36.9	39.6	42.2	45.1	47.9
Kitchener MTS # 3	108.0	55.1	48.2	59.1	60.1	61.3	63.0	65.2	67.2	85.0	95.9	98.2
Kitchener MTS # 4	90.0	58.6	71.8	63.1	64.4	65.9	68.2	71.0	73.6	76.3	79.3	82.2
Kitchener MTS#5	79.7	72.0	58.1	77.2	78.4	80.0	91.4	94.8	97.7	100.6	98.5	102.5
Kitchener MTS#6	90.0	57.0	64.7	61.1	62.3	63.6	65.7	68.1	70.4	72.7	75.4	78.0
Kitchener MTS#7	54.0	37.4	39.8	40.6	41.7	43.0	44.9	47.2	49.4	51.6	54.1	56.5
Kitchener MTS#8	54.0	36.2	36.5	40.0	41.6	43.3	46.5	50.1	53.5	41.1	44.7	48.3
Kitchener MTS#9	90.0	32.3	20.3	28.7	29.5	30.3	37.5	38.9	40.3	41.7	43.2	44.7
Preston TS[3]	112.5	102.4	109.8	135.5	144.5	190.1	198.0	206.4	214.4	223.0	233.0	242.8
Puslinch DS	56.3	32.7	39.6	40.3	41.0	41.8	42.3	43.0	43.7	44.4	45.4	46.2
Rush MTS	67.5	50.6	54.7	55.6	56.6	57.8	58.6	62.0	65.3	69.4	73.7	78.0
Scheifele MTS (T3/T4)	99.0	83.6	89.7	91.3	92.9	94.9	96.1	101.9	107.3	114.0	113.7	110.1
Scheifele MTS (T1/T2)	62.1	50.5	54.0	55.0	56.0	57.1	57.9	61.4	64.7	58.0	54.8	58.8
Waterloo North MTS#3	76.5	48.4	52.6	53.5	54.5	55.6	56.3	59.7	62.9	77.4	86.0	90.3
Wolverton DS	54.4	18.2	18.2	18.7	19.1	19.7	20.0	20.6	21.0	21.6	22.2	22.8
CTS 1		4.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3] Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.2:KWCG Region – Coincident – Normal Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	30.0	34.2	17.8	20.1	21.8	22.6	23.8	24.6	26.0	27.3	28.6
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.3	89.1	88.8	89.2	89.2	89.5	90.0	91.0
Campbell TS (T3/T4)	56.3	43.0	44.0	50.8	52.8	53.3	53.3	53.8	54.1	54.5	55.2	55.7
Cedar TS (T1/T2)	103.3	57.1	61.6	62.7	63.6	65.6	66.2	67.5	68.6	70.0	71.6	73.0
Cedar TS (T7/T8)	39.9	40.4	44.6	46.3	47.9	50.1	50.7	51.7	52.4	53.5	54.6	55.5
Elmira TS	55.0	36.7	33.6	33.7	33.8	34.0	34.0	36.2	36.3	36.5	36.8	37.1
EnergyInc(Cam) MTS#1	101.7	95.8	105.0	109.2	113.5	118.3	122.4	127.6	132.6	138.0	144.3	150.5
Fergus TS	153.5	86.2	88.1	89.9	92.5	95.6	98.5	101.6	103.9	106.5	110.6	112.9
Galt TS	169.4	83.8	91.5	95.4	99.2	103.4	107.0	111.6	116.0	121.2	126.6	132.1
Hanlon TS	42.9	24.3	26.4	27.1	27.6	28.5	29.1	30.0	30.6	31.8	32.8	34.2
Kitchener MTS # 1	54.0	25.1	26.4	27.8	29.1	30.5	32.9	35.5	38.1	40.6	43.4	46.1
Kitchener MTS # 3	108.0	51.8	45.3	55.5	56.4	57.6	59.2	61.2	63.1	79.8	90.1	92.2
Kitchener MTS # 4	90.0	53.9	66.1	58.1	59.3	60.7	62.8	65.4	67.8	70.3	73.0	75.7
Kitchener MTS#5	79.7	65.8	53.0	70.4	71.6	73.0	83.5	86.6	89.2	91.8	90.0	93.6
Kitchener MTS#6	90.0	49.5	56.2	53.0	54.0	55.2	57.0	59.1	61.1	63.2	65.5	67.7
Kitchener MTS#7	54.0	34.4	36.6	37.3	38.4	39.5	41.4	43.5	45.5	47.5	49.8	52.0
Kitchener MTS#8	54.0	32.7	32.8	36.0	37.4	39.0	41.9	45.1	48.2	37.0	40.3	43.5
Kitchener MTS#9	90.0	29.2	17.7	25.3	26.0	26.7	33.7	35.1	36.3	37.5	39.0	40.3
Preston TS[3]	112.5	98.8	108.3	133.7	142.6	187.6	195.4	203.7	211.6	220.1	229.9	239.6
Puslinch DS	56.3	32.1	38.9	39.5	40.2	41.0	41.5	42.2	42.9	43.6	44.5	45.4
Rush MTS	67.5	46.3	50.0	50.9	51.8	52.9	53.6	56.8	59.8	63.5	67.5	71.4
Scheifele MTS (T3/T4)	99.0	75.2	80.6	82.0	83.5	85.2	86.4	91.5	96.4	102.4	102.2	98.9
Scheifele MTS (T1/T2)	62.1	49.6	53.0	54.0	54.9	56.1	56.8	60.2	63.5	57.0	53.8	57.7
Waterloo North MTS#3	76.5	43.0	46.4	47.3	48.1	49.1	49.8	52.7	55.5	68.3	75.9	79.7
Wolverton DS	54.4	13.2	14.4	14.8	15.1	15.5	15.8	16.3	16.6	17.1	17.6	18.1
CTS 1		2.1	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3]Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.3: KWCG Region Non-Coincident – High Growth Net Load Forecast

Station/DESN	LTR	Historical	Summer Net Forecast									
	(MW)	(MW)	(MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45	35.1	34.2	17.8	21.2	23.8	25.0	26.8	28.1	30.1	32.0	34.0
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.7	90.0	89.6	90.1	90.2	90.5	91.3	92.9
Campbell TS (T3/T4)	56.3	45.7	46.9	54.2	57.1	58.0	58.1	58.8	59.3	60.0	61.0	61.8
Cedar TS (T1/T2)	103.3	82.5	89.0	90.7	92.7	96.8	98.3	101.1	103.3	106.6	109.9	112.8
Cedar TS (T7/T8)	39.9	40.7	45.0	46.8	49.1	52.5	53.4	54.8	55.9	57.6	59.3	60.7
Elmira TS	55	36.7	33.8	33.9	34.1	34.4	34.3	37.7	37.9	38.1	38.6	39.0
EnergyInc(Cam) MTS#1	101.7	115.2	125.5	130.5	138.2	146.8	154.2	163.5	172.5	182.1	193.3	204.4
Fergus TS	153.5	91.0	93.9	95.9	100.0	105.0	109.5	114.5	118.1	122.3	128.6	132.1
Galt TS	169.4	113.6	117.0	121.9	129.1	137.2	144.1	152.9	161.3	171.0	181.4	191.7
Hanlon TS	42.9	25.7	27.9	28.7	29.4	30.8	31.8	33.3	34.2	36.1	37.6	39.9
Kitchener MTS # 1	54	26.1	27.5	28.9	30.9	33.0	36.8	40.9	44.9	48.9	53.2	57.4
Kitchener MTS # 3	108	55.1	48.2	59.1	60.6	62.4	65.0	68.3	71.2	98.0	114.4	117.8
Kitchener MTS # 4	90	58.6	71.8	63.1	65.0	67.3	70.8	75.0	78.9	83.0	87.5	91.8
Kitchener MTS#5	79.7	72.0	58.1	77.2	79.1	81.4	98.6	103.7	107.9	112.3	109.2	115.1
Kitchener MTS#6	90	57.0	64.7	61.1	62.9	64.9	67.9	71.7	75.1	78.6	82.5	86.4
Kitchener MTS#7	54	37.4	39.8	40.6	42.3	44.2	47.1	50.6	53.8	57.2	60.9	64.4
Kitchener MTS#8	54	36.2	36.5	40.0	42.4	45.0	49.8	55.1	60.2	41.7	47.1	52.5
Kitchener MTS#9	90	32.3	20.3	28.7	29.9	31.2	41.8	44.1	46.1	48.2	50.5	52.7
Preston TS[3]	112.5	102.4	109.8	135.5	149.0	217.3	229.3	241.8	253.9	266.8	281.7	296.5
Puslinch DS	56.3	32.7	39.6	40.3	41.3	42.5	43.2	44.4	45.4	46.5	47.9	49.2
Rush MTS	67.5	50.6	54.7	55.6	57.1	58.9	60.0	65.2	70.2	76.2	82.8	89.2
Scheifele MTS (T3/T4)	99	83.6	89.7	91.3	93.7	96.7	98.6	107.1	115.3	125.3	124.9	119.5
Scheifele MTS (T1/T2)	62.1	50.5	54.0	55.0	56.5	58.2	59.4	64.5	69.5	59.6	54.7	60.7
Waterloo North MTS#3	76.5	48.4	52.6	53.5	54.9	56.6	57.8	62.8	67.6	89.3	102.2	108.7
Wolverton DS	54.4	18.2	18.2	18.7	19.4	20.2	20.7	21.5	22.2	23.0	24.0	24.9
CTS 1		4.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10	20.6

[3] Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.4: KWCG Region – Coincident – High Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	30.0	34.2	17.8	21.2	23.8	25.0	26.8	28.1	30.1	32.0	34.0
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.7	90.0	89.6	90.1	90.2	90.5	91.3	92.9
Campbell TS (T3/T4)	56.3	43.0	44.0	50.8	53.7	54.5	54.6	55.3	55.7	56.4	57.4	58.1
Cedar TS (T1/T2)	103.3	57.1	61.6	62.7	64.1	67.0	68.0	69.9	71.5	73.7	76.0	78.1
Cedar TS (T7/T8)	39.9	40.4	44.6	46.3	48.6	52.0	52.9	54.3	55.4	57.1	58.7	60.1
Elmira TS	55.0	36.7	33.6	33.7	33.9	34.2	34.1	37.5	37.6	37.9	38.4	38.8
EnergyInc(Cam) MTS#1	101.7	95.8	105.0	109.2	115.6	122.8	129.1	136.9	144.4	152.5	161.9	171.2
Fergus TS	153.5	86.2	88.1	89.9	93.8	98.5	102.7	107.5	110.9	114.9	121.0	124.3
Galt TS	169.4	83.8	91.5	95.4	101.0	107.4	112.9	119.7	126.3	134.1	142.3	150.4
Hanlon TS	42.9	24.3	26.4	27.1	27.8	29.2	30.1	31.4	32.3	34.1	35.6	37.7
Kitchener MTS # 1	54.0	25.1	26.4	27.8	29.7	31.8	35.4	39.4	43.2	47.1	51.2	55.2
Kitchener MTS # 3	108.0	51.8	45.3	55.5	56.9	58.6	61.0	64.1	66.9	92.0	107.4	110.6
Kitchener MTS # 4	90.0	53.9	66.1	58.1	59.9	61.9	65.2	69.1	72.7	76.4	80.5	84.5
Kitchener MTS#5	79.7	65.8	53.0	70.4	72.2	74.3	90.0	94.7	98.6	102.5	99.7	105.1
Kitchener MTS#6	90.0	49.5	56.2	53.0	54.6	56.4	59.0	62.2	65.2	68.2	71.7	75.0
Kitchener MTS#7	54.0	34.4	36.6	37.3	38.9	40.6	43.4	46.6	49.6	52.6	56.1	59.3
Kitchener MTS#8	54.0	32.7	32.8	36.0	38.2	40.5	44.9	49.7	54.3	37.5	42.5	47.3
Kitchener MTS#9	90.0	29.2	17.7	25.3	26.3	27.5	38.0	40.0	41.8	43.7	45.8	47.8
Preston TS[3]	112.5	98.8	108.3	133.7	147.0	214.5	226.3	238.6	250.6	263.3	278.0	292.6
Puslinch DS	56.3	32.1	38.9	39.5	40.5	41.7	42.4	43.6	44.6	45.6	47.0	48.3
Rush MTS	67.5	46.3	50.0	50.9	52.3	53.9	55.0	59.7	64.3	69.8	75.8	81.6
Scheifele MTS (T3/T4)	99.0	75.2	80.6	82.0	84.2	86.9	88.6	96.3	103.6	112.6	112.3	107.4
Scheifele MTS (T1/T2)	62.1	49.6	53.0	54.0	55.4	57.2	58.3	63.4	68.2	58.5	53.7	59.6
Waterloo North MTS#3	76.5	43.0	46.4	47.3	48.5	50.0	51.0	55.4	59.7	78.9	90.3	96.0
Wolverton DS	54.4	13.2	14.4	14.8	15.3	15.9	16.4	17.0	17.6	18.2	19.0	19.7
CTS 1		2.1	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3]Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Arlen MTS	115	B5C/B6C
2.	Campbell TS (T1/T2)	230	D6V/D7V
3.	Campbell TS (T3/T4)	230	D6V/D7V
4.	Cedar TS (T1/T2)	115	B5C/B6C
5.	Cedar TS (T7/T8)	115	B5C/B6C
6.	Elmira TS	115	D10H
7.	Energy+ MTS #1	230	M20D/M21D
8.	Fergus TS	230	D6V/D7V
9.	Galt TS	230	M20D/M21D
10.	Hanlon TS	115	B5C/B6C
11.	Kitchener MTS # 1	115	D11K/D12K
12.	Kitchener MTS # 3	115	D7F/D9F
13.	Kitchener MTS # 4	115	D11K/D12K
14.	Kitchener MTS #5	115	F11C/F12C
15.	Kitchener MTS #6	230	M20D/M21D
16.	Kitchener MTS #7	115	D7F/D9F
17.	Kitchener MTS #8	230	M20D/M21D
18.	Kitchener MTS #9	230	D4W/D5W
19.	Preston TS	230	M20D/M21D
20.	Puslinch DS	115	B5C/B6C
21.	Rush MTS	115	D10H/D8S
22.	Scheifele MTS	230	D6V/D7V
23.	Waterloo North MTS#3	230	D6V/D7V
24.	Wolverton DS	115	D7F/D9F
25.	CTS - 1	230	M20D/M21D
26.	CTS - 2	115	B5C/B6C

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1.	D6V/ D7V	Detweiler TS	Orangeville TS
2.	M20D/ M21D	Detweiler TS	Middleport TS
3.	D4W/ D5W	Detweiler TS	Buchanan TS
4.	B22D/ B23D	Detweiler TS	Bruce TS
5.	D7F/ D9F	Detweiler TS	Free Port SS
6.	F11C/ F12C	Free Port SS	Cedar TS
7.	B5C/ B6C	Cedar TS	Burlington TS
8.	D11K/ D12K	Detweiler TS	Kitchener MTS #4
9.	D8S	Detweiler TS	St. Mary TS
10.	D10H	Detweiler TS	Hanover TS

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Energy + Inc
2	Alectra
3	H1 Distribution
4	Enova Power Corp
5	Centre Wellington Hydro
6	Halton Hills Hydro
7	Milton Hydro
8	Wellington North Power Inc

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Township of Blandford-Blenheim
2	City of Cambridge
3	City of Kitchener
4	City of Waterloo
5	Regional Municipality of Waterloo
6	Township of North Dumfries
7	Township of Wellesley
8	Township of Wilmot
9	Township of Woolwich
10	Region of Waterloo
11	City of Guelph
12	County of Wellington
13	Township of Centre Wellington
14	Township of Puslinch
15	County of Perth
16	Town of St. Marys

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Kitchener-Waterloo-Cambridge-Guelph Integrated Regional Resource Plan

July 8, 2026

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Powering Tomorrow.

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CTS	Customer Transformer Station
DER	Distributed Energy Resource
DESN	Dual-Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	electricity Demand-Side Management
EOL	End-of-life
FIT	Feed-in-Tariff
GBE	GrandBridge Energy
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
km	kilometre
kV	kilovolt
KWCG	Kitchener-Waterloo-Cambridge-Guelph
LDC	Local Distribution Company
LMC	Load-Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere

Acronym	Definition
MW	Megawatt
MWh	Megawatt-hour
NWA	Non-Wires Alternative
ORTAC	Ontario Resource and Transmission Assessment Criteria
SS	Switching Station
TS	Transformer Station

Executive Summary

The Kitchener-Waterloo-Cambridge-Guelph Integrated Regional Resource Plan (KWCG IRRP) addresses electricity needs in the region over the twenty-year period from 2026-2045. The KWCG region is in southwestern Ontario, and encompasses the Region of Waterloo, the cities of Kitchener, Waterloo, Cambridge, and Guelph, and the townships of Wellesley, Woolwich, Wilmot, North Dumfries, portions of Perth, and Oxford. Wellington county and the municipalities of Blandford-Blenheim, Centre Wellington, Guelph/Eramosa, and Puslinch are also included.

Regional electricity planning for the KWCG region has occurred regularly, with this being the third IRRP published since 2015. This IRRP builds upon those previous regional and bulk plans to continue to ensure reliable electricity supply across the region. In this iteration, electricity demand in KWCG is expected to grow rapidly, driven by strong residential, commercial, and industrial development, increasing electrification, and new large loads such as data centres. Significant population and employment growth —alongside major developments like new housing, healthcare facilities, and commercial expansion — will further accelerate electricity needs. In addition, climate change and local climate action plans are expected to increase demand through greater adoption of electric heating, cooling, and electric vehicles, contributing to higher winter peaks.

Engagement was a key input to the development of this IRRP. The IESO engaged with municipalities, stakeholders, and the public throughout the planning process. Activities included targeted one-on-one discussions and four public webinars to share information and solicit written feedback. The overarching themes of feedback received primarily focused on demand forecast inputs and assumptions; leveraging existing and local generation; and regulations for reserving capacity for critical public infrastructure. The feedback received helped shape the demand forecast, identify local priorities, and inform the recommended solutions.

In response to significant growth, the Technical Working Group recommends both immediate actions and longer-term investments:

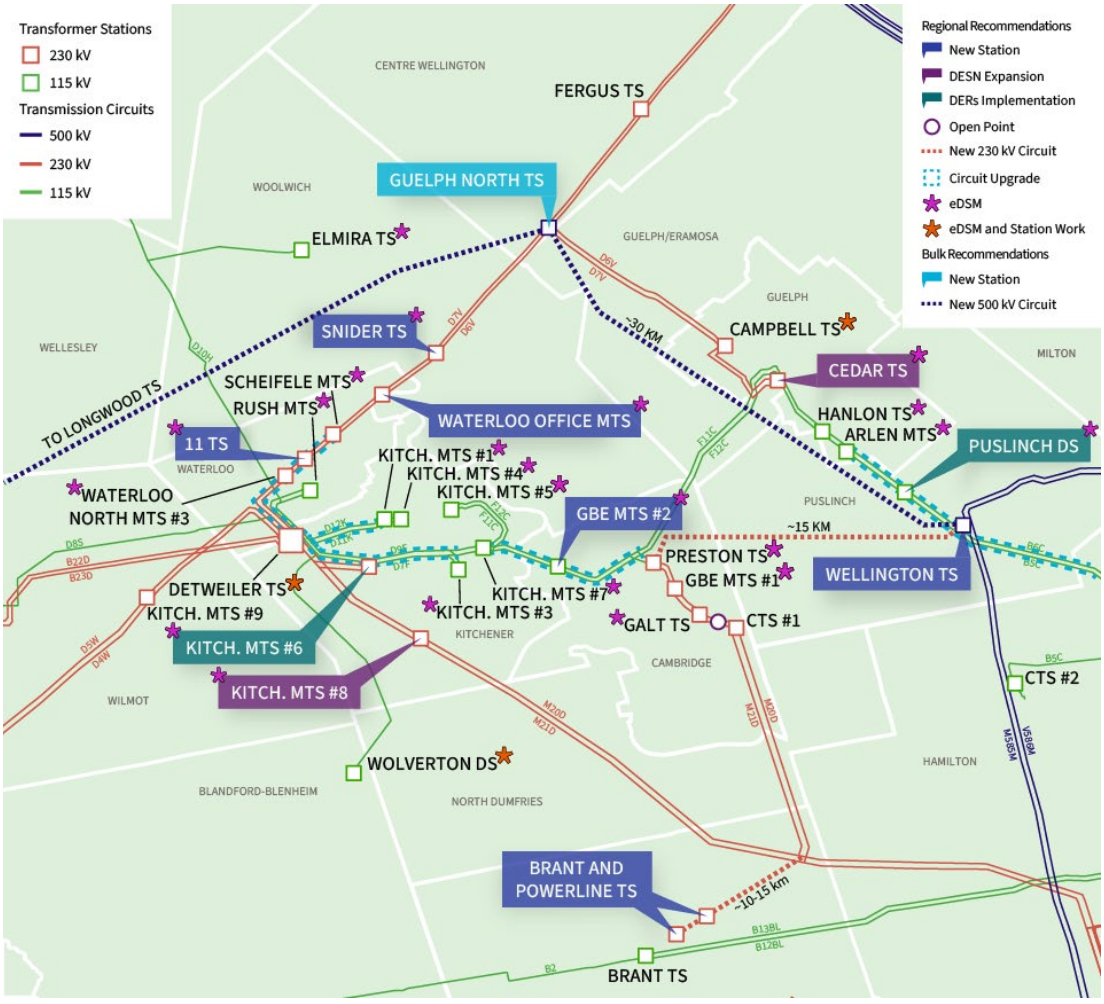
- Considering additional peak demand savings available from electricity demand-side management programming;
- Constructing a 500/230 kV autotransformer station in Puslinch, with a double-circuit 230 kV transmission line connecting it with Preston Transformer Station (TS);
- Conducting station work at Detweiler TS to mitigate the adverse impact of the existing operating instructions to manually trip the static VAR compensator or capacitor under certain breaker-open conditions, and exploring reactive support on the 115 kV sub-system;
- Converting Cedar T7/T8 to 230 kV upon its end of life to address the local station capacity need;
- Uprating various existing 115 kV circuits, as well as sections of the 230 kV circuits between Detweiler and Orangeville;
- Transferring loads on the distribution system to maximize the use of existing transformer stations and supply capability;

- Constructing new 115 kV and 230 kV transformer stations in Cambridge, Kitchener, Guelph, and the Waterloo area;
- Implementing station work at Campbell TS and Wolverton Distribution Station (DS) to increase their capacity; and
- Implementing distributed energy resources at Puslinch DS and Kitchener Municipal Transformer Station #6 to solve station capacity needs.

The Technical Working Group will continue to monitor growth across the region to determine if or when further reinforcements will be needed — including long-term options identified in this plan for a switching station at Galt and further 230 kV transmission lines to Waterloo or Kitchener. The Technical Working Group will meet to develop the Regional Infrastructure Plan, as well as annually between regional planning cycles to monitor any future community energy plans, electrification trends, customer connection queues, and changes to local generation. If underlying assumptions change significantly, plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

The figure below visually depicts the near- to medium-term IRRP recommendations across the KWCG region (note that distribution-level load transfers are omitted for simplicity).

Figure 1 | Overview of Recommended Solutions for the KWCG IRRP



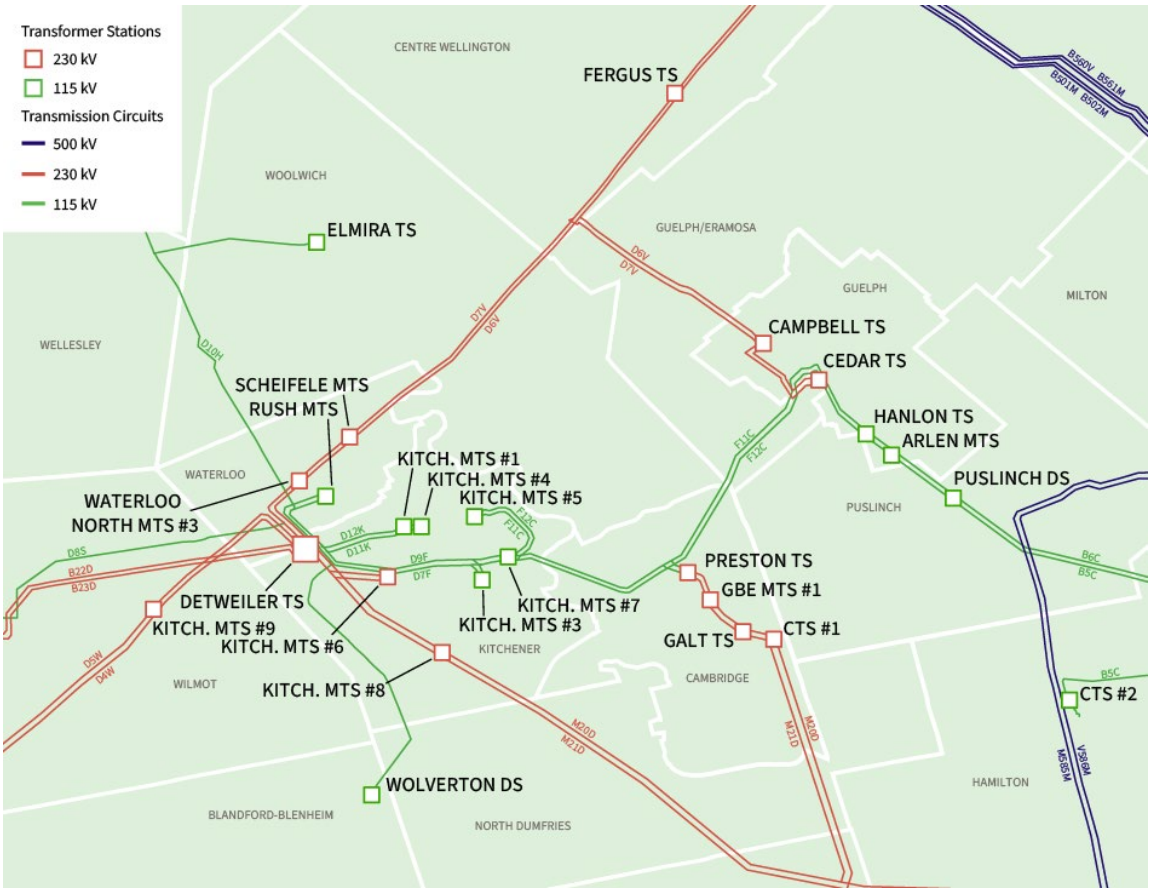
1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region over the 20-year period from 2026 to 2045. The KWCG region is in southwestern Ontario, and encompasses the Region of Waterloo, the cities of Kitchener, Waterloo, Cambridge, and Guelph, and the townships of Wellesley, Woolwich, Wilmot, North Dumfries, portions of Perth, and Oxford. Wellington county and the municipalities of Blandford-Blenheim, Centre Wellington, Guelph/Eramosa, and Puslinch are also included in the region.

The IESO also acknowledges that KWCG is the traditional territory of many nations, and is committed to ongoing, meaningful dialogue with Indigenous communities to inform long-term planning in the region and across Ontario. To raise awareness about the regional planning cycle in KWCG, and invite participation in the engagement process, the IESO's engagement efforts included outreach to Indigenous communities throughout the development of the plan, including to the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, and Métis Nation of Ontario.
The region's electricity is delivered by eight Local Distribution Companies (LDCs): Enova Power, Alectra Utilities, GrandBridge Energy, Centre Wellington Hydro, Wellington North Power, Halton Hills Hydro Inc., Hydro One Networks Inc. ("Hydro One Distribution"), and Milton Hydro. Hydro One Networks Inc. ("Hydro One Transmission") is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of the LDCs, Hydro One Transmission, and the IESO.

Figure 2 depicts the electrical transmission infrastructure for the KWCG region. Power is transmitted into the region via 230 kilovolt (kV) and 115 kV circuits originating from Detweiler Transformer Station (TS) and Burlington TS. There are also load stations supplied by double-circuit 230 kV lines connecting Detweiler TS from Orangeville TS (D6V & D7V), Middleport TS (M20D & M21D), and Buchanan TS (D2W & D5W).

Figure 2 | Map of the KWCG Region and Transmission System



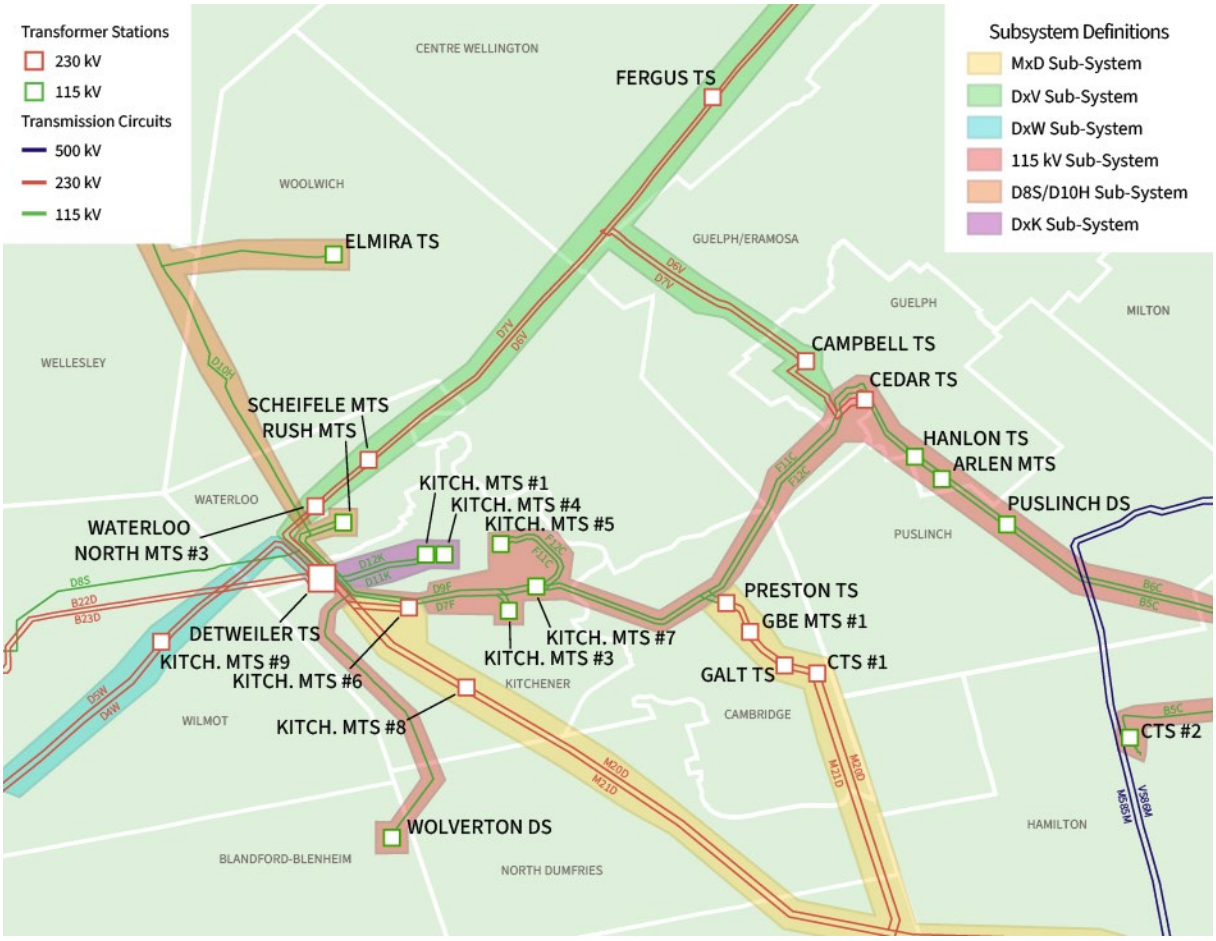
For the purposes of regional planning, the KWCG region has been divided into multiple electrical sub-systems, as shown below in Figure 3.

Detweiler is currently the key bulk supply point for the KWCG region, so many of the sub-systems are defined with this station. For instance, the **Middleport to Detweiler (MxD) sub-system** in the south of the region is electrically defined by the 230 kV supply that connects Detweiler TS in Kitchener to Preston TS in Cambridge, as well as beyond the KWCG region and into Brant. Multiple transformer stations across Kitchener and Cambridge are served by these MxD circuits.

KWCG is characterized by two other 230 kV sub-systems: the double-circuit lines that connect **Detweiler to Orangeville (DxV)**, and **Detweiler to Buchanan (DxW)**. These sub-systems connect the KWCG region to neighbouring regions, but they also supply stations across Waterloo, Wilmot, Guelph, and Centre Wellington.

Much of the KWCG region is otherwise supplied by three lower voltage sub-systems: the **115 kV sub-system** that serves most of Kitchener and to the northeast in Guelph and Puslinch, as well as radial 115 kV lines between **Detweiler and Elmira TS (D10H), Detweiler and Rush Municipal Transformer Station (MTS) (D8S/D10H)**, and **Detweiler and Kitchener MTS #1 and #4 (DxK)**.

Figure 3 | Map of the KWCG Region Sub-Systems



There are two transmission-connected customers in the region served by Customer Transformer Stations (CTS). The distribution-connected resources (DERs), or distributed generation (DG), in the region include solar and wind resources; there are currently no local generation resources connected at the transmission level.

This report is the culmination of the KWCG IRRP, which was initiated in July 2024 following the publication of the Needs Assessment Report in April 2024 by Hydro One, and the Scoping Assessment Outcome Report in July 2024 by the IESO. The Scoping Assessment identified needs requiring further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and recommend appropriate investments or other electricity system initiatives.

2. The Integrated Regional Resource Plan

The electricity demand forecast, provided by the LDCs for this IRRP, anticipates significant growth over the twenty-year period from 2026 to 2045, driven by population and employment growth, electrification, urban intensification, and commercial sector expansion in KWCG. This IRRP provides recommendations to address electricity needs that arise from this growth. Needs are identified based on the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC), as well as reliability standards governed by the North American Electric Reliability Corporation. The IRRP's recommendations are informed by an evaluation of different options to meet the needs, considering reliability, cost, technical feasibility, maximizing use of the existing electricity system (where economical), and feedback from stakeholders.

The IRRP recommendations below are organized by near-term, medium-term, and other ongoing or long-term initiatives to address needs within the KWCG network. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over different time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term as electrification, energy efficiency, and development plans evolve.

2.1 Status of Ongoing Work

Following the last cycle of region planning, several projects previously recommended have now been completed or are presently underway. The status of these projects is summarized in Table 1.

Table 1 | Summary of Ongoing and Recently Completed Projects

Circuit/Station	Need	Recommended Action	Status
B5C 115 kV transmission line	End of life (EOL)	Line section replacement; line tap section from Harper's JCT to CTS 1	Completed Q3 2025
Hanlon TS (T1 & T2)	EOL	Transformer replacement	Completed Q3 2022
Kitchener MTS #5 (T9 & T10)	EOL	Transformer replacement	Completed Q2 2025
Preston TS (T3 & T4)	EOL	Transformer replacement	Completed Q2 2026
Campbell TS (T1 & T2)	EOL	Breaker replacement	Expected completion in 2032

Circuit/Station	Need	Recommended Action	Status
Scheifele MTS (T1, T2, T3 & T4)	EOL	Transformer replacement	T3/T4 expected completion in 2029-2030; T1/T2 expected completion in 2033-2034
Galt TS	EOL	Breaker and component replacement	Hydro One will continue to monitor and take appropriate action
Fergus TS (T3 & T4)	EOL	Transformer replacement	Hydro One will continue to monitor and take appropriate action
GrandBridge Energy MTS #1 (T1 & T2)	Station Capacity	Load transfer to Galt TS and Preston TS	Underway
Preston TS	Station Capacity	Load transfer to Galt TS and GrandBridge Energy MTS #1	Underway
Scheifele MTS (T1+T3)/(T2+T4)	Station Capacity	Load transfer to Waterloo North MTS #3, Rush MTS, and Elmira TS	Evaluated by Enova Power and completed as needed
Campbell TS (T3 & T4)	Station Capacity	Load transfer to Cedar TS and Cedar TS T1/T2	Need re-evaluated and addressed in this IRRP

2.2 Near- to Medium-Term Plan

The Technical Working Group recommends the near- to medium-term plan outlined below, including several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. These investments include new stations in Cambridge, Puslinch, Waterloo, and Guelph, upgrades to existing transmission lines, station expansions and load transfers in Kitchener, new lines between Cambridge and Puslinch, additional electricity demand-side management (eDSM), and distributed resources.

Table 2 summarizes the near- to medium-term recommendations for KWCG, organized by need and timing.

Table 2 | Summary of the Near- to Medium-Term Plan

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
Wolverton DS station capacity need	Install fan monitoring project.	Hydro One Distribution	2027

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
DxV sub-system supply capacity need	Transfer load from DxV sub-system to DxW sub-system.	Enova Power	2028
115 kV sub-system supply capacity need	Uprate B5C/B6C, D7F/D9F, and F11C/F12C.	Hydro One Transmission	2028
Preston TS, GrandBridge Energy (GBE) MTS #1, and Galt TS station capacity needs	Construct a new 115 kV transformer station (GBE MTS #2) to supply up to 75 MW of load.	GrandBridge Energy	2028
Puslinch DS station capacity need	Implement distributed energy resources.	Hydro One Distribution, with IESO support to explore value-stacking opportunities	2030-2042
Rush MTS, Scheifele MTS, and Waterloo North MTS #3 station capacity needs	Construct 230 kV stations, including 11 TS, Office MTS, and Snider TS	Enova Power	2030+
Kitchener MTS #8 station capacity need	Expand with a new 230 kV Dual-Element Spot Network (DESN).	Enova Power	2030+
MxD sub-system supply, restoration, and security needs	Construct a new 500/230 kV autotransformer station (Wellington TS) in Puslinch, with new double-circuit 230 kV lines to Preston TS and a normally open point at Ameristeel junction. Per the 2024 Burlington to Nanticoke IRRP: Construct two new 230 kV DESNs within or in the vicinity of County of Brant, connecting to the MxD lines.	Hydro One Transmission	2031 or earlier

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
Campbell TS station capacity needs	Install additional metal-clad switchgear to fully utilize T3/T4 capacity and transfer load from T1/T2.	Alectra and Hydro One Transmission	2031
DxV sub-system supply capacity need	Uprate DxV and implement station work at Detweiler TS to mitigate existing operating instructions. Evaluate reactive support (such as low-voltage capacitor at Elmira TS) in the Regional Infrastructure Plan to meet interim needs.	Hydro One Transmission	2031
Cedar T1/T2 and T7/T8 station capacity needs, T7/T8 end-of-life need	Replace T7/T8 with a 230 kV DESN and transfer load from T1/T2 to T7/T8.	Alectra and Hydro One Transmission	2032
Rush MTS station capacity need	Transfer load to new 230 kV stations on DxV sub-system.	Enova Power	2032
Kitchener MTS #1, 4, 5, 6, 7 station capacity needs	Optimize existing station capacity and transfer load on the distribution system between stations.	Enova Power	2033
DxK supply capacity need	Uprate D11K/D12K.	Hydro One Transmission	2033
Kitchener MTS #6 station capacity need	Implement distributed energy resources.	Enova Power, with IESO support to explore value-stacking opportunities	2034-2042

2.3 Long-Term Plan and Other Initiatives

In the long term, the KWCG region's electricity demand is projected to continue to grow. This IRRP recommends long-term actions to ensure that options are preserved to address future needs in the most efficient and cost-effective way, if and when they ultimately arise. Table 3 summarizes the long-term recommendations for KWCG, organized by need.

Table 3 | Summary of the Long-Term Plan for the KWCG IRRP

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Timing
Arlen TS and Hanlon TS station capacity needs	Monitor long-term load growth (including eDSM savings); provide update at the next Annual Technical Working Group meeting between regional planning cycles.	Alectra	2028 (next Annual Technical Working Group meeting)
MxD supply capacity and restoration needs	Monitor long-term load growth between Detweiler TS and Middleport TS and re-evaluate need for Galt Switching Station (SS).	Technical Working Group	2028 (next Annual Technical Working Group meeting)
Kitchener MTS #1, 4, 5, 6, 7 station capacity needs	Monitor distribution load transfers and long-term load growth. In the next regional planning cycle, re-assess needs and 230 kV supply options for a new 230 kV DESN in the Kitchener Freeport area.	Enova Power	2029 (next cycle of regional planning in KWCG begins)
DxV sub-system supply capacity need	Monitor long-term load growth and re-evaluate the need for double-circuit 230 kV lines from Guelph North TS to the Waterloo area in future planning cycles.	Hydro One Transmission, Enova Power	2029 (next cycle of regional planning in KWCG begins)
Preston TS, GBE MTS #1, and Galt TS station capacity needs	Construct a new 230 kV transformer station in Cambridge (GBE MTS #3).	GrandBridge Energy	2035 or earlier (in-service)

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region — defined by common electricity supply infrastructure — over the near, medium, and long term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is led by the IESO, in collaboration with the transmitters and LDCs in each region. It consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which identifies the appropriate mix of investments in conservation and demand management, generation, transmission facilities or distribution facilities, or other electricity system initiatives to address the identified needs of a region requiring coordinated planning; and/or
4. A Regional Infrastructure Plan (RIP), led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in the appendix.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report, is posted on the IESO's website.

3.2 Kitchener-Waterloo-Cambridge-Guelph and IRRP Development

The development of the KWCG IRRP was initiated in July 2024, following the publication of the Needs Assessment report in April 2024 by Hydro One and the Scoping Assessment Outcome Report in July 2024 by the IESO. The Scoping Assessment recommended that the needs identified for the KWCG region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

Electricity planning in Ontario typically occurs on a cyclical basis; this is the third cycle of regional planning for the KWCG region, with earlier IRRPs published in 2015 and 2021. The previous regional recommendations are summarized in the sections below, alongside information on current regional and bulk planning that impacts the KWCG region.

4.1 Previous Regional Planning Cycle

The previous cycle of regional planning for the KWCG region in 2021 implemented a multi-pronged approach to address electricity needs across the region. This includes:

- EOL transformer replacements at Hanlon TS (T1/T2), Kitchener MTS #5 (T9/T10), Preston TS (T3/T4), Scheifele MTS (T1/T2, T3/T4), and Fergus TS (T3/T4);
- EOL breaker replacements at Campbell TS (T1/T2) and Galt TS;
- EOL transmission line replacements on a section of the 115 kV B5/6C line; and
- Various load transfers off stations forecast to be at capacity (GBE MTS #1, Preston TS, Scheifele MTS, Campbell TS (T3/T4), Kitchener MTS #7 (T13/T14), and Kitchener MTS #8 (T15/T16).

The 2021 KWCG IRRP also identified multiple longer-term needs to monitor and assess: supply capacity needs along the B5C and D10H circuits, station capacity needs at Arlen MTS, Hanlon TS, Rush MTS, Elmira TS, Kitchener MTS #1, and Waterloo North MTS #3, and a load restoration need on the M20D/M21D 230 kV lines.

4.2 Bulk Planning and Other Developments

The KWCG region is included in the South and Central Bulk Plan, which the IESO developed to address transmission limitations in a wide-spanning geographic area from Bruce to the Greater Toronto Area, and along the Windsor to Hamilton corridor. The objectives of the study are to enable new generation, enable the phase-out of emitting resources, and support future growth and economic development across various load centres in Ontario.

4.3 Current Cycle of Regional Planning

The current cycle of regional planning began in 2024, with the publication of the Needs Assessment. The 2023 Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan that covers the time period from 2026 to 2045; recommendations are made to meet KWCG regional electricity needs in the near, medium, and long term.

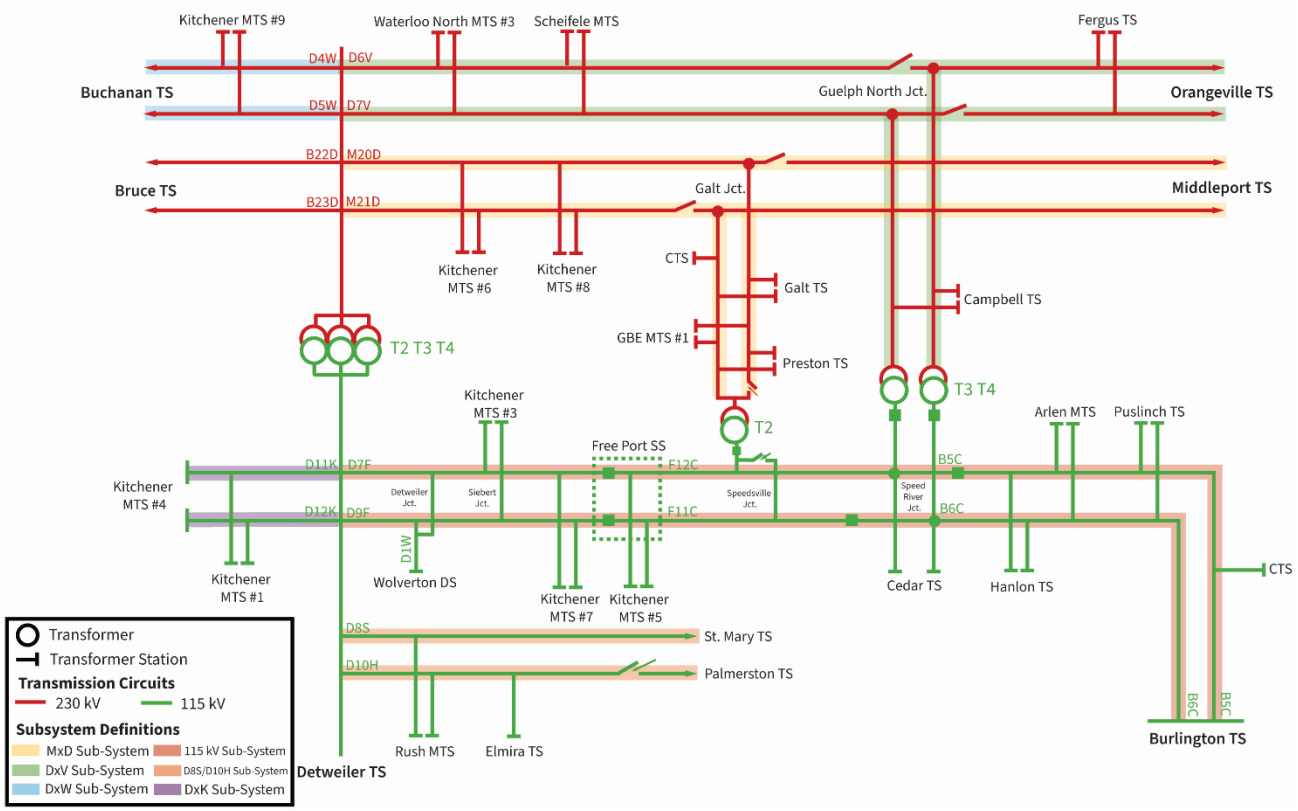
The plan was prepared by the IESO on behalf of the Technical Working Group, and considers forecast electricity demand growth, eDSM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The following transmission facilities were included in the scope of this study:

- Transformer stations: Arlen MTS, Campbell TS (T1/T2), Campbell TS (T3/T4), Cedar TS (T1/T2), Cedar TS (T7/T8), Elmira TS, GrandBridge Energy MTS #1, Fergus TS, Galt TS, Hanlon TS, Kitchener MTS # 1, Kitchener MTS # 3, Kitchener MTS # 4, Kitchener MTS #5, Kitchener MTS #6, Kitchener MTS #7, Kitchener MTS #8, Kitchener MTS #9, Preston TS, Puslinch DS, Rush MTS, Scheifele MTS, Waterloo North MTS #3, Wolverton DS, and two CTS.
- 115 kV transmission circuits: D7F/D9F, F11C/F12C, B5C/B6C, D11K/D12K, D8S, and D10H.
- 230 kV transmission circuits: D6V/D7V, M20D/M21D, D4W/D5W, and B22D/B23D.

The single line diagram of the KWCG region is shown in Figure 4. Note that the bulk system transfer capabilities into the region are not within the scope of the IRRP, and are encompassed in the South and Central Bulk Plan. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

Figure 4 | Single Line Diagram of the KWCG Region



The KWCG IRRP was developed by:

- Establishing alternatives to address system needs, including (where feasible and applicable): generation, transmission and/or distribution, and other approaches such as non-wires alternatives, including additional eDSM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near- and long-term needs.

- Considering the impact of the low and high forecast as a sensitivity of the flexibility and optionality of potential alternatives.
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the KWCG region. It highlights assumptions made for peak demand forecasts, including weather correction, the contribution of eDSM and DG, and the development of low and high growth forecast scenarios. The reference case "Planning Scenario" was derived based on firm loads (current and planned), organic growth, residential development, electrification, community energy plans, and industrial growth as described in more detail in the appendix. The "Planning Forecast" is net of existing DG and eDSM and corrected for extreme weather. It is used to assess the electricity needs of the area over the planning horizon.

The "High Scenario" incorporates potential demand growth that is less certain, in terms of timelines, magnitude, and location, into the Planning Scenario. The "High Forecast" is also the result of the High Scenario adjusted to be net of existing DG and eDSM, and corrected for extreme weather. The High Forecast is used as the basis for sensitivity analysis as described further in Section 5.7.2.

The "Low Scenario" accounts for uncertainty of growth and reconsiders committed growth that may not materialize due to delayed timelines and technological, economical, and political circumstances. The "Low Forecast" is also the result of the Low Scenario adjusted to be net of existing DG and eDSM, and corrected for extreme weather. The Low Forecast is used as the basis for sensitivity analysis as described further in Section 5.7.3.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. In the past, the KWCG region peak loading has historically occurred in the summer. However, with recent developments in electrification and decarbonization, the region is shifting towards winter-peaking.

5.1 Historical Demand

Summer peak electricity demand within the KWCG region has remained stable in the five years prior to this IRRP, which began in 2024. Figure 5 shows the summer coincident net actual, gross actual, and gross median weather-corrected historical demand. The summer gross median weather-corrected demand has averaged just under 1,400 MW over the past five years, with the peak demand hour for each year occurring between approximately 11 a.m. to 5 p.m. in the summer and 2 p.m. to 7 p.m. in the winter.

Since the forecast was developed in 2024, the 2023 summer and winter gross median weather-corrected peaks at each station in the KWCG region were used as the starting points for the forecast.

Figure 5 | Historical Summer Peak Demand in the KWCG Region

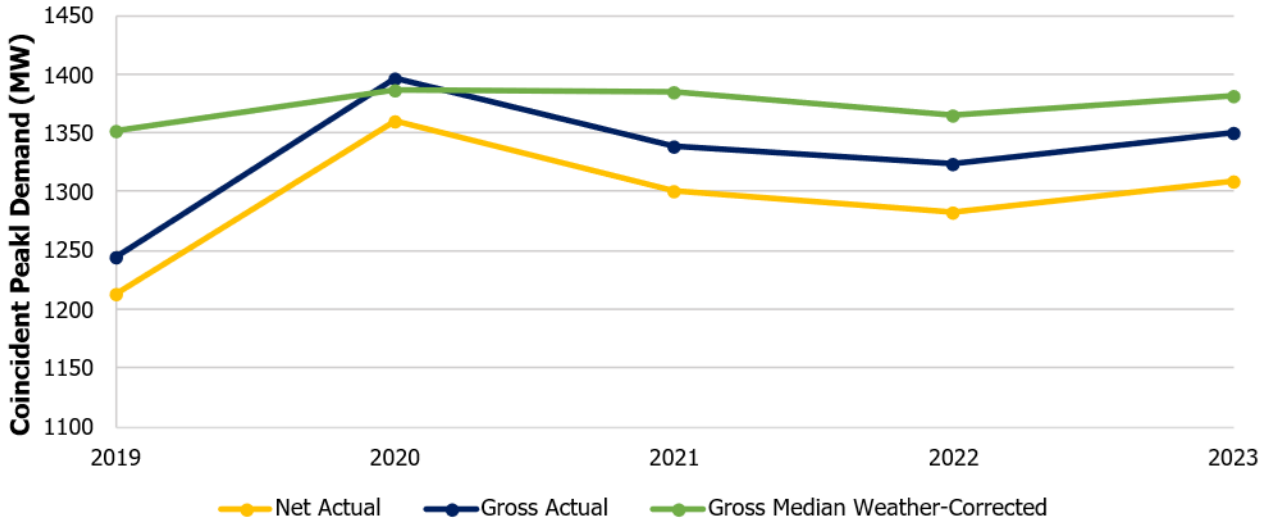
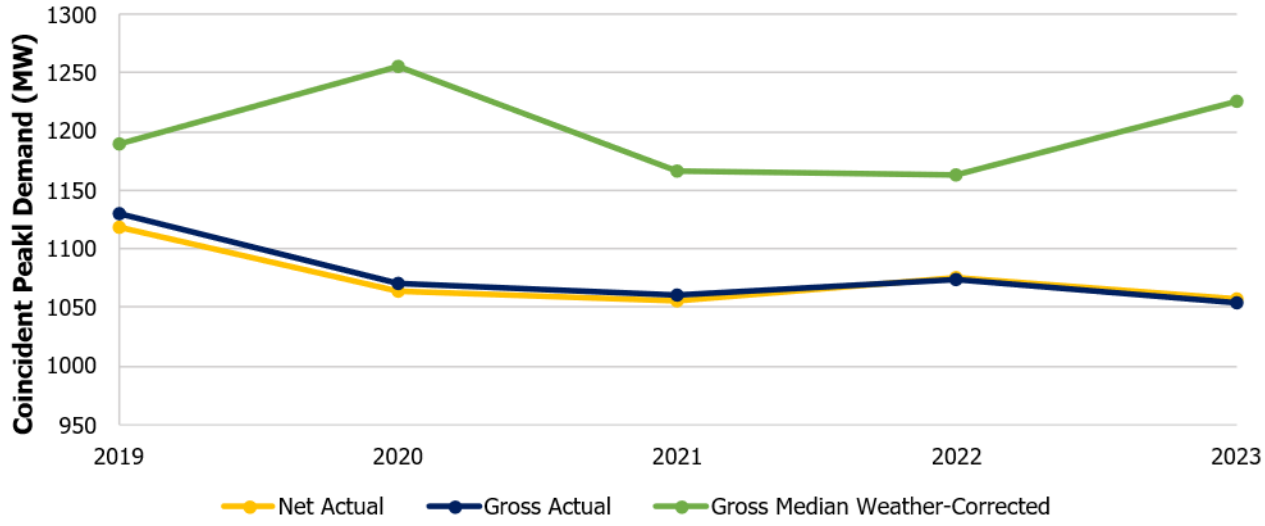


Figure 6 | Historical Winter Peak Demand in the KWCG Region



5.2 Current Drivers of Load Growth

Electricity demand in the KWCG region is projected to grow at a rapid pace due to residential, commercial, and industrial growth, electrification, and several new large developments. This includes several requests to connect from potential data centre customers. Broader economic development across the region and local climate action plans are also expected to be key factors for future electricity needs. These drivers of growth are used by the LDCs to inform the forecasts developed for the region and are discussed in more detail below.

Load growth based on organic growth in the residential, commercial, and industrial sectors is driven by population growth, employment growth, housing activities, and industrial and commercial building activities. The population in the KWCG region is expected to see a large increase over the next 25 years according to the Region of Waterloo Official Plan (923,000 increase by 2051) and City of Guelph Official

Plan (208,000 increase by 2051). This population growth will encourage residential development, and the region expects steady increases in housing as detailed in the Region of Waterloo, County of Wellington, and City of Guelph municipal plans. Employment in the KWCG region is also expected to see an increase over the next 25 years. This is accompanied by new commercial and industrial development, informed by the region's stakeholders which include cities, townships, and large customers. Some examples include new large-scale subdivision expansion, a new Waterloo hospital, planned expansion to existing customer facilities, and new large data centres.

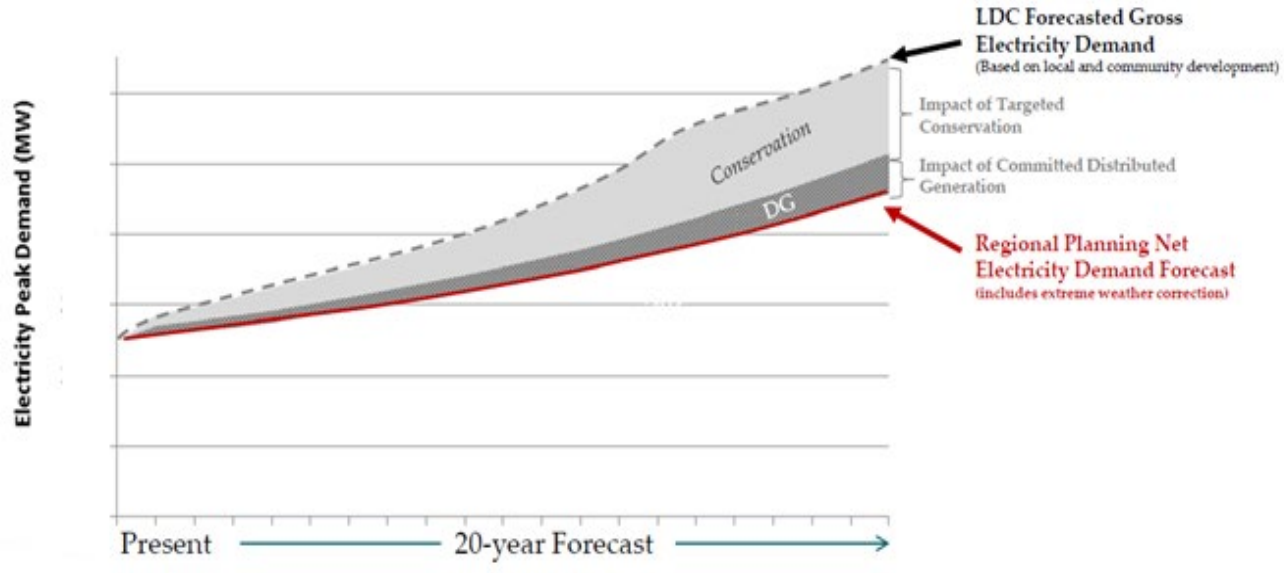
The region anticipates climate change and resulting extreme weather will have an impact on electricity demand due to electrification. As highlighted by Region of Waterloo and City of Guelph climate action plans, the KWCG region will see an increase in temperatures and number of warm days, driving up the need for electric cooling. The electrification of heating is also a key driver and contributes to higher winter demand peaks. In addition to electric heating, electric vehicle uptake is expected to increase in the area due to municipal fleets and more broadly by community members.

5.3 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 7. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT, and adjusted to reflect extreme weather conditions to produce a Planning Forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in the appendix. The Ontario Energy Board has also published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 7 | Illustrative Development of Demand Forecast

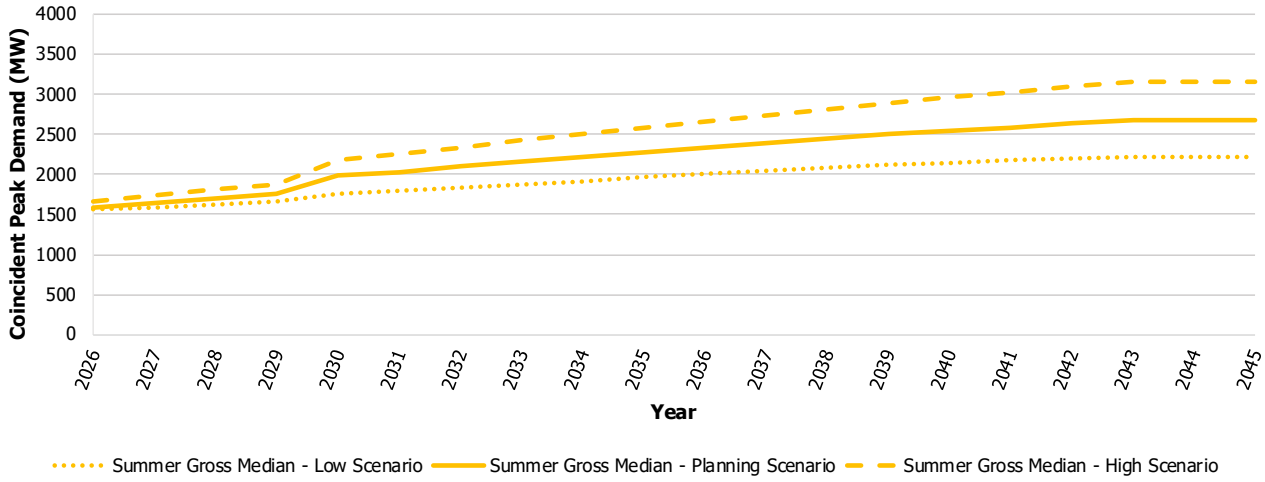


5.4 Gross LDC Forecasts

Each participating LDC in the KWCG region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and in response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.5). The gross LDC forecasts assume median on-peak weather conditions and loading that is coincident to each station.

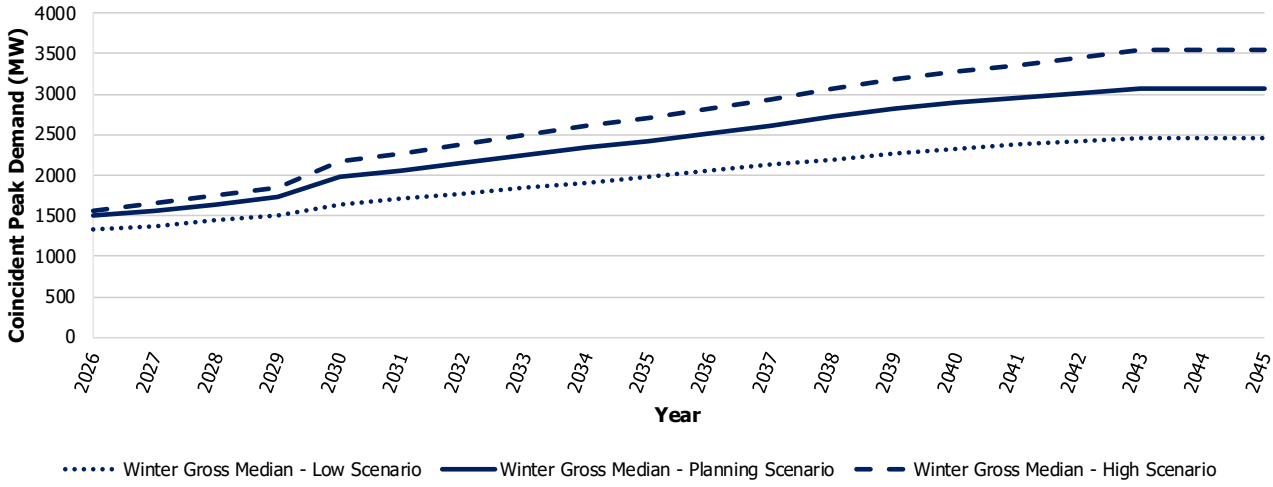
Figure 8 and Figure 9 show the gross coincident demand forecasts provided by the LDCs for the KWCG region under the Low Scenario, Planning Scenario, and High Scenario for summer and winter peak demand.

Figure 8 | Total Summer Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)[1]



[1] Excludes existing transmission-connected industrial customers in the KWCG region (historically contributing an average of 9 MW to the summer coincident peak demand).

Figure 9 | Total Winter Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)[2]



LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities and communities that they serve. The IESO typically carries out demand forecasting at the provincial level. More details on LDC load forecast assumptions can be found in the appendix.

5.5 Contribution of Energy Efficiency to the Forecast

Energy efficiency is a clean and cost-effective resource that helps meet Ontario's electricity needs and is an integral component of provincial and regional planning. Energy efficiency is achieved through a mix of codes and standards amendments, as well as eDSM program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to eDSM program-related activities account for the 2021–2024 Conservation and Demand Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. Under the 2021–2024 Conservation and Demand Management Framework, the IESO centrally delivered programs on a province-wide basis to serve business and residential customers, as well as Indigenous communities.

The KWCG demand forecast was finalized before approval of the new 2025–2036 eDSM Framework and its savings targets, and assumes that programs continue at 2021–2024 Conservation and Demand Framework levels, with adjustments for gross demand growth. The increased targets under the new framework may impact the exact scale and timing of needs.

[2] Excludes existing transmission-connected industrial customers in the KWCG region (historically contributing an average of 7 MW to the winter coincident peak demand).

Figure 9 shows the estimated total yearly reduction to the demand forecast due to energy efficiency (from codes, standards, and eDSM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in the appendix.

Figure 10 | Total Summer Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)

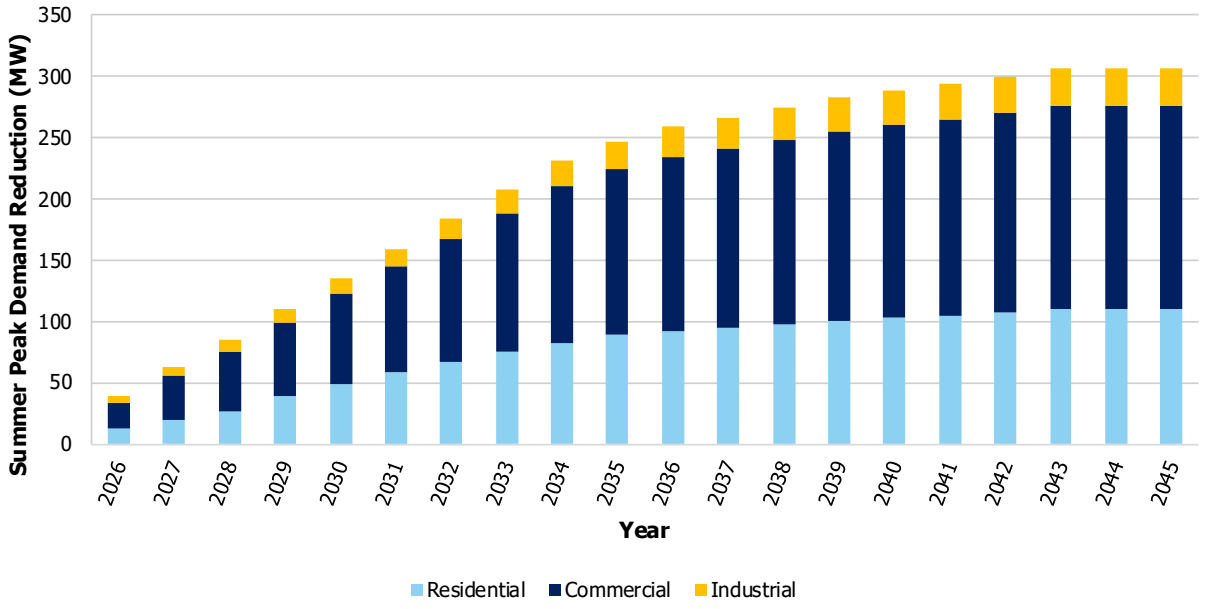
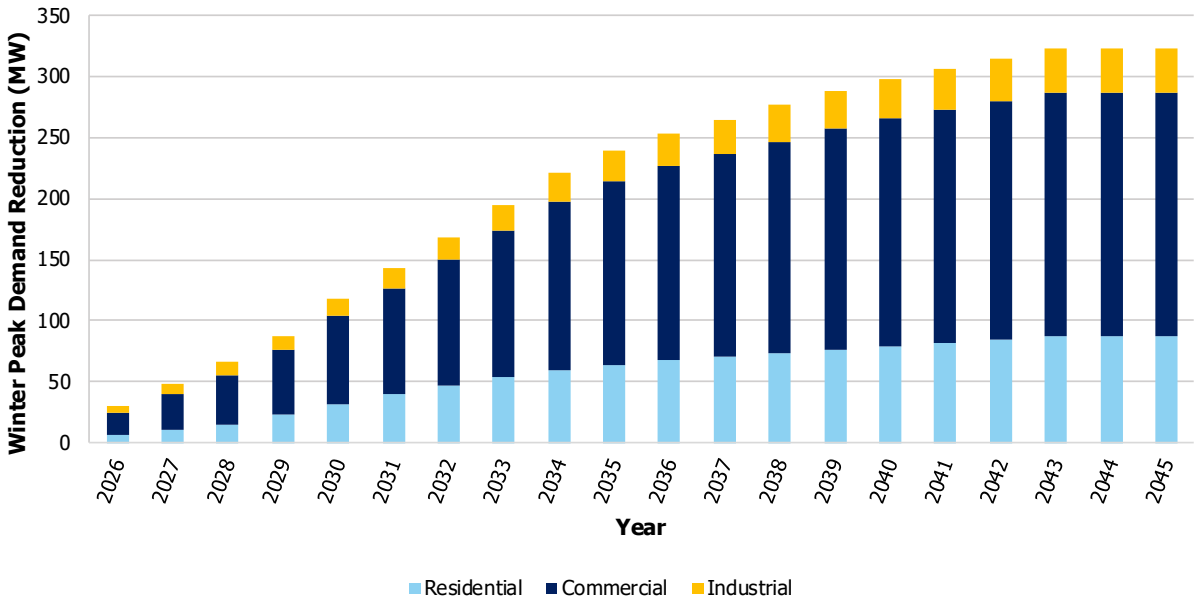


Figure 11 | Total Winter Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)

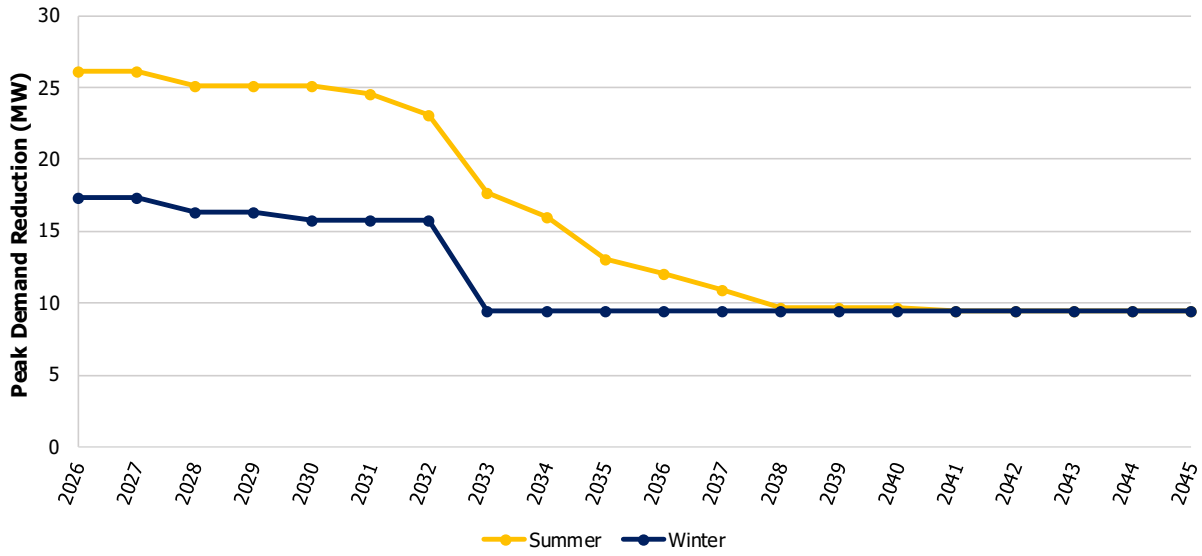


5.6 Contribution of Distributed Generation to the Forecast

In addition to energy efficiency, DG in the KWCG region is also forecast to offset peak demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in of the accompanying IRRP Data Tables (provided as a separate Excel file). All the installed DG capacity in the KWCG region is wind and solar.

After reducing the demand forecast due to energy efficiency (as described in Section 5.5), the forecast is further reduced by the expected contribution from contracted DG. Figure 12 shows the impact of DG on reducing the KWCG region demand forecasts. Note that facilities without a contract with the IESO were not included in the DG peak demand reduction forecast.

Figure 12 | Peak Demand Reduction Due to DG



5.7 Planning Forecasts

After taking into consideration the combined impacts of energy efficiency and DG, a 20-year net demand forecast was produced for the KWCG region considering the Low Scenario, Planning Scenario, and High Scenario. The following subsections describe the implementation of weather correction to create the Low Forecast, Planning Forecast, and High Forecast, and the total demand outlook for the region.

5.7.1 Net Extreme Weather Planning Forecast

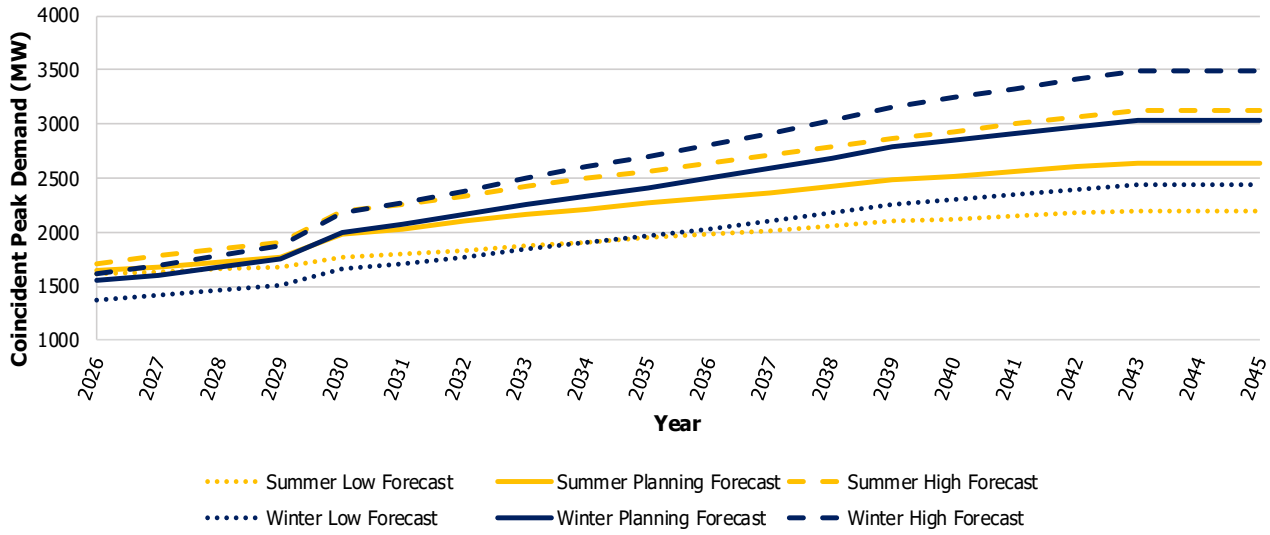
The net extreme weather forecast is created by adjusting the net median weather forecast (the gross demand forecast including the forecast DG and eDSM impacts) for extreme weather conditions. The weather correction methodology is described in the appendix. The Planning Forecast results from the net extreme-weather forecast applied to the Planning Scenario.

Note that this Planning Forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This allows need dates to be identified for regional

needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past five years.

The coincident net extreme weather forecast for the KWCG region is shown in Figure 13 for the Low Forecast, Planning Forecast, and High Forecast representing peak summer and winter demand.

Figure 13 | Net Extreme Weather Planning Forecast, Low Forecast, and High Forecast for the KWCG Region



5.7.2 High Forecast Scenario

The Technical Working Group developed a High Forecast sensitivity scenario for the KWCG region, which is also shown in Figure 13. The High Forecast is meant to quantify prospective development in the KWCG region that is not yet committed. This higher demand scenario is driven by increased electrification rates and increased commitment from prospective large-scale customers looking to connect.

The High Forecast can be used as a proxy for a variety of factors that could drive demand higher over the next 20 years, including, but not limited to:

- electric vehicle charging;
- electrified space and water heating;
- a faster pace of residential development;
- unanticipated new industrial customers of growth among existing industrial customers; and
- data centres.

The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future electricity concerns may be and when they could materialize. This information can also be useful for communities conducting community energy plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders to consider when planning various projects in

the region. Moreover, while developing this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.7.3 Low Forecast Scenario

The Technical Working Group also developed a Low Forecast sensitivity scenario, which is also shown in Figure 13. The Low Forecast is meant to consider slowed organic growth and prospective development in the KWCG region that is committed, but sensitive to economical, technological, political, and social factors. This lower demand scenario is primarily driven by lower electrification rates and lower demand from large-scale customers.

The lower demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where growth could slow down and where future electrical infrastructure improvements could be delayed. Similarly to the High Forecast scenario, this information can be useful for communities conducting community energy plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders to consider when planning various projects in the region. Moreover, while developing this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate lower long-term growth.

5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) were developed to characterize some needs with finer granularity. The profiles were based on historical load data and adjusted for variables that impact demand, such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak Planning Forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of resource options.

Additional load profile details can be found in the appendix. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify precise hourly energy requirements. Real-time loading is subject to various factors, like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of the implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, North American Electric Reliability Corporation TPL-001-5.1, and Northeast Power Coordinating Council Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment (i.e., breakers, disconnect switches, low-voltage bus, or high voltage circuits) or by voltage drop limitations, which are independent of thermal ratings.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is referred to as the load-meeting capability (LMC) of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-5.1, and Northeast Power Coordinating Council Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter or LDC by an asset condition assessment, which is based on a range of considerations, such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early medium-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the KWCG IRRP can be found in the appendix. The needs identified are discussed in Sections 6.3 to 6.7 for each season of each sub-system.

6.2 115 kV Sub-System

The 115 kV sub-system refers to the stations in Kitchener, Guelph, and Puslinch that are served by the Detweiler-Freeport (DxF), Freeport-Cedar (FxC), and Burlington-Cedar (BxC) double-circuit 115 kV circuits. There is an asset replacement need at Cedar TS T7/T8 and station capacity needs at Arlen TS, Cedar TS T1/T2, Cedar TS T7/T8, Hanlon TS, Kitchener MTS #5, Kitchener MTS #7, Puslinch DS, and Wolverton DS. There are also supply capacity needs on the 115 kV sub-system transmission circuits. The table below summarizes the needs for the 115 kV sub-system under the Planning Forecast.

Table 4 | Summary of 115 kV Sub-System Planning Needs

Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Cedar TS T7/T8 end-of-life	2032	N/A	2032	N/A
Arlen TS station capacity	N/A	N/A	2042	4
Cedar TS T1/T2 station capacity	2034	25	2037	37
Cedar TS T7/T8 station capacity	2033	13	2037	19
Hanlon TS station capacity	2042	1	2038	15
Kitchener MTS #5 station capacity	2037	10	2043	<1
Kitchener MTS #7 station capacity	2036	12	2032	39
Puslinch DS station capacity	2029	13	2036	4
Wolverton DS station capacity	Immediately	17	Immediately	11
115 kV supply capacity	2037	22	2036	50

6.2.1 Asset Replacement Needs

6.2.1.1 Cedar TS T7/T8

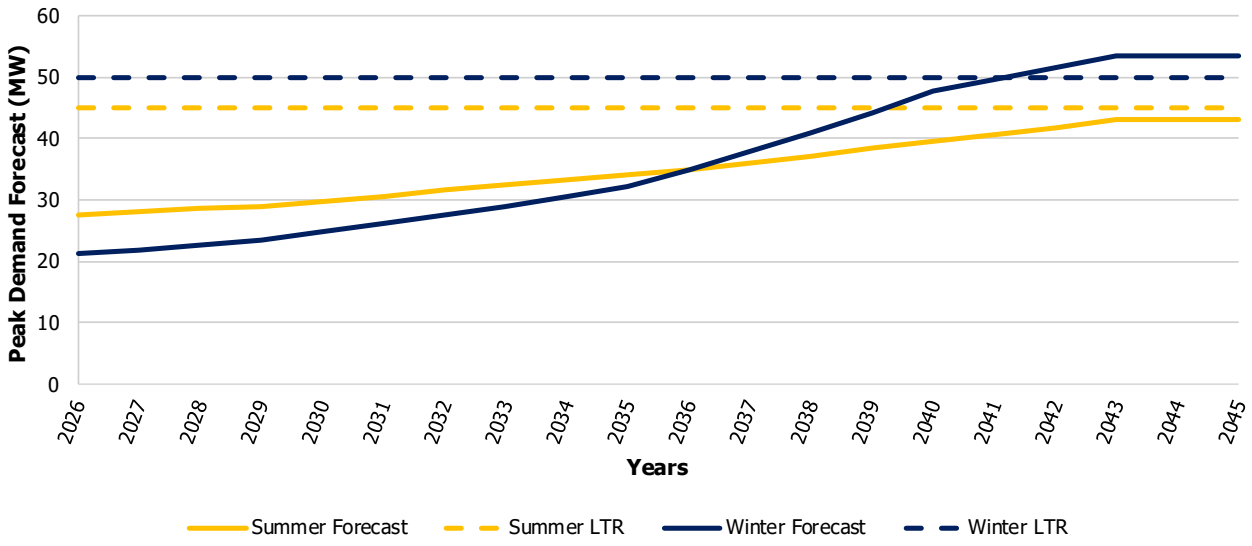
Cedar TS T7/T8 transformers were identified as requiring replacement based on asset condition by 2032. The IRRP 20-year demand forecast also identified station capacity needs at Cedar TS T7/T8, necessitating the need to consider increasing capacity over a like-for-like replacement.

6.2.2 Station Capacity Needs

6.2.2.1 Arlen TS

Arlen TS consists of two 115 kV/13.8 kV transformers with a summer LTR of 45 MW and a winter LTR of 50 MW. Arlen TS has a station capacity need of 2 MW in winter 2042, which increases to 4 MW by winter 2045. Figure 14 shows the Arlen TS demand forecast in relation to the summer and winter LTR values.

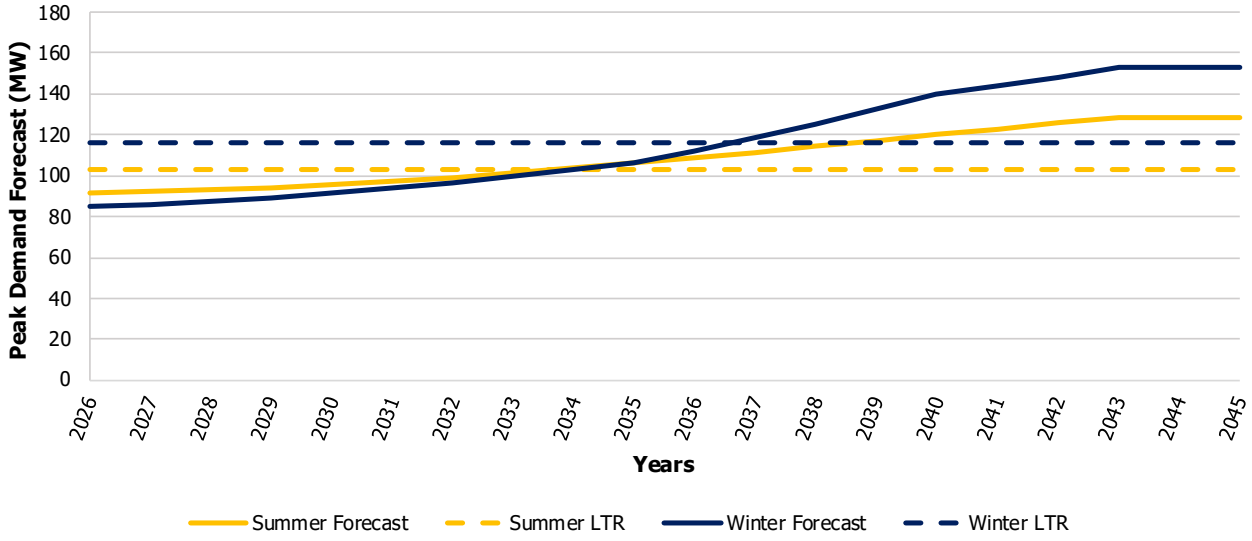
Figure 14 | Arlen TS Station Capacity Need



6.2.2.2 Cedar TS T1/T2

Cedar TS T1/T2 consists of two 115 kV/13.8 kV transformers with a summer LTR of 103 MW and a winter LTR of 116 MW. Cedar TS T1/T2 has a station capacity need of less than a megawatt in summer 2034, which increases to 37 MW by winter 2045. Figure 15 shows the Cedar TS T1/T2 demand forecast in relation to the summer and winter LTR values.

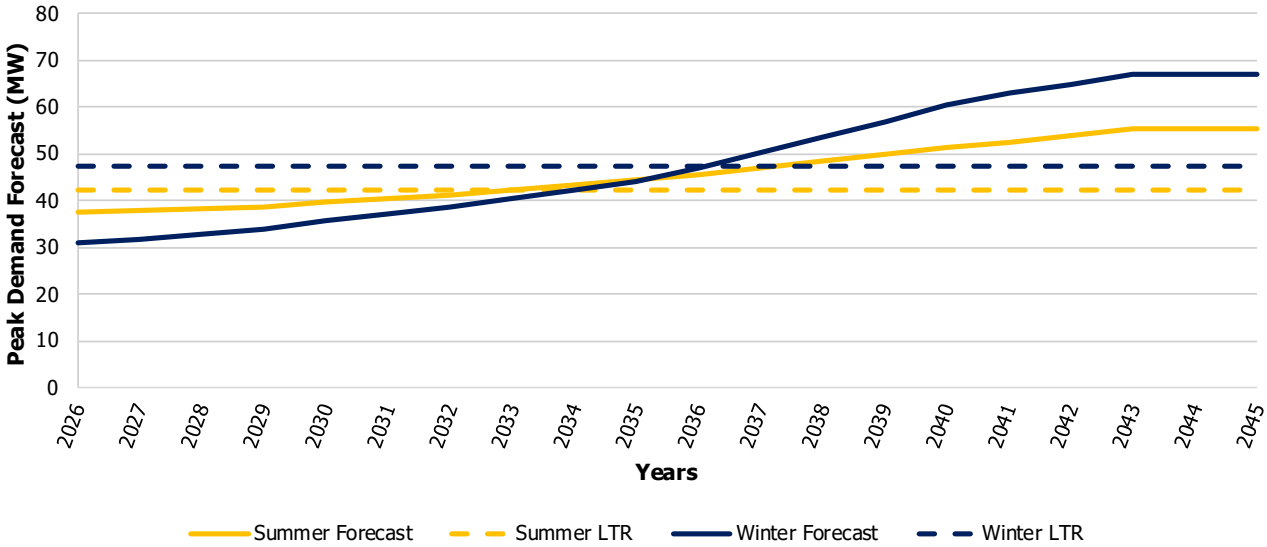
Figure 15 | Cedar TS T1/T2 Station Capacity Need



6.2.2.3 Cedar TS T7/T8

Cedar TS T7/T8 consists of two 115 kV/13.8 kV transformers with a summer LTR of 42 MW and a winter LTR of 47 MW. Cedar TS T7/T8 has a station capacity need of under one megawatt in summer 2033, which increases to 19 MW by winter 2045. Figure 16 shows the Cedar TS T7/T8 demand forecast in relation to the summer and winter LTR values.

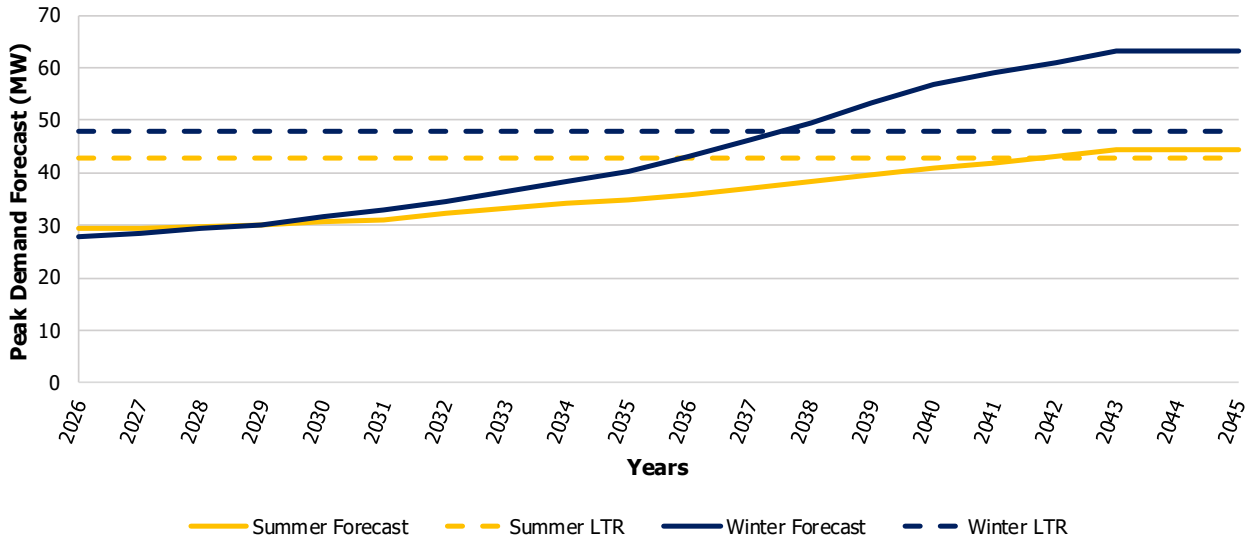
Figure 16 | Cedar TS T7/T8 Station Capacity Need



6.2.2.4 Hanlon TS

Hanlon TS consists of two 115 kV/13.8 kV transformers with a summer LTR of 43 MW and a winter LTR of 48 MW. Hanlon TS has a station capacity need of 2 MW in winter 2038, which increases to 15 MW by winter 2045. Figure 17 shows the Hanlon TS demand forecast in relation to the summer and winter LTR values.

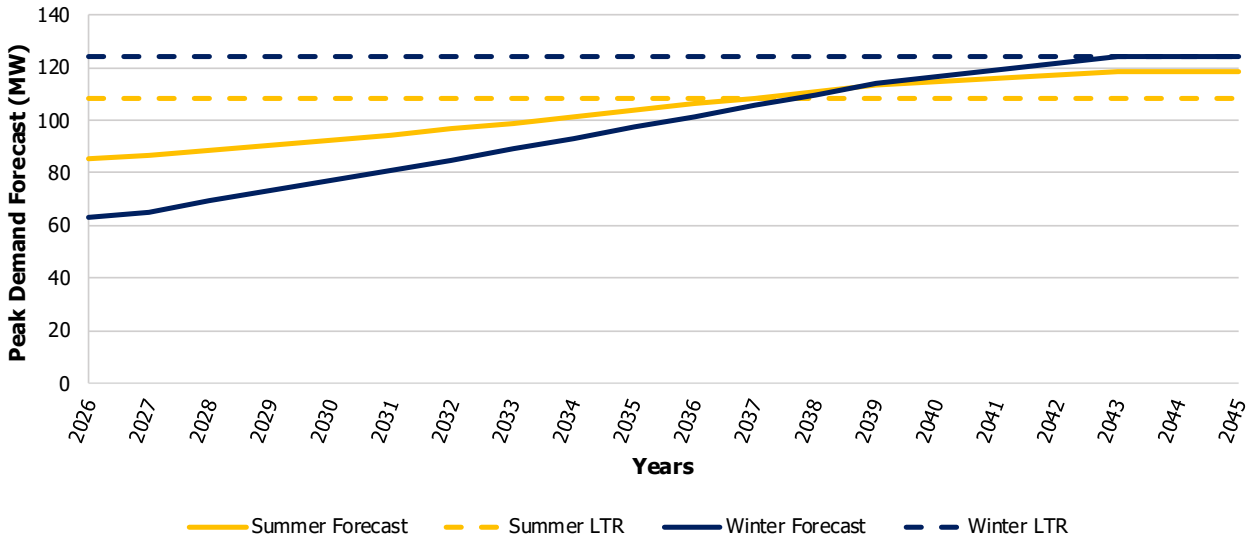
Figure 17 | Hanlon TS Station Capacity Need



6.2.2.5 Kitchener MTS #5

Kitchener MTS #5 consists of two 115 kV/13.8 kV transformers with a summer LTR of 108 MW and a winter LTR of 124 MW. Kitchener MTS #5 has a station capacity need of 1 MW in summer 2037, which increases to 10 MW by summer 2045. Figure 18 shows the Kitchener MTS #5 demand forecast in relation to the summer and winter LTR values.

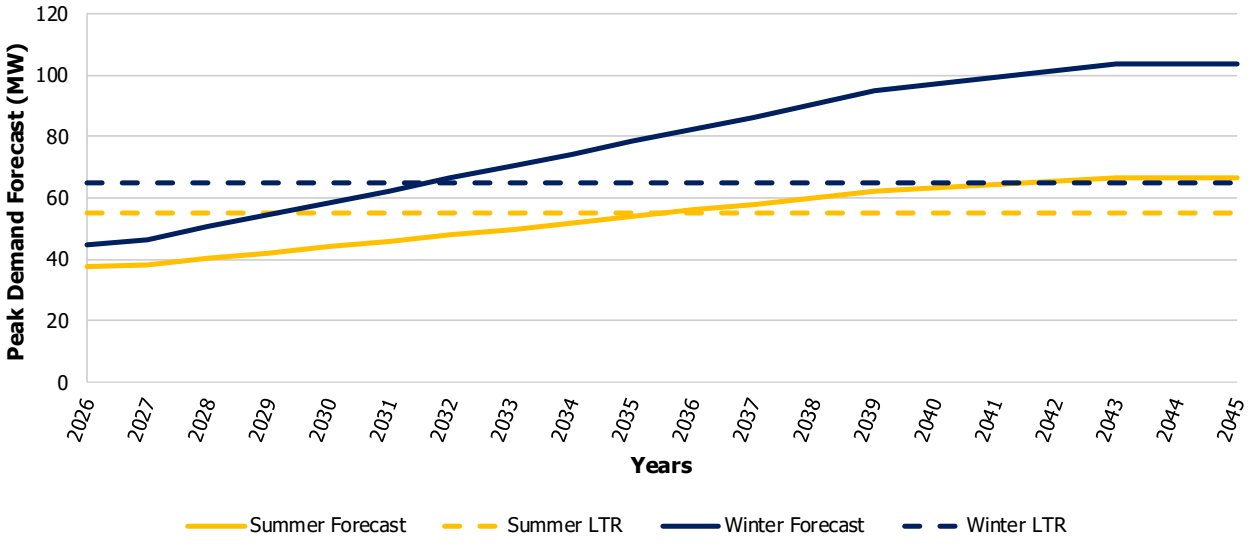
Figure 18 | Kitchener MTS #5 Station Capacity Need



6.2.2.6 Kitchener MTS #7

Kitchener MTS #7 consists of two 115 kV/13.8 kV transformers with a summer LTR of 55 MW and a winter LTR of 65 MW. Kitchener MTS #7 has a station capacity need of 2 MW in winter 2032, which increases to 39 MW by winter 2045. Figure 19 shows the Kitchener MTS #7 demand forecast in relation to the summer and winter LTR values.

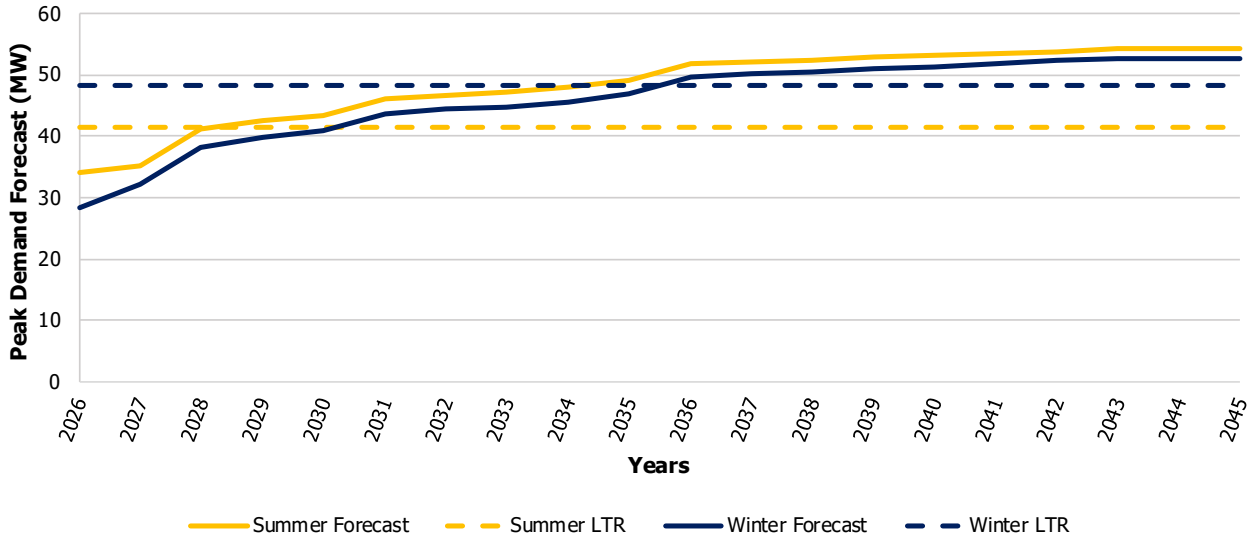
Figure 19 | Kitchener MTS #7 Station Capacity Need



6.2.2.7 Puslinch DS

Puslinch DS consists of two 115 kV/27.6 kV transformers with a summer LTR of 42 MW and a winter LTR of 48 MW. Puslinch DS has a station capacity need of 1 MW in summer 2029, which increases to 13 MW by summer 2045. Figure 20 shows the Puslinch DS demand forecast in relation to the summer and winter LTR values.

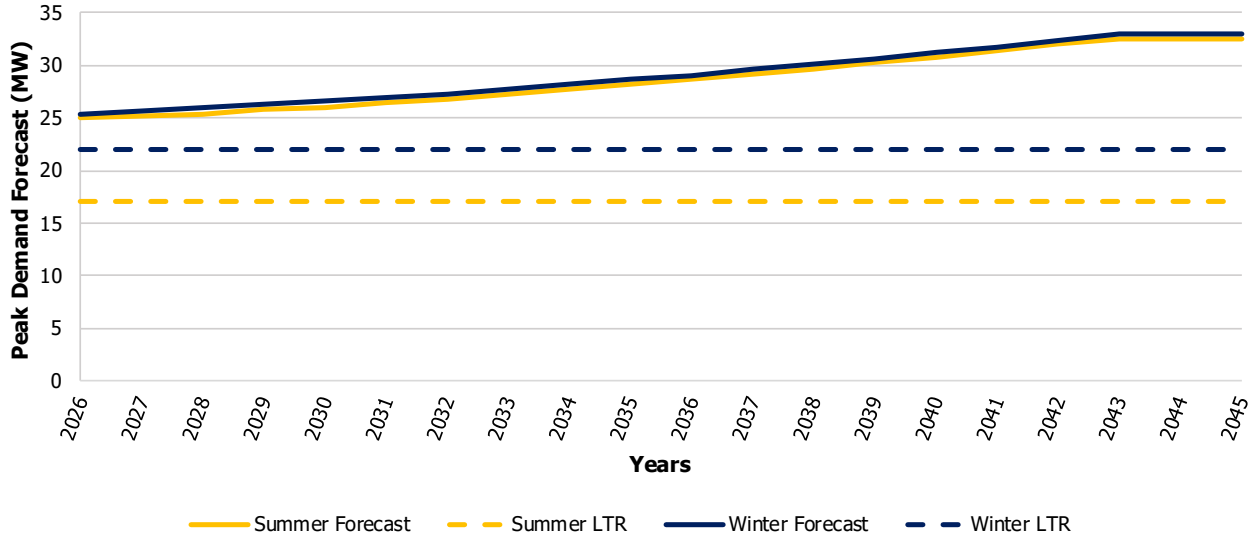
Figure 20 | Puslinch DS Station Capacity Need



6.2.2.8 Wolverton DS

Wolverton DS consists of two 115 kV/27.6 kV transformers with a summer LTR of 17 MW and a winter LTR of 22 MW. Wolverton DS has an immediate summer station capacity need of 8 MW, which increases to 16 MW by summer 2045. Figure 21 shows the Wolverton DS demand forecast in relation to the summer and winter LTR values.

Figure 21 | Wolverton DS Station Capacity Need



6.2.3 Supply Capacity Need

The load in the 115 kV sub-system is supplied through 115 kV transmission lines between Detweiler TS, Freeport SS, Cedar TS, and Burlington TS. The 230/115 kV autotransformers at Detweiler TS, Cedar TS, and Preston TS supply the 115 kV circuits and there is no local transmission-connected generation. There are two distinct load groups in the 11 5kV sub-system. One group consists of Kitchener MTS #3, Kitchener MTS #5, and Kitchener MTS #7 which are served by the 115 kV circuits between Detweiler TS and the Preston TS autotransformer. The second group consists of Hanlon TS, Arlen TS, and Puslinch DS which are served by the 115 kV circuits between Burlington TS and the Cedar TS autotransformers.

Supply on the 115 kV Sub-System Between Detweiler TS and Preston TS Autotransformer

The LMC of 115 kV supply between Detweiler TS and Preston TS autotransformer is limited to 230 MW in the summer and 260 MW in the winter based on the thermal capability of circuit sections from Detweiler TS going towards Freeport SS, under the various planning scenarios and applicable contingencies to the DxF circuits. Considering the forecast growth in the area, this part of the sub-system has a supply capacity need of 3 MW in summer 2037 which increases to 22 MW by summer 2045 and 50 MW by winter 2045.

Supply on the 115 kV Sub-System Between Burlington TS and Cedar TS Autotransformers

The LMC of 115 kV supply between Burlington TS and Cedar TS autotransformers are impacted by the loading between Detweiler TS and Preston TS autotransformer and the MxD sub-system. Considering the expected Detweiler TS-Preston TS autotransformer loading, the LMC of this part of the sub-system is limited to 155 MW in the summer and 187 MW in the winter based on the thermal capability of circuit

sections from Burlington TS going towards Cedar TS, under the various planning scenarios and applicable contingencies to the MxD and BxC circuits.

There is no need on the BxC transmission lines if only accounting for load connected to BxC. However, increasing load on the MxD and 115 kV sub-systems between Detweiler TS and Preston autotransformer can introduce limitations on the BxC transmission lines. Therefore, BxC circuits become constraining for future load growth in these other load pockets.

6.2.4 Low and High Forecast Needs

Depending on the low or high forecast, the 115 kV supply capacity need ranges from 32 MW to 77 MW, and timing ranges from 2034 to 2038.

The station capacity needs of the stations in the 115 kV sub-system vary in need sizes and timing across the different planning scenarios and could be delayed as much as up to five years, or advanced by three years depending on the scenario.

6.3 MxD Sub-System

The MxD sub-system refers to the stations (primarily in Kitchener and Cambridge) that are served by the 230 kV Middleport to Detweiler circuits. In this sub-system, there are station capacity needs at Kitchener MTS #6, Kitchener MTS #8, Preston TS, GBE MTS #1, and Galt TS. There are also supply capacity, load security, and load restoration needs on the M21D/M22D circuits. The table below summarizes the needs for the MxD sub-system under the Planning Forecast.

Table 5 | Summary of MxD Sub-System Planning Needs

Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Kitchener MTS #6 station capacity	2034	16	2039	10
Kitchener MTS #8 station capacity	2029	40	2030	81
Preston TS station capacity	See note below			
GBE MTS #1 station capacity	See note below			
Galt TS station capacity	See note below			
MxD supply capacity	Immediate	230	2032	202
MxD load security	2033	159	2033	210
MxD load restoration	Immediate	472	Immediate	471

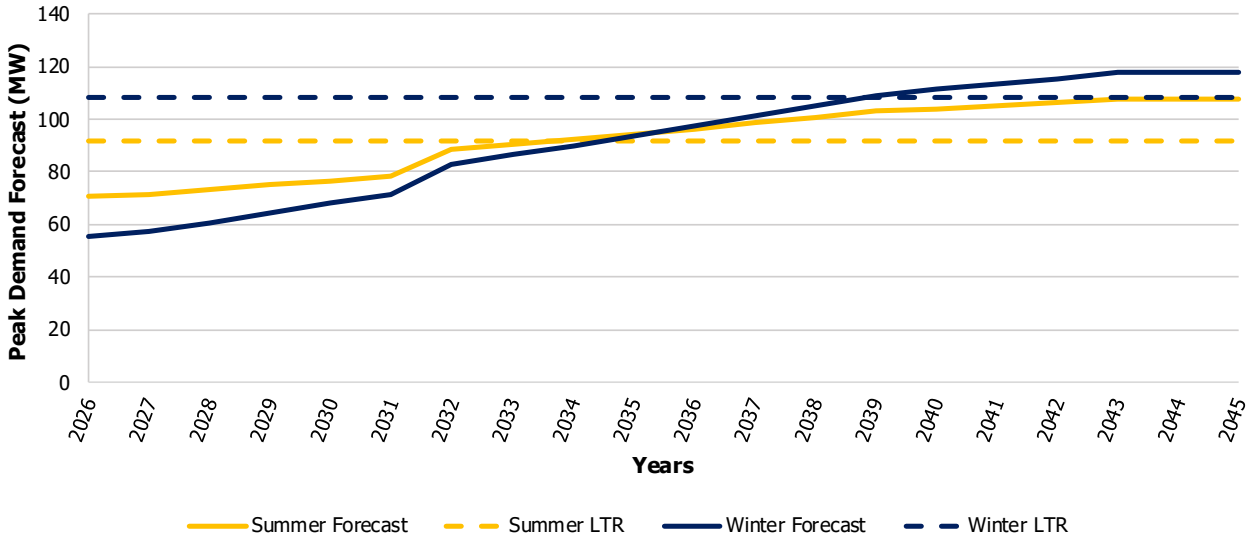
Preston TS, GBE MTS #1, and Galt TS have been loaded up to their LTRs in all planning scenarios. The cumulative need of these stations is 7 MW in 2029, and it increases to 147 MW in the summer 2045 and 130 in winter 2045. As there is no capacity at Preston TS, GBE MTS #1, and Galt TS, this additional load will have to be sited at a different station – this is explained further in Section 7.2.2.

6.3.1 Station Capacity Needs

6.3.1.1 Kitchener MTS #6

Kitchener MTS #6 consists of two 230 kV/13.8 kV transformers with a summer LTR of 92 MW and a winter LTR of 108 MW. Kitchener MTS #6 has a station capacity need of 1 MW in summer 2034, which increases to 16 MW by summer 2045. Figure 22 shows the Kitchener MTS #6 demand forecast in relation to the summer and winter LTR values.

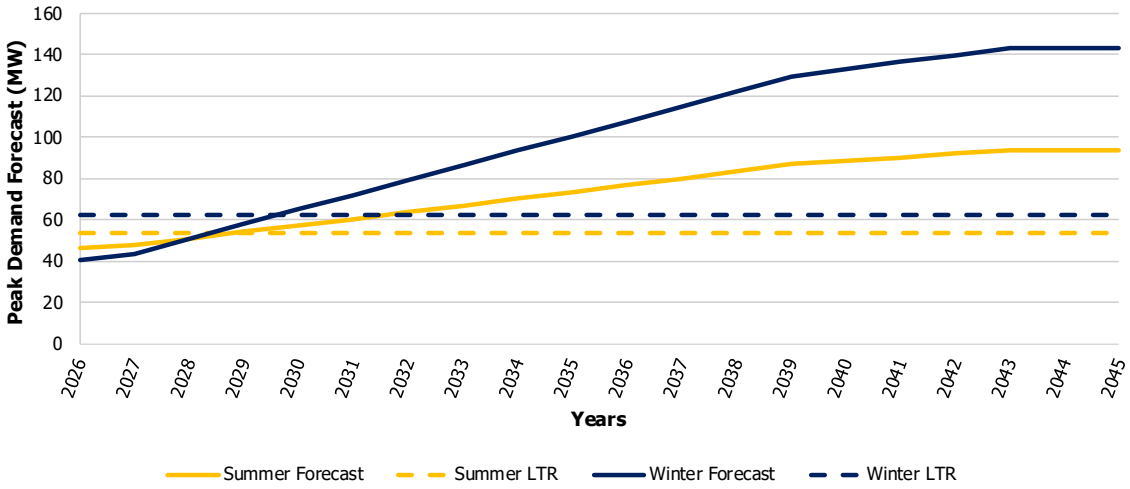
Figure 22 | Kitchener MTS #6 Station Capacity Need



6.3.1.2 Kitchener MTS #8

Kitchener MTS #8 consists of two 230 kV/13.8 kV transformers with a summer LTR of 54 MW and a winter LTR of 62 MW. Kitchener MTS #8 has a station capacity need of under a megawatt in summer 2029, which increases to 81 MW by winter 2045. The figure below shows the Kitchener MTS #8 demand forecast in relation to the summer and winter LTR values.

Figure 23 | Kitchener MTS #8 Station Capacity Need



6.3.1.3 Preston TS, Galt TS, and GBE MTS #1

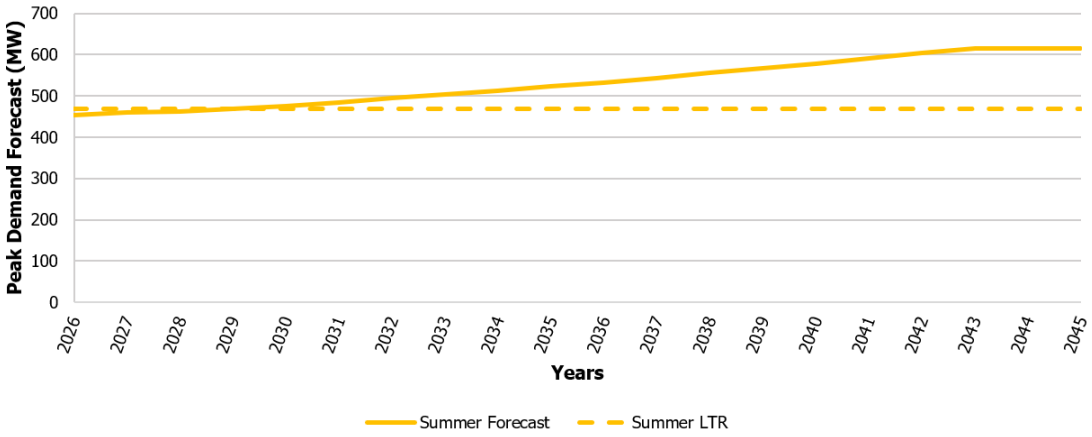
As noted with Table 5, Preston TS, GBE MTS #1, and Galt TS have been loaded up to their LTRs in all planning scenarios. Demand growth is expected to continue beyond the combined station capacity and will need to be sited at a future station (GBE MTS #2). Before a new station can be built, load will be managed between the existing MxD stations, which is described below.

- Preston TS consists of two 230 kV/27.6 kV transformers with a summer LTR of 190 MW and a winter LTR of 210 MW[3].
- Galt TS consists of two 230 kV/27.6 kV transformers with a summer LTR of 178 MW and a winter LTR of 201 MW.
- GBE MTS #1 consists of two 220 kV/27.6 kV transformers with a summer LTR of 102 MW and a winter LTR of 120 MW.

The figure below shows the cumulative Preston TS, Galt TS, and GBE MTS #1 station forecasts relative to their combined summer and winter LTR values. This highlights the outstanding station capacity need in this part of the sub-system.

[3] Upon completion of the ongoing Preston T3/T4 transformer replacement, new station LTR is expected to be in the range of 190 MW.

Figure 24 | Cumulative Preston TS, Galt TS, and GBE MTS #1 Station Capacity Needs[4]



6.3.2 Supply Capacity Need

The load in the MxD sub-system is supplied through 230 kV transmission lines between Galt junction and Detweiler TS, Preston TS, and Middleport TS. There is bulk supply at the 500/230 kV autotransformers at Middleport TS. Moreover, the MxD sub-system also connects to the KWCG region's 115 kV sub-system.

There are two distinct load groups in the MxD sub-system. One group consists of Preston TS, GBE MTS #1, Galt TS, and a CTS which are supplied by the MxD circuits between Galt junction and Preston TS. The second group consists of Kitchener MTS #6 and Kitchener MTS #8 which are supplied by the MxD circuits between Detweiler TS and Galt junction.

Load Supply Between Galt Junction and Preston TS

The load supply capacity between Galt junction and Preston TS is impacted by the loading between Detweiler TS and Galt junction. Accounting for expected Detweiler TS-Galt junction loading, the LMC between Galt TS and Preston TS is limited to 391 MW in the summer and 442 MW in the winter based on the thermal capability of the circuits between Preston TS and Galt junction under the various planning scenarios and applicable contingencies. Considering the forecast, this part of the sub-system has an immediate 17 MW summer supply capacity need which increases to 181 MW by summer 2045 and 129 MW by winter 2045.

Load Supply Between Galt Junction and Detweiler TS

The load supply capacity between Detweiler TS and Galt junction is impacted by loading between Galt TS and Preston TS. Accounting for expected Galt TS-Preston TS loading, the LMC of the sub-system between Detweiler TS and Galt junction is limited to 138 MW in the summer and 166 MW in the winter. This is due to the thermal capability of the BxC circuits in the 115 kV sub-system under the loss of D7V and M21D circuits; under these contingencies, flow through the BxC circuits from Burlington TS must increase to compensate for loss of supply from Detweiler TS. Considering the forecast, this part of the

[4] Winter forecast and LTR have been omitted as updates are required. Will be updated for the Regional Infrastructure Plan.

sub-system has a supply capacity need starting in summer 2032 with 3 MW, which increases to 49 MW by summer 2045 and 73 MW by winter 2045.

6.3.3 Load Security and Restoration Needs

As per ORTAC Section 2.4.10.1[5], no more than 150 MW is allowed to be interrupted by configuration following a single-element contingency, and no more than 600 MW by configuration following a two-element contingency. Over the forecast period, there is a load security need of 6 MW in 2033 which increases to 159 MW in summer 2045 and 210 MW by winter 2045 when there is a loss of both M20D and M21D circuits.

By the end of the study period, all forecast load (over 750 MW) on the MxD circuits would be interrupted following an outage to both circuits, M20D and M21D, by configuration. Of this load, Hydro One Transmission has indicated that approximately 100 MW Preston load, and the Kitchener MTS #6 and Kitchener MTS #8 load could be restored in a timely fashion through existing 230 kV in-line switches at Galt junction and Preston TS. Thus, the restoration targets of load in excess of 250 MW cannot be restored within 30 minutes, nor can the load in excess of 150 MW be restored within four hours. This is in violation of load restoration planning requirements (ORTAC Section 2.4.10.2) and is summarized below.

Table 6 | Load Restoration Planning Requirements on the MxD Supply Lines

Time Post-Contingency	ORTAC Requirement: Restoration Target	2045 Peak Load to be Restored	Achievable Based on the Current and Planned Transmission System?
Within 30 minutes	Load in excess of 250 MW	509 MW	No
Within four hours	Load in excess of 150 MW	609 MW	No, only 287 MW is achievable
Within eight hours	All load	759 MW	Exceeds 600 MW load security limits

6.3.4 Low and High Forecast Needs

Depending on the low or high forecast, the MxD supply capacity need ranges from 97 MW to 461 MW, but the timing is immediate regardless. This illustrates the urgency and magnitude of the supply need in this sub-system regardless of the forecast scenario. The timing and magnitude of load security and restoration needs would be adjusted similarly to the supply needs.

The station capacity needs at Kitchener MTS #6 and Kitchener MTS #8 could be delayed by up to 4 years, or advanced by 2 years depending on the forecast scenario.

The cumulative need at Preston TS, GBE MTS #1, and Galt TS could be delayed by up to eight years, or advanced by two years depending on the forecast scenario.

[5] The assumption is that there is no load curtailment and rejection.

6.4 DxV Sub-System

The DxV sub-system refers to the stations in Waterloo, Centre Wellington, and Guelph that are served by the double-circuit 230 kV DxV lines. There are multiple forecast station capacity needs. There are also supply capacity, load restoration, and load security needs affecting the overall DxV sub-system; the LMC is limited to 350 MW based on the thermal capability of the circuits between Detweiler TS and Waterloo North MTS #3. DxV supply can also be limited depending on other scenarios and applicable contingencies; its LMC is interdependent with the load on the DxW sub-system. Table 7 summarizes the needs for the DxV sub-system under the Planning Forecast.

Table 7 | Summary of DxV Sub-System Planning Summer Needs

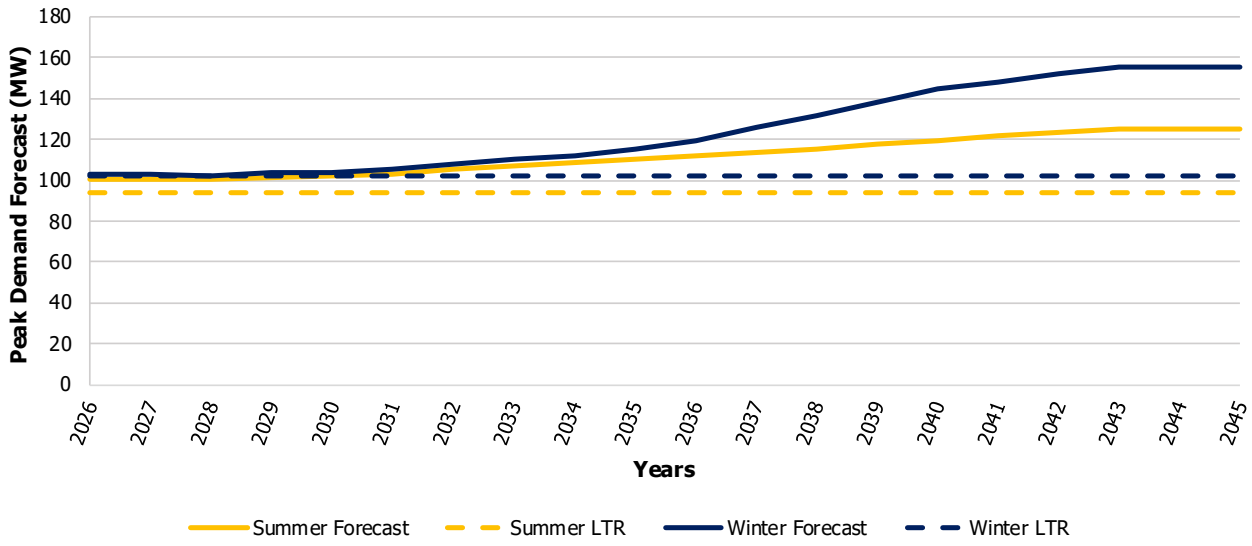
Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Campbell TS T1/T2 station capacity	Immediate	31	Immediate	54
Campbell TS T3/T4 station capacity	Immediate	17	2035	22
Scheifele MTS station capacity	2028	144	2029	185
Waterloo MTS #3 station capacity	Immediate	254	2028	243
DxV supply capacity	Immediate	574	Immediate	640
DxV load security	2030	324	2030	435
DxV load restoration	Immediate	663	Immediate	774

6.4.1 Station Capacity Needs

6.4.1.1 Campbell TS T1/T2

Campbell TS T1/T2 consists of two 230 kV/13.8 kV transformers with a summer LTR of 93 MW and a winter LTR of 101 MW. It has an immediate summer station capacity need, growing to a 54 MW need in the winter of 2045. The figure below shows the Campbell TS T1/T2 demand forecast in relation to the summer and winter LTR values.

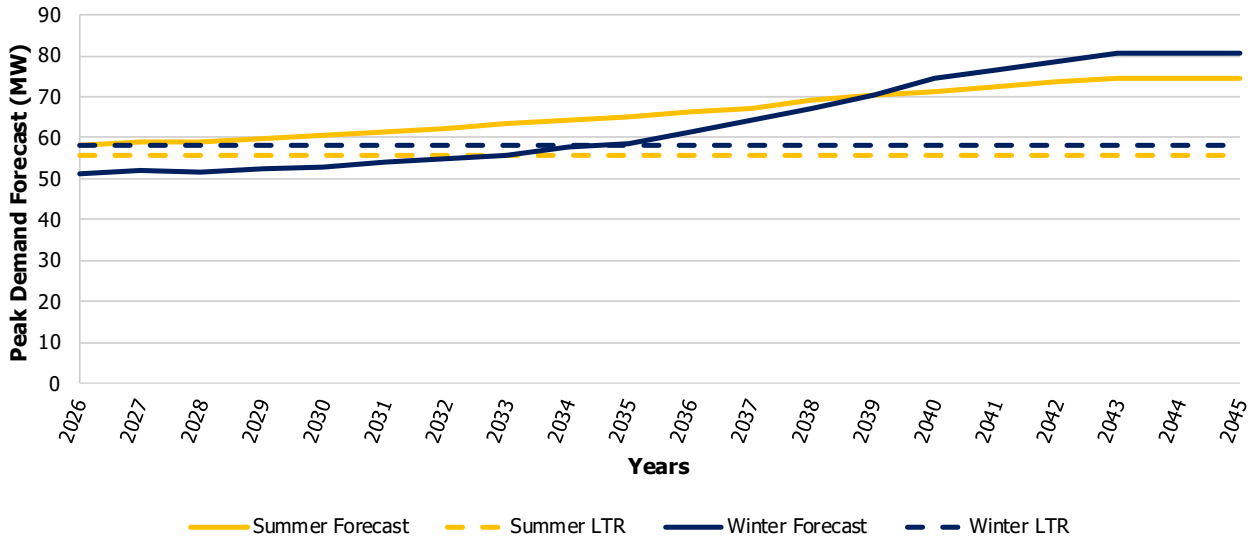
Figure 25 | Campbell TS T1/T2 Station Capacity Need



6.4.1.2 Campbell TS T3/T4

Campbell TS T3/T4 consists of two 230 kV/13.8 kV transformers with a summer LTR of 56 MW and a winter LTR of 58 MW. It has an immediate summer station capacity need, growing to a 22 MW need in the winter of 2045. Figure 26 shows the Campbell TS T3/T4 demand forecast in relation to the summer and winter LTR values.

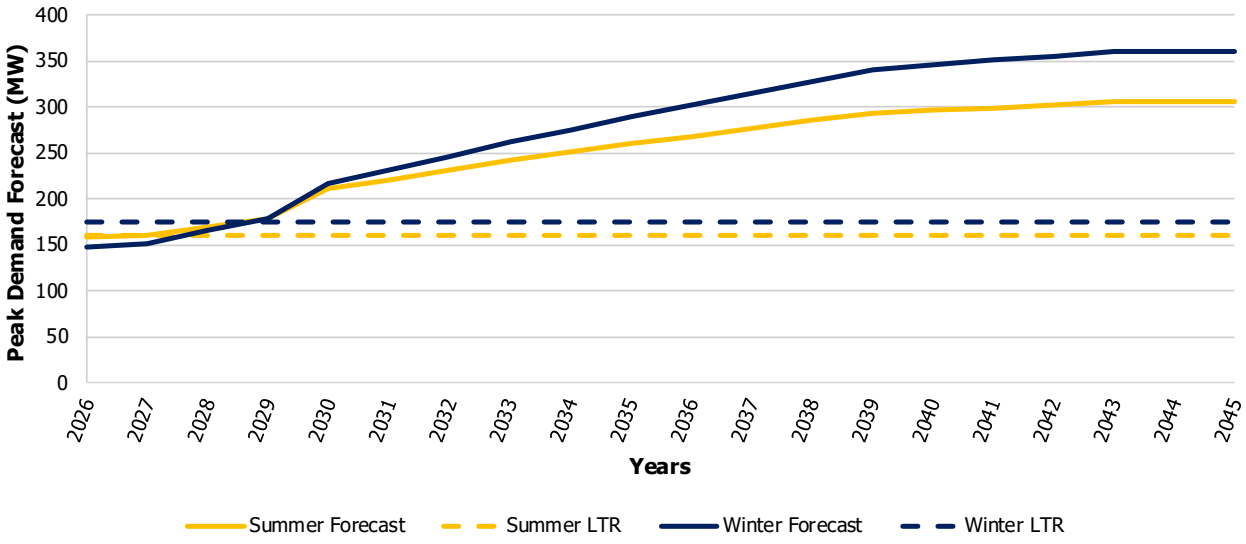
Figure 26 | Campbell TS T3/T4 Station Capacity Need



6.4.1.3 Scheifele MTS

Scheifele MTS consists of four 230kV/13.8kV transformers with a summer LTR of 161 MW and a winter LTR of 175. It is forecast to have a summer station capacity need starting in 2028, growing to a 185 MW need in the winter of 2045.

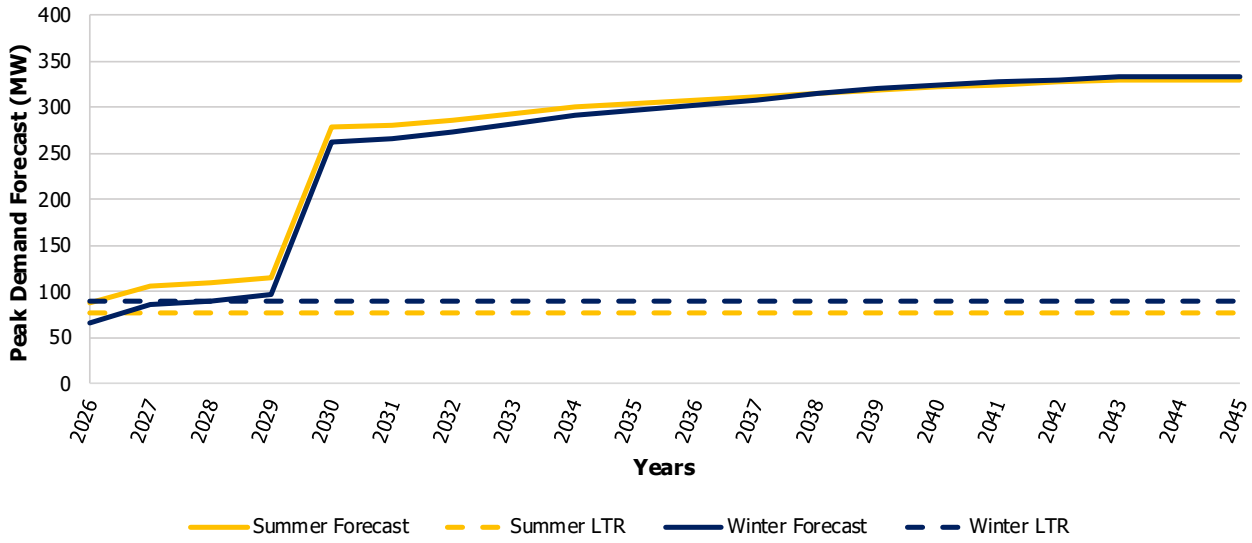
Figure 27 | Scheifele MTS Station Capacity Need



6.4.1.4 Waterloo North MTS #3

Waterloo North MTS #3 consists of two 230 kV/27.6 kV transformers with a summer LTR of 76 MW and a winter LTR of 90 MW. It is forecast to have a summer station capacity need starting in 2026, growing to a 254 MW need in the summer of 2045.

Figure 28 | Waterloo North MTS #3 Station Capacity Need



6.4.2 Supply Capacity Need

The 230 kV DxV transmission lines connect from Detweiler TS in Kitchener to Fergus TS in Centre Wellington, to Cedar TS in Guelph. The sub-system does not have any local transmission-connected generation. The LMC is limited to 350 MW in the summer and 395 MW in the winter, and it is based

on the thermal capability of the circuits between Detweiler TS and Waterloo North MTS #3.[6] Considering the forecast growth in the sub-system, there is an immediate supply capacity need in both summer and winter that increases to 574 MW by summer of 2045 and 640 MW in the winter.

6.4.3 Load Security and Restoration Needs

As per ORTAC Section 2.4.10.1, no more than 150 MW is allowed to be interrupted by configuration following a single-element contingency, and no more than 600 MW by configuration following a two-element contingency. Over the forecast period, there is a load security need of 129 MW in 2030 which increases to 324 MW in summer 2045 and 435 MW by winter 2045 when there is a loss of both D6V and D7V circuits.

By the end of the study period, all forecast load (more than 900 MW) on the DxV circuits would be interrupted following an outage to both circuits, D6V and D7V, by configuration. Of this load, Hydro One Transmission has indicated that only approximately 260 MW of the load could be restored in a timely fashion through existing 230 kV in-line switches. Thus, the restoration targets of load in excess of 250 MW cannot be restored within 30 minutes, nor can the load in excess of 150 MW be restored within four hours. This is in violation of load restoration planning requirements (ORTAC Section 2.4.10.2) and is summarized in Table 8.

Table 8 | Load Restoration Planning Requirements on the DxV Lines

Time Post-Contingency	ORTAC Requirement: Restoration Target	2045 Peak Load to be Restored	Achievable Based on the Current and Planned Transmission System?
Within 30 minutes	Load in excess of 250 MW	676 MW	No
Within four hours	Load in excess of 150 MW	776 MW	No, only 260 MW is achievable
Within eight hours	All load	926 MW	Exceeds 600 MW load security limits

6.4.4 Low and High Forecast Needs

Depending on the low or high forecast, the DxV supply capacity need ranges from 403 MW to 801 MW, and the timing is immediate regardless. This illustrates the urgency and magnitude of the supply need in this sub-system regardless of the forecast scenario. The timing and magnitude of load security and restoration needs would be adjusted similarly to the supply needs.

The station capacity needs at Campbell TS, Scheifele MTS, and Waterloo North MTS #3 could be delayed by up to one year, or advanced by two years depending on the forecast scenario.

[6] This is based on the simultaneous forecast loading on the DxW sub-system, since the LMCs for the DxW and DxV sub-systems are interdependent.

6.5 DxW Sub-System

The 230 kV DxW transmission lines supply Detweiler TS from Buchanan TS in London and includes no local transmission-connected generation. The LMC of the DxW sub-system is interdependent with the LMC of the DxV subsystem; it also is impacted by assumed loading at Preston TS. With a total of approximately 400 MW at Preston, GBE MTS#1 and Galt TS, and with the load on the DxV circuits at the maximum limit (350 MW, as described in Section 6.4.2), DxW supply is limited to 100 MW. This is due to voltage violations at Preston TS or GBE MTS#1 TS after contingencies resulting in the loss of an MxD circuit and the static VAR compensator or a shunt capacitor at Detweiler TS. Increased loading between Preston TS and Galt TS degrades the DxV and DxW LMCs further on the existing system – in fact, additional load on the MxD and 115 kV sub-systems generally can reduce DxV and DxW supply.

There is no direct need on the DxW transmission lines if only accounting for the Kitchener MTS #9 forecast. However, as described above, the DxW LMC depends on the DxV sub-system loading. This is described further in Section 7.2.3.

6.6 D8S/D10H Sub-System

The D8S-D10H sub-system refers to the stations within the KWCG region that are served by the Detweiler-Seaforth (D8S) and Detweiler-Hanover (D10H) circuits. There is a station capacity need at Rush MTS and a supply capacity need on the D8S-D10H circuits transmission circuits, which are 115 kV circuits from Detweiler TS towards Seaforth TS and Hanover TS. Table 9 summarizes the needs for the D8S/D10H sub-system under the Planning Forecast.

Table 9 | Summary of D8S/D10H Sub-System Planning Needs

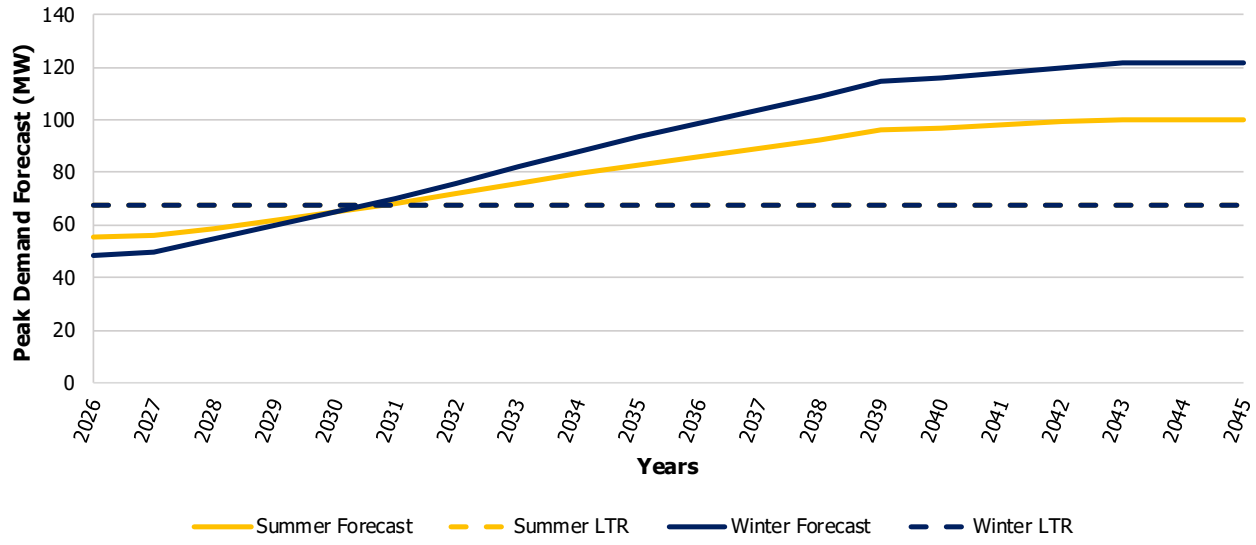
Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Rush MTS station capacity	2031	33	2031	54
D8S-D10H supply capacity	2033	26	2037	19

6.6.1 Station Capacity Needs

6.6.1.1 Rush MTS

Rush MTS consists of two 115 kV/13.8 kV transformers with an LTR of 68 MW. Rush MTS has a station capacity need of 3 MW in winter 2031, which increases to 54 MW by winter 2045. Figure 29 shows the Rush MTS demand forecast in relation to the summer and winter LTR values.

Figure 29 | Rush MTS Station Capacity Need



6.6.2 Supply Capacity Need

The load in the D8S-D10H sub-system is supplied through 115 kV transmission lines between Detweiler TS, Seaforth TS, and Hanover TS. The 230/115 kV autotransformers at Detweiler TS supply the D8S-D10H sub-system. The LMC of the sub-system is limited to 120 MW in the summer and 144 MW in the winter based on the thermal capability of the circuits between Detweiler TS, Leong junction, and Waterloo junction. Considering the forecast growth in the area, this sub-system has a 2 MW supply capacity need starting in 2033 that increases to 26 MW by 2045.

6.6.3 Low and High Forecast Needs

Depending on the low or high forecast, the D8S-D10H supply capacity need ranges from 2 MW to 47 MW, and timing ranges from 2030 to 2041. This suggests that the need is sensitive to different forecast scenarios and growth should be closely monitored.

The station capacity need at Rush MTS could be delayed by five years, or advanced by one year depending on the forecast scenario.

6.7 DxK Sub-System

The DxK sub-system refers to Kitchener MTS #1 and Kitchener MTS #4 and their radial double-circuit 115 kV supply from the Detweiler-Kitchener transmission circuits. There are station capacity needs at Kitchener MTS #1 and #4, and a supply capacity need on the DxK circuits. Table 10 summarizes the needs for the DxK sub-system under the Planning Forecast.

Table 10 | Summary of DxK Sub-System Planning Summer Needs

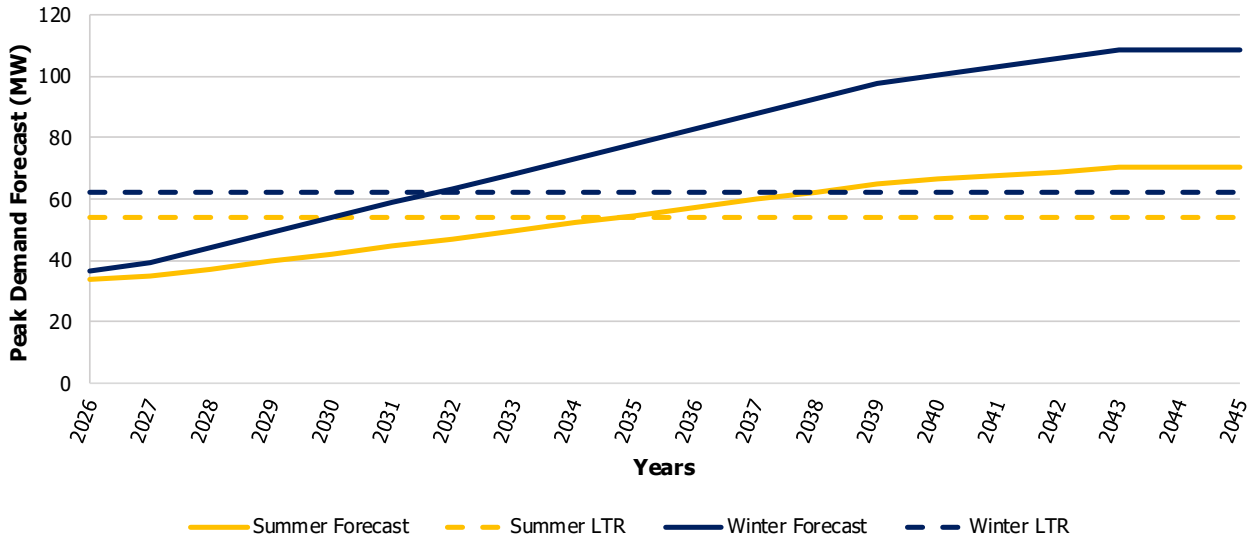
Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Kitchener MTS #1	2035	16	2032	46
Kitchener MTS #4	2035	19	2032	50
DxK supply capacity	2033	42	2031	96

6.7.1 Station Capacity Needs

6.7.1.1 Kitchener MTS #1

Kitchener MTS #1 consists of two 115 kV/13.8 kV transformers with a summer LTR of 54 MW and a winter LTR of 62 MW. Kitchener MTS #1 has a station capacity need of 1 MW in winter 2032, which increases to 46 MW by winter 2045. Figure 30 shows the Kitchener MTS #1 demand forecast in relation to the summer and winter LTR values.

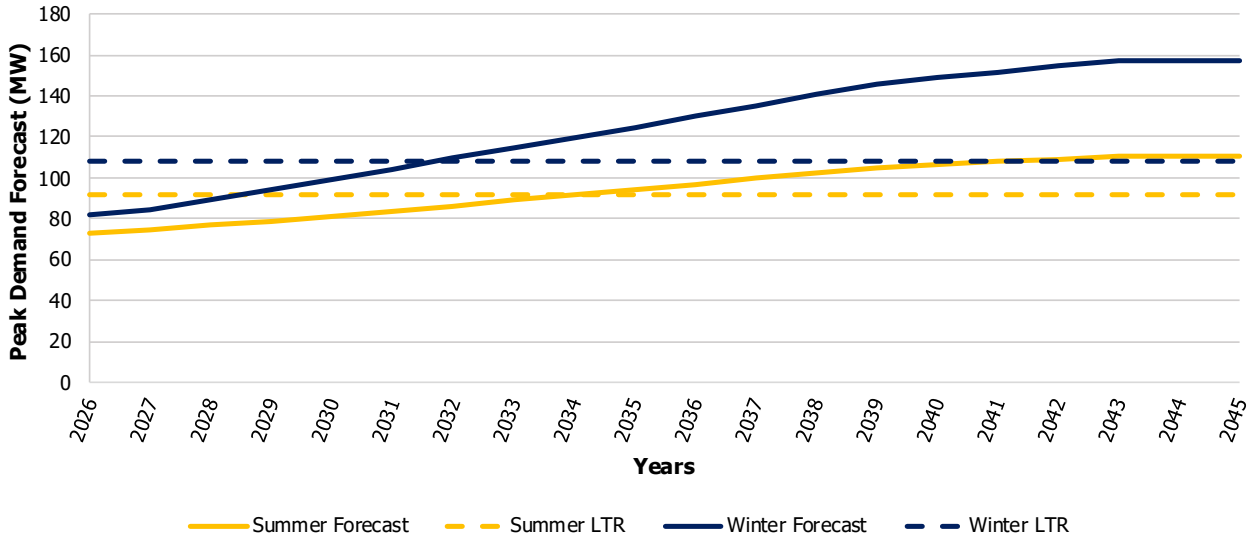
Figure 30 | Kitchener MTS #1 Station Capacity Need



6.7.1.2 Kitchener MTS #4

Kitchener MTS #1 consists of two 115 kV/13.8 kV transformers with a summer LTR of 92 MW and a winter LTR of 108 MW. Kitchener MTS #4 has a station capacity need of 1 MW in winter 2032, which increases to 50 MW by winter 2045. Figure 31 shows the Kitchener MTS #4 demand forecast in relation to the summer and winter LTR values.

Figure 31 | Kitchener MTS #4 Station Capacity Need



6.7.2 Supply Capacity Need

The load in the DxK sub-system is supplied through radial 115 kV transmission lines from the Detweiler TS 115 kV bus. The LMC of the sub-system is limited to 127 MW in the summer and 148 MW in the winter based on the thermal capability of the circuits between Detweiler TS, Kitchener MTS #1, and Kitchener MTS #4. Considering the forecast growth in the area, this sub-system has a 1 MW supply capacity need starting in 2031 which increases to 96 MW in 2045.

6.7.3 Low and High Forecast Needs

Depending on the low or high forecast, the DxK supply capacity need ranges from 79 MW to 117 MW, and timing ranges from 2031 to 2032. This illustrates the magnitude and firmness of the supply need in this sub-system regardless of the forecast scenario.

The station capacity needs at Kitchener MTS #1 and Kitchener MTS #4 could be either delayed or advanced by one year depending on the forecast scenario.

6.8 Operability and Operational Issues

Operational issues are not defined as planning needs. However, if they affect the reliability of the region, the Technical Working Group may consider opportunities to address operational issues while addressing planning needs.

Operational issues that impact reliability were identified for the KWCG region; they are driven by the switchyard/breaker configuration at Detweiler TS. Detweiler TS is a major supply point for the region and these operational issues have significant impact on potential LMCs.

With the existing Detweiler switchyard configuration, the Detweiler static VAR compensator or capacitors may cause damaging ferroresonance oscillations or high voltages under certain forced or planned outage conditions – for example, a bus fault if followed by specific secondary forced outages. To protect equipment from damage, Hydro One has operating procedures to manually remove the

Detweiler static VAR compensator or capacitors from service under these outage conditions before the secondary forced outages occur.

If these operating restrictions are executed, there are post-outage instances in which up to six elements at Detweiler TS, including both capacitors and the static VAR compensator, would be lost. This can significantly reduce the supply capability for the region.

As the Technical Working Group explores solutions to eliminate the need for these operating procedures (such as protection schemes and/or reconfiguring the Detweiler TS switchyard), their impact on the reported LMCs was ignored. This is described further in Section 7.2.3.

6.9 Bulk Supply into KWCG

The focus of regional planning is to ensure reliable supply within a region. Supply into the region is out of scope, but it is studied in the South and Central Bulk Plan, which was developed in parallel with the KWCG IRRP. This bulk plan includes:

- Identifying/confirming the transmission required to enable the connection of future bulk generation resources.
- Exploring the transmission required to enable decreased reliance on emitting resources.
- Determining transmission required to enable reliable supply under high economic growth/ electrification scenarios, including the connection of new large loads and data centres in the Greater Toronto Area and the Hamilton to Windsor corridor.
- Identifying opportunities to assess and preserve potential new or expanded corridors for future electricity infrastructure.

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the KWCG region. When developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, federal regulations, technical feasibility, cost effectiveness, lead time, local preferences, and consistency with longer-term needs in the area.

There are generally two approaches to address regional needs:

- Build new transmission or distribution infrastructure. These are commonly referred to as wire options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing capability. These are commonly referred to as non-wire alternatives (NWAs) and can include things like local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or additional eDSM.

Section 7.1 provides a more in-depth overview of the NWA considerations in this IRRP. Subsequently, Section 7.2 presents the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Non-Wires Analysis Process in IRRPs

Wires options are always considered in regional planning, and while they are always viable options for regional needs, NWAs may be more suitable for specific need types and characteristics. To select and appropriately size NWAs like generation or battery storage, additional work is required — including the creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the unserved energy profile, which is the hourly demand above the existing station or system capability The profile indicates the duration, frequency, magnitude, and total energy associated with each need. More details on the NWA process and analysis are provided in appendix.

7.1.1 Approach to Needs Screening

NWAs are suitable for specific types of needs, as described in the Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives. An initial screening step is performed to identify which NWAs may be suitable for the type of need addressed.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. Similarly, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. The complete list of assumptions used in the needs screening and options analysis is provided in the appendix.

The IESO is mandated to centrally deliver province-wide eDSM programs for Ontario that target businesses, residential customers, and First Nations. The IESO offers incentives and rebates to electricity customers through a suite of Save On Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs. Demand savings from centrally-delivered energy efficiency programs under the 2021–2024 Conservation and Demand Management Framework and Save on Energy brand are already included in the load forecast, as discussed in Section 5.5. This forecast assumed the programming continues through the forecast period at levels consistent with the 2021-2024 CDM Framework.

Additional eDSM above and beyond that included in the demand forecast can also play a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Results from the IESO's latest (2022) provincial energy efficiency Achievable Potential Study inform estimates of the additional peak demand savings potential available from eDSM programming, and the cost to acquire those peak demand savings.

The new 2025-2036 eDSM Framework provides the IESO with a twelve-year mandate and $10.9B budget ceiling to expand and enhance eDSM programming. Higher provincial savings targets under the new framework relative to the 2021-2024 CDM Framework may contribute to delivering additional eDSM recommended to address specific regional needs. The new framework also establishes new mechanisms for IESO and Local Distribution Company eDSM collaboration, including specific funding for LDC-delivered programming that provides both local and regional or provincial benefits.

Generally, additional eDSM programming is suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few per cent per year). These considerations are discussed further in Section 7.1.2. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors to leverage distribution rates to help address distribution and transmission system needs using NWAs. In some cases, NWAs can help manage needs in the interim before wires reinforcements are in-service.

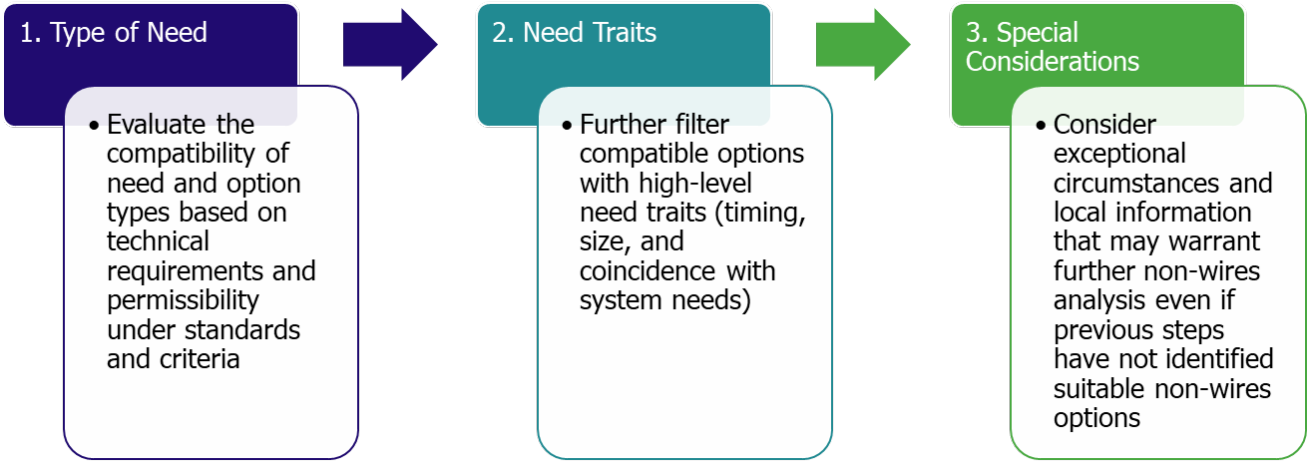
Where NWAs are screened in and determined to be feasible, the upfront capital and operating costs for both wire options and NWAs are compiled to generate levelized annual capacity costs (measured in dollars per kW per year). In this scenario, the cash flow of the levelized costs for the options are compared over the lifespan of the wire option and the net present value of these levelized costs is the primary basis through which feasible options are compared. Where NWAs are screened out or determined to be infeasible for meeting the need, overnight capital costs for wire options are used instead.

NWAs are subject to uncertainties in the procurement in terms of both the resource costs bid my proponents and the overall success of the procurement. Moreover, it is important to recognize that there is a significant uncertainty around cost estimates at the planning stage (from minus 50 per cent on the low side to plus 100 per cent on the high side), as they are only intended to enable comparison between options during the IRRP. The transmitter-led Regional Infrastructure Plan (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. The IESO continues to participate in the Technical Working Group during the Regional Infrastructure Plan and revisits these recommendations if cost estimates differ significantly.

7.1.2 Non-Wires Screening Results

Screening occurs early in the IRRP development – after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) toward the most promising options. The three-step, high-level approach is shown in Figure 32.

Figure 32 | IRRP Screening Mechanism



The results of applying the screening mechanism to the KWCG IRRP needs are summarized and described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in the appendix. The list of assumptions made in the needs screening and option analysis can also be found in the appendix.

Table 11 | Results of the KWCG IRRP Screening

Sub-System	Need	Options Screened In	Options Screened Out[7]
Middleport to Detweiler, MxD	Station capacity, supply capacity, load restoration and security	Additional eDSM DG Demand response Transmission-connected generation Wires	
115 kV	Station capacity and supply capacity	Additional eDSM Demand response DG Wires	Transmission-connected generation

[7] Since the IESO is mandated to centrally deliver provincial eDSM programs, the incremental eDSM potential is estimated for each need regardless of its ability to meet the need.

Sub-System	Need	Options Screened In	Options Screened Out[7]
Detweiler to Orangeville, DxV	Station capacity, supply capacity, load restoration and security	Additional eDSM Wires	DG Demand response Transmission-connected generation
Detweiler towards Elmira, D8S/D10H	Station capacity and supply capacity	Additional eDSM Wires	Transmission-connected generation
Detweiler to Kitchener MTS #1 and #4, DxK	Station capacity and supply capacity	Additional eDSM DG Demand response Transmission-connected generation Wires	

7.2 Options Evaluation and Recommendations

7.2.1 115 kV Sub-System

Options for Station Capacity Needs

Arlen TS and Hanlon TS

With station capacity needs arising in the long term (more than 10 years out), options for Arlen TS and Hanlon TS are not required currently. This is applicable even under the high forecast scenario. However, the Technical Working Group can continue to monitor load growth the Guelph area and re-assess these station capacity needs in the next cycle of regional planning.

Cedar TS

Additional eDSM programs could meet 19 MW of the 38 MW summer station capacity need in 2045, as illustrated below. The estimated cost of achieving these eDSM savings is $58 million, which is considered cost effective for provincial adequacy needs.

Figure 33 | Estimated Incremental eDSM Potential for Cedar T1/T2

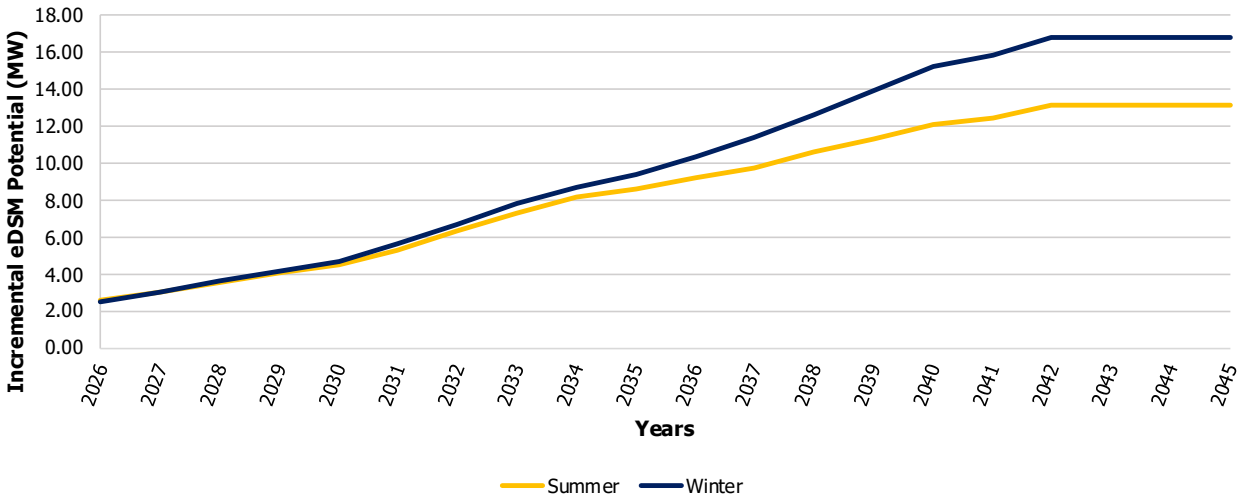
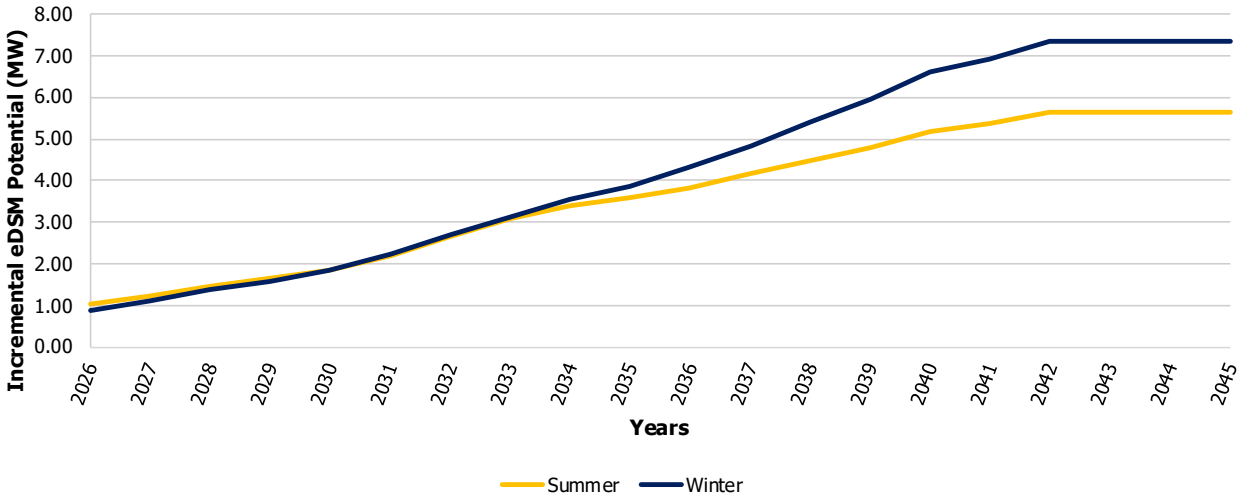


Figure 34 | Estimated Incremental eDSM Potential for Cedar T7/T8



For the end-of-life need at Cedar T7/T8 in 2032, only wires options were considered:

1. Like-for-like 115 kV transformer replacement ($20 million, three-years lead time);
2. Upsized 115 kV transformer replacement ($55 million, four-years lead time)[8]; or
3. Voltage conversion of existing 115 kV DESN to a new 230 kV DESN ($60M, four-years lead time).

Option 1 addresses the end-of-life need and increases the LTR to 58 MVA (52 MW), which does not meet the T7/T8 station capacity need in the long term. Options 2 and 3 provide more station capacity, with both offering an LTR of 140 MVA (126 MW). This not only accommodates the capacity need at T7/T8 but can address the capacity need at T1/T2 if load is transferred on the distribution system.

Option 3 offers an additional benefit to offload the constrained 115 kV sub-system. 230 kV supply to a new 230 kV Cedar T7/T8 is enabled by the DxV sub-system recommendations (see Section 7.2.3); in

[8] Assumes new transformers and second metal-clad switchgear.

contrast, option 2 is not feasible without further 115 kV sub-system reinforcements — beyond those described later in this in section.

Kitchener MTS #5 and #7

Additional eDSM programs could meet 13 MW of the Kitchener MTS #5's summer station capacity need of 10 MW in 2035 and 7 MW of MTS #7's summer station capacity need of 12 MW in 2035, as illustrated in Figure 38. The estimated cost of achieving these eDSM savings is $72.7 million, which is considered cost effective for provincial adequacy needs.

Figure 35 | Estimated Incremental eDSM Potential for Kitchener MTS #5

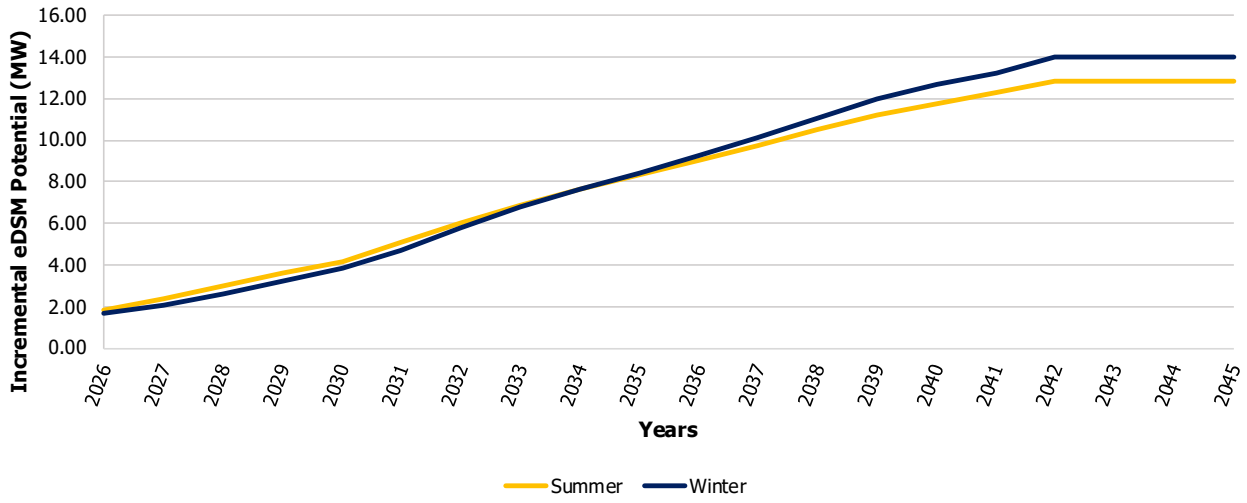
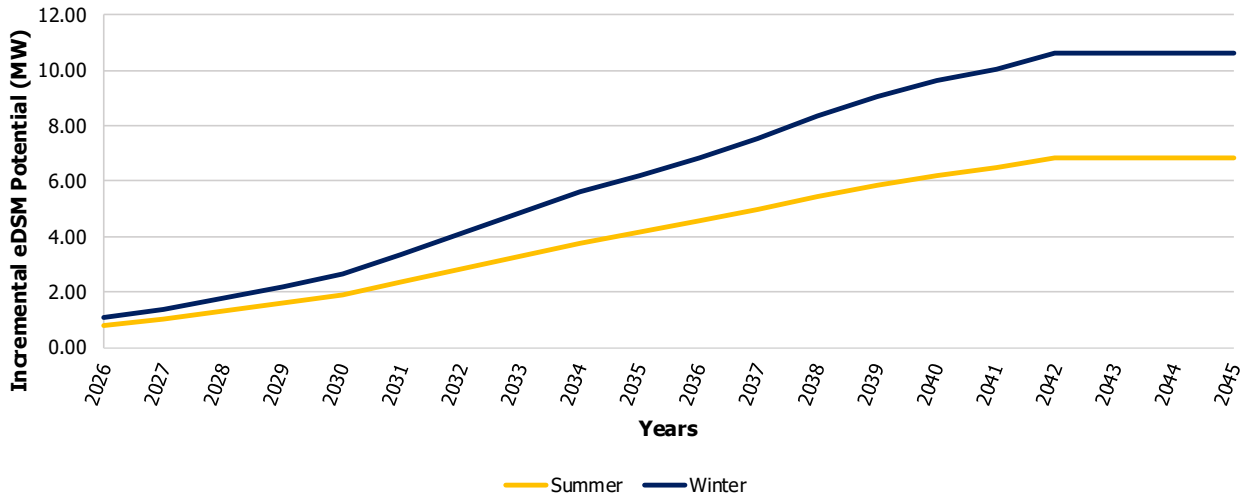


Figure 36 | Estimated Incremental eDSM Potential for Kitchener MTS #7



Given the nearer term need at Kitchener MTS #7, other non-wires options were evaluated:

1. DG; and
2. demand response.

By 2045, the need profile for Kitchener MTS #7 net of additional eDSM peaks at 32 MW, lasts up to 90 consecutive hours, and sums to approximately 40,000 MWh of energy. The need also occurs primarily in the winter. Based on these need characteristics, the following options were screened in:

- wind;
- BESS;
- combined wind and BESS;
- combined wind and solar;
- combined solar and BESS;
- combined solar, wind, and BESS; and
- demand response.

Solar as a standalone option was screened out due to the winter need, and small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. This complements the municipal preferences of the city of Kitchener.

Among the screened-in generation options, none were feasible either because of the need profile and size, and/or the available DG connection capacity at the station. For the latter, consideration was given to Enova Power undertaking feeder breaker and switchgear replacement work to increase the short circuit rating by 20 per cent. Even if ignoring DG connection capacity, feasible options would have a land requirement (like wind and BESS, at an estimated total of 15 km^2) that can be difficult to accommodate near Kitchener MTS #7.

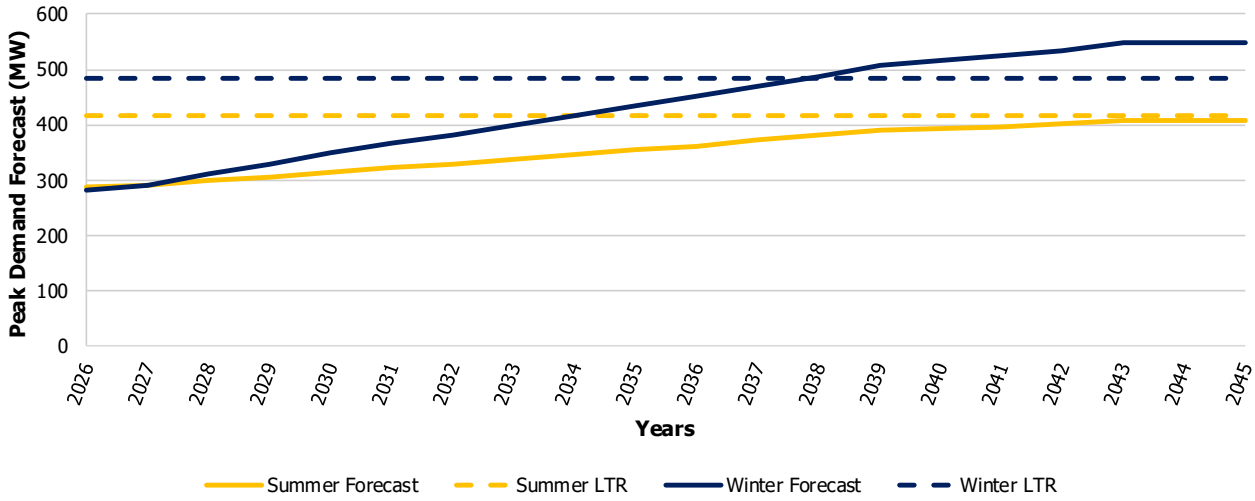
For the station capacity needs at Kitchener MTS #5 and #7, the following wires options were evaluated:

1. load transfers on the distribution system starting in 2032[9]; and
2. new station in Kitchener.

Option 1 is to leverage capacity on the existing transmission system to transfer and optimize load between the 115 kV Kitchener stations (both in the 115 kV sub-system and in the DxK sub-system). Currently, Kitchener MTS #5 has ties with MTS #1, #4, and #7; MTS #7 has ties with MTS #3 and #5. There is sufficient station capacity for the 115 kV Kitchener stations until 2039 (including those served by the DxK sub-system), assuming distribution-level load transfers to enable the optimal load reallocation are possible. Each new distribution tie is estimated to cost $500,000.

[9] Could be delayed depending on the amount of additional eDSM savings are achieved.

Figure 37 | Cumulative Station Capacity Needs at 115 kV Kitchener Stations[10]



Option 2 can be considered alongside option 1 for an integrated solution. Option 2 involves a new station sited in Kitchener in the Freeport area to provide enough station capacity (at least 70 MW) for the cumulative station needs at Kitchener MTS #1, 4, and 7. It would be required starting in 2039 if distribution load transfer capability allows all existing station capacity to be utilized, but could also be later depending on additional eDSM savings. If the new station is connected to the 230 kV system, options include:

- A 6.5 km, 230 kV double-circuit line extension from Kitchener MTS #6 to Kitchener MTS #7, where:
  - MTS #7 is converted to 230 kV ($2-5 million); or
  - a new 230 kV station is built on its existing property ($30-45 million).

About 1.3 km of the 230 kV line extension may utilize the existing underground duct bank and cost $30 million; the remaining overhead line is expected to cost $44 million. It is also possible for the new 230 kV double-circuit line extension to come from Preston TS to the Kitchener Freeport area.

Alternatively, new station capacity in Kitchener could be added at the 115 kV level. Given the 115 kV sub-system limitations described in Section 6.2, this can occur in two ways:

- reinforcements to the 115 kV sub-system beyond the circuit upgrades recommended in later this this section; or
- long-term offloading of the 115 kV sub-system through a 230 kV line extension from Preston TS to a converted GrandBridge Energy MTS #2 (also described in Section 7.2.2).

Puslinch DS

The following non-wires options were evaluated for the station capacity need at Puslinch DS:

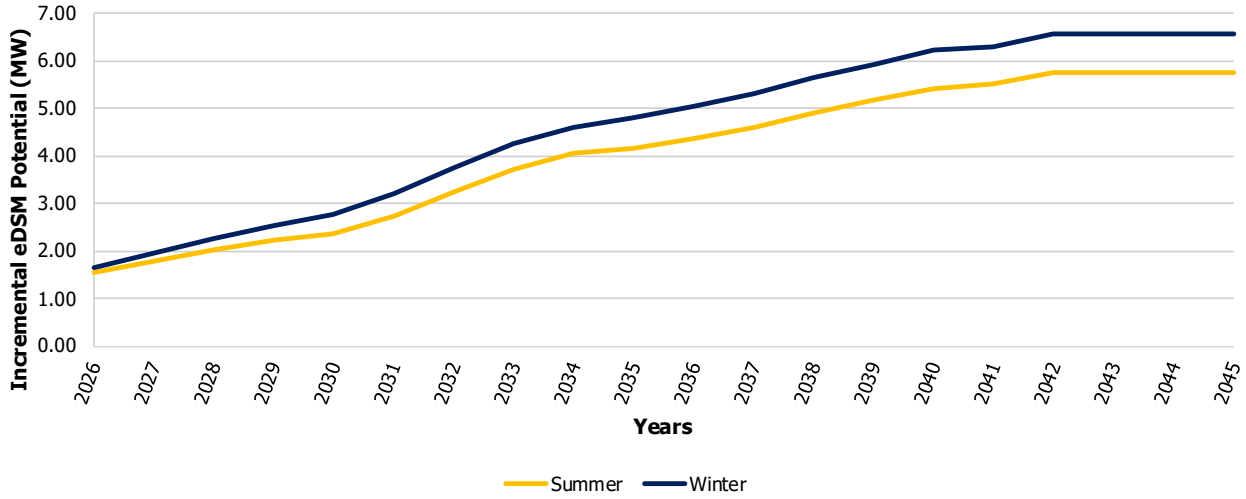
1. Additional eDSM;
2. DG; and

[10] Graph includes Kitchener MTS #1, 3, 4, 5, and 7.

3. demand response.

Additional eDSM programs could meet 6 MW of the 13 MW summer station capacity need in 2035. The estimated cost of achieving these eDSM savings is $15.6M, which is cost-effective for provincial adequacy needs.

Figure 38 | Estimated Incremental eDSM Potential for Puslinch DS



By 2045, the need profile for Puslinch DS peaks at 13 MW, lasts up to 17 consecutive hours, and sums to approximately 2,500 MWh of energy. Based on these need characteristics, the following non-wires options were screened in:

- solar;
- BESS;
- combined solar and BESS;
- combined solar, wind, and BESS;
- demand response; and
- natural gas.

Wind as a standalone option and wind with BESS were screened out due to the need primarily occurring during summer daylight hours, and small modular reactors were screened out since the need size does not warrant this type of technology.

Among the screened-in DG options, only two could meet the need profile into the long term:

- 12 MW of solar and 8 MW/47 MWh of BESS[11] deployed between 2030 and 2042; or
- 13 MW of natural gas.[12]

[11] Could meet the reference need until 2042.

[12] While this IRRP has primarily focused on options that reduce the reliance on emitting resources, gas generation was explored to help provide context on the cost and feasibility of alternatives to the solar and BESS option.

Between the feasible options, solar and BESS are estimated to cost $41-50 million compared to $101 million for natural gas. Of these total costs, up to $41 million and $34 million could be attributed to system benefits (i.e., contribute to provincial resource adequacy needs), respectively. Therefore, the net cost of the most cost-effective non-wires option of solar and BESS is $0 to $9 million, with the latter being more applicable since it represents distribution-connected rather than utility-scale resources. Distribution-connected resources are required for station capacity needs.

A wires option was also considered for the Puslinch DS need: reconfiguring the station to a new 230 kV DESN for $65 million with a five-year lead time. This option is more expensive, however, does offer additional station capacity for growth beyond the high forecast. The station should be at the 230 kV level given the constrained 115 kV sub-system in the KWCG region.

The economic assessment for the options at Puslinch DS is summarized in the table below. Note that these are planning-level cost estimates subject to change during implementation.

Table 12 | Summary of Economic Assessment of Options for Puslinch DS[13]

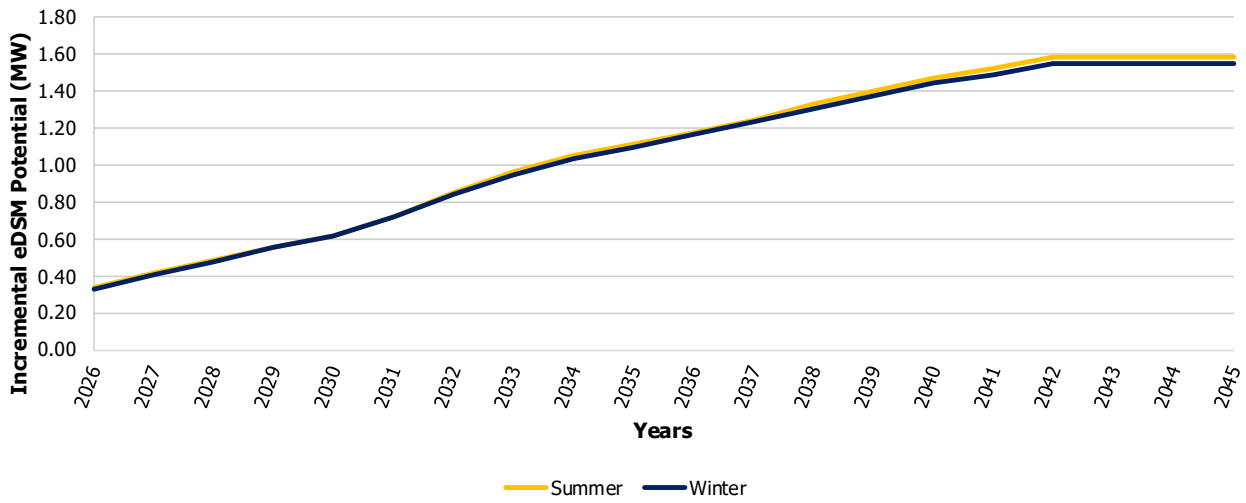
Option	Total Cost	System Benefits (Utility Scale)[14]	Net Benefit (Cost to Ratepayer)
New 230 kV station with overnight capital cost of $65M	$65M	$0M	-$65M
BESS and solar	$41M to $50M	$41M	$0M to -$9M
Natural gas	$101M	$34M	-$67M

Wolverton DS

Additional eDSM targeted to Wolverton DS could meet 2 MW of the 16 MW summer station capacity need in 2035. The estimated cost of achieving these eDSM savings is $5.2 million, which is cost-effective for provincial adequacy needs.

[13] Costs are net present values for 2026 to 2073 in 2025 real dollars.
[14] Estimates based on changing system needs as identified by the Annual Planning Outlook.

Figure 39 | Estimated Incremental eDSM Potential for Wolverton DS

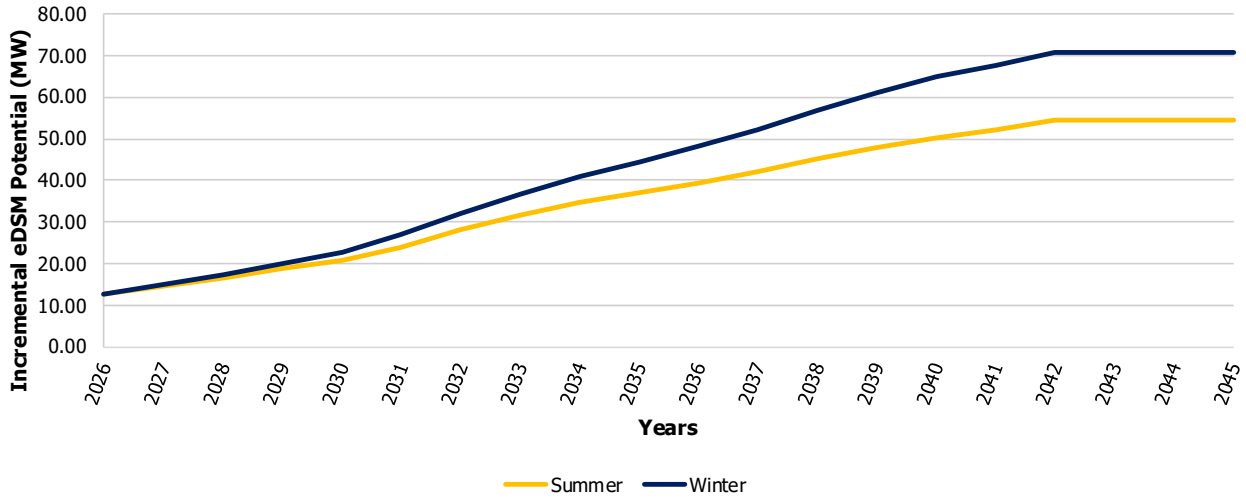


The wires option considered for the Wolverton need is the fan monitoring project already underway by Hydro One Distribution. Once implemented by early 2027, the LTR increases to 31 MVA and 40 MVA for summer and winter respectively. Combined with additional eDSM, this project defers the Wolverton DS station capacity need to 2041.

Options for 115 kV Supply

Given the nature of the 115 kV sub-system supply constraints described in Section 6.2, the only non-wires option considered was additional eDSM (see Figure 40). Additional eDSM programs could meet 54 MW of the 90 MW summer station capacity need in 2045, as illustrated below. The estimated cost of achieving these eDSM savings is $172.2 million, which is considered cost-effective for provincial adequacy needs.

Figure 40 | Estimated Incremental eDSM Potential for 115 kV Sub-System



Other non-wires options, such as transmission-connected resources, were screened out from further analysis due to increased operational complexity and the specific requirements of any resource option:

- Multiple generation units would have to be sited at both Freeport junction and Puslinch TS and connected to both 115 kV circuits.
- A three-breaker ring bus configuration ($60M, two-to-three-year lead time) or tap ($3 million, one-to-two-year lead time) would be required for each generation connection.
- Deliverability of resources connected to the BxC and FxC circuits was limited per the LT2 RFP connection guidance.

Alternatively, three sets of circuit uprates were evaluated for wires options:

1. B5C between Burlington and Harper ($3.5M) and D9F between Detweiler and Siebert ($12 million);
2. B6C between Harper and Puslinch ($2.2M) and F12C between Speedville and Freeport ($18 million); and
3. further uprates to B5C between Harper and Puslinch, and B6C between Burlington and Harper ($3 million total).

With uprates sets #1 and #2, the 115 kV sub-system supply capacity need is addressed, with additional room for up to 75 MW. Set #3 of uprates increases this by another 20 MW, depending on where on the 115 kV network load is added. Beyond these uprates, the 115 kV sub-system becomes voltage-limited.

Upgrading the companion sections on the D7F circuit at an estimated cost of $6 million, as well as the F11C circuit at an estimated $9 million, enables more flexibility for future connections to be supplied by both circuits in the double-circuit line.

Recommendations

Additional eDSM that is cost-effective to the system should be targeted to all station capacity needs in the KWCG 115 kV sub-system.

For the station capacity need at Wolverton DS, Hydro One Distribution should proceed with the fan monitoring project to increase the station LTR by early 2027.

To address the 115 kV sub-system supply capacity need, it is recommended for Hydro One to implement upgrades to increase the thermal ratings of B5C/B6C, D7F/D9F, and F11C/F12C by 2028, per sets 1 and 2 upgrades described above.

To address the station capacity needs at Cedar T1/T2 and T7/T8 DESN, as well as the end-of-life need at the latter, it is recommended that T7 & T8 are replaced by 2032 with a new 230 kV DESN supplied by the existing DxV transmission lines.

Starting in 2033, load between Kitchener MTS #5 and #7 should be transferred off as required to respect their station LTRs. This is recommended to be implemented through the distribution system between Kitchener MTS #1, 3, 4, and 6. In the long-term, a new station is required in the Kitchener Freeport area. In future planning, the Technical Working Group should consider cost-effective opportunities for 230 kV reinforcements to address long-term needs, given the constraints and less flexibility of the 115 kV sub-system.

In the long term, load growth (including the impact of eDSM savings) should be monitored at Arlen TS and Hanlon TS to manage potential station capacity needs.

To address the Puslinch DS station capacity need, it is recommended to implement distribution-connected resources between 2030 and 2042.

Two key considerations accompany this non-wires recommendation:

- potential for Hydro One Distribution's low or high forecast at Puslinch DS to materialize; and
- implementation mechanisms for DERs for regional planning needs.

While the most cost-effective, feasible option for Puslinch DS' reference case need is the combination of solar and BESS, Hydro One Distribution should consider the potential for its low or high forecast to occur. Load trending closer to the low forecast scenario would re-affirm the value of proceeding with non-wires options that can be sized in smaller increments and staged over multiple years to avoid overbuilding — as opposed to the wires alternative of a 230 kV DESN that offers excess capacity. In contrast, if load trends beyond the high forecast scenario, the integrated non-wires recommendation should be re-evaluated and a new station may be required or may be more cost-effective.

The analysis in this IRRP also specifically identified that an integrated package of 12 MW of solar and 8 MW/47 MWh of BESS, staged over the period of 2030 to 2042, is the most cost-effective solution given the wires alternative for Hydro One Distribution's station capacity need. The non-wires solution also has system value – it can contribute as part of the new resources that otherwise would have to be acquired for provincial resource adequacy needs, as signaled through the Annual Planning Outlook. Any resources participating in IESO procurements would need to ensure they are able to comply with the requirements of those procurements and associated contractual obligations. Other combinations and timing of distributed resources may be sufficient for Puslinch DS, if they can adequately address the need profile (see KWCG IRRP Data Tables), meet technical requirements, and are more cost-effective than the wires alternative explored in this IRRP.

At least three years is the typical lead time for new solar and BESS, but timelines may vary depending on the implementation approach. The IESO signals system needs through connection guidance and future procurement processes, including the LT2 RFP. These procurements are technology-agnostic and are open to distribution-connected projects. Distributed resources can also participate in the Capacity Auction to help meet system needs. In parallel, various initiatives are underway by the Ontario Energy Board that can impact the implementation of non-wires options, including initiatives on distribution system operator capabilities. Related, the Benefit-Cost Analysis Framework sets out guidance for LDCs when assessing the economic feasibility of non-wires solutions for distribution need — including an Energy System Test that accounts for impacts to the broader energy system.

The implementation mechanism for the non-wires recommendations for Puslinch DS will be identified after the IRRP. As a next step, the Technical Working Group will monitor Puslinch DS' forecast such that the wires alternative of a new 230 kV DESN is triggered if still required and the non-wires recommendation cannot be implemented in time. The IESO will work with the LDC to support the exploration of value-stacking opportunities.

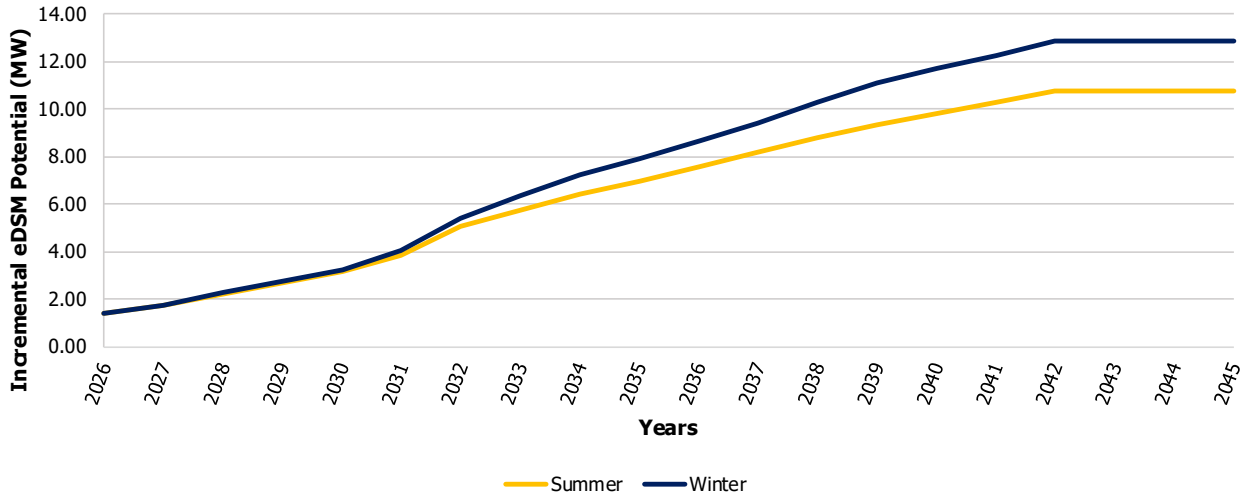
7.2.2 MxD Sub-System

Options for Station Capacity Needs

Kitchener MTS #6

Additional eDSM programs could meet 11 MW of the 16 MW summer station capacity need in 2045, as illustrated below. The estimated cost of achieving these eDSM savings is $40.5 million, which is considered cost effective for provincial adequacy needs.

Figure 41 | Estimated Incremental eDSM Potential for Kitchener MTS #6



Other non-wires options were evaluated:

1. DG; and
2. Demand response.

By 2045, the need profile for Kitchener MTS #6 net of additional eDSM peaks at 12 MW, lasts up to eight consecutive hours, and sums to approximately 290 MWh of energy. The need also occurs primarily in the summer evening.

Based on these need characteristics, BESS was screened in for further evaluation. Solar and wind as standalone options were screened out due to the primarily summer need occurring in the evenings. Small modular reactors were screened out since the need size does not warrant this type of technology. Demand response is possible only until 2036 as the energy shortfall and number of consecutive hours of need grows over the planning horizon. Lastly, natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. This complements the City of Kitchener's participation in ClimateActionWR, a collaborative effort with local municipalities and organizations to reduce community-wide GHG emissions. The City has set GHG reduction targets, including an 80 per cent reduction by 2050 from 2010 levels, with interim goals such as a 30 per cent reduction by 2030.

12 MW/58 MWh of BESS, deployed between 2034 and 2042, was assessed to be feasible to meet the need profile and estimated to cost $25-30 million. Of these total costs, $25 million could be attributed to system benefits (i.e., contribute to provincial resource adequacy needs). Therefore, the net cost of the cost-effective non-wires option of BESS is $0 to $4 million, with the latter being more applicable

since it represents distribution-connected rather than utility-scale resources. For the Kitchener MTS #6 station capacity need, the BESS should be distribution-connected at or downstream of the MTS. Land requirements for the BESS are estimated to be 0.002 km^2.

A wires option was also considered for MTS #6: expanding the station with a new 230 kV DESN for $30-45M. This option is more expensive but offers additional station capacity for growth beyond the high forecast. Kitchener MTS #6 also has distribution ties for load transfers with MTS #4 and #8, but those stations are also reaching their LTRs.

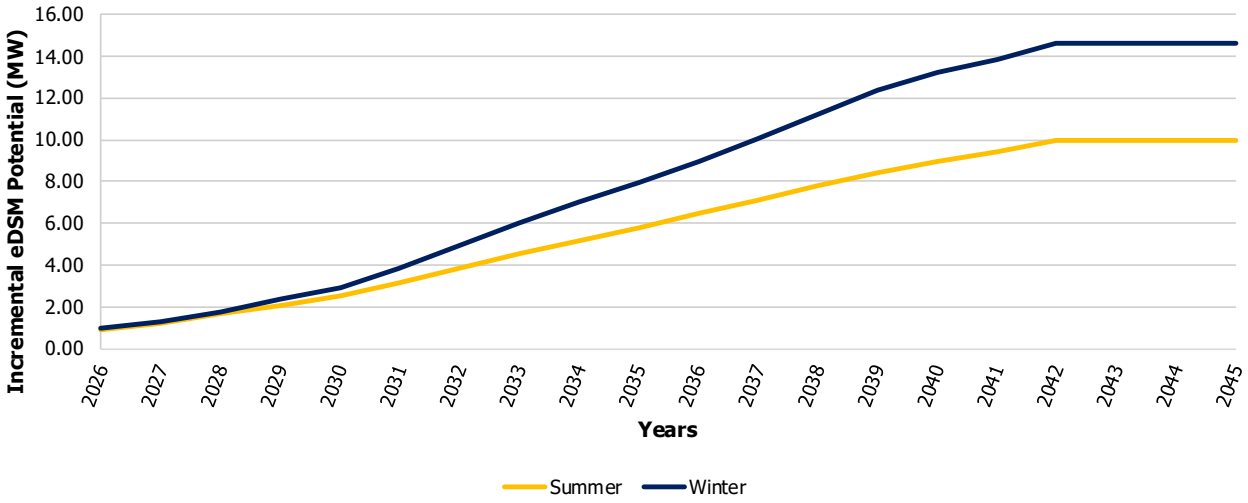
Table 13 | Summary of Economic Assessment of Options for Kitchener MTS #6[15]

Option	Total Cost	System Benefits (Utility Scale)[16]	Net Benefit (Cost to Ratepayer)
New 230 kV station with overnight capital cost of $30M to $45M	$26M to $39M	$0M	-$26M to -$39M
BESS-only	$25M to $30M	$25M	$0M to -$4M

Kitchener MTS #8

Additional eDSM was screened in for further consideration at Kitchener MTS #8. This non-wires option could meet 10 MW of the 40 MW summer station capacity need in 2045, as illustrated in Figure 33. The estimated cost of achieving these eDSM savings is $38.6 million, which is considered cost effective for provincial adequacy needs.

Figure 42 | Estimated Incremental eDSM Potential for Kitchener MTS #8



[15] Costs are net present values for 2026 to 2073 in 2025 real dollars. Note that these are planning-level cost estimates subject to change during implementation.

[16] Estimates based on changing system needs as identified by the Annual Planning Outlook.

While eDSM can help reduce the station capacity need, it is not sufficient alone and does not defer it. A wires alternative is to expand Kitchener MTS #8 with a new 230 kV DESN at a cost estimate of $30-45 million, in-service by 2030 when the need arises. There are also distribution ties for load transfers to Kitchener MTS #3 and #6, but capacity at the former is already required to offload some of the 115 kV Kitchener stations. At the latter, there is already a station capacity need.

Preston TS, GBE MTS #1, and Galt TS

Due to the urgent and large station capacity needs between Preston TS, GBE MTS #1, and Galt TS, eDSM was considered to help manage needs until wires options could be implemented. Additional eDSM could address 49 MW of the station capacity needs between Preston TS, GBE MTS #1, and Galt TS by 2045. The estimated cost of achieving these eDSM savings is $144.3 million, which is considered cost effective for provincial adequacy needs.

Otherwise, the Technical Working Group focused on the following wires options:

1. 115 kV station ($40 million) supplied by the existing F11C/F12C circuits; or
2. 230 kV station ($45 million) supplied by a new 230 kV double-circuit line from Preston TS ($75M).

These options' ability to meet the collective KWCG station capacity needs in GrandBridge Energy's service territory are closely intertwined with the 115 kV sub-system and MxD sub-system supply needs.

Option 1 provides station capacity in the Cambridge area as early as 2028 since its preferred location enables connection to existing 115 kV circuits. However, there is limited 115 kV supply capacity, even after accounting for the circuit upgrades recommended in Section 7.2.1. In contrast, Option 2 requires longer to implement for two reasons: new 230 kV double-circuit lines are needed to connect the station (depending on where the station can be sited), and reinforcements for MxD supply also need to be in-service first (see next section).

An integrated solution is also possible. With the 115 kV circuit upgrades recommended in Section 7.2.1, option 1 can provide 75 MW of station capacity to the Cambridge area in the near term, meeting the cumulative need until 2035 (or earlier, if load materializes at a faster rate than in the reference forecast). After, when the MxD supply reinforcements are in-service, a new larger 230 kV DESN can meet the remaining capacity needs in the longer term.[17] Its siting in the eastern part of Cambridge (near the Speedsville and Maple Grove area) is subject to where GrandBridge Energy load growth materializes in the 2030s, as well as routing of new 230 kV transmission lines connecting Puslinch with Cambridge.

Wires Options for MxD Supply, Load Restoration, and Load Security

The following wires options were considered to address MxD supply capacity needs:

1. Reconductor 19 km of the MxD line, from Cambridge junction to Galt junction ($40 million);
2. Rebuild 19 km of the MxD line, from Cambridge junction to Galt junction ($115 million);

[17] Planning-level cost estimate is subject to the size of the new DESN, depending on how load materializes.

3. Sectionalize the MxD lines at Galt junction with a new 230 kV SS (including two 195 MVAR capacitor banks) ($170 million), reconductor between Galt and Preston, and build:
    a. 32 km double-circuit 230 kV lines to Detweiler ($380 million); or
    b. 25 km double-circuit 230 kV lines to Middleport ($310 million).
4. Build new 500/230 kV autotransformer station ("Wellington TS") near Puslinch (including two 100 MVAR capacitor banks[18]) and 15 km double-circuit 230 kV line to Preston TS ($280 million total), with:
    a. Normally open point at Ameristeel junction; or
    b. 230 kV switching station at Galt junction ($160 million).
5. Build new 46 km double-circuit 230 kV line from Middleport to Galt to Preston ($480 million); and
6. Build new 53 km double-circuit 230 kV line from Detweiler to Galt to Preston ($550 million).

Option 1 increases the supply capability between Galt TS and Preston TS by approximately 50 MW; Option 2's performance is similar, though offers higher thermal ratings on the transmission lines.

Options 3a and 3b increase supply capability between Galt SS and Preston TS by approximately 110 MW and 130 MW, respectively. In contrast, options 4a and 4b increase supply capability between Preston TS and Wellington TS by about approximately 100-170 MW[19] and 400 MW[20], respectively. Since these options address the MxD supply capacity needs, the more expensive options 5 and 6 were not studied further.

Consideration for Brant and Powerline Load

In the 2024 Burlington to Nanticoke IRRP, two 230 kV DESNs were recommended to address capacity needs at Brant TS and Powerline MTS in the County of Brant. These new stations are to be connected to the MxD circuits, pending outcomes of the KWCG IRRP.

Therefore, the KWCG Technical Working Group considered each MxD wires option and their LMC for load supply to the Brant/Powerline area:

- Options 3a and 3b enable the new DESNs to be connected with new radial 230 kV lines from Galt SS. However, neither provide sufficient capacity for the forecast (300 to 350 MW) required for Brant/Powerline.
- Options 4a and 4b allow the new DESNs to tap the MxD lines between Detweiler TS and Middleport TS, or Galt SS, respectively, and enables up to the 600 MW load security limit on the Kitchener MTS #6/#8 and Brant/Powerline side.

[18] Additional capacitor banks may be required in the longer term as load grows.
[19] Supply capability ultimately depends on where additional load (such as GBE MTS #3) is sited; if close to Preston TS, the LMC increases by 170 MW. If load is sited closer to Galt TS, the LMC will be lower.
[20] The 600 MW total load security criterion will be limiting first.

Consideration for Load Security and Restoration Needs

As described in Section 6.3.3, supply capacity needs on the MxD sub-system are also accompanied by load security and load restoration needs. Therefore, the Technical Working Group considered the security and restoration benefits offered by options 4a and 4b (the only wires options capable of solving the supply capacity needs, as described above).

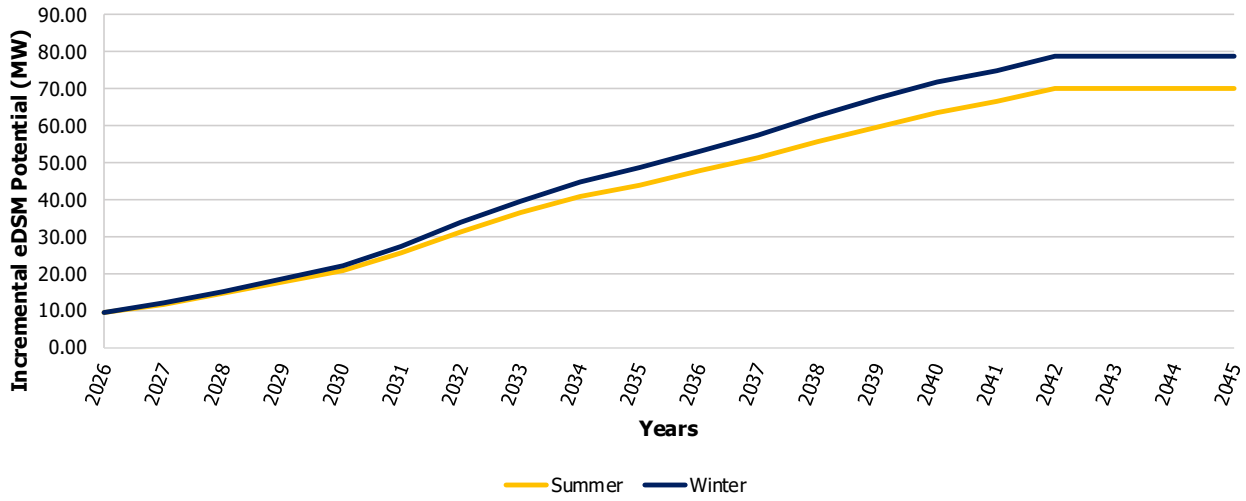
With either the open point or SS, security needs are resolved because the loads on the current MxD lines would be sectionalized such that no more than 600 MW of load could be interrupted by a contingency event based on configuration of the system alone. There are also load restoration benefits: with option 4a, motorized switches on both the Detweiler side and Middleport side of Galt junction allow the restoration of Kitchener MTS #6 and #8, as well as Brant/Powerline load, depending on where the contingency occurs. Restoration of loads between Galt TS and Preston TS would be possible from Wellington TS. The Galt SS in option 4b offers even greater restoration capability through re-termination of the existing MxD circuits at Galt junction.

Non-Wires Options for MxD Supply

For the MxD supply capacity need, two types of non-wires options were evaluated: additional eDSM and transmission-connected resources.

Additional eDSM programming targeting load supplied by the MxD sub-system could meet 79 MW of the 202 MW winter 2045 need. This is illustrated below. The estimated cost of achieving these eDSM savings is $246.5 million, which is considered cost effective to the system.

Figure 43 | Estimated Incremental eDSM Potential for MxD Sub-System



Given the magnitude of needs affecting the MxD sub-system, the Technical Working Group considered the feasibility of an integrated solution where a new transmission-connected resource is implemented alongside a Galt SS to defer additional 230 kV transmission lines. To achieve this and meet the need, the resource would have to be sited on the 230 kV side of Preston TS. It would also necessitate a three-breaker ring bus at Preston TS ($60 million, two to three-year lead time).

By 2045, the need profile for this resource (after additional eDSM is accounted for) peaks at 337 MW, lasts up to 334 consecutive hours, and sums to approximately 865,000 MWh of energy. Based on these characteristics, the following resource types were screened in:

- combined wind and BESS;
- combined solar and BESS; and
- combined solar, wind, and BESS.

Solar, wind, and BESS as standalone options were screened out due to the need characteristics, and small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out given municipal preferences to phase out natural gas, and federal policy direction per the Clean Electricity Regulations at the time of IRRP development.

All screened-in generation options have a large land requirement, and of them, only the combination of wind, solar, and BESS could meet the need profile. This option is estimated to require almost 400 km^2 (1,115 MW of wind, 432 MW of solar, and 1,089 MW/10,000 MWh of BESS). This is not feasible given the specific siting requirements for the generation, and the dense urban area and limited space around Preston TS.

Recommendations

Additional eDSM that is cost-effective to the system should be targeted to all station capacity needs in the KWCG MxD sub-system.

To address the station capacity needs in the near term, a new 230 kV DESN expansion at Kitchener MTS #8 is recommended by 2030. In Cambridge, a new 115 kV station (GBE MTS #2) supplied by F11C/F12C should be implemented by 2028, accommodating up to 75 MW.

GrandBridge Energy may choose to explore a dual-voltage TS for its MTS #2, with a primary operating voltage of 115 kV and 230 kV and a secondary distribution voltage of 27.6 kV, at an additional cost of $2 million. This 230 kV capability may offer flexibility for future load connection requirements, which could be considered in subsequent planning cycles as circumstances evolve.

For the broader MxD supply, security, and restoration needs, a 500/230 kV autotransformer station (Wellington TS) in the Puslinch area is required by 2031 (or as early as 2029), as well as a new 230 kV double-circuit line from this station to Preston TS and a normally open point at Ameristeel junction.

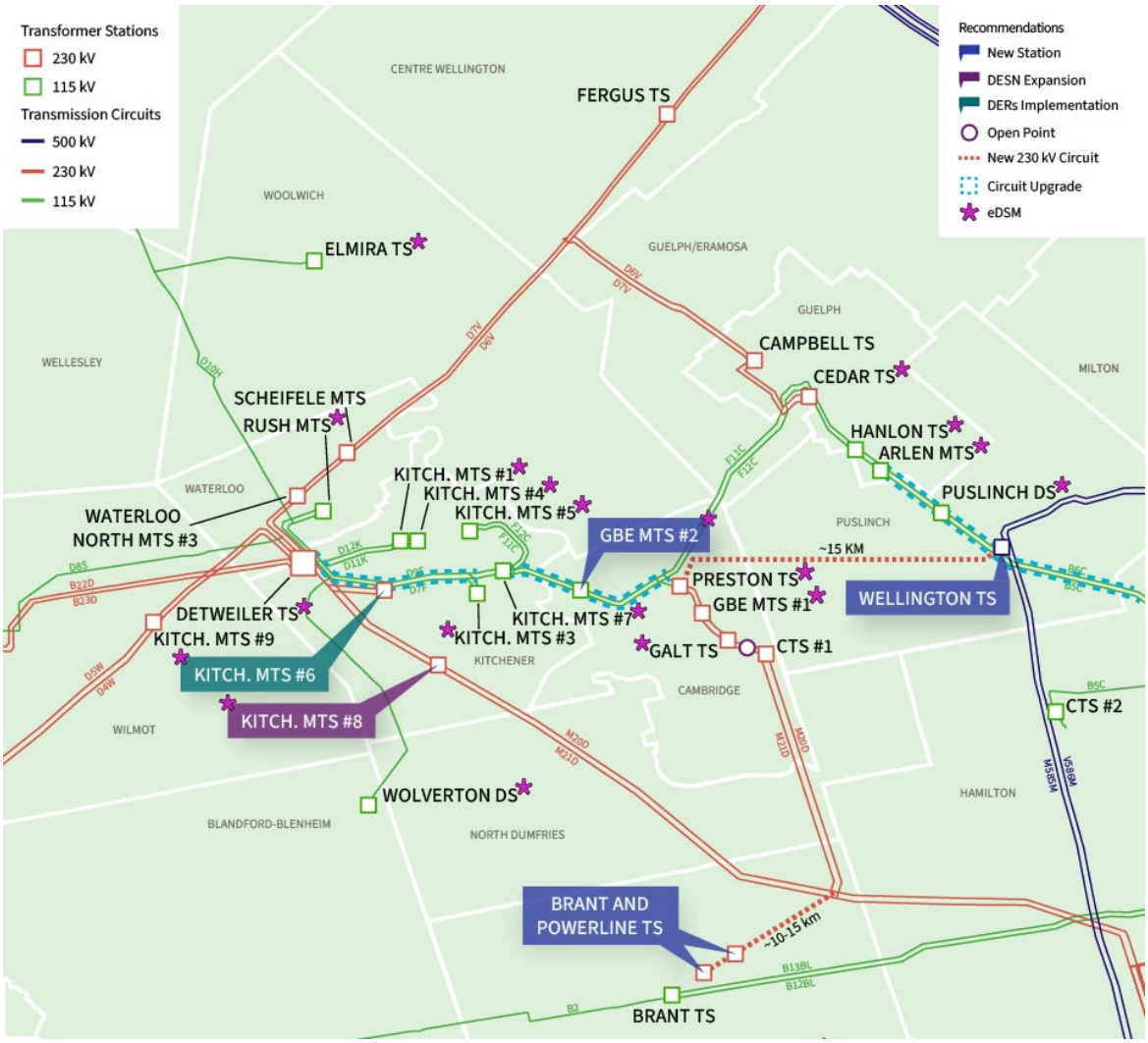
A subsequent 230 kV DESN (GBE MTS #3) is recommended by 2035 (or earlier, depending on how load materializes) for longer term station capacity needs in Cambridge after MTS #2 is fully subscribed.

The siting of GBE MTS #3 and its 230 kV supply is subject to where long-term load growth materializes in GrandBridge Energy's service territory and the routing of the new 230 kV Wellington TS to Preston

TS line. MTS #3 may be required earlier depending on the pace of forecast growth – under the high scenario, it should be in-service by 2031. At the time of this IRRP publication in 2026, GrandBridge Energy's forecast information indicates that load is trending towards the high scenario, with MTS #3 potentially required as early as 2032.

Note that the recommendations above also enable connection of two new 230 kV transformer stations to Galt junction. This enables the offloading of the 115 kV Brant TS and Powerline TS, as recommended by the 2024 Burlington to Nanticoke IRRP to address immediate capacity needs in the Brant 115 kV Extended Area.

Figure 44 | Map of MxD Sub-System Near- to Medium-Term Recommendations[21]



In the long-term, the Technical Working Group should monitor the amount of load supplied by the MxD transmission lines; when forecast demand between Detweiler TS and Middleport TS exceeds the load security threshold of 600 MW, a switching station at Galt junction is required. The need for this switching station is not expected in this IRRP's planning horizon under the reference scenario.

[21] Distribution-level load transfers are not shown, for simplicity.

For the station capacity need at Kitchener MTS #6, it is recommended to implement additional eDSM immediately, as well as distribution-connected resources starting in 2034.

The analysis in this IRRP identified that 12 MW/58 MWh of BESS, staged over the period of 2034 to 2042, is the most cost-effective solution given the wires alternative for Enova Power's station capacity need. The BESS option also has system value — these distributed energy resources can contribute as part of the new resources that otherwise would have to be acquired anyway for provincial resource adequacy needs, as signaled through the Annual Planning Outlook. Any resources participating in IESO procurements would need to ensure they are able to comply with the requirements of those procurements and associated contractual obligations. Other combinations and timing of distributed resources may be sufficient for Kitchener MTS #6, if they can adequately address the need profile (see KWCG IRRP Data Tables), meet technical requirements, and are more cost-effective than the wires alternative explored in this IRRP and summarized in Table 13.

At least three years is the typical lead time for new BESS, but timelines may vary depending on the implementation approach. The IESO signals system needs through connection guidance and future procurement processes, including the LT2 RFP. These procurements are technology-agnostic and open to distribution-connected projects. Distributed resources can also participate in the Capacity Auction to help meet system needs. In parallel, various initiatives are underway by the Ontario Energy Board that can impact the implementation of non-wires options, including initiatives on distribution system operator capabilities. Related, the Benefit-Cost Analysis Framework sets out guidance for LDCs when assessing the economic feasibility of non-wires solutions for distribution need — including an Energy System Test that accounts for impacts to the broader energy system.

The implementation mechanism for the non-wires recommendations for Kitchener MTS #6 will be identified following the IRRP. The IESO will work with the LDC to support the exploration of value-stacking opportunities. The Technical Working Group will monitor Kitchener MTS #6's forecast such that the wires alternative of a new 230 kV DESN is triggered if still required and the non-wires recommendation cannot be implemented in time.

7.2.3 DxV Sub-System

As presented in Section 6.4, station and supply capacity needs were identified for the DxV sub-system. Options to address these needs are described below.

Wires Options for Campbell TS

A wires option to address station capacity needs at Campbell TS is to install additional metal-clad switchgear on T3/T4's spare winding to utilize the full LTR potential of 100 MVA (90 MW). This is estimated to cost $25 million and can be implemented as early as 2031. The additional station capacity at T3/T4 can also be used to accommodate forecast growth at Campbell T1/T2 through load transfers on the distribution system.

Non-Wires Options for Campbell TS

New eDSM programs in the area could meet 19 MW of the 50 MW summer station capacity need in 2035, as illustrated below. The estimated cost of achieving these eDSM savings is $52.6 million, which is considered cost effective for provincial adequacy needs.

Figure 45 | Estimated Incremental eDSM Potential for Campbell T1/T2

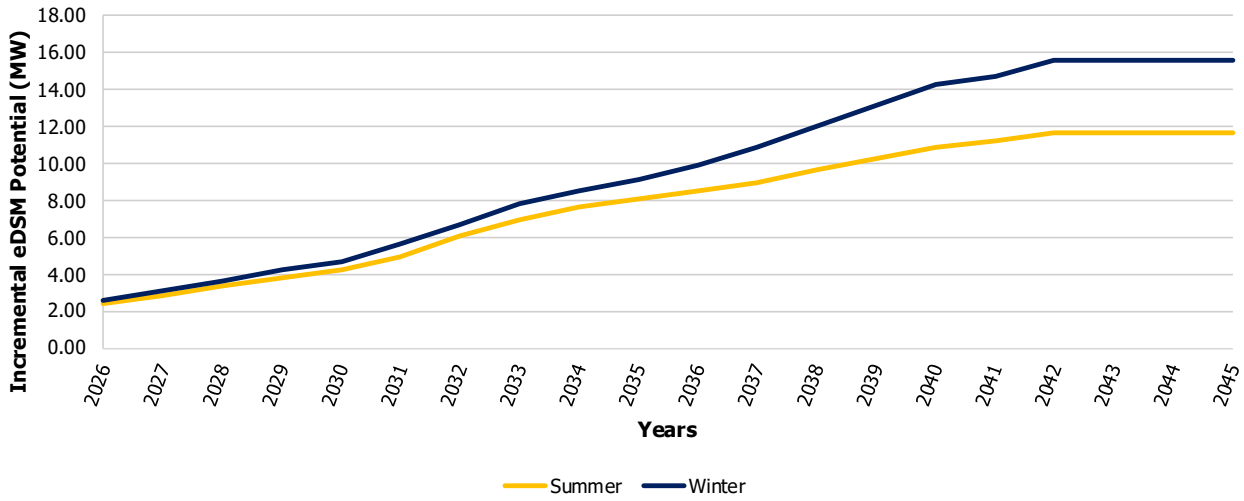
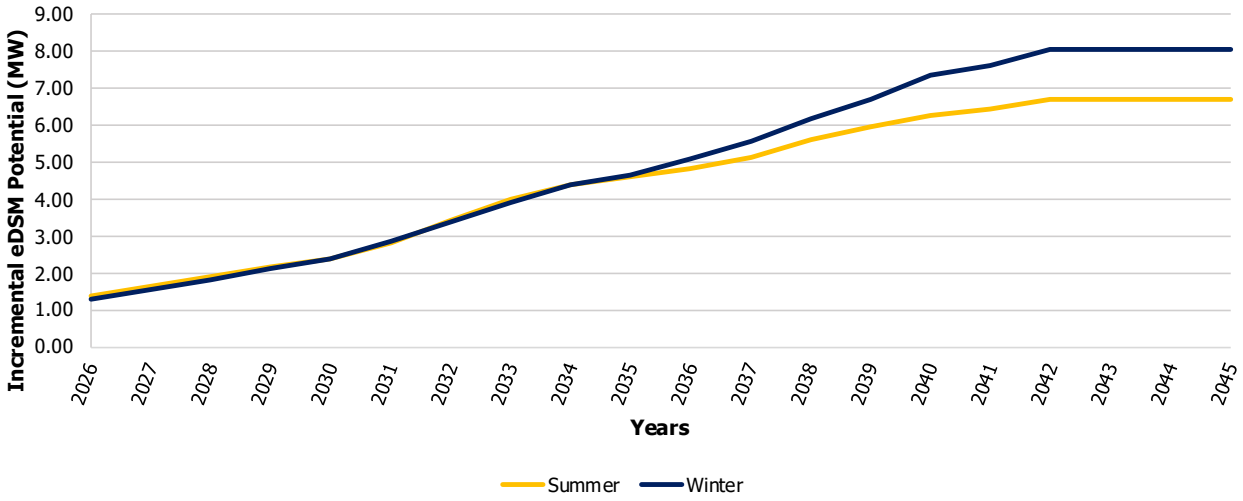


Figure 46 | Estimated Incremental eDSM Potential for Campbell T3/T4



Wires Options for Other DxV Sub-System Needs

Based on the location of forecast growth and new large load customers, Enova Power identified three potential new 230 kV stations (11 TS, Office MTS, and Snider TS) in Waterloo that, together, would provide sufficient station capacity for needs at Rush MTS, Scheifele MTS, and Waterloo North MTS #3.

To address the supply capacity needs of the DxV sub-system and to enable new 230 kV stations, transmission expansion options were evaluated. Given the scale and urgency of the needs, options to address thermal and voltage limitations in the near- to medium-term were assessed alongside longer term supply options for when DxV loads exceeded the 600 MW load security threshold. Moreover, due

to the phased approach taken during the development of the IRRP where recommendations for the MxD sub-system were made first, the second option below accounts for reinforcements described in Section 7.2.2 and includes Wellington TS. LMCs specified below also assume the DxW sub-system forecast of about 50 MW by 2045.

DxV Sub-System: Near-Term Options

The following wires options were evaluated to increase DxV supply capability in the near term:

1. Voltage support at the Preston 230 kV junctions ($95 million) and at Speedville 115 kV junctions ($95M), plus uprates to the DxV circuits between Detweiler TS and the new Waterloo stations ($15 million);
2. A double-circuit 230 kV line ($150 million) from Wellington TS to Cedar TS, a 230 kV switchyard at Cedar TS ($65 million), DxV uprates between Detweiler TS and the new Waterloo stations ($15 million), and additional capacitor bank at Elmira TS ($5 million); or
3. Reconfiguration work at Detweiler TS, and DxV uprates between Detweiler TS and the new Waterloo stations ($15 million).

With each option, the DxV LMC is still limited by the ORTAC load security criteria at 600 MW. Option 1 requires four years of development and comes at a cost estimate of $205M. Option 2 is the most expensive near/medium-term option at a cost of $235 million and can take up to five years, though it can be considered in future planning cycles for supply to the Guelph area.

Option 3 has the potential to be the most cost-effective option and fastest to implement among the three options above. Specifically, option 3 aims to mitigate the most limiting contingency at Detweiler TS that defines the DxV sub-system LMC; this includes the existing operating instructions that would result in the removal of Detweiler static VAR compensator and/or 230kV capacitor bank(s) upon 230 kV bus fault or specific breaker failures contingencies.

Option 3 also has the benefit of increasing the DxV supply capability in near to medium term, as well as in the long term. In the near to medium term, option 3 can increase DxV supply capability to the 600 MW load security limit. It is also required to achieve the LMC described in the next section for option C of the DxV long-term options.

In addition to the three options listed above, up to 150 MW of load transfers to the DxW sub-system is possible based on supply capability with Wellington TS in-service. As described in Section 6.5, the LMCs between the DxV and DxW sub-systems are related. Depending on the location of the load growth, distribution buildout, and existing distribution ties, Enova Power could leverage the DxW supply capability for some forecast load currently allocated to stations served by the DxV sub-system.

DxV Sub-System: Medium- to Long-Term Options

In the medium to long term, further reinforcements and points of supply to the DxV area are still required given the magnitude of the needs.

Hydro One Transmission input during early options development indicated limited feasibility to expand Detweiler 230 kV yard or construct a new 500 kV yard at the existing Detweiler site. As such, the following wires options were considered to address DxV supply capacity needs in the long term and to supply Enova Power's proposed transformer stations in the Waterloo area ($30–45 million each):

A. Build a double-circuit 230 kV line ($360 million) from Wellington TS to new transformer stations in Waterloo;

B. Leverage the preliminary bulk option identified in the South and Central Bulk Plan: build a single-circuit 500 kV line from Longwood TS to a 500/230 kV station near Detweiler TS on the DxW circuits ("Detweiler #2 TS"), and a single-circuit 500 kV line from Detweiler #2 TS to Milton TS; or

C. Leverage the final bulk option identified in the South and Central Bulk Plan: build a single-circuit 500 kV line from Longwood TS to a 500/230 kV station at Guelph North junction ("Guelph North TS") ($270 million), and a single-circuit 500 kV line from Guelph North TS to Wellington TS.

Option A can increase supply to Waterloo by 400 MW, but the overall LMC depends on the amount of load served by the 230 kV circuits from Wellington TS to Preston TS (recommended in Section 7.2.2). Option B was determined infeasible for regional needs because it necessitates extensive circuit and tower upgrades for the DxV and DxW paths, and separate reinforcements for 115 kV system voltage violations. Conversely, Option C increases supply between Detweiler TS and Guelph North TS on the existing DxV lines to approximately 900 MW. However, the load security limit of 600 MW applies. With new, approximately 15 km, radial, double-circuit, 230 kV lines to Waterloo from Guelph North TS ($180 million), another 600 MW can be supplied to the area.

While both options A and C meet the reference forecast supply and load security needs, option C has a few key advantages for regional needs:

- It offers more total supply capability than option A — enough for the high forecast scenario.
- The introduction of Guelph North TS sectionalizes the existing DxV circuits, which allows new stations in Waterloo to be sited and supplied directly from the DxV circuits rather than from new longer (30 km) radial lines (as is the case for option A).
- Option C can be staged in a flexible way such that radial lines/or other options are not triggered until needed, unlike with option A.
- It increases capacity for the DxV sub-system without using up the supply capability from Wellington TS for MxD sub-system needs.
- It introduces a new supply point through Guelph North TS, which sectionalizes and re-terminates the existing DxV lines – therefore offering more restoration capability to the DxV sub-system and diversifying paths of supply to the region.

Option C is enabled by the South and Central Bulk Plan recommendations. The 500 kV reinforcements from Longwood TS to the KWCG region, enabled by new 500 kV supply points at Guelph North TS and Wellington TS, are required for addressing bulk system transfer needs. These options were studied as part of the bulk plan's Portfolio B, which are the preferred set of recommendations to meet the South and Central Bulk Plan objectives. The bulk needs and options are described in detail in the final report issued in Q3 2026.

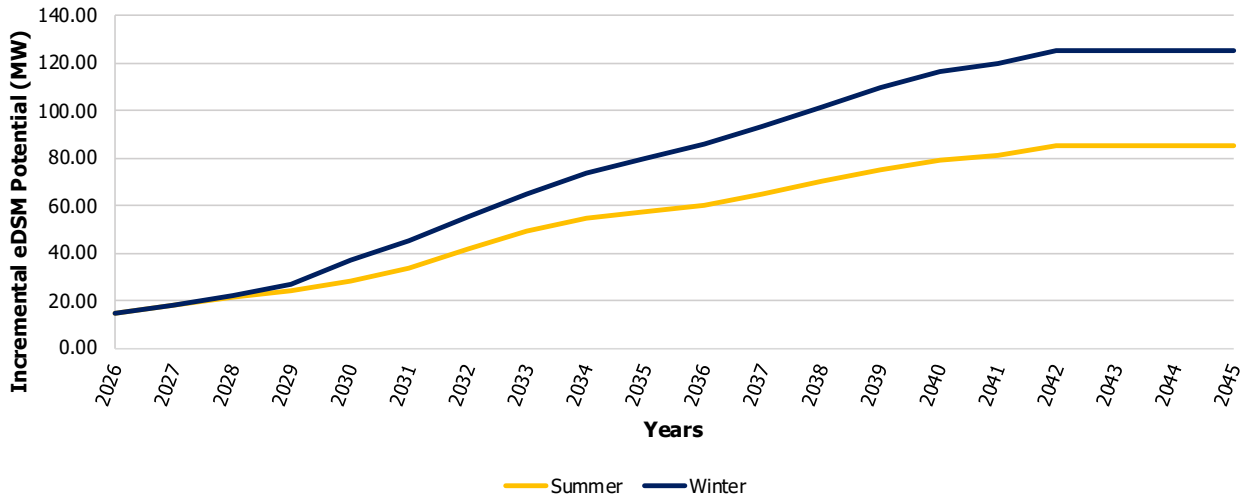
Recognizing that long-term solutions could have a longer lead time relative to the pace of load growth, the Technical Working Group investigated interim solutions of implementing reactive support within KWCG's 115 kV sub-system, such as at Elmira TS, at 10-20 MVAR each. Analysis shows that, while the addition of capacitor(s) cannot fully satisfy the sub-system's load forecast, it increases the DxV sub-

system LMC in the interim until bulk reinforcements for 500 kV supply into the region is in-service. Once 500 kV bulk supply into Guelph North TS is in-service, supply capacity needs are met even without this additional reactive support.

Non-Wires Options for Other DxV Sub-System Needs

As presented in Section 7.1.2, eDSM was screened in further consideration for the DxV needs. Under the existing eDSM framework and programs, up to 85 MW of additional total summer peak savings could be achieved at an expected cost of $247.8 million. eDSM is important for managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply.

Figure 47 | Estimated Incremental eDSM Potential for the Overall DxV Sub-System



Recommendations

It is recommended to target additional eDSM programs in the DxV sub-system to increase capacity and provide broader system benefits.

Considering the uncertainty among the forecast drivers in the region and the increased eDSM targets under the new 2025–2036 eDSM Framework, the Technical Working Group will continue to monitor growth in the region to determine whether sector trends and connection requests indicate a need for development beyond the reference planning forecast.

In the near term, the recommendation to address the Campbell TS station capacity need is to implement additional system cost-effective eDSM and install metal-clad switchgear at T3/T4 to increase its LTR. After this is implemented by 2031, 19 MW of load should be transferred through the distribution system from T1/T2 to T3/T4. Needs in the interim, before additional station capacity is available, will be monitored and evaluated by Alectra.

To address the remaining DxV station capacity, supply capacity, load security, and load restoration needs, the Technical Working Group recommends the integrated wires option that

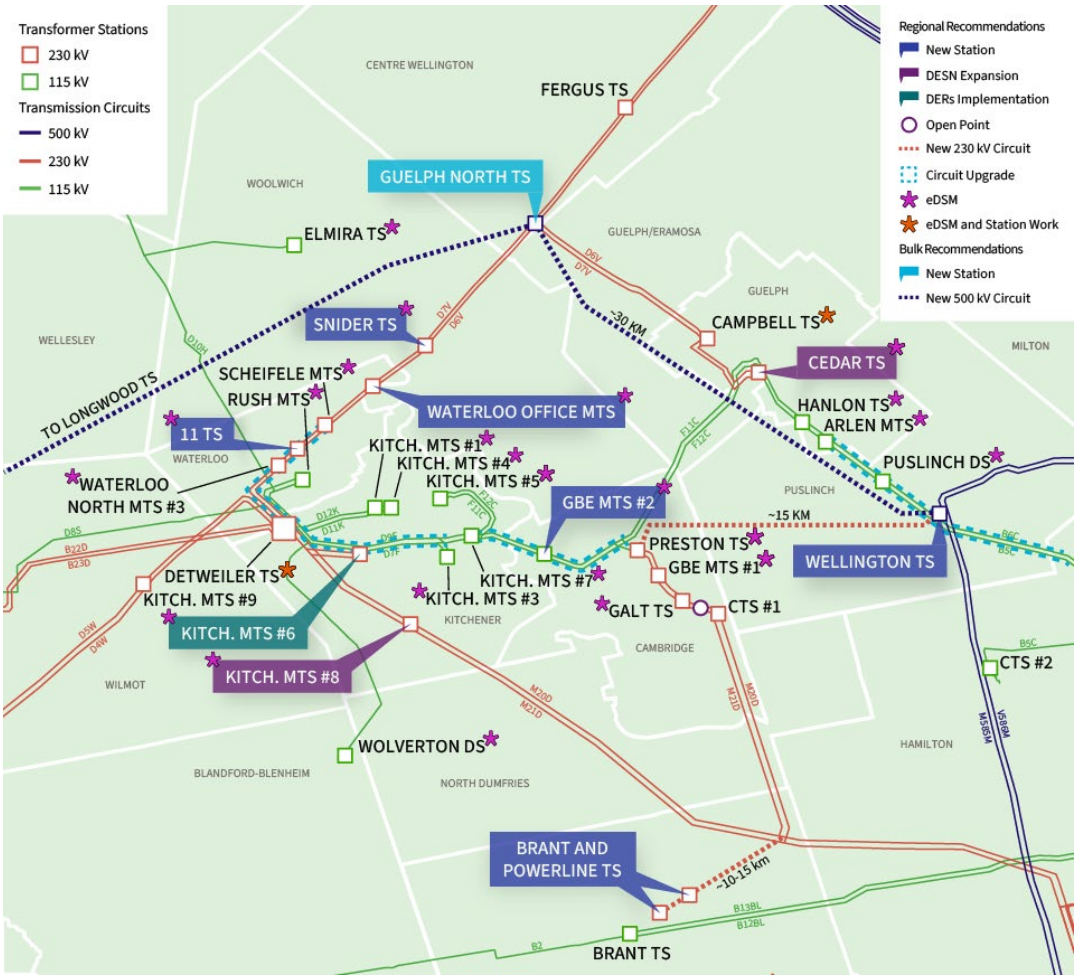
includes, in the near term: DxV uprates and station work at Detweiler TS mitigate the impact of existing operating instructions. By the mid-2030s, bulk reinforcements recommended from the South and Central Plan are required: a new 500/230 kV Guelph North TS, and a single-circuit 500 kV line from Longwood TS to Guelph North TS to Wellington TS. Specifically, the Guelph North TS and 500 kV line to from Guelph North TS to Wellington TS should be advanced to 2031 for regional needs.

The Technical Working Group should closely monitor the pace of load growth on the DxV sub-system. If the longer-term recommendations are delayed, additional load growth in the near term should be enabled by installing a new 10-20 MVAR capacitor at Elmira TS.

Lastly, new 230 kV transformer stations in Waterloo are recommended to be supplied by the existing DxV lines. In the long term, the Technical Working Group should monitor load growth and re-evaluate the need for new radial 15 km double-circuit 230 kV lines from Guelph North TS to the Waterloo area.

This set of recommendations is shown in Figure 48.

Figure 48 | Map of DxV and MxD Sub-System Near- to Medium-Term Recommendations[22]



[22] Distribution-level load transfers are not shown, for simplicity.

The KWCG Regional Infrastructure Plan, led by Hydro One after the IRRP, should further assess and refine the scope of work at Detweiler TS required to mitigate the loss of a static VAR compensator and/or capacitor after outages. Additionally, the cost and feasibility for low voltage capacitors at Elmira TS or on the 115 kV sub-system should be evaluated to bridge the supply capacity gap until the long-term solution for 500 kV bulk reinforcements to the region are implemented. Other alternatives, such as operational measures like undervoltage load shedding schemes, for resolving post-contingency voltage decline violations, can also be considered.

7.2.4 D8S/D10H Sub-System

Options for Rush MTS

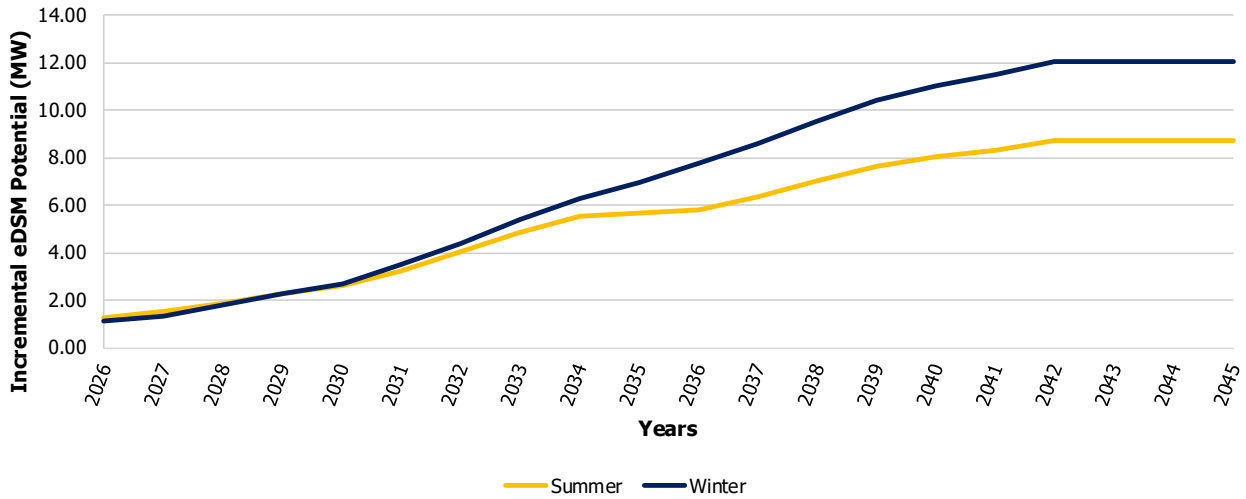
Wires options for the station capacity need at Rush MTS were considered in conjunction with Enova Power's station needs at Scheifele MTS and Waterloo North MTS #3. As described in Section 7.2.3, the three new 230 kV stations proposed (11 TS, Office MTS, and Snider TS) should be sized to meet the cumulative station capacity needs between Rush MTS, Scheifele MTS, and Waterloo North MTS #3.

For Rush MTS, the following non-wires options were also assessed:

1. Additional eDSM; and
2. DG.

Additional eDSM programs could meet 9 MW of the 33 MW summer station capacity need in 2035, as illustrated in Figure 49. The estimated cost of achieving these eDSM savings is $26 million, which is considered cost effective to the system.

Figure 49 | Estimated Incremental eDSM Potential for Rush MTS



By 2045, the need profile for Rush MTS peaks at 51 MW, lasts up to 94 consecutive hours, and sums to approximately 42,000 MWh of energy. Based on these need characteristics, the following non-wires options were screened in:

- wind;
- BESS;

- combined wind and BESS;
- combined wind and solar;
- combined solar and BESS; and
- combined solar, wind, and BESS.

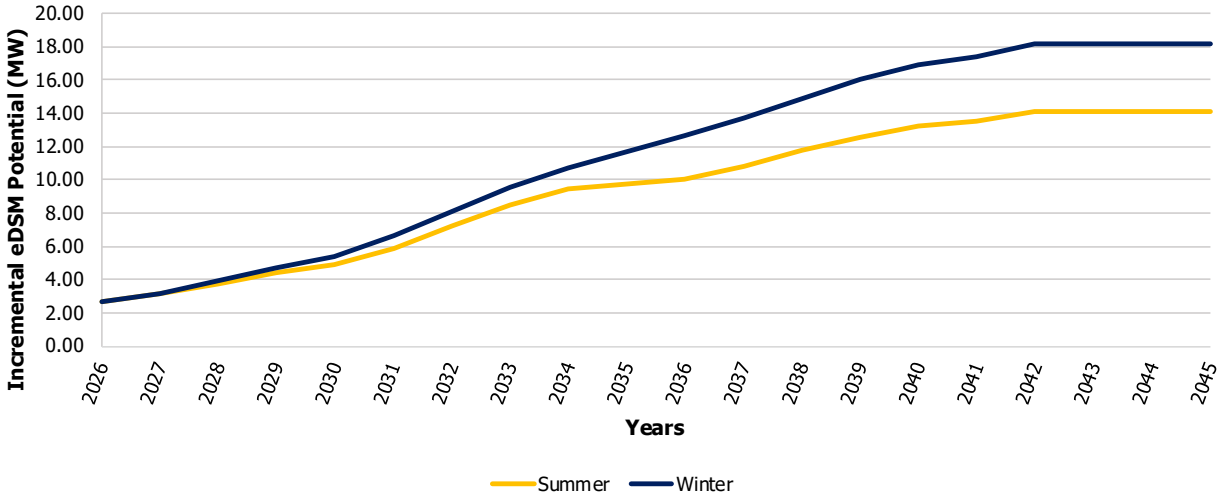
Solar as a standalone option was screened out due to the need occurring in both summer and winter and often at night. Small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. Note that the City of Waterloo has set greenhouse gas reduction targets similar to the City of Kitchener, reducing community-wide emissions by 30 per cent by 2030 and 80 per cent by 2050, through the TransformWR strategy from ClimateActionWR.

Among the screened-in generation options, none were feasible given the need profile and/or the DG connection capacity at Rush MTS, even if assuming Enova Power undertakes feeder breaker and switchgear replacement work to increase the short circuit rating by 20 per cent. Moreover, if these solutions were feasible, they would have to be sited relatively close to Rush MTS on primarily residential land.

Options for D8S/D10H Supply

Additional eDSM programs (savings shown in Figure 50) could meet 14 MW of the 26 MW D8S/D10H supply capacity need and defer the need until 2032. The estimated cost of achieving these eDSM savings is $40.7 million, which is considered cost effective to the system.

Figure 50 | Estimated Incremental eDSM Potential for D8S/D10H Sub-System



A few wires options were also considered:

1. reconductoring the D8S and D10H circuits to 719 A and 920 A, respectively ($3.5M to $5M, one to two years lead time); or
2. offloading some load from Rush MTS to the DxV sub-system through the new 230 kV stations recommended in Section 7.2.3.

Recommendations

In the near term, the recommendation to address the Rush MTS station and D8S/D10H supply capacity needs is to implement additional system cost-effective eDSM.

By 2032, load in excess of the Rush MTS LTR should be transferred on the distribution system to instead be served by the DxV sub-system.

These recommendations are sufficient to meet the reference need for this IRRP's planning horizon. In the long term, or if higher growth materializes, the reconductoring of D8S and D12H may be required – this results in supply capacity for approximately another 28 MW beyond Rush MTS' current LTR, as well as another 25 MW beyond Elmira TS' current LTR.

7.2.5 DxK Sub-System

Wires Options for Kitchener MTS #1 and #4

For the station capacity needs at Kitchener MTS #1 and #4, the same wires options were evaluated as for Kitchener MTS #5 and #7:

1. Load transfers on the distribution system starting in 2032.
2. New station in Kitchener.

Considering option 1, Kitchener MTS #1 has distribution-level ties with MTS #3 and #4; MTS #4 has ties with MTS #1 and 6. Option 2 was described in more detail in Section 7.2.1.

Non-Wires Options for Kitchener MTS #1 and #4

For Kitchener MTS #1 and #4, the following non-wires options were assessed:

1. Additional eDSM;
2. DG; and
3. demand response.

eDSM programs targeting load supplied by Kitchener MTS #1 and #4 could meet 10 MW of the 16 MW summer 2035 station capacity need and 11 MW of the 19 MW summer 2035 station capacity need, respectively. The estimated cost of achieving these eDSM savings is $40 million and $42 million respectively, which is considered cost effective to the system.

Figure 51 | Estimated Incremental eDSM Potential for Kitchener MTS #1

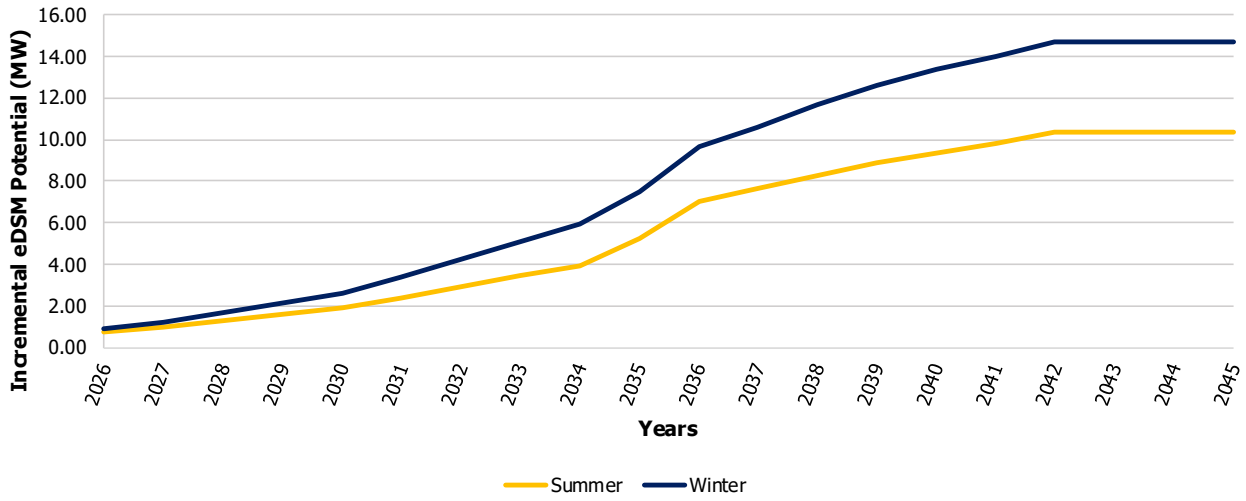
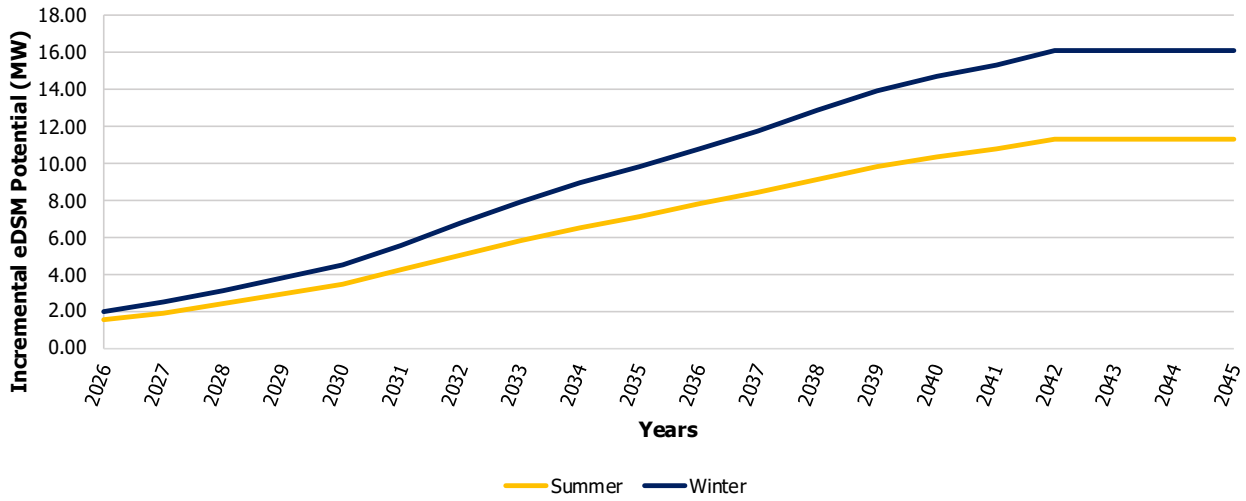


Figure 52 | Estimated Incremental eDSM Potential for Kitchener MTS #4



By 2045, the need profile for Kitchener MTS #1 peaks at 43 MW, lasts up to 21 consecutive hours, and sums to approximately 30,000 MWh of energy. Based on these need characteristics, the following non-wires options were screened in:

- wind;
- BESS;
- combined wind and BESS;
- combined wind and solar;
- combined solar and BESS;
- combined solar, wind, and BESS; and
- demand response.

Solar as a standalone option was screened out due to the need occurring in the winter, and small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. There are also municipal preferences that support the reduction of greenhouse gas emissions.

Among the screened-in generation options, none were feasible given either the need profile and/or the DG connection capacity at Kitchener MTS #1, even if assuming Enova Power undertakes feeder breaker and switchgear replacement work to increase the short circuit rating by 20 per cent. Even if these solutions were feasible, they would have to be sited relatively close to Kitchener MTS #1 on heavily developed residential and commercial urban land.

For Kitchener MTS #4, the non-wires analysis yielded similar results. By 2045, the need profile for Kitchener MTS #4 peaks at 47 MW, lasts up to 46 consecutive hours, and sums to approximately 44,000 MWh of energy. Based on these need characteristics, the same resource types were screened in for further analysis as for Kitchener MTS #1. Outcomes of the evaluation were also similar: the NWAs were infeasible given the need profile and/or the DG connection capacity at Kitchener MTS #4, even if assuming upgrades to increase short circuit capability. Depending on the option, up to 9 km^2 of land would be required near the station in urban Kitchener.

Wires Options for DxK Supply

A wires option to address DxK supply is the reconductoring of D11K and D12K to increase its summer Long-Term Emergency thermal rating to 1035 A (and 1180 A for winter). This is expected to cost $6.3 million and take 1-2 years, and with additional DSM, will meet the summer supply need and delay the winter need until 2041.

Non-Wires Options for DxK Supply

For the DxK supply capacity need, the same non-wires options were assessed as for Kitchener MTS #1 and #4: wind, BESS, solar, demand response, and additional eDSM (as illustrated in the figures earlier). However, given the nature of supply capacity needs, potential resource options can also be transmission-connected (not just distribution-connected).

By 2045, the need profile for the DxK supply need grows to 90 MW and more than 100,000 MWh. The need occurs in the winter and lasts up to 141 consecutive hours – requiring infeasibly large resource options in a dense urban area.

Meanwhile, the cumulative additional eDSM at Kitchener MTS #1 and #4 can delay the DxK supply need until 2033.

Recommendations

In the near term, the recommendation to address the Kitchener MTS #1 and #4 station capacity needs is to implement additional system cost-effective eDSM, and optimize and transfer load through the distribution system starting in 2033 between Kitchener MTS #1, 3, 4, and 6. In the

long-term, a new station is required in the Kitchener Freeport area, should the reference load forecast materialize.

Considering long-term forecast uncertainty in the region and potential for increased eDSM, the Technical Working Group will continue to monitor where, when, and how much electricity demand grows. These factors, alongside any new resources and other system changes, can influence the need and options for long-term Kitchener station capacity needs.

In the medium-term, the recommendation to address the DxK supply capacity need is to reconductor both D11K and D12K to increase its summer Long Term Emergency thermal rating to 1035 A (and 1180 A for winter).

Given the Planning Forecast, this uprate should be implemented by 2033. Under the low and high reference scenarios, timing of the uprate can shift up to two years.

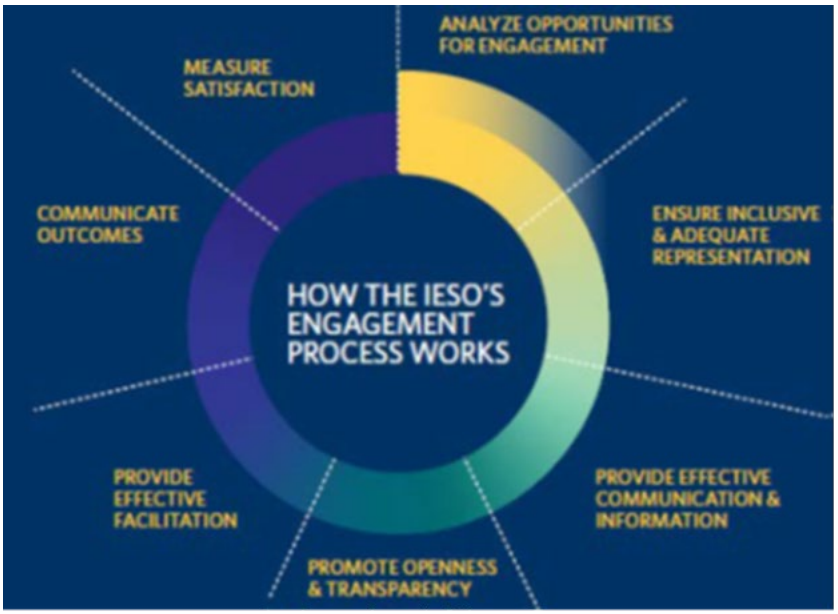
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the KWCG IRRP.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 53 | The IESO's Engagement Principles



8.2 Engagement Approach

To ensure that the IRRP reflects the unique needs and perspectives of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement involved:

- Leveraging the KWCG engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback.
- Timely and targeted discussions with municipalities to help inform the engagement approach for this planning cycle.

- Sharing letters with relevant Mayors and Councillors to provide informative updates on the plan to foster purposeful engagement.
- Hosting a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions.
- Encouraging all interested parties to stay informed on the planning underway through communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.
- Hosting targeted discussions with specific communities and stakeholders to clearly communicate updates as planning progressed and ensure that their identified needs are addressed.

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning for the KWCG region, and to establish new relationships and dialogue where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report that involved sending an invitation to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the KWCG Scoping Assessment Outcome Report. A public webinar was held in June 2024 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed planning approach moving forward. The final report was posted later in July 2024, identifying the need for a coordinated regional planning approach and development of an IRRP.

Later in December 2024, a targeted outreach meeting involving all municipalities in the region was hosted to ensure growth and development plans were accurately captured in the Technical Working Group's draft demand forecast, and to solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to subscribers of IESO updates for the KWCG region to ensure that all interested parties were made aware of this opportunity for input.

Four public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar. The four stages of engagement at which input was invited were:

1. The draft engagement plan, electricity demand forecast, and early identified needs — to set the foundation of this planning work.
2. The identified priority electricity needs for the region and high-level screening of potential options to meet the identified priority needs.
3. The analysis of options and draft IRRP recommendations to address priority needs, and the high-level screening of potential options to meet the identified remaining needs.
4. The analysis of options and draft IRRP recommendations to address remaining needs.

Comments received during public engagements primarily focused on:

- Questions regarding inputs and assumptions considered by the IESO when developing the demand forecast scenarios, and how municipalities can influence routing and property impacts.
- Significant population growth, transit and economic development projects across the region.
- Alignment of electricity planning with local priorities, such as local Climate Action Plans.
- Regulations regarding reserving capacity for critical public infrastructure.
- The importance of addressing immediate capacity needs to ensure the region remains resilient.
- Interest in leveraging existing and local generation.
- Exploring and understanding alternative solutions, such as non-wire options, to meet the area's electricity needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

In recognition of the interdependencies between a parallel South and Central Bulk Plan looking at the provincial electricity system's broad capability to support future generation connections, and demand growth in key areas throughout southern and central Ontario, KWCG engagement focused on establishing linkages between the bulk and regional electricity plans. The IESO has undertaken efforts to ensure engagement activities and recommendations for the KWCG IRRP are aligned and integrated with those of the South and Central Bulk Plan.

All interested parties were kept informed throughout this engagement initiative via email to KWCG subscribers, municipalities, and Indigenous communities. Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with the significant forecasted growth and development both within specific municipalities and the region more broadly (e.g., new large-scale customers and electrification, planned development and growth). Through the development of the IRRP it was determined that the existing electricity system did not meet reliability standards. With that, another key focus area was developing an approach to quickly identify, engage on, and develop solutions to address priority electricity needs while also balancing addressing remaining electricity needs. These insights have been valuable to the IESO — as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's KWCG engagement webpage.

8.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on its planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with all municipalities in the KWCG electrical region to share key developments and to provide an opportunity for municipal feedback on the forecasted regional electricity needs, options for meeting the region's

future needs, and broader community engagement. Through engagement it was learned that the tiered approach of addressing needs in the region added an extra layer of complexity in understanding the development of the IRRP.

To address this feedback, additional engagement was conducted to foster education and understanding of the recommendations to address priority needs. This included the IESO engaging elected officials and all municipalities impacted by the recommendations to address priority needs by sharing letters prepared for mayors and councillors and hosting an information session with elected officials and municipal staff to review the electricity planning developments, and to provide an opportunity for discussion. These meetings helped to inform the municipal and community electricity needs and priorities, establish new relationships, and provide opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions, valuable feedback was received and considered in the final IRRP recommendations, including:

- The City of Kitchener encouraged the inclusion of multiple forecast scenarios in the IRRP process and collaboration between municipalities and local distribution companies to understand the development of the electricity demand forecast scenarios. Additionally, the City emphasized their commitment to supporting the energy transition by leveraging its role as a gas distributor and focusing on the electrification of transportation and space and water heating. The City also encouraged the IESO to consider efficient, low-carbon heating solutions, including the use of waste heat from large electricity users.
- The City of Guelph recommended sharing the assumptions used when calculating the electricity demand forecast scenarios, addressing short circuit limitations at Campbell TS as it is hindering solar PV projects, and also raised the need for additional support to promote eDSM initiatives.
- Several municipalities emphasized that population growth, transit expansion, climate action, and energy plans should be reflected in electricity demand forecasts, and they encouraged the use of non-wire alternatives to support their net-zero and decarbonization goals.
- Municipalities also suggested improving future engagement materials by clearly outlining municipal boundaries on study-area maps, reducing industry-specific terminology to more easily understand the process to develop the IRRP, and providing increased clarity on the interaction of eDSM and electrification efforts on a region's electricity capacity and needs.
- Enbridge Gas Inc. recommended co-ordinated energy system (gas and electric) planning be completed and due consideration be given to a diversified energy system approach in the forecasts for the KWCG electrical region.

8.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, meaningful dialogue with Indigenous communities to help shape long-term planning in regions across Ontario. This engagement was part of a broader commitment to fostering respectful relationships, ensuring transparency, and supporting informed participation in regional energy planning. Throughout the development of this plan, the IESO's engagement with Indigenous communities included inviting Indigenous communities to participate in

online information sessions (held on December 12, 2024, May 27, 2025, September 23, 2025 and June 10, 2026), as well as extending the opportunity to meet one-on-one to ask questions and provide input.

To share information about the regional planning activities and invite participation in the engagement process, outreach was made to the following Indigenous communities:

- Mississauga of the Credit Frist Nation;
- Six Nations of the Grand River, represented by the Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council; and
- Métis Nation of Ontario.

Detailed non-confidential feedback submitted to the IESO and the IESO's responses can be viewed on the KWCG engagement webpage. However, the IESO did not receive feedback from the identified First Nation communities. Although invitations were extended to participate in the webinar and to engage in one-on-one meetings, no responses or feedback were provided.

Indigenous Participation and Engagement in Transmission Development

Indigenous engagement during the regional planning process assists the IESO in its assessment of various options to address future transmission system needs. By conducting regional planning, the IESO determines the most reliable and cost-effective option after it has engaged with stakeholders and Indigenous communities and publishes those recommendations in the applicable IRRP. Where the IESO determines that the lead time required to implement those solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report, such as through a hand-off letter to the lead local transmitter in the region.

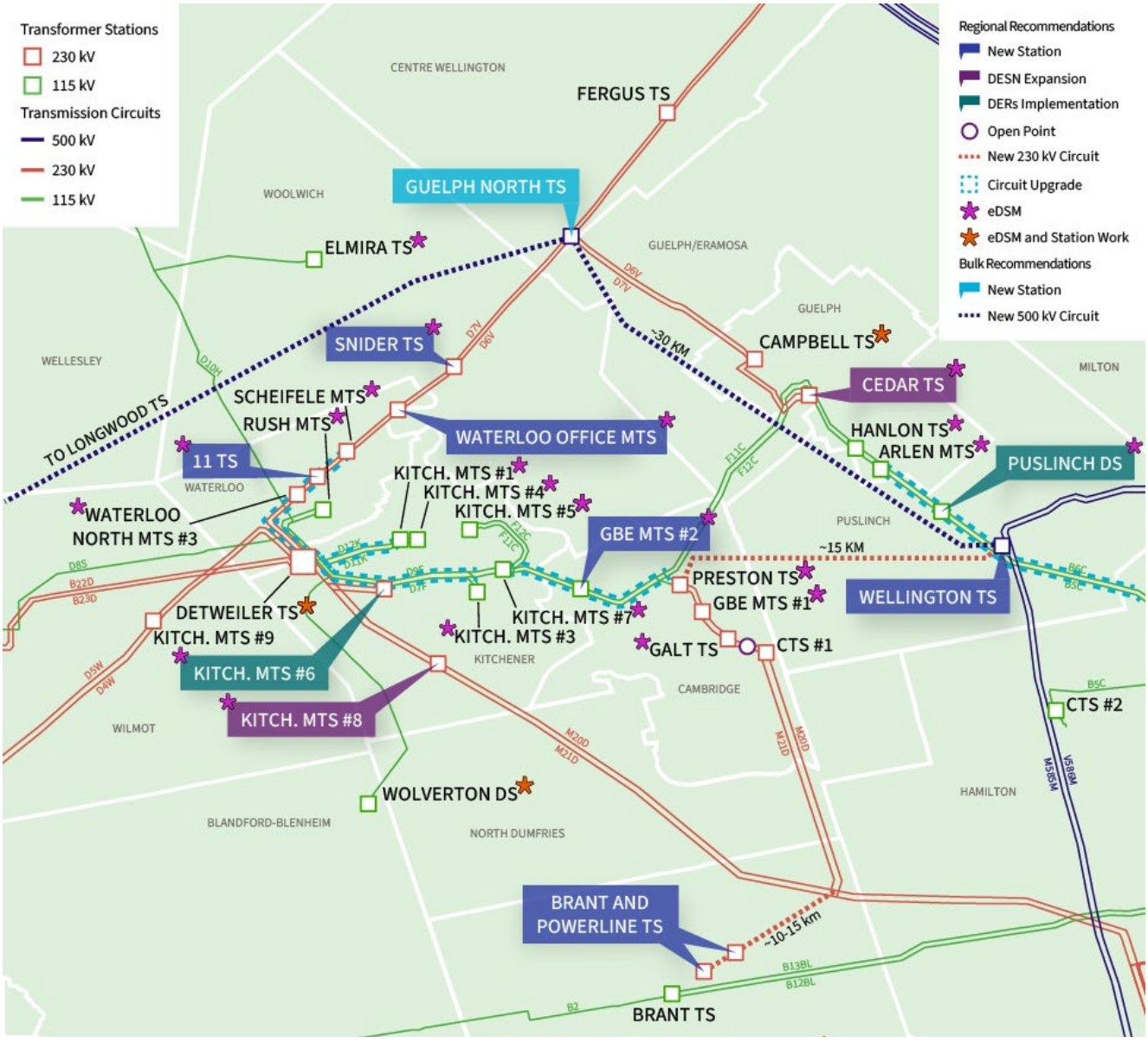
If a recommendation is made in an IRRP to proceed with a transmission solution, the transmission project proponent (not the IESO) will be responsible for obtaining applicable regulatory approvals from the provincial and/or federal governments, including an Environmental Assessment (EA). Where an EA is required, Indigenous consultation will be undertaken as part of the EA process. Other regulatory processes may also trigger the duty to consult. The relevant Crown entity is responsible for consultation but will delegate certain aspects of consultation to the proponent to carry out. In addition to fulfilling these delegated consultation obligations, project proponents are encouraged to engage early with Indigenous communities on ways to enable participation in particular projects.

In addition to the EA process, a project proponent will need to submit a Leave to Construct application to the Ontario Energy Board prior to starting construction. The *Ontario Energy Board Act, 1998* limits the scope of the Ontario Energy Board's determination on whether the project is in the public interest to consideration of price, reliability, and quality of electricity service. Accordingly, it is not within the Ontario Energy Board's purview to assess whether the Crown's duty to consult has been satisfied in respect of the transmission project.

9. Conclusion

The KWCG IRRP identifies electricity needs in the region over the 20-year period from 2026 to 2045, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. Figure 54 visually depicts these recommendations across the region.

Figure 54 | Overview of Recommended Near- to Medium-Term Solutions for KWCG IRRP[23]



Overall, the Technical Working Group recommends targeting eDSM programs across the KWCG region to support both near-term and long-term growth.

[23] Distribution-level load transfers are not shown, for simplicity.

In the near and medium term, the Technical Working Group recommends multiple integrated solutions: 115 kV line upgrades, new 115 kV and 230 kV stations in Waterloo, Cambridge, and Kitchener, a 500/230 kV autotransformer stations, a new double-circuit 230 kV line, and a normally open point at Ameristeel junction. Projects should also proceed to increase station capacity: at Wolverton DS and Campbell TS, through station work; at Cedar TS, through the conversion to 230 kV when T7/T8 reach end of life. Moreover, the Technical Working Group recommends the optimization of existing station capacity where possible by leveraging distribution load transfers. Finally, at Puslinch DS and at Kitchener MTS #6, distribution-connected resources are required.

Some of these near-term recommendations were issued before this IRRP was finalized, through an urge letter focused on the immediate supply needs on the Middleport to Detweiler transmission lines. This was coordinated with the 2024 Burlington to Nanticoke IRRP recommendations for the Brant 115 kV Extended Area.

In the long term, the Technical Working Group should continue monitoring and re-assessing regional needs through future planning cycles and annual Technical Working Group meetings. In particular, demand growth, eDSM savings, and distribution load transfers should be monitored at Arlen TS, Hanlon TS, the MxD sub-system, and across multiple Kitchener MTS — especially those at the 115 kV voltage level. The need for a switching station at Galt junction should also continue to be considered, as well as a new 230 kV station and 230 kV connection lines in the Kitchener Freeport area.

The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a co-ordinated approach. The Technical Working Group will continue to monitor growth across the region to determine if or when further reinforcements will be needed. This includes any future community energy plans, electrification trends, customer connection queues, changes to local generation, and changes to eDSM programs. The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

Toronto Integrated Regional Resource Plan

October 31, 2025

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List of Acronyms

DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
eDSM	Electricity Demand Side Management
ESS	Energy Storage System
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

Executive Summary

This Integrated Regional Resource Plan (IRRP) addresses electricity needs in the Toronto Region over a 20-year period, to 2044. The Toronto Region is defined by electrical infrastructure boundaries and the municipal boundaries of the City of Toronto.

For the purposes of this IRRP, the Toronto Region has been divided into three electrical subsystems: Northern, Western, and Eastern Toronto. These subsystems reflect the configuration of the transmission system and the location of major step-down transformer stations and other points of system supply. The IRRP focuses on identifying and addressing electricity needs in each of these subsystems, while also coordinating with broader bulk system planning.

The IRRP considers the reliability impacts of the significant demand growth forecast for the Toronto Region. Peak demand is expected to nearly double by 2043 and while the region has historically been summer-peaking, the region could become winter peaking by the early-2030s. The plan considered reference and high electrification forecast scenarios to determine the needs of the region, identify potential investments to address those needs, and offer corresponding recommendations to ensure the system remains reliable and resilient to demand growth uncertainties in the long term.

To identify near, medium, and long-term needs, the Technical Working Group[1] assessed station capacity, supply capacity, reliability, and load security needs across the region. A combination of wires and non-wires solutions were evaluated, with a number of recommendations made to address needs as they arise.

Recommendations include immediate actions to develop infrastructure such as new and expanded transmission stations to increase the amount of electricity that can flow into Toronto, and two locations for energy storage facilities to inject electricity when needed and improve reliability.

Given the pace of growth in the City of Toronto, the IESO is also recommending a new underwater transmission line connecting downtown Toronto to Bowmanville via Lake Ontario. While the IESO assessed alternative options including over and underground transmission options, the underwater Third Line is the preferred option. This line can accommodate significantly more growth in Toronto and the GTA, enabling 900 MW of supply to flow from the east; improving supply diversity and resilience by introducing a true third supply path into the downtown core; as well as supporting load restoration following major power disruptions, among other benefits.

Non-wires alternatives (NWAs) such as targeted electricity demand-side management (eDSM) and distributed energy resources (DERs) including solar and storage, are also recommended to help potentially defer long-term infrastructure requirements. The plan recommends an incremental 320 MW of summer and 121 MW of winter savings by 2045, on top of the planned delivery of 847 MW of summer and 756 MW of winter savings through Save on Energy programs. For context, the current peak demand of Toronto is close to 5,000 MW. These local programs will be developed and made available to Toronto residents and businesses as part of the new eDSM Framework. The

[1] The Technical Working Group includes the IESO, the Local Distribution Company, Toronto Hydro Electric-System Limited and the lead transmitter, Hydro One Networks Inc.

Technical Working Group encourages all Toronto residents and businesses to take full advantage of Save on Energy programs to maximize incremental eDSM achieved in the City.

Options for monitoring long-term needs, towards the end of the study period, are also proposed. While they do not yet require action, it is important to preserve the long-term viability of certain solutions.

PEC is currently critical to the reliability of both Toronto's and the broader province's electricity supply. The Third Line is foundational to a future without PEC; however, the line is needed regardless of the future of PEC. Once the line comes into service, local reliance on PEC will be reduced, but it may still be needed to meet the provincial grid's peak needs. The Toronto IRRP is focused on local supply and does not address matters of provincial supply.

The study has also considered points of coordination with ongoing bulk planning initiatives, including the South and Central Bulk Plan, which is studying bulk system needs and potential upgrades with a notional 2035 focus. A second, longer term bulk planning study, expected to be initiated later in 2026 will focus on bulk system needs into the 2040s, including the potential impact of bulk enhancements on regional supply. Both studies have the potential to affect longer term needs and the feasibility of solutions available to/in the area. Specifically, in terms of PEC's contribution to provincial resource adequacy, the Bulk Plan will be looking at the need and timing of bulk transmission upgrades needed for a future where PEC (and other emitting resources in the GTA) may be out-of-service. The current study is expected to be complete in early 2026.

Engagement was a key input to the development of this IRRP. The IESO engaged with municipalities, Indigenous communities, stakeholders, and the public throughout the planning process. Activities included targeted one-on-one discussions with the City of Toronto and Indigenous communities, technical briefings with communities and six public webinars to share information and solicit written feedback. The overarching themes of feedback received during the development of the IRRP primarily focused on the future of PEC; preference for non-wire options; enhanced transparency for data/information and decision rationale; alignment with City of Toronto decarbonization initiatives; recognition of the need for a third supply line; coupled with requests for more information on the evaluation of options, impacts of routing options, and concern it would bring nuclear energy into the City. The feedback received helped shape the demand forecast, identify local priorities, and inform the recommended solutions.

The Technical Working Group will continue to monitor growth, electrification trends, and large customer connections across the region. The group will meet regularly to track progress, assess changing conditions, and update the plan as needed. If underlying assumptions change significantly, the IRRP may be amended, or a new planning cycle initiated ahead of the standard five-year schedule mandated by the Ontario Energy Board.

Summary of Recommendations

Needs identified and resulting recommendations[2] emerging from this plan to enable growth driven by urban and economic development and electrification, consist of:

[2] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

Table 1 | Northern Toronto Recommendations

Need	Project	Expected In-Service (based on Reference Forecast)
Overall Station Capacity and Supply Capacity	Build Downsview MTS	2033

Table 2 | Western Toronto Recommendations

Need	Project	Expected In-Service (based on Reference Forecast)
Manby TS (West) Autotransformers	Reliance on the Manby Remedial Action Scheme[3]	Ongoing
	Permanent transfer of Copeland MTS T2/T4 to Leaside Supply	2026
	Incremental eDSM	Ongoing
	Develop Energy Storage Systems at or downstream of the Manby West autotransformers	2029/2030
Manby TS (East) Autotransformers	Reliance on the Manby Remedial Action Scheme	Ongoing
	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
	Incremental eDSM	Ongoing
Manby to Riverside Circuits	Increase transmission capacity by upgrading circuits from Manby TS to Riverside TS[4]	2028
St Clair to Fairbank Circuits	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Fairbank TS	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Strachan TS	Incremental eDSM	Ongoing
Manby DESN	Monitor station capacity need as need arises towards the end of forecast	Ongoing

[3] A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and MVar), tripping load, or reconfiguring the system.

[4] Note that this was also recommended by the 2022 Needs Assessment Report, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto_Region_Needs_Assessment_Report_Third_Cycle_Regional_Planning.pdf

Table 3 | Eastern Toronto Recommendations

Need	Project	Expected In-Service (based on Reference Forecast)
Leaside to Bridgman to Dufferin Circuits	Increase transmission capacity to Dufferin TS by upgrading underground circuits between Dufferin TS and the Bartlett/Dufferin Junctions	2036
	Transfer Dufferin TS load to upgraded Wiltshire TS	2036
	Develop Energy Storage Systems at or downstream of Dufferin TS	2036
Leaside to Bloor to Hearn Circuits	Increase transmission capacity by upgrading circuits from Leaside TS to Bloor JCT and from Hearn SS to Basin TS	2036
	Incremental eDSM	Ongoing
Scarboro TS, Warden TS, and Sheppard TS	Develop an additional DESN at Scarboro TS to increase capacity	2035
Glengrove TS	Investigate the feasibility of load transfers from Glengrove TS to Duplex TS	2042
Dufferin TS	Develop Energy Storage Systems at or downstream of Dufferin TS	2040
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	2036
Overall Supply Capacity	Develop underwater HVDC transmission supply towards Hearn SS	2034

1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Toronto Region (the "Region") over a 20-year period, from 2025 to 2044. The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 1. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations – Leaside Transformer Station (TS) and Manby TS. A small number of distribution feeders from Toronto also supply customers in the neighbouring cities of Mississauga and Pickering.

In addition to the transmission infrastructure, the Portlands Energy Centre (PEC) is a 600-megawatt (MW) capacity natural gas-fired combined cycle power plant that provides a major source of supply to Toronto. This station is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS), south of Basin TS, as shown in Figure 1.

The region is summer peaking and the 2022 weather-corrected peak summertime electricity demand in the Toronto region was approximately 4,600 MW.[5]

The region's electricity is delivered by the local distribution company (LDC) Toronto Hydro-Electric System Limited (Toronto Hydro). Hydro One Networks Inc. (Hydro One) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of Toronto Hydro, Hydro One, and the IESO.

The IESO also acknowledges that Toronto is the traditional territory of many nations, and is committed to ongoing, meaningful dialogue with Indigenous communities to inform long-term planning in Toronto and across Ontario. To raise awareness about the regional planning cycle in Toronto, and invite participation in the engagement process, the IESO's engagement efforts included outreach to Indigenous communities throughout the development of the plan, including to the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, Alderville First Nation, Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, and Métis Nation of Ontario.

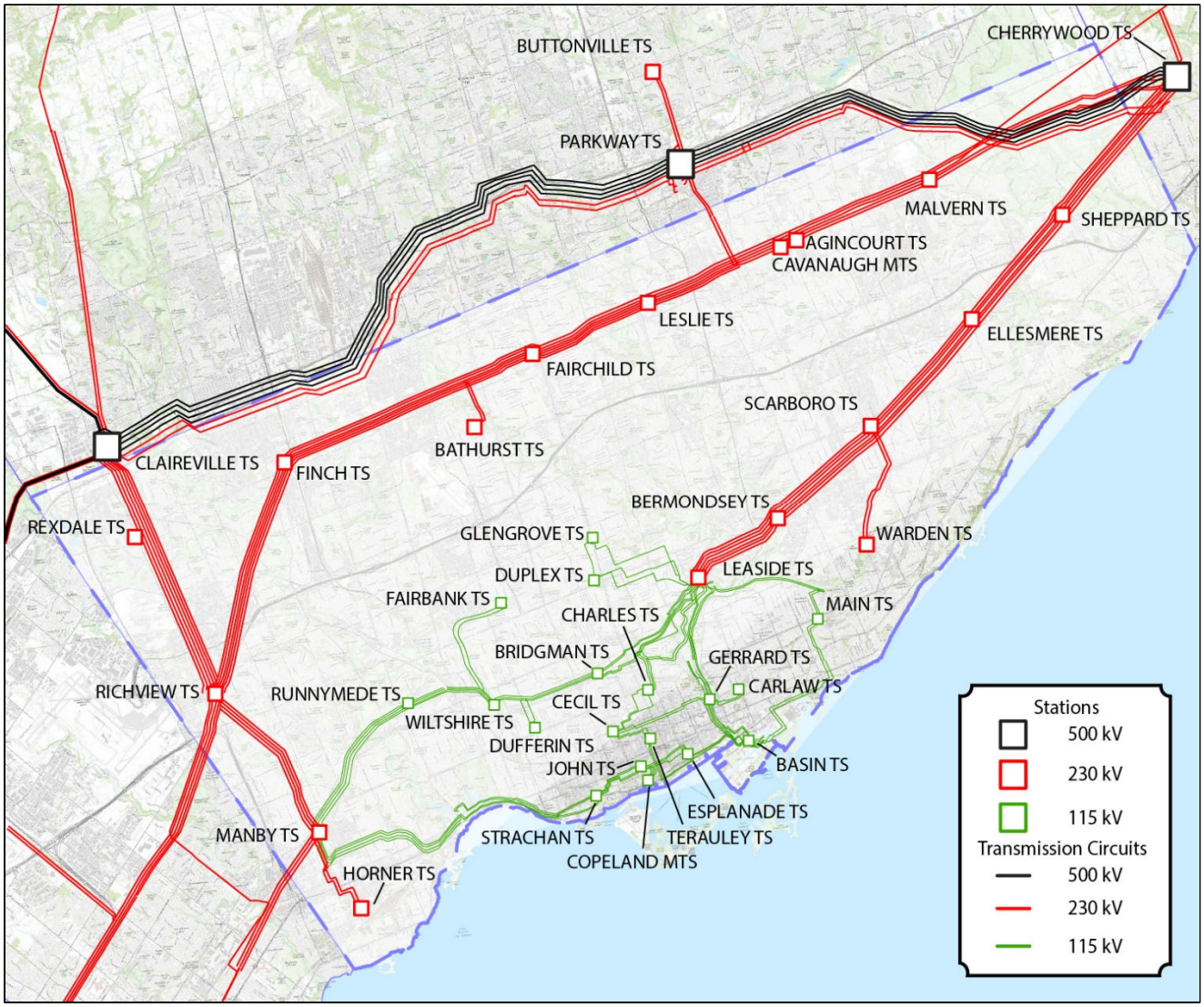
This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[5] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2022, demand was 4,356 MW.

- Demand forecast scenarios, and electricity Demand Side Management (eDSM) and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An overview with the linkages to the South and Central Bulk Study in Section 8; and
- A summary of engagement activities is provided in Section 9;

Figure 1 | Overview of the Toronto Region[6]



[6] IRRP regions are defined by electricity infrastructure; geographical boundaries are approximate.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Toronto Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

2.1 Status of Plans from Previous IRRP Cycles

Following the previous cycle of region planning, which concluded with the 2nd Cycle RIP report, several projects were recommended which have now been completed or are presently underway. The status of these projects is summarized in Table 4.

Table 4 | Needs Identified in the Previous Cycle with Implementation Plan Update

Infrastructure	Need	Expected In-Service
Bridgman TS	Transformer replacement (T11, T12, T13, T14)	2024
Fairbank TS	Transformer replacement (T1, T2, T3, T4)	2024
Main TS	Transformer replacement (T3, T4)	2024
John TS	Transformer replacement (T5, T6)	2025
Between Esplanade TS and Terauley TS	C5E/C7E underground cable replacement	2026
Richview TS to Manby TS	Corridor Upgrade: 115 kV double-circuit line is rebuilt to operate at 230 kV	2026
Copeland TS Phase 2	Capacity need: additional DESN added	2026
Horner TS	Installation of second DESN	2022 (Complete)
Runnymede TS	Transformer replacement (T3, T4)	2021-2022 (Complete)
Sheppard TS	Transformer replacement (T3, T4)	2021-2022 (Complete)
Strachan TS	Transformer replacement (T12)	2021-2022 (Complete)
John TS	Transformer replacement (T1, T2, T4)	2019-2021 (Complete)

2.2 IRRP Recommendations for Northern Toronto

Table 5 provides a summary of recommendations to address the needs and accommodate load growth and maintain reliability in Northern Toronto.

Table 5 | Northern Toronto Recommendations

Infrastructure	Project	Expected In-Service (based on Reference Forecast)
Station Capacity and Supply Capacity	Build Downsview MTS	2033

2.3 IRRP recommendations for Western Toronto

Table 6 provides a summary of recommendations to address the needs and accommodate load growth and maintain reliability in Western Toronto.

Table 6 | Western Toronto Recommendations

Infrastructure	Project	Expected In-Service (based on Reference Forecast)
Manby TS (West) Autotransformers	Reliance on the Manby Remedial Action Scheme	Ongoing
	Permanent transfer of Copeland MTS T2/T4 to Leaside Supply	2026
	Incremental eDSM	Ongoing
	Develop Energy Storage Systems at or downstream of the Manby West autotransformers	2029/2030
Manby TS (East) Autotransformers	Reliance on Manby RAS	Ongoing
	Permanent Load Transfer from Fairbank TS to Downsview MTS	2036
	Incremental eDSM	Ongoing
Manby to Riverside Circuits	Increase transmission capacity by upgrading circuits from Manby TS to Riverside TS[7]	2028
St Clair to Fairbank Circuits	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Fairbank TS	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Strachan TS	Incremental eDSM	Ongoing
Manby DESN	Monitor station capacity need as need arises towards the end of forecast	Ongoing

[7] Note that this was also recommended by the 2022 Needs Assessment Report, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto_Region_Needs_Assessment_Report_Third_Cycle_Regional_Planning.pdf

2.4 IRRP Recommendations for Eastern Toronto

Table 7 provides a summary of recommendations to address the needs and accommodate load growth and maintain reliability in Eastern Toronto.

Table 7 | Eastern Toronto Recommendations

Infrastructure	Project	Expected In-Service (based on Reference Forecast)
Leaside to Bridgman to Dufferin Circuits	Increase transmission capacity to Dufferin TS by upgrading underground circuits between Dufferin TS and the Bartlett/Dufferin Junctions	2036
	Transfer Dufferin TS load to upgraded Wiltshire TS	2036
	Develop Energy Storage Systems at or downstream of Dufferin TS	2036
Leaside to Bloor to Hearn Circuits	Increase transmission capacity by upgrading circuits from Leaside TS to Bloor JCT and from Hearn SS to Basin TS	2036
	Incremental eDSM	Ongoing
Scarboro TS, Warden TS, and Sheppard TS	Develop an additional DESN at Scarboro TS to increase capacity	2035
Glengrove TS	Investigate the feasibility of load transfers from Glengrove TS to Duplex TS	2042
Dufferin TS	Develop Energy Storage Systems at or downstream of Dufferin TS	2040
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	2036
Overall Supply Capacity	Develop underwater HVDC transmission supply towards Hearn SS	2034

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and identifies appropriate investments to meet the needs of a region over the next 20 years.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities
3. An IRRP, led by the IESO, which identifies the appropriate mix of investments in conservation and demand management, generation, transmission facilities or distribution facilities, or other electricity system initiatives in order to address the identified needs of a region and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. The IESO also carries out bulk system planning and Local Distribution Companies are responsible for distribution system planning. There are inherent linkages in all three levels of electricity infrastructure planning.

3.2 Toronto IRRP Development

The process to develop the Toronto IRRP was initiated in May 2023, following the publications of the Needs Assessment Report in December 2022 by Hydro One and the Scoping Assessment Outcome Report in March 2023 by the IESO. The Scoping Assessment recommended that the needs identified for the Toronto Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region. On April 5, 2024, the IESO requested an extension for the Toronto IRRP to March 20, 2025 due to the complexity of developing forecast scenarios, and additional scope included into the plan to enable the consideration of the impacts of retiring PEC, which requires the IESO to introduce additional engagement to ensure governments, businesses, developers, Indigenous communities, the City of Toronto and residents are informed and can provide input to efforts taken to decarbonize the electricity system in Toronto. On January 20, 2025, the IESO requested for an additional extension

to October 31, 2025, to accommodate the results of a Local Achievable Potential Study in the IRRP in recognition of the keen interest from communities and stakeholders on renewable generation, energy storage, and energy efficiency. The IESO received approval for the extension on March 31, 2025.

4 Background and Study Scope

This is the third cycle of regional planning for the Toronto Region. The previous planning cycle for the Region concluded in 2020. For electricity planning purposes, planning regions are generally defined by the electricity infrastructure boundaries; however, the Toronto Region roughly conforms to an area within the City of Toronto municipal boundary.

The IESO acknowledges that Toronto is the traditional territory of many nations, and is committed to ongoing, meaningful dialogue with Indigenous communities to help inform long-term planning. To raise awareness about the regional planning cycle in Toronto, and invite participation in the engagement process, the IESO's engagement efforts included outreach to Indigenous communities throughout the development of the plan, including to the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, Alderville First Nation, Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, and Métis Nation of Ontario.

This IRRP develops and recommends options to meet the electricity needs of the Toronto Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, eDSM, distributed generation (DG), transmission and distribution system capability, relevant community plans, age and condition of transmission infrastructure assets, and bulk transmission system needs and opportunities.

The following transmission facilities were included in the scope of this study:

Transformer stations:

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

230 kV transmission circuits:

C10A	C15L	C5R	K23C	R13K	V72R	V77R
C2L	C16L	C18R	R24C	R15K	V73R	V79R
C3L	C17L	C20R	R1K	P21R	V74R	
C14L	C4R	K21C	R2K	P22R	V76R	

115 kV transmission circuits:

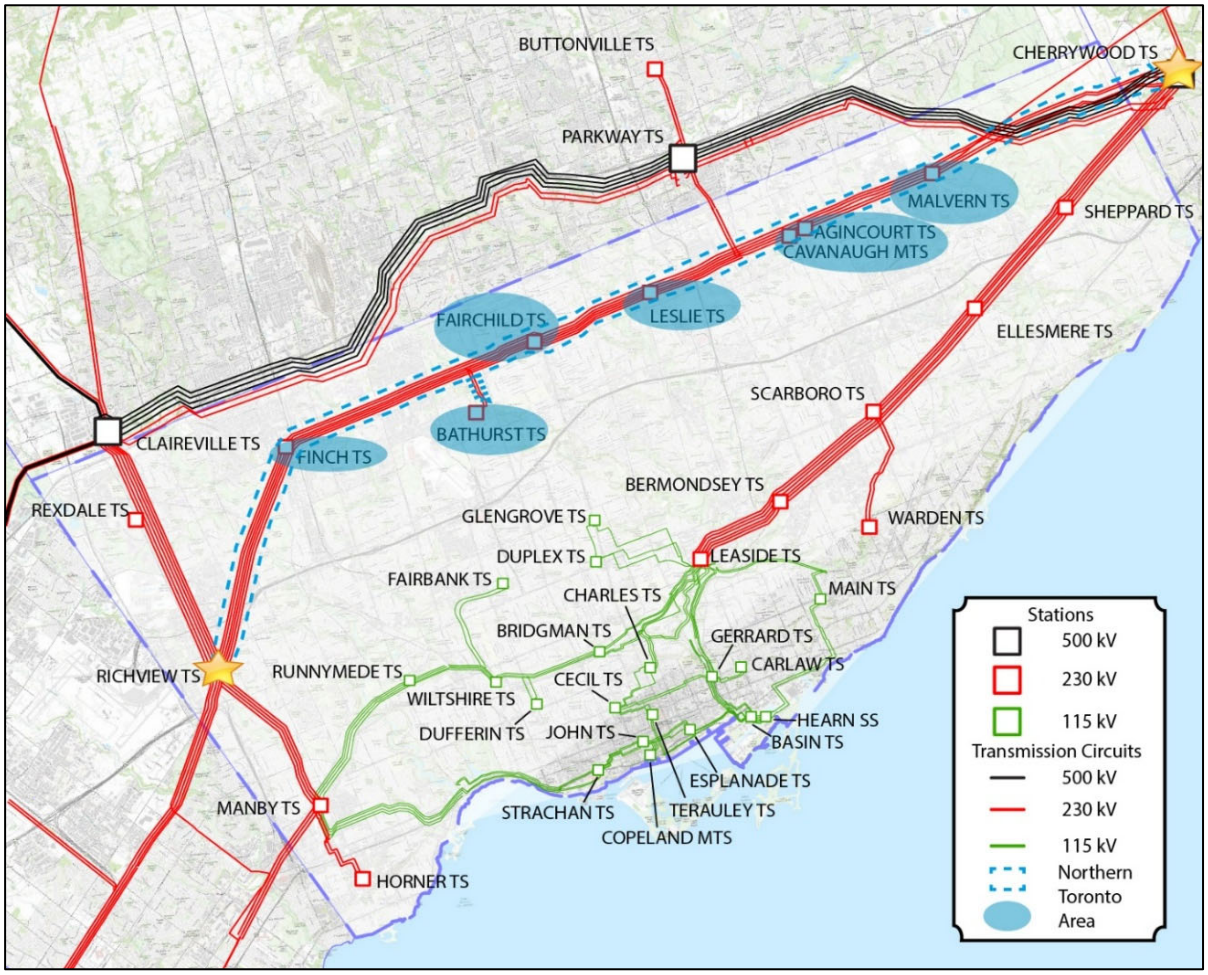
C5E	H9DE	H7L	K13J	K12W	L16D	L2Y
C7E	H10DE	H11L	K14J	L4C	L13W	
D11J	H2JK	H6LC	K1W	L9C	L14W	
D12J	H1L	H8LC	K3W	L12C	L15	
D6Y	H3L	K6J	K11W	L5D	L18W	

The Toronto Region can be further categorized into three sub-areas, which align with the main direction of incoming transmission supply in each area:

- **Northern Toronto**

Northern Toronto consists of the 230 kV circuits and stations supplied from the 230 kV transmission corridor between Richview TS to Cherrywood TS, also known as the Finch Corridor. This area primarily serves the northern areas of the City of Toronto, including North York and the northern areas of Etobicoke and Scarborough. A map of Northern Toronto is shown in Figure 2.

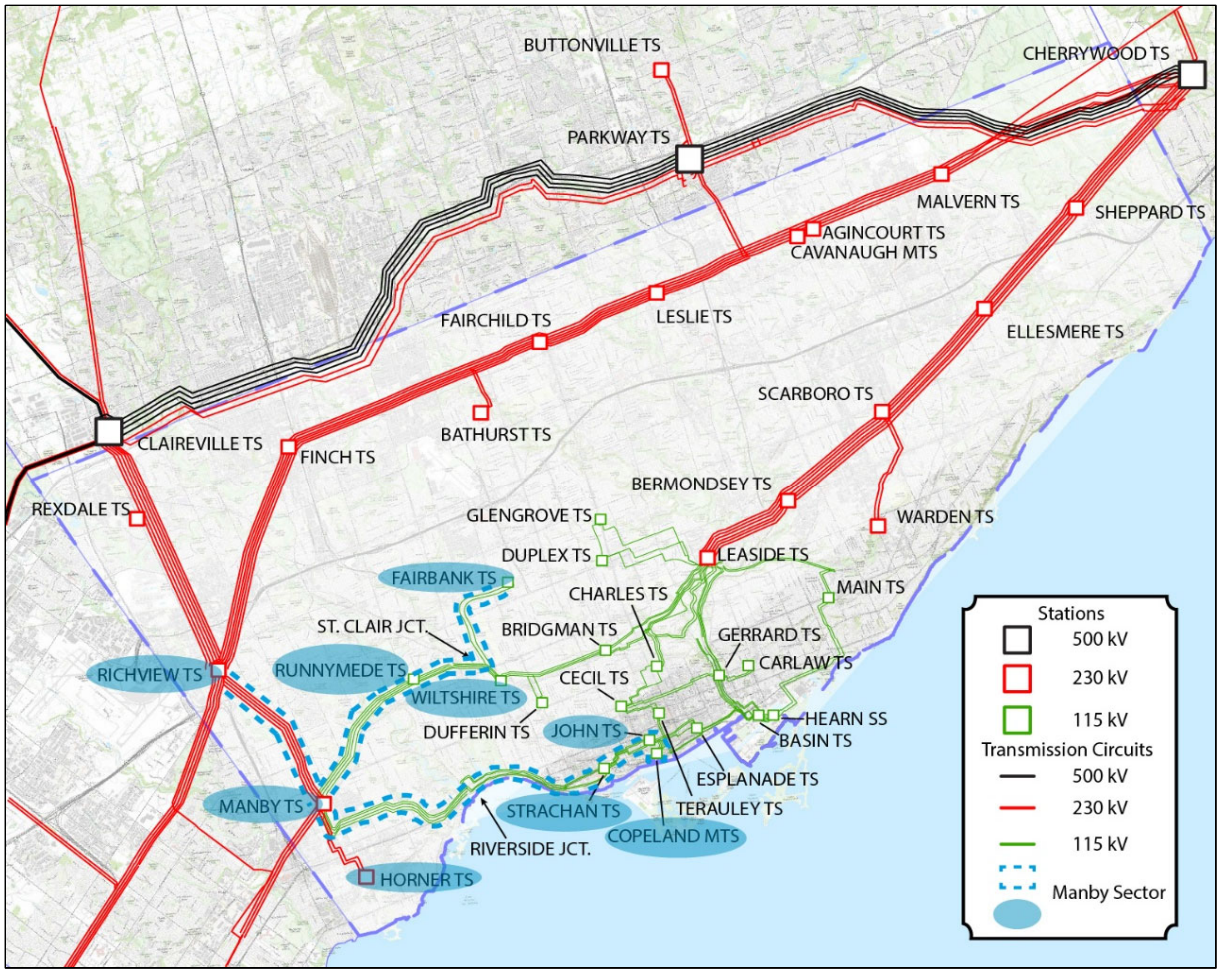
Figure 2 | Map of Northern Toronto Area



- **Western Toronto**

Western Toronto consists of the stations and circuits downstream of the Richview to Manby transmission corridor in Etobicoke. The area is serviced by a combination of 230 kV and 115 kV lines and nine stations, which provide power to southern Etobicoke and portions southwest Toronto and the downtown core. The electricity supplied by the six 115 kV stations in central Toronto and the 230 kV Horner TS in Etobicoke flows through the transmission infrastructure at Manby TS. A map of the Western Toronto area is shown in Figure 3.

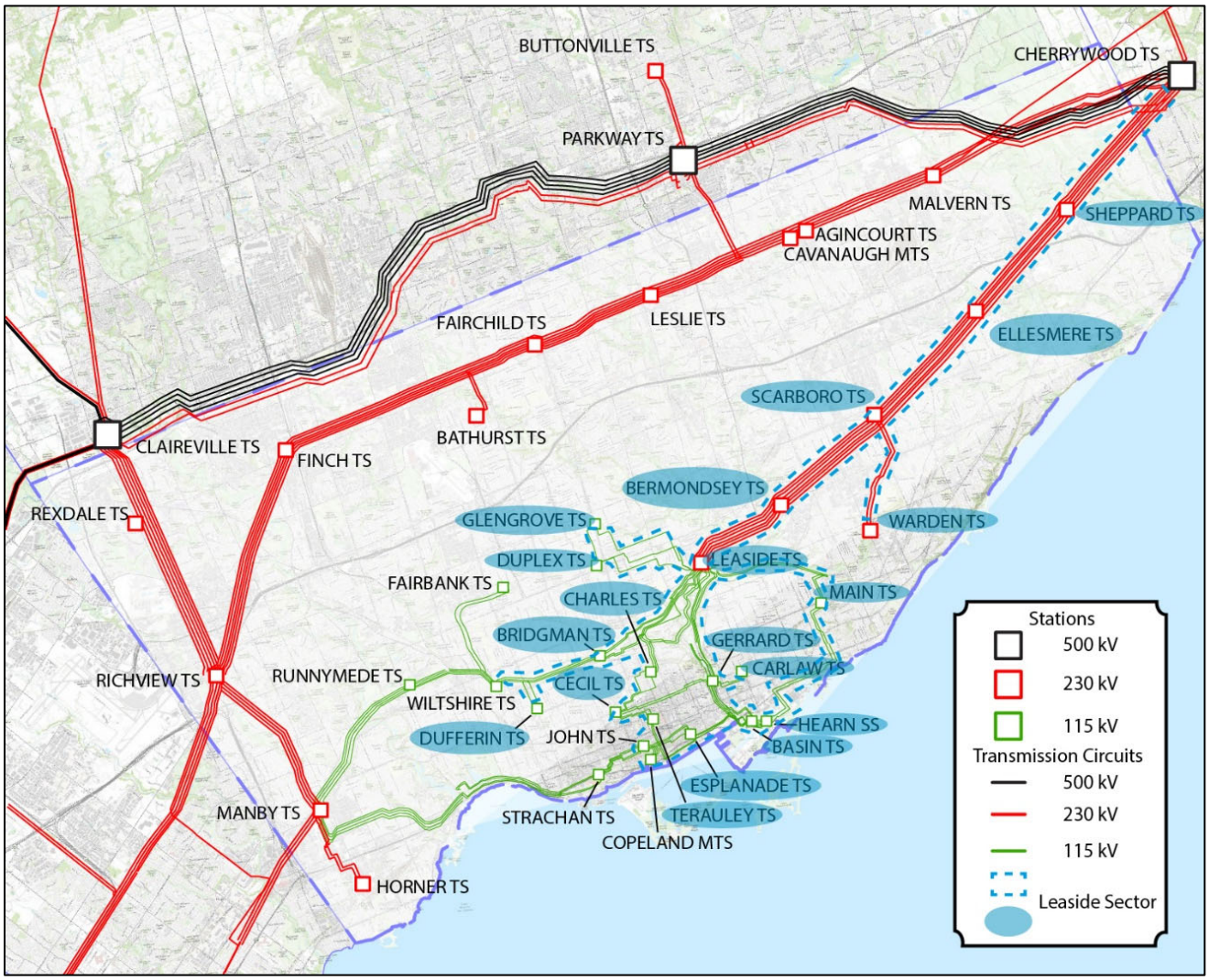
Figure 3 | Map of Western Toronto Area



- **Eastern Toronto**

Eastern Toronto includes the stations and circuits that are supplied by the Cherrywood TS to Leaside TS corridor (also known as the Gatineau Energy Corridor, and the Meadoway). These transmission lines and stations serve most of Scarborough, portions of the downtown core, East York and York. PEC is located in this area and provides local capacity that is crucial to maintaining local reliability during periods of peak demand or during transmission outages. A map of the area is shown in Figure 4.

Figure 4 | Map of Eastern Toronto Area



The Toronto IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps).
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC, NPCC and NERC standards and criteria.
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
- Confirming identified asset replacement needs and timing with the transmitter and the LDC.
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wire alternatives including additional eDSM.
- Engaging with communities on needs and possible alternatives.
- Evaluating alternatives to address near-term to long-term needs.
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Toronto region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of eDSM and distributed generation (DG). Toronto Hydro, the only LDC in this region, provided forecasts for a reference case, and a high growth scenario. Toronto Hydro's scenarios considered different levels of growth for three drivers: electric vehicles, electrified heating, and data centres.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum.

The regional planning process also considered non-coincident peaks which refers to each station's individual peak, regardless of whether these peaks occur at different times. Non-coincident peaks are used to understand the potential needs of the stations.

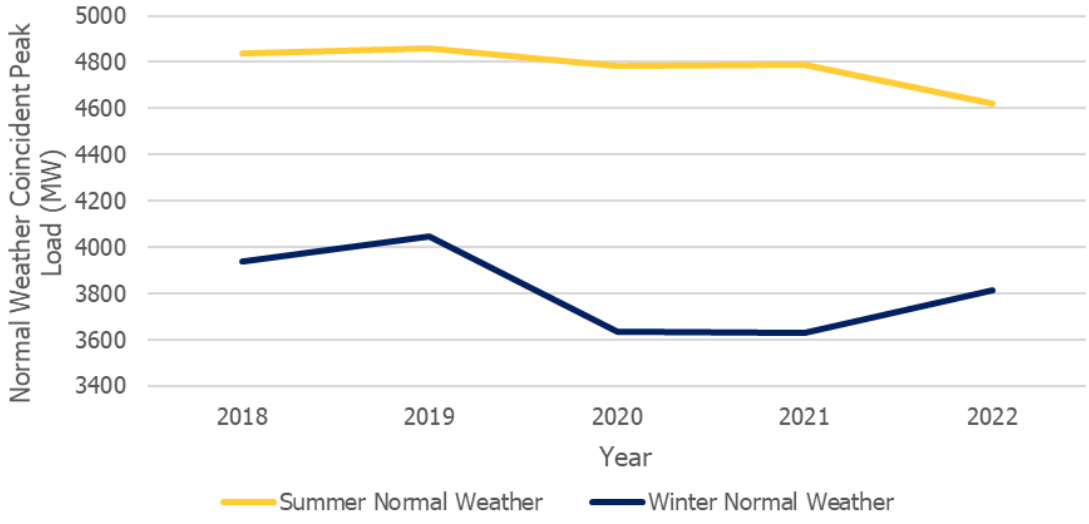
5.1 Historical Demand

The peak electricity demand within Toronto has been flat or slightly downward trending over the years preceding the forecast for this IRRP, from 2018 to 2022.

Figure 5 shows both the winter and summer coincident normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for the Toronto region. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand. Weather-corrected demand is more appropriate for evaluating growth trends.

The weather-corrected demand for the Toronto region has averaged 4,780 MW in the summer and 3,813 MW in the winter over the last five years.

Figure 5 | Toronto Region Historical Normal Weather Coincident Forecast

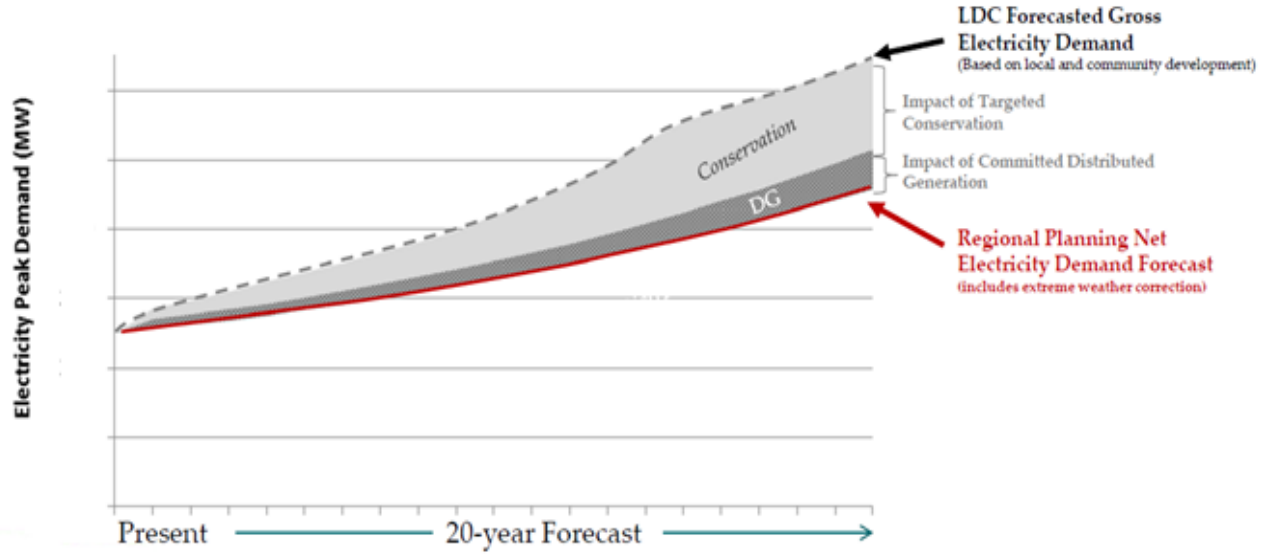


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast starting from LDC forecasts is illustrated in Figure 6. A gross demand forecast, which assume the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), was developed by Toronto Hydro. The forecast was then modified to reflect the forecasted peak demand impacts of eDSM and DG as contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT. Finally, the forecast was adjusted to reflect extreme weather conditions to produce a reference forecast for planning assessments. This net, extreme-weather forecast was then used to assess the electricity needs in the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO since they have the most direct involvement with their customers, connection applicants, municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the components of the demand forecast are provided in the following sections. Assumptions specific to Toronto Hydro's forecast are provided in Section 5.8. The Ontario Energy Board has also published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

Toronto Hydro prepared a gross demand forecast at the station level, or at the station bus level for multi-bus stations. The gross demand forecast accounts for increases in demand from new or intensified development, plus known customer connection applications. In addition, when producing the gross demand forecast, the impact of existing DG was removed, as DG impacts are accounted for later (see Section 5.5). Therefore, gross demand forecasts show the demand expected without any DG contributions, new or existing.

Toronto Hydro cited alignment with municipal plans and credited the City of Toronto as a source for input data. Toronto Hydro was also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices (natural

conservation), but not for the impact of future eDSM measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes normal weather conditions, e.g., median weather, or 1-in-2 year expected weather, representing the station level loading at the time of the regional peak.

5.4 Contribution of eDSM to the Forecast

Electricity Demand Side Management[8] (eDSM) is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak-demand and has been an integral component of provincial and regional planning. EDSM is achieved through a mix of codes and standards amendments, as well as eDSM program-related activities. These approaches complement each other to maximize conservation results.

The estimated demand reduction from codes and standards is based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities is based on the IESO's Annual Planning Outlook eDSM savings forecasts which were informed by the 2021-2024 Conservation and Demand Management (CDM) Framework programs, federal programs expected to result in electricity savings in Ontario and forecasted long-term energy efficiency program savings aligned with the 2021-2024 framework. Through the 2021-2024 CDM Framework the IESO centrally delivered programs on a province-wide basis to residential, commercial and institutional customers, as well as Indigenous communities. Following finalization of the IRRP's demand forecast, the Ontario government directed the IESO to create the 2024-2036 eDSM Framework, which expands the scale and scope of the Save-on Energy programs, including launch of the Home Renovation Savings program for residential customers and new incentives for rooftop solar for both residential and business customers. Higher savings targets under the new framework may impact the timing or magnitude of identified needs.

[8] In alignment with the language of the November 7, 2024 directive to the IESO regarding a new program framework for 2025-2036, this IRRP uses the term "electricity demand side management" replacing "conservation and demand management" used in previous IRRPs and other IESO planning documents.

Figure 7 and Figure 8 show the estimated total yearly reduction to the peak electrical demand due to eDSM, from codes and standards and eDSM programs, for the winter and summer peaks.

Figure 7 | Peak Winter Demand Reduction Due to eDSM

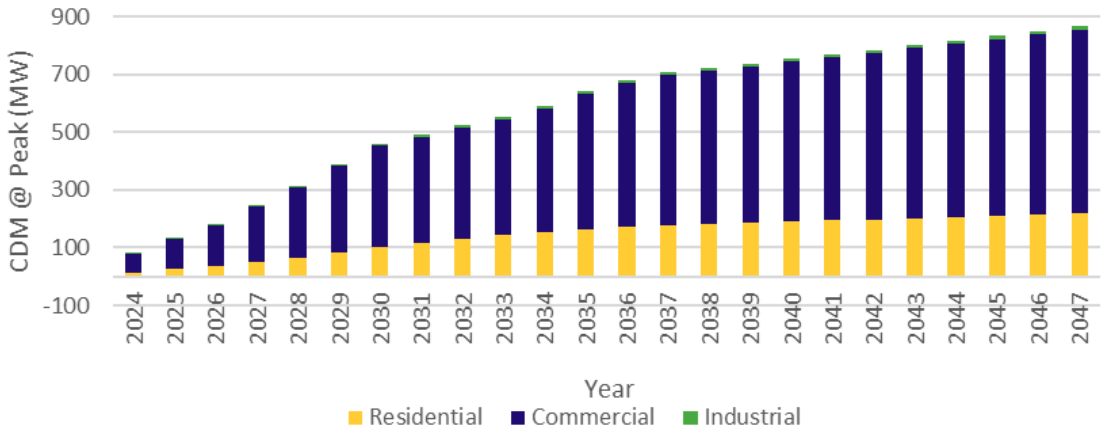
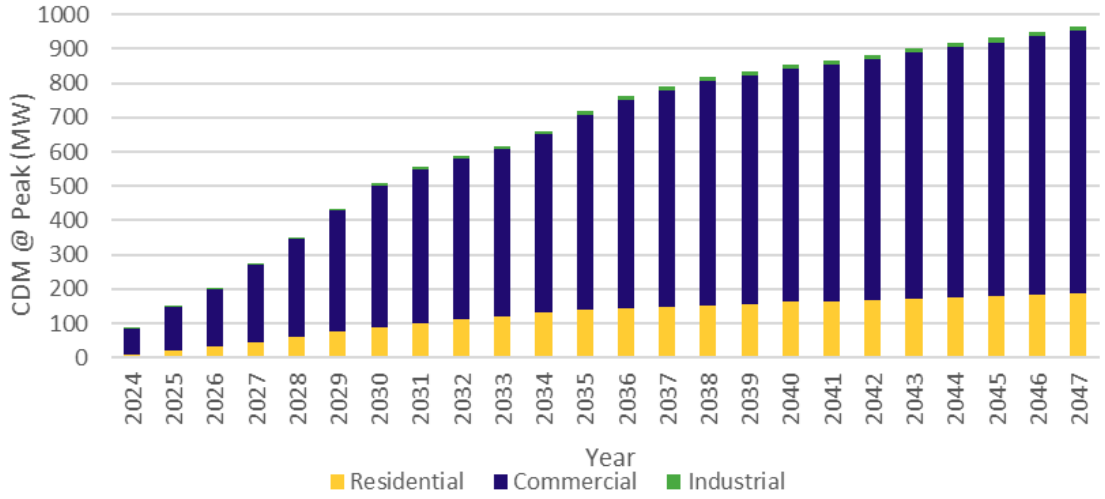


Figure 8 | Peak Summer Demand Reduction Due to eDSM



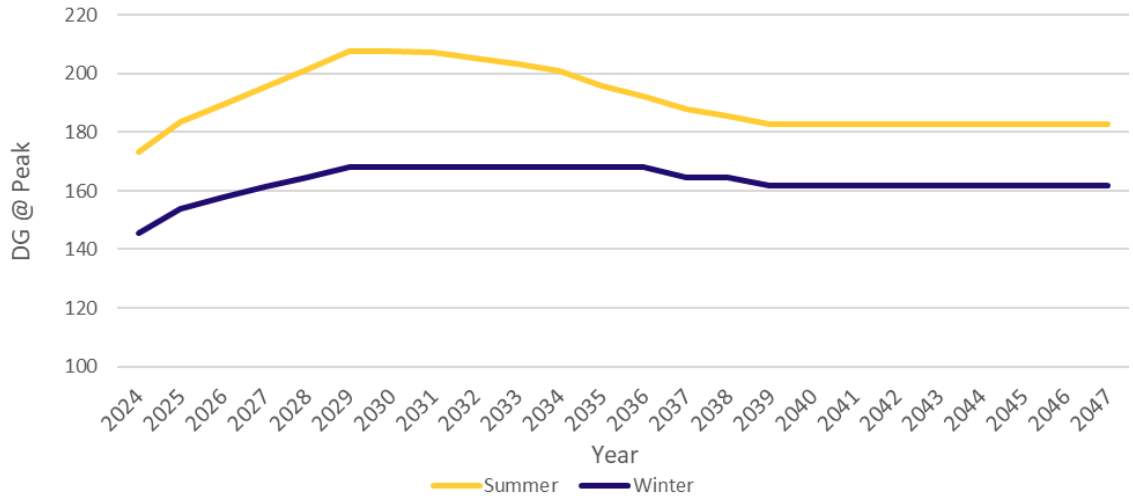
5.5 Contribution of Distributed Generation to the Forecast

In addition to eDSM resources, DG is also forecasted to offset peak-demand requirements. This includes resources contracted under Ontario's FIT and microFIT programs which increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and the associated contribution factor assumptions can be found in data tables posted on the IESO website.[9] Most of the total contracted installed DG capacity in the Toronto region is non-renewable.

[9] Regional Electricity Planning – Toronto, https://ieso.ca/torontoplanning

Figure 9 shows the estimated impact of DG on the Toronto Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast, and therefore the total contribution of DG in Toronto is higher than shown (e.g., net metered and other behind-the-meter and non-contracted facilities).

Figure 9 | Peak Demand Reduction Due to Distributed Generation



5.6 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is traditionally a region-wide coincident forecast, meaning that each station forecast reflects its expected contribution to the regional peak demand. This supports the identification of need dates for regional needs that are driven by more than one station and allows for temporary load transfer capabilities between stations to be accounted for when assessing supply capacity.

The planning forecast is produced from two main steps: adjusting for extreme weather and converting to a net forecast.

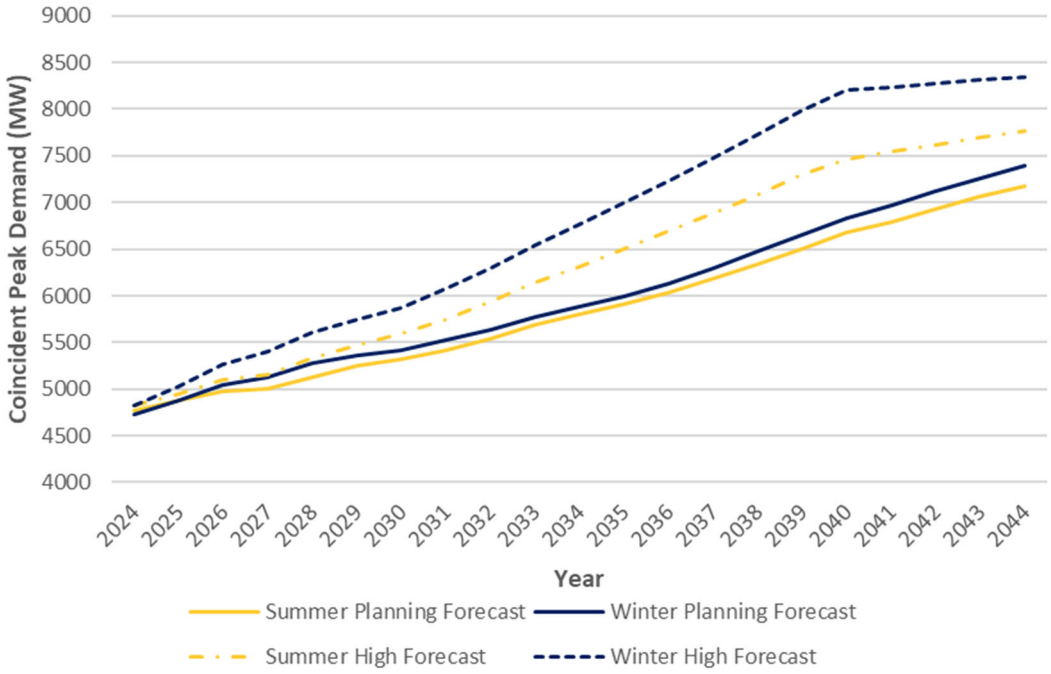
The first step is to adjust the coincident gross normal weather forecast for extreme weather conditions. This results in a coincident gross forecast which assumes extreme weather.

The last step is to adjust the resulting coincident gross extreme weather forecast for DG and conservation impacts. This is done by subtracting the forecasted DG and eDSM impacts (as described in the above Sections) from the coincident gross extreme weather forecast. This results in a coincident net extreme weather forecast, which is the "planning" forecast used to identify system needs.

For station-specific needs, a non-coincident net extreme weather forecast is used instead. The process for producing this forecast is similar to above and includes an additional step. The coincident forecast is first converted to a non-coincident forecast by applying a coincidence factor to each station. The factor is based on the station's non-coincident peaks compared to the station's historical contribution to the regional peak demand over the past five years (2018-2022 in this case).

The coincident net extreme weather reference and high electrification summer and winter forecasts (together forming the "planning" forecasts) for the Toronto Region is shown in Figure 10.

Figure 10 | Toronto Region Net Extreme Weather Coincident Forecast



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles (8,760 hours per year over the 20-year forecast horizon) for various collections of stations were developed to better assess non-wire alternatives to address needs. These profiles were used to quantify the magnitude, frequency, and duration of needs, as described later in Section 7. The profiles were based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year.

Hourly profiles of the identified needs have been posted to the IESO Toronto IRRP webpage. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan through Annual Working Group meetings until the next cycle of regional planning.

5.8 Toronto IRRP Forecast Methodology and Assumptions

Toronto Hydro, with input from the Technical Working Group, developed the forecast methodology and assumptions for the IRRP. The primary drivers of the forecast include economic growth, electrification trends, customer connection activity, and municipal development plans. These drivers are modeled to reflect their impact on electricity demand across the City of Toronto over the planning horizon. Below is a summary of the main drivers found in the forecast methodology document.[10]

5.8.1 Economic Growth

Economic activity is a foundational input to the demand forecast. Historical non-coincident system peak loads are regressed against economic indicators to establish relationships between load and macroeconomic conditions. Then, these relationships are used to project future system peaks under normal temperature conditions. Due to the lack of long-term GDP forecasts, GDP growth is held constant beyond the five-year outlook.

5.8.2 Electrification Trends

Electrification is a critical driver of future load growth, particularly in the context of market trends and the City of Toronto's Net Zero "TransformTO" strategy. The methodology incorporates three key electrification components:

5.8.2.1 Electric Vehicles

Electric vehicle (EV) adoption is forecasted across light-, medium-, and heavy-duty vehicle segments. Adoption rates vary by scenario, with the high scenario aligned with TransformTO targets (30% EVs by 2030, 100% by 2040). EV load is allocated geographically based on the distribution of existing vehicles, assuming electrification of current fleets. Hourly charging profiles are applied to estimate contributions to system peak.

5.8.2.2 Electrified Heating

Electrified heating adoption is modeled as the percentage of buildings using electric heating systems. Residential and commercial/industrial adoption rates are forecasted separately. Allocation to the bus level is based on customer counts, with higher adoption assumed in areas with greater density. Electrified heating is a significant contributor to winter peak demand.

5.8.2.3 Transit Electrification

Transit electrification is modeled based on TTC's commitment to electrify its bus fleet by 2040. The forecast assumes 190 buses are electrified annually. Space heating for transit stations is also included, modeled at 0.05 kW/m² and converted to electrical demand using a Coefficient of Performance of 2.5.

[10] Toronto Forecast Methodology, https://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/toronto-irrp-20240416-forecasting-methodology.pdf

5.8.3 Data Centres

Data centre development is expected to drive substantial near-term load growth. Forecasts incorporate known firm connection requests and anticipated developments. Load is allocated using a combination of proximity to existing stations, historical data centre locations, and random distribution with a bias toward downtown Toronto. Saturation is assumed by 2038 due to land constraints.

5.8.4 Customer Connection Activity

Firm customer connection requests are integrated into both the high electrification and reference forecasts. These requests provide specific timing, and demand estimates for new developments. Additionally, planned permanent load transfers are included to reflect operational changes in the distribution system.

5.8.5 Municipal Development Plans

Municipal planning documents are referenced to align the forecast with expected urban growth and electrification goals. These include:

- City of Toronto Official Plan
- Secondary Plan Areas (including the Port Lands, Update Downsview and the Golden Mile)
- TransformTO Net Zero Strategy
- TTC Green Bus Program

Load projections from City development plans are included based on high certainty of execution. These projections are derived from consultations with the City of Toronto staff and third-party consultants.

5.8.6 Scenario-Based Modeling

To address uncertainty, the reference forecast was developed using a probabilistic approach. Key drivers—temperature, economic growth, EVs, heating, and data centres—were treated as random variables. Monte Carlo simulations were used to generate a distribution of outcomes, with the median forming the final reference forecast. Before performing the Monte Carlo simulation to arrive at the reference forecast, four scenarios (High, Medium, Low, Business as Usual) were defined to reflect varying levels of policy implementation and market adoption.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of the IESO's ORTAC, Northeast Power Coordinating Council (NPCC) Directory #1 Criteria, and NERC TPL-001-4 Standards. The Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following categories.

Station Capacity Needs describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by the thermal ratings of downstream or upstream equipment, i.e., breakers, disconnect switches, medium-voltage bus or high voltage circuits; or, by voltage drop limitations, which are independent of thermal ratings.

Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-5, and NPCC Directory #1. LMC studies are conducted by performing power system simulation analyses using industry-standard software. A summary of the criteria used is below:

- N-1, N-1-1 and N-2,[11] events were evaluated for the forecasted extreme weather demand.
- Per section 2.6 of the ORTAC, "(w)here reliability depends on local generation, sensitivity studies should be done to assess the impact of outages of local generation." For example, such N-G-1 and N-G-2 events were evaluated assuming G3 at PEC is O/S for normal weather demand. Only subareas which are impacted by the status of PEC unit status were evaluated.
- N-1-2 scenarios were only evaluated on areas designated NPCC Bulk Power System (BPS) for normal weather demand.

[11] The ORTAC does not require double element contingency events to be evaluated for local area (non-bulk) transmission systems, unless the contingency propagates to a higher voltage level or causes a net load loss greater than 1,000 MW. However, for the City of Toronto double element contingencies were evaluated due to the social and economic importance of continuous electricity supply to the area. It is important to note that the post-contingency topology of N-1-1 and N-2 events are similar in many cases as such the needs reflected from N-2 events would also be present for N-1-1 events in lieu of the available system control actions between contingencies.

Asset Replacement Needs are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term asset replacement needs should reflect the potential for the date to change based on updated information concerning the asset condition.

Load Security and Restoration Needs describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 2.4.10 of ORTAC.

6.2 Needs Identified in Northern Toronto

6.2.1 Station Capacity Needs

Two stations supplying Northern Toronto are expected to exceed their station capacity, namely Bathurst TS and Finch TS. Table 8 shows the year each station is expected to reach its capacity need and the MW exceedances at the end of the study period, for both the reference and high electrification forecast. These needs are primarily due to expected new community developments per the City of Toronto's Update Downsview Secondary Plan.

Table 8 | Northern Toronto Station Capacity Needs

	Reference Forecast		High Electrification Forecast	
Station	**Need Year**	**2044 Need (MW)**	**Need Year**	**2044 Need (MW)**
Bathurst TS	2034	201	2034	211
Finch TS	2038	41	2034	71

6.2.2 Supply Capacity Needs

Like the station capacity needs, the supply capacity needs in Northern Toronto are primarily due to expected new developments as a result of the City of Toronto's Update Downsview Secondary Plan. The Bathurst TS tap lines are expected to reach their LMC by 2038 in the reference forecast and 2037 in the high electrification forecast, respectively.

6.3 Needs Identified in Western Toronto

6.3.1 Supply Capacity Needs

6.3.1.1 Manby West Autotransformers

The Manby West autotransformers are expected to reach their LMC of 490 MW by 2028 in both reference and high electrification forecasts. The LMC is reached when T1/T12 exceeds its LTR following the loss of two autotransformers (as an outage + contingency scenario), with the Manby RAS fully utilized. This need arises primarily due to planned load increases at the Copeland MTS downtown, and due to growth at John TS and Strachan TS. High electrification does not accelerate the need, but it results in higher levels of unserved load.

Hydro One has indicated that Manby West T12 is expected to be replaced in 2029-2030 as per the Needs Assessment. At the time of this assessment, no new parameters were available, and the existing parameters were used. The existing T12 autotransformer has the lowest rating of the existing Manby West autotransfomers.

6.3.1.2 Manby East Autotransformers

The Manby East autotransformers are expected to reach their LMC of 500 MW by 2044 and 2035 for the reference and high electrification scenarios, respectively. The LMC is reached when T7 exceeds its LTE following the loss of two autotransformers, with the Manby RAS fully utilized. It should be noted that Hydro One has indicated that Manby East T7 and T9 are expected to be replaced in 2029-2030 as per the Needs Assessment. The existing T7 autotransformer has the lowest rating of the existing Manby East autotransformers.

6.3.1.3 Manby to Riverside Junction Circuits

The loss of K6J or H2JK plus K13J or K14J leads to K14J or K13J to exceed its short-term emergency (STE) ratings starting in 2026. This need is coincident with planned load increases at Copeland MTS. High electrification does not accelerate the need but does result in additional amounts of unserved load.

6.3.1.4 St. Clair to Fairbank Circuits

The loss of K1W or K3W will result in the companion circuit exceeding LTE rating by 2036 and 2031 for the reference and high electrification forecasts, respectively. It is recognized that Hydro One plans to replace approximately 3.2 km of the 4.5 km section of K1W and K3W with higher ampacity conductors by 2029 leaving a 1.3 km section unmodified.

6.3.1.5 Richview to Manby Circuits

The Richview to Manby circuits are currently undergoing an upgrade, referred to as the Etobicoke Greenway Project.[12] This project involves decommissioning an existing, idle 115 kV double circuit transmission like and replacing it with a new 230 kV double circuit line. This project is expected to be in-service by 2026. In addition, two of the existing 230 kV circuits from Richview to Manby are

[12] Etobicoke Greenway Project (Hydro One), https://www.hydroone.com/about/corporate-information/major-projects/etobicoke-greenway

expected to be unbundled and tie Claireville TS and Richview TS, further increasing the LMC to 1,840 MW. This unbundling project is expected to be completed no later than 2031 and was recommended in the 2019 Toronto IRRP.

Due to the expected load growth in the Manby sector, the circuits are expected to reach their new LMC by 2032 and 2030 under the reference and high electrification forecasts, respectively. This limitation is caused by breaker fail contingency at Richview, which would remove two circuits from service, resulting in a remaining circuit exceeding its long-term emergency (LTE) rating.

6.3.2 Station Capacity Needs

Three load supply stations in West Toronto are expected to exceed their station capacity, namely Fairbank TS, Strachan TS, and the Manby DESN. Table 9 shows the year each station is expected to reach its capacity need and the capacity exceedances (in MW) at the end of the study period, for both the reference and high electrification forecasts.

Table 9 | Western Toronto Station Capacity Needs

	Reference Forecast		High Electrification Forecast	
Station	**Need Year**	**2044 Need (MW)**	**Need Year**	**2044 Need (MW)**
Fairbank TS	2042	12	2036	38
Strachan TS	2039	22	2033	47
Manby DESN	2043	5	2037	21

6.4 Needs Identified in Eastern Toronto

6.4.1 Supply Capacity Needs

The following circuits and stations were identified to have supply capacity needs in Eastern Toronto.

Table 10 shows the year each need emerges and the MW exceedances at the end of the study period at the circuits and stations for the reference and high electrification forecast, respectively. Two City of Toronto Secondary Plans, namely the Port Lands redevelopment and Golden Mile, are major drivers of growth in the Eastern Toronto area.

Table 10 | Eastern Toronto Supply Capacity Needs

	Reference Forecast	High Electrification Forecast
Circuit/Station	**Need Year**	**Need Year**
L13W and L18W Bridgman x Barlet / Dufferin JCT.	2036	2029
L18W Leaside TS to Bridgman TS	2041	2033

	Reference Forecast	High Electrification Forecast
Circuit/Station	**Need Year**	**Need Year**
L15 Leaside TS x Bridgman TS	2036	2026
L14W Birch JCT x Bridgman TS	-	2037
H1L/H3L Leaside TS x Bloor St.	2036	2036
H1L/H3L Hearn SS x Basin TS	2041	2037
C2L + C3L Double Contingency	<2025	<2025
Leaside Area Voltage Support	2038	2034

6.4.1.1 Leaside to Bridgman to Dufferin Circuits

The circuits that supply Bridgman TS and Dufferin TS from Leaside TS (namely L13W, L15, L14W, and L18W) are expected to reach their LMC by the 2036 winter reference forecast (potentially as soon as 2026 for the high electrification forecast). The most limiting element is L15, which will overload following the loss of L13W and L18W. Overloading on other circuits (e.g., L14W and L18W) occurs later but is caused by the same growth drivers at Dufferin TS and Bridgman TS.

6.4.1.2 Leaside to Bloor Circuits

The sections between Leaside TS and Bloor Junction (JCT) on H1L and H3L are expected to be overloaded by 2036, for both the reference and high electrification case, during an outage at PEC (G3 unit) followed by a breaker failure at Hearn. In their Needs Assessment, Hydro One indicated the overhead sections of H1L and H3L between Leaside TS and Bloor JCT are to be replaced with the largest size possible conductor while retaining existing tower structures.

6.4.1.3 Hearn to Basin Circuits

The 0.5 km sections between Hearn SS and Basin TS on H1L and H3L are expected to be overloaded by 2041 and 2036 for the reference and high electrification case, respectively. These circuits will exceed their LTE ratings following the loss of the companion circuit. This need is driven by the additional load attributed to the Port Lands Secondary Plan development.

6.4.1.4 Cherrywood to Leaside Circuits

The loss of two of the Cherrywood TS to Leaside TS circuits, namely C2L and C3L, results in voltage instability in the Leaside sector when loading is sufficiently high. This need exists in the current system and is managed by control actions.

As load continues to grow, the contingencies that can lead to voltage instability expands beyond what can be managed with existing control actions. Instability is forecast to occur between 2035 and 2039 for the loss of C16L or C17L followed by the loss of two elements that remove two Cherrywood

to Leaside (CxL) circuits and two capacitors at Leaside TS (i.e., specific Leaside breaker failures). In subsequent years this need continues to expand to include other combinations of transmission equipment outages.

Given ORTAC's requirement of keeping within a 10% margin on voltage stability, LMC of the Cherrywood to Leaside circuits is about 2,610 MW, resulting in a need date corresponding to 2038 and 2034 for the reference and high electrification forecasts, respectively. The size of the need (due to the demand forecast) and considering a scenario with reduced reliance on PEC necessitates that a new supply be built to Toronto. More details can be found in Section 6.5 below.

6.4.2 Station Capacity Needs

Six load supply stations in Eastern Toronto are expected to exceed their station capacity, namely Scarboro TS, Sheppard TS, Warden TS, Glengrove TS, Dufferin TS, and Basin TS. Table 11 shows the year each of these needs emerges, and the MW exceedances at these stations at the end of the study period for the reference and high electrification forecast, respectively.

Table 11 | Eastern Toronto Station Capacity Needs

	Reference Forecast		High Electrification Forecast	
Station	**Need Year**	**2044 Need (MW)**	**Need Year**	**2044 Need (MW)**
Scarboro TS	2035	166	2034	181
Sheppard TS	2038	27	2033	48
Warden TS	2036	28	2032	42
Glengrove TS	2042	10	2035	31
Dufferin TS	2040	27	2033	66
Basin TS	2036	79	2036	81

6.5 Need for New Supply in Eastern Toronto

Electricity system needs in the East Toronto area in the medium term (up to 2035) are driven primarily by local growth and development plans, including secondary plans for the Port Lands district and the Golden Mile in Scarborough. Together with other policy and economic drivers such as urban intensification, electrification and decarbonization, the electricity demand in East Toronto is expected to exceed the capacity of the transmission system within the next 10 to 15 years. The largest of the needs involves the 230 kV transmission supply from Cherrywood TS. More specifically, load growth will cause exceedances of the line capacity of the 230 kV transmission circuits between Cherrywood TS and Leaside TS, and the autotransformers at Leaside TS. With PEC in-service, planning studies show that credible planning contingencies such as the loss of two 230 kV supply circuits will result in voltage instability by 2038.

6.5.1 Portlands Energy Centre Scenario

The IRRP investigated a scenario with PEC out-of-service (i.e., not operating/contributing to meeting demand in Toronto). This scenario was driven by a need to consider options for maintaining cost-effective and reliable electricity supply given the facility's contract expiration date of April 2034. Both the *Pathways to Decarbonization* and *Powering Ontario's Growth* reports indicated a need to study the transmission reinforcements required to eventually phase out local gas-fired generation in consideration of the development lead time to implement transmission alternatives. The retirement scenario is also responsive to local community opposition to the continued operation of the gas plant in the urban centre, and a 2024 Toronto City Council resolution requesting the IESO to study phasing out PEC by 2035.[13] Given the facility's contribution to local reliability, the IRRP technical studies confirmed that a transmission reinforcement would be needed to accommodate a future without PEC, and must be in place before the facility can retire With or without the capacity contribution of PEC, the transmission is still needed to supply the forecasted load growth. The IESO will continue to investigate possible measures that can reduce local reliance on PEC in the interim period while a transmission solution is being implemented.[14]

In addition, while local reliance on PEC will be reduced once the Third Line is in place, it may still be needed to meet the provincial grid's peak needs into the 2030s. The Toronto IRRP is focused on local supply and does not address matters of provincial supply.

6.6 Addressing Resilience of Toronto's Electricity System

Through the engagement of the Toronto IRRP, the Technical Working Group heard that system resilience should be an important consideration to the plan. Based on this feedback, the Technical Working Group considered resilience in the development of IRRP options, and to inform future planning.

6.6.1 Flooding of Manby Transformer Station

In July 2024, Toronto experienced a severe summer storm that caused flash floods across the city. One of the most significant impacts was the flooding at Manby TS, which is one of two major transmission supply paths into downtown Toronto. The storm caused widespread outages, affecting the electricity supply to about 190,000 customers.[15] The flooding of Manby TS and subsequent load loss underscores the importance of system resilience especially from extreme weather events, and considering climate change.

[13] Toronto City Council Meeting, Item – 2024.MM19.9, https://secure.toronto.ca/council/agenda-item.do?item=2024.MM19.9

[14] Some non-wires alternatives may also serve to mitigate against possible timeline risks of the transmission solution.

[15] Severe Toronto storm causes flooding, major power outages | CBC News

7 Plan Options and Recommendations

This section describes the options considered and offers recommendations to address the needs in the Toronto Region. In developing the plan, the Technical Working Group considered a range of integrated options, which included combinations of options. These options were screened and further evaluated based on key considerations including technical feasibility, cost, lead time, other benefits, and consistency with longer-term needs in the area.

Generally, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new transmission or distribution infrastructure. These are commonly referred to as "wire" options and can include utility investments such as new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing lines and stations, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wire" options and can include measures such as locally sited generation or storage resources connected to the transmission system, distributed energy resources including generation and demand response that are distribution-connected, or additional eDSM.

Section 7.1 begins with an in-depth overview of options considered in IRRPs. Section 7.2 provides a summary of the Local Achievable Potential Study, and Section 7.3 speaks to thermal energy networks and the opportunity to coordinate with long-term electricity system planning. Section 7.4 describes the screening approach used to assess which needs would be best suited for wires and/or non-wires options. Subsequently, Sections 7.6 to 7.9 present the options ultimately developed and evaluated according to cost and other factors to inform the IRRP recommendations.

7.1 Options Considered in the IRRP

Both wire and non-wire options were considered in the development of this IRRP. Wire options are well suited for addressing a range of power system reliability issues and generally provide a substantial increase in the LMC for both summer and winter peak seasons. Non-wire options such as eDSM, locally sited renewable resources or storage generally help to maintain or reduce energy demand requirements, with significant variances among these various resources in terms of their ability to target the winter and/or summer peak demand. To evaluate non-wire options such as local generation or energy storage, the additional step of creating hourly load profiles is required, as described in Section 5.7. Suitable technology types are chosen by examining the "unserved energy" profile, which represents the hourly duration and magnitude of the demand that exceeds the system LMC. The load profile indicates the duration, magnitude as well as the frequency and total energy requirement associated with each need. Hourly profile data for the Toronto IRRP have been published on the IESO's webpage.

Planning level cost estimates for wire options were based on input provided by Hydro One and Toronto Hydro, as well as informed by transmission costs from other IESO planning studies and industry benchmarks. Cost estimates for non-wire options were based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and community preferences, new natural gas-fired generation was not considered an option for addressing local needs in the City of Toronto. Energy storage, solar PV, and wind generation were considered.

The assumed energy efficiency savings from programs under the 2021-2024 CDM Framework and Save on Energy brand were included in the demand forecast, as discussed in the Section 5.4. The IESO was also directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is one tool that is available to target the delivery of additional savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. Additional demand savings from the eDSM framework beyond those already embedded in the forecast were evaluated as potential options to address identified regional needs. Generally, eDSM is suitable for needs where growth is gradual to and the magnitude of the overload relative to the total demand is small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.4, as part of the options screening.

For both wire and non-wire options, the upfront capital and operating costs are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wire option (typically 70 years for transmission line infrastructure). The net present value (in 2024 $CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize the error margin around cost estimates at the planning stage. These costs serve to enable comparison of the different options during the IRRP. The transmitter-led RIP (following the IRRP) is an opportunity to carry out further analysis allowing for cost estimates to be refined prior to implementation. The Technical Working Group can revisit specific recommendations if cost estimates or other parameters change significantly. Further, certain options including non-wires could be tested through pilot or demonstration projects in cases where other barriers or implementation challenges need to be worked through (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints).

7.2 Local Achievable Potential Study

To further enhance and supplement the regional planning work underway for Toronto, the IESO retained energy consultancy ICF International to conduct a local achievable potential study (LAPS) to identify the potential for additional eDSM programming, above and beyond the already planned eDSM included in the IRRP demand forecasts, to cost-effectively meet regional needs. The purpose of the study was to identify and quantify both electricity energy and demand savings potential attainable through a range of behind-the-meter DERs, with associated costs. Energy efficiency, demand response, and other resources including solar PV and energy storage were considered over the 20-year period. Although a long-term view was included in scope for the LAPS, there remains much uncertainty about the timing of technology advancements in the DER space. The study results

will inform decisions in the near-term (first five years of the plan), while still allowing for innovation to happen in eDSM and DER programs/procurements and/or pilots and demonstration projects. The LAPS results are not intended to represent a maximum of the amount of savings that may be achieved through province-wide and/or local program performance; and it is not intended to preclude new measures from being introduced as program offerings in the future.

The LAPS was carried out for two local forecasts aligned with the IRRP reference and high demand forecast scenarios. For each scenario, the study used a bottom-up approach to determine the energy savings potential from technical, economic and achievable perspectives.

- Technical Potential is the estimated savings resulting from the implementation of all technically feasible measures, ignoring cost-effectiveness, customer awareness, equipment turnover rates, or other "real world" barriers.
- Economic Potential is the savings resulting from the implementation of all technically feasible measures that pass a cost-effectiveness test (Program Administrator Cost or "PAC" test).
- Achievable Potential is the final savings remaining after adoption rates over the period of the study are applied and is intended to represent a realistic estimate of the savings that could be acquired through programs.

These savings are simulated at the building level using a "digital twin" model for the residential and commercial sectors and aggregated to the station level for each scenario. Measures in scope include:

- Behind-the-Meter DER including energy storage systems, solar PV and thermal storage.
- Energy Efficiency measures including heat pumps, HVAC, lighting, appliances, weatherization, and hot water.
- Demand Response including EV charging, HVAC equipment, and water heaters.

Under the reference demand scenario, the LAPS estimates a total of 1,167 MW of summer peak demand savings potential and 878 MW of winter peak demand savings potential over 20 years. After deducting savings from planned eDSM already captured in the demand forecast this represents an incremental opportunity of 320 MW of summer and 121 MW of winter peak demand savings.

The LAPS Final Report will be published and made available on the IESO website. These documents provide detailed descriptions of the methods, data sources, input assumptions, and results of the study.

In reviewing the LAPS results, it is important to acknowledge that planners must consider several factors in assessing whether estimated eDSM potential can help address an identified need. These include:

- How much of the estimated achievable potential is incremental to the savings already captured in the eDSM savings forecast?
- Can the incremental eDSM potential satisfy both summer and winter needs if applicable?
- How much incremental achievable potential is available in the specific need area (e.g. additional potential in Etobicoke cannot help a station capacity need in Scarborough)?

- How does the timing of incremental eDSM potential becoming available align with the timing of need?

These key considerations will help inform the implementation of IRRP recommendations to acquire incremental eDSM savings throughout Toronto.

7.3 Thermal Energy Networks

The City of Toronto presented to Toronto Hydro and the IESO results of their *Toronto Port Lands Demand Justification & DER Potential Assessment*. Their study reviewed the potential for thermal energy networks (TENs) and stringent Building Performance Standards to reduce the summer and winter peak demand impact of planned mixed-use urban development in the Port Lands. The scope of this study was specifically the loads served, or to be supplied by Basin TS.

The Technical Working Group recognizes the potential for district energy to continue to be a valuable resource that will contribute meaningfully to the City of Toronto's future energy needs, particularly in the context of reducing emissions and meeting the city's climate goals. District energy systems distribute thermal energy to multiple buildings and offer scalable, efficient, lower carbon solutions that align with the City of Toronto's TransformTO climate action plan and net-zero targets. The successful development and integration of district energy projects will require continued leadership from the City of Toronto and active participation from district energy service providers, developers and customers.

Municipal coordination, policy support, and investment are essential to unlocking the full potential of district energy as part of a diversified and resilient energy strategy for the City. The Technical Working Group recommends the City of Toronto keep Toronto Hydro informed of plans to implement district energy systems to ensure their impact on the electricity system can be properly assessed in local and regional plans. As it will take new developments like the Port Lands, as well as Downsview and the Golden Mile several decades to be fully realized, there is time for coordinated planning and action to understand the potential co-benefits of new thermal energy networks for deferring or avoiding additional investment in electricity transmission and distribution infrastructure.

7.4 Options Screening Results

As explained in the previous section, an array of options to meet local needs is developed during an IRRP. Each of these options is screened based on whether it meets the technical requirements for a solution, and the technically feasible options are then evaluated to arrive at a set of recommended options. Options are preferred based on their cost-effectiveness, as well as other decision-making factors including risk mitigation as it relates to future costs, implementation considerations, and community and stakeholder preferences and feedback, amongst other considerations.

Screening occurs early in the IRRP study after local reliability needs are known but before detailed analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 11 and further discussed in the next sections. A summary of the options screening results for the Toronto IRRP is provided in Table 12.

Figure 11 | IRRP NWAs Screening Mechanism

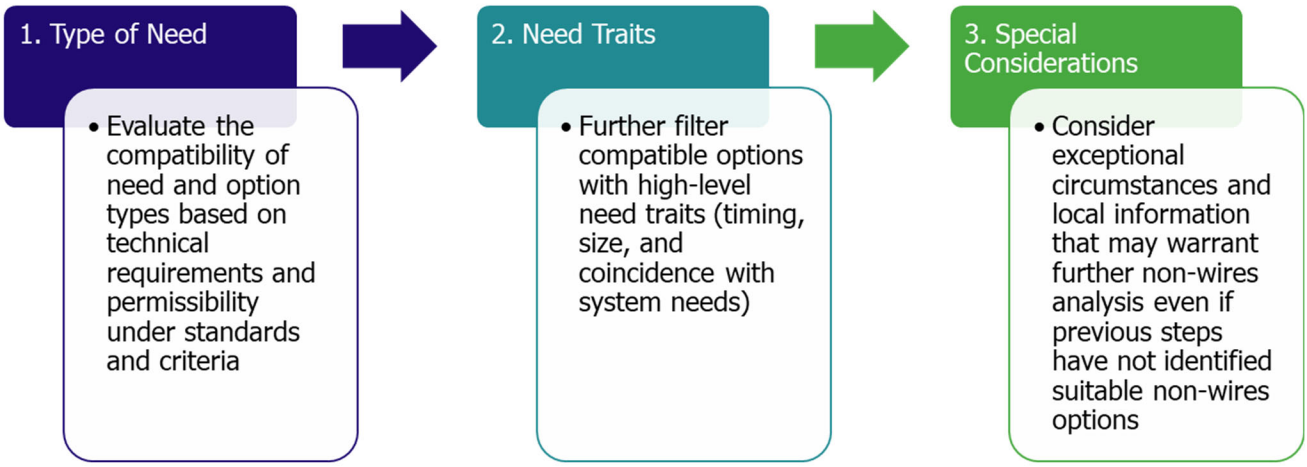


Table 12 | Options Screening Results for Toronto Needs

Area	Need	Screened In	Screened Out
Northern Toronto	**Supply Capacity**	• Wires (new transmission lines) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
	Station Capacity	• Wires (new station) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
Western Toronto	**Supply Capacity**	• Wires (upgrades to existing lines) • Energy Storage[16] • Wires plus integrated approaches including energy storage, additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation

[16] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

Area	Need	Screened In	Screened Out
	Station Capacity	• Wires (new or expanded stations) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
Eastern Toronto	**Supply Capacity**	• Wires (new and upgraded transmission lines) • Wires plus integrated approaches including energy storage, additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
	Station Capacity	• Wires (new or expanded stations) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation

7.5 Options and Recommendations for Northern Toronto

In Northern Toronto, the supply and station capacity needs have common drivers. Load growth at both Bathurst TS and Finch TS (and the circuits supplying the two stations) will exceed their capacity limits due to electricity demand growth driven by the Update Downsview Secondary Plan. As this Secondary Plan involves brand new communities, new transmission and distribution infrastructure will be needed to supply them. A new Downsview MTS would also provide an opportunity to offload Bathurst TS, Finch TS, Fairchild TS and Fairbank TS, thereby ensuring these stations remain within their capacity limits.

As a result, Toronto Hydro, as part of their 2025 Distribution System Plan, proposed a new transformer station named Downsview MTS to be connected to the Finch Corridor circuits. This new station was approved by the OEB as part of Toronto Hydro's recent rates application. The Technical Working Group supports this decision and continues to recommend Downsview MTS be built to meet needs of the area.

As part of the IRRP, two potential connection arrangements were studied for Downsview MTS. The first arrangement would involve building a Downsview Switching Station (SS) which would connect all six circuits on the Finch Corridor to Downsview SS which would then feed Downsview MTS. The

second arrangement would involve connecting Downsview MTS directly to two of six Finch Corridor circuits.

7.5.1 Wires Options – Build Downsview SS and Downsview MTS

The proposed Downsview SS would consist of two 230 kV buses each tapping three of the six 230 kV circuits in the Finch Corridor. The two supplies for Downsview MTS would then come from the two 230 kV buses at Downsview SS. The construction of Downsview MTS/SS, along with the load transfers to Downsview from the surrounding load stations, defers the expected timing when sections of P21R reaches its LTE ratings for select N-1-1 events to 2042 (for both the reference and the high electrification forecast). This exceedance can be mitigated if manual load rejection (up to 150 MW) post contingency at Downsview MTS is possible within 15 minutes, as the STE rating is not forecast to be exceeded. Alternatively, small amounts of incremental eDSM and/or DER starting in 2040 would defer the need past the forecast period (i.e., beyond 2044).

7.5.2 Wires Options – Connect Downsview MTS directly to two of Finch Corridor Circuits

An alternate arrangement was assessed to determine if Downsview MTS could be connected directly to two of the six circuits between Richview TS and Cherrywood TS/Parkway TS thereby eliminating the need for Downsview SS. The pairs of circuits assessed in this alternative are listed below:

1. C4R and C18R
2. C4R and C20R
3. C4R and P22R
4. C5R and C18R
5. C5R and C20R
6. C5R and P22R
7. P21R and C18R
8. P21R and C20R
9. P21R and P22R

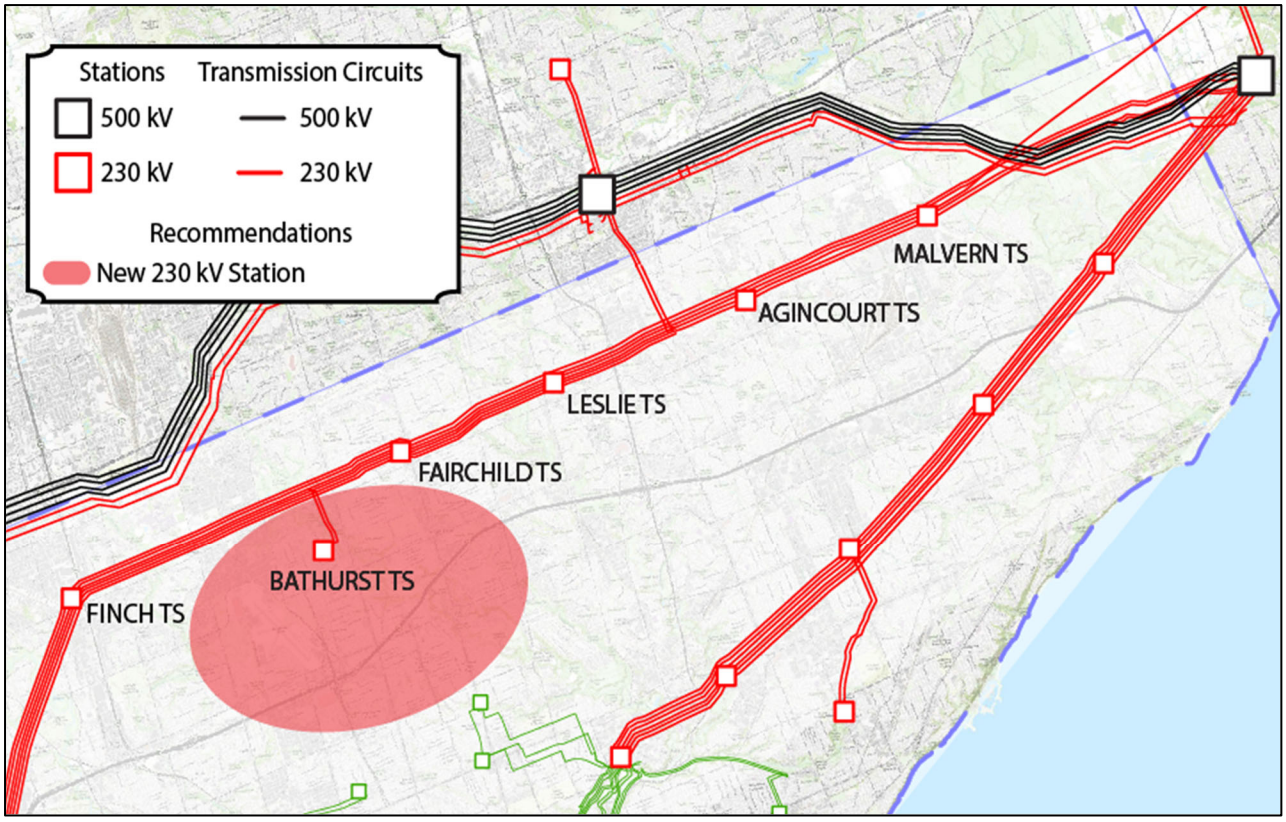
Study results show that any option involving P21R or P22R (i.e., pairs 3, and pairs 6 – 9) are the most limiting arrangements. Any option involving these circuits leads to supply limitations starting in 2038 (via the loss of non-Parkway to Richview circuit overloading the remaining Parkway to Richview circuit). For all the other options, the six circuits between Richview TS and Cherrywood TS/Parkway TS remain under LTE ratings within the forecast period, for all the single and multiple-element contingencies considered.

7.5.2.1 Recommendation for Northern Toronto

The studies demonstrate both connection arrangement options allow for the reliable connection of the new Downsview MTS and its associated forecast demand. It is important to note that while the Downsview SS and Downsview MTS combined option was approved by the OEB, while the further analysis carried out in this IRRP shows that connecting Downsview MTS directly to two of the Finch Corridor circuits leads to lower overall costs for Toronto Hydro.

This recommended action is expected to cost approximately $170 Million in Canadian dollars and is expected to have a lead time of five to seven years.

Figure 12 | Recommended Option for Northern Toronto



Therefore, the Technical Working Group recommends that Toronto Hydro proceed with Downsview MTS, and that Toronto Hydro and Hydro One finalize their preferred connection arrangements in the upcoming RIP, keeping in mind that a solution should be in place by 2034.

7.6 Options and Recommendations for Western Toronto

In the following sections, the options that passed the initial screening to address system needs in Western Toronto are discussed. The Western Toronto supply capacity needs, as discussed in Section 6.3.1, include overloads at the Manby TS autotransformers (Manby West and Manby East), the Manby TS to Riverside Junction 115 kV transmission circuits, the Richview TS to Manby TS 230 kV circuits, and the St. Clair to Fairbank TS circuits. Stations in Western Toronto that are expected to reach their capacity in the study period include Fairbank TS, Strachan TS, and the Manby DESN.

The recommended actions for Western Toronto are a mix of integrated solutions including investments in wires and non-wires.

7.6.1 Options for Addressing Manby West Autotransformers

7.6.1.1 Wires Options – Manby Crossover Option

One option that could alleviate autotransformer loading at Manby West involves swapping K13J (or K14J) terminals at the Manby West 115 kV yard with the any one of the Manby to Wiltshire circuits in the Manby East 115 kV yard ("Manby Crossover Option"). This would result in more even distribution of power flow between the Manby East and Manby West autotransformers. It also provides additional system redundancy in the event of a loss of an autotransformer in either yard as it will allow for Manby East to support Manby West and vice-versa. Further, implementing this option would reduce the need to rely on the existing Manby RAS until the 2042 high electrification forecast materializes.

Hydro One estimates this option would cost between $15 million and $20 million to implement. However, short circuit studies performed by Hydro One demonstrate that the Manby Crossover Option will greatly increase fault levels at Manby, imposing a severe constraint on future system development including the addition of any new DERs in the area. Additional costs are expected to remediate the resulting short circuit limitations at impacted stations. Future studies would be needed to determine the feasibility of addressing these limitations and the additional costs.

7.6.1.2 Wires Options – Reliance on Manby RAS

The Manby Remedial Action Scheme (Manby RAS) is an existing scheme that allows operators to arm certain loads for rejection upon the loss of one or more autotransformers at Manby TS. For example, upon the loss of any Manby West autotransformer, transferring the entire Copeland MTS facility to Leaside supply in case of the loss of a second autotransformer defers the needs past the end of the study period for the high electrification forecast, provided up to 150 MW of load rejection between John TS and Strachan TS is used following the loss of the second autotransformer. This level of load rejection is allowable per the IESO's ORTAC.

The HVDC Third Supply increases available capacity to the Leaside sector and allows for this option to be implemented. It should be noted that this option would limit the emergency load transfer of Esplanade TS, which is normally supplied by Leaside, to Manby supply in an emergency event. Further studies, including extreme contingency events and their likelihood can inform whether future actions to enhance emergency load transfer capabilities should be explored.

7.6.1.3 Wires Options – Permanent transfer of Copeland MTS T2/T4 to Leaside Supply

This option involves permanently transferring supply of Copeland MTS T2/T4 from Manby to Leaside supply starting in 2026. This will alleviate overloading issues at the Manby West autotransformers.

7.6.1.4 Non-wires Options – Incremental eDSM

Informed by the local achievable potential study, incremental eDSM potential was estimated at the stations downstream of Manby West, namely Strachan TS and John TS. This incremental eDSM is in addition to that to the planned eDSM that is already assumed in the demand forecast. Table 13 shows the incremental eDSM potential at five-year intervals over the planning horizon. It is important to note that the planned and incremental eDSM savings also provide a net provincial system benefit by avoiding generation at peak.

Table 13 | Incremental eDSM at Strachan TS and John TS

Station	Incremental eDSM (MW, cumulative)			
	2025	2030	2035	2040
Strachan TS	3	9	13	16
John TS	1	7	14	17

7.6.1.5 Non-wires Options – Energy Storage Systems

The hourly profile of this need aligns well with the capabilities of an energy storage solution.[17] Table 14 shows the minimum capacity and energy build-out requirements, assuming either a single ESS or multiple ESS that are aggregated, to meet the need on an annual basis. Locating ESS in Manby West will not only serve both the identified regional need but will also contribute to provincial resource adequacy. Note that for the ESS to address the Manby West autotransformer need, they would need connect to the transmission system via any combination of K13J, K14J, H2JK, or K6J circuits or the Manby 115 kV bus. The ESS can also be connected to the distribution system if they eventually connect downstream of:

- Strachan TS
- John TS
- Copeland MTS (T1/T3 only[18])

Table 14 | Requirements for ESS to meet Manby West Autotransformer Need

Year	ESS Incremental Capacity Requirements (MW)	ESS Incremental Energy Storage Requirements (MWh)
2029	5	20
2030	6	35
2031	6	44
2032	9	75
2033	16	162
2034	-	-
2035	-	-
2036	-	-
2037	7	70
2038	9	95
2039	8	70
2040	6	60
Total	**72**	**631**

[17] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.
[18] Assuming Copeland MTS T2/T4 is permanently transferred to Leaside supply.

This local ESS is expected to have a net system cost of $0 to $30 million, which accounts for the broader system benefit it enables through a reduction in overall provincial capacity needs. The combination of addressing local and provincial needs, along with using less land and having a shorter lead-time than other NWAs, make this option an attractive one for the Manby West Autotransformer need.

7.6.1.6 Recommendation to Address Manby West Autotransformer Needs

The Technical Working Group recommends the following integrated set of options to address the Manby autotransformer need:

- Continued reliance on Manby RAS
- Permanent transfer of Copeland MTS T2/T4 to Leaside Supply
- Incremental eDSM
- Energy Storage Systems

The above options are recommended as they take advantage of the existing transmission system's transfer and operational capabilities (e.g., reliance on existing Manby RAS and permanent transfer of Copeland MTS T2/T4). The permanent transfer of Copeland MTS T2/T4 will need to be in place by 2026 to address the supply capacity needs in the Manby to Riverside Junction circuits prior to its upgrade as discussed in Section 7.6.3 below, according to both the reference and high electrification forecasts. Incremental eDSM can be targeted as part of the current eDSM framework.

An ESS (or multiple ESS) capable of meeting the incremental capacity and energy requirements is also recommended to mitigate the risk of load rejection being used. Local ESS connected to the aforementioned stations and circuits can provide local capacity should an autotransformer suffer an outage during a period of high demand.

The IESO and Toronto Hydro will need to collaborate to scope the technical requirements, achievable implementation timelines, and decide on the most suitable procurement approaches. The IESO and Toronto Hydro will ensure the Technical Working Group is kept updated on progress and any challenges through annual Technical Working Group meetings.

Although the Manby Crossover option greatly increases capacity, the short circuit limitations at Manby do not allow it to be recommended at this time. In order to preserve this option for the future, it is recommended that Hydro One determine the scope a detailed short circuit study for the Toronto Region. This study scope should include timelines for completing the studies, with the objective of identifying options that can alleviate transmission short circuit constraints in Toronto, should any exist. Insights from this study will allow this option to be more fulsomely considered in future regional plans.

A summary of the expected costs and lead times for the recommended wires options is provided in Table 15.

Table 15 | Recommended Wires Options to address Manby West Autotransformer Needs

Recommendation	Capital Costs ($M CAD)	Lead Time
Reliance on Manby RAS	N/A	Ongoing
Permanent transfer of Copeland MTS T2/T4 to Leaside Supply	N/A	1 year

7.6.2 Options for Addressing Manby East Autotransformers

7.6.2.1 Wires Options – Reliance on Manby RAS

This option involves continuing to rely on the existing Manby RAS. Upon the loss of any Manby East autotransformer, transferring the Wiltshire T2/T7 DESN to Leaside supply defers the needs past the end of the study period for the high electrification forecast, provided up to 150 MW of load rejection between Runnymede TS, Fairbank TS, and Wiltshire T1/T6 is utilized.

The HVDC Third Supply increases available capacity on the Leaside sector and allows for this solution to be implemented. It should be noted that this option would limit the emergency load transfer of Dufferin TS to Manby supply in an emergency event on the Leaside sector. Further studies, including extreme contingency events and their likelihood can inform whether future actions to enhance emergency load transfer capabilities should be explored.

7.6.2.2 Wires Options – Permanent Load Transfer from Fairbank to Downsview

This option involves transferring from 10 MW to 77 MW of load from Fairbank TS to the new Downsview MTS by 2044 (i.e., the same solution proposed in Section 7.6.4). This action would remove this load from the Manby to Wiltshire circuits as Downsview MTS will connect to circuits in northern Toronto. More details on the new Downsview MTS can be found in Section 7.5.

The Technical Working Group acknowledges that transferring load from a transmitter-owned station to an LDC-owned station when station load is below a station's LTR may incur by-pass compensation as per the Transmission System Code. By-pass compensation, in addition to project costs should be examined when comparing wires options in further detail in the Regional Infrastructure Plan.

7.6.2.3 Non-wires Options – Incremental eDSM

The LAPS identified up to 32 MW of incremental eDSM (and behind-the-meter) potential that can be achieved by 2044 in the Manby East area, specifically at Runnymede TS, Fairbank TS, and Wiltshire TS. These incremental eDSM measures pass system cost effectiveness tests, meaning they provide system benefits outweighing their costs.

7.6.2.4 Non-wires Options – Energy Storage Systems

The hourly profile of this need aligns well with the capabilities of a ESS solution. However, the need only emerges towards the later end of the forecast. The Technical Working Group will continue monitoring this need and update the feasibility of ESS in future regional plans.

7.6.2.5 Recommendation to address Manby East Autotransformer needs

The Technical Working Group recommends the following integrated set of options to address the Manby East autotransformer need:

- Continued reliance on Manby RAS
- Permanent Load Transfer from Fairbank TS to the new Downsview MTS
- Incremental eDSM

The above options are recommended as they take advantage of the existing transmission system's operational capabilities and new recommended transmission infrastructure in Northern Toronto through the reliance on existing Manby RAS and permanent transfer of load to Downsview MTS. Incremental eDSM can be targeted as part of the current eDSM framework. A ESS is not recommended at this time, given that it is only needed towards the end of the forecast. A ESS solution can be considered in future regional plans should the load increase more than currently expected.

A summary of the expected costs and lead times for the recommended wires options is provided in Table 16.

Table 16 | Recommended Wires Options to address Manby East Autotransformer Need

Recommendation	Capital Costs ($M CAD)	Lead Time
Reliance on Manby RAS	N/A	Ongoing
Permanent Load Transfer from Fairbank TS to Downsview MTS	To be developed further in upcoming RIP	Less than 3 years (Requires Downsview MTS to be in-service)

7.6.3 Options for Addressing Manby to Riverside Circuits

7.6.3.1 Wires Option – Reconductoring of K13J and K14J from Manby to Riverside

Hydro One first identified the need to upgrade the Manby to Riverside circuits (specifically K13J and K14J) in the 2022 Toronto Needs Assessment Report.[19] Hydro One is currently developing a transmission solution to increase capacity on K13J and K14J to be at least equal to that found on K6J and H2JK circuits. Furthermore, in Energy for Generations,[20] the Ministry of Energy and Mines confirmed support for Hydro One developing this transmission solution.

[19] Hydro One, Needs Assessment Report: Toronto Region, December 2022, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto_Region_Needs_Assessment_Report_Third_Cycle_Regional_Planning.pdf

[20] Ministry of Energy and Mines, Energy for Generations, July 2025, https://www.ontario.ca/page/energy-generations#section-7

7.6.3.2 Recommendation to address Manby to Riverside Circuits

The Technical Working Group recommends Hydro One continue developing the transmission solution for the Manby to Riverside circuit upgrades in the upcoming RIP. Hydro One estimates that this upgrade will cost $25 million and is expected to be in-service by 2028.

7.6.4 Options for Addressing St Clair to Fairbank Circuits

7.6.4.1 Wires Options – Permanent Load Transfer from Fairbank to Downsview

This option involves transferring between 10 MW and 77 MW of load (reference and high electrification forecasts, respectively) from Fairbank TS to the new Downsview MTS by 2044. This also reduces the loading on the Manby East autotransformers as Downsview MTS will connect to circuits in northern Toronto. More details on the new Downsview MTS can be found in Section 7.5. Transfers should begin by 2036 (i.e., when Fairbank TS demand reaches 179 MW) to respect the current limits of the K1W and K3W circuits.

The Technical Working Group acknowledges that transferring load from a transmitter-owned station to an LDC-owned station when station load is below a station's LTR may incur by-pass compensation as per the Transmission System Code. By-pass compensation, in addition to project costs should be examined when comparing wires options in further detail in the Regional Infrastructure Plan.

7.6.4.2 Recommendation to address St Clair to Fairbank Circuits

The Technical Working Group recommends implementing the load transfer from Fairbank TS to Downsview MTS to alleviate constraints on the St Clair to Fairbank TS circuits. Transfers should be completed by 2036 to respect limits of the K1W and K3W circuits (transfers would need to begin by 2031 to respect the high electrification forecasts).

This cost of this recommended action is included in the Downsview MTS development cost detailed in Section 7.5.2.1. The action is expected to have a lead time of less than three years and requires Downsview MTS to be in-service.

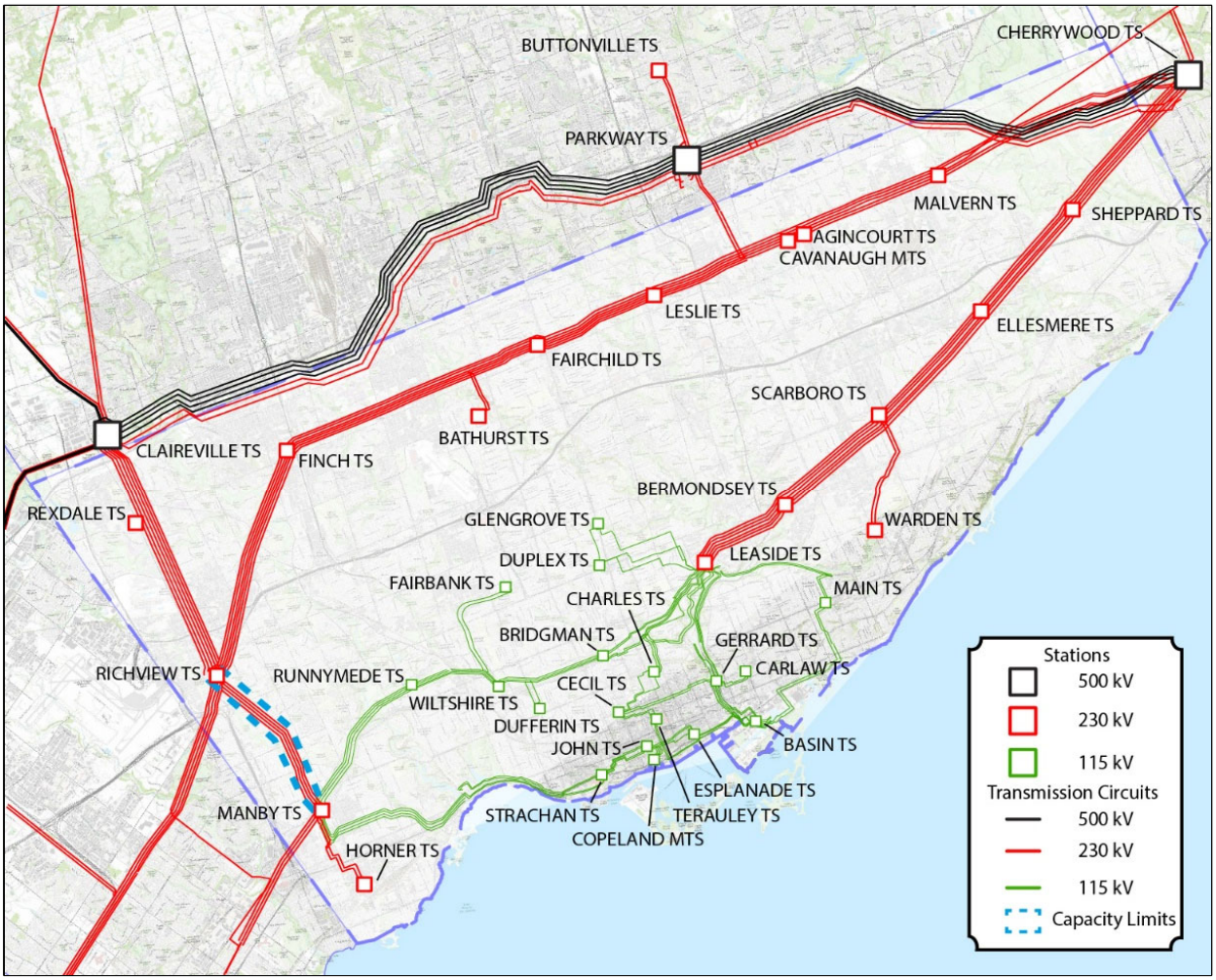
7.6.5 Options for Addressing Richview to Manby Circuits

The Richview to Manby 230 kV circuits supply the western portion of downtown Toronto, Etobicoke, and southern Mississauga (which is part of the GTA West region), as shown in Figure 13. The forecast for the GTA West region, released in May 2025, shows significant load growth especially in southern Mississauga, which will further strain the Richview to Manby circuits. The South and Central Bulk Study is considering wires solutions to meet the needs of both GTA West and Toronto regions. One such solution undergoing evaluation in the South and Central Bulk Study is a 230 kV double circuit line from Trafalgar TS to Oakville TS. This solution will be further explored in the GTA West IRRP where the forecast growth in both GTA West and Toronto regions will be considered. From 2032 in the reference forecast more than 150 MW of load will be required to be shed post contingency to return the loading to below the LTE rating which is a violation of the ORTAC.

Therefore, the Technical Working Group recommends further evaluation of the Trafalgar TS to Oakville TS option continue as part of the South and Central Bulk Study and the GTA West IRRP. The

South and Central Bulk Study and GTA West IRRP expect to publish their findings by Q1 2026 and mid-to-late 2026, respectively.

Figure 13 | Richview to Manby Circuits



7.6.6 Options for Addressing Station Capacity Needs in Western Toronto

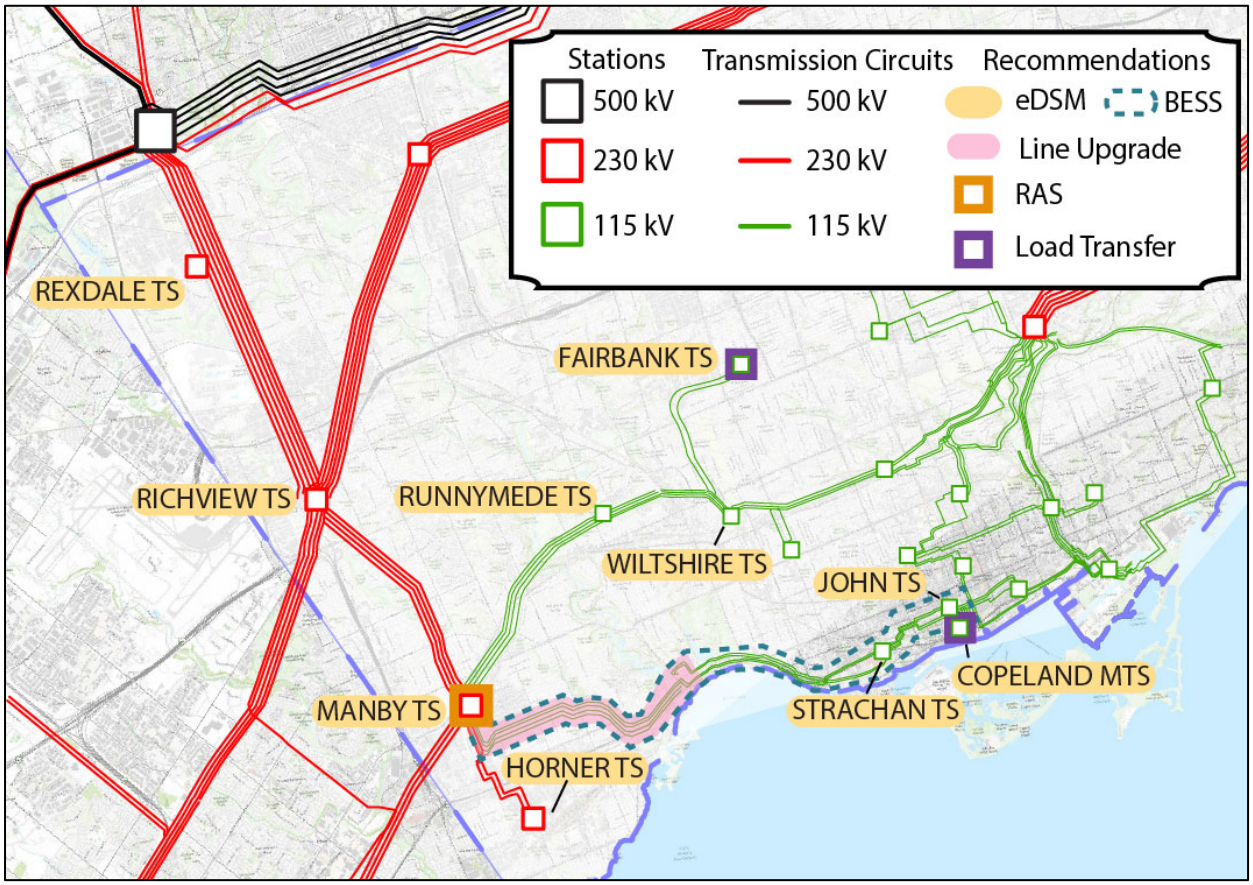
Three stations supplying West Toronto are expected to exceed their station capacity, namely Fairbank TS, Strachan TS, and the Manby DESN. The options identified in the preceding sections will also alleviate the needs at Fairbank TS and Strachan TS. For Fairbank TS, transferring up to 77 MW of load to Downsview MTS to address supply capacity needs will also eliminate the capacity need at the station. Similarly, estimated incremental eDSM at Strachan TS of up to 19 MW by 2040 can defer station capacity needs to the latter part of the forecast. Therefore, the Strachan station capacity need can be further reviewed in the next regional planning cycle.

The needs at Manby DESN occur towards the end of the forecast period, following the asset renewal replacement of the transformers. Since the need isn't expected to occur until 2042 or 2037 under the reference and high electrification forecasts respectively, the Technical Working Group recommends this need be monitored in future regional planning cycles.

This cost of this recommended action is to be developed further in the upcoming Regional Infrastructure Plan. The action is expected to have a lead time of less than three years and requires Downsview MTS to be in-service.

Figure 14 shows the location/connection points of the recommended solutions in Western Toronto

Figure 14 | Recommended Options for Western Toronto



7.7 Options and Recommendations for Eastern Toronto Needs

7.7.1 Options for Addressing Leaside to Bridgman to Dufferin Circuits

7.7.1.1 Wires Option – Increase transmission capacity to Dufferin TS

This option involves upgrading 1.3 km of underground circuits between Dufferin TS and the Bartlett/Dufferin Junctions to a higher capacity (similar ratings to the new C5E and C7E circuits between Terauley TS and Esplanade TS). This option allows for Dufferin TS to be loaded to its station limit (180 MW in summer and 203 MW in winter), as it is currently limited to 135 MW by the transmission supply into Dufferin TS.

7.7.1.2 Wires Option – Permanently transfer Dufferin TS load to expanded Wiltshire TS

This option involves upsizing the T1/T6 transformers at Wiltshire TS to add an additional 62 MW of capacity. This will then allow up to 62 MW of load to be transferred from Dufferin TS to Wiltshire TS. Note that this requires the load transfers from Manby East to Northern Toronto as detailed in Section 7.6.4 to be feasible.

While an upgrade at Wiltshire TS provides the station capacity needed to enable significant load transfers, there are physical limitations based on available underground space in the road allowance and other geographical constraints between the two stations. These limitations make it challenging and expensive to transfer large amounts of load between the stations and will limit how much load can ultimately be transferred.

7.7.1.3 Wires Option – Resolve transmission limits on all lines supplying Dufferin TS

This option involves increasing transmission capacity to Dufferin TS (as seen in Section 7.7.1.1) and from Leaside TS to Bartlett JCT. This will require rebuilding overhead lines including 1.7 km from Leaside TS to Bayview JCT, 2.2 km from Bayview JCT to Birch JCT, and 1.4 km from Birch JCT to Bridgman TS. In addition, a 2.2 km underground section between Bayview JCT to Birch JCT will need to be upgraded.

7.7.1.4 Non-wires Options – Incremental eDSM

The LAPS identified up to 36 MW of incremental eDSM (and behind-the-meter) potential that can be achieved by 2044 in the Leaside to Bridgman to Dufferin area, specifically at Dufferin TS and Bridgman TS. These incremental eDSM activities pass system cost effectiveness tests, meaning they provide system benefits outweighing their cost.

7.7.1.5 Non-wires Options – Energy Storage Systems

The hourly profile of this need aligns well with the capabilities of an energy storage solution[21]. Table 17 shows the minimum capacity and energy build-out requirements, assuming either a single ESS or multiple ESS that are aggregated, to meet the need on an annual basis. Although the ESS will be

[21] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

locally connected, it would serve both the identified regional need and also contribute to provincial resource adequacy. The ESS can be connected to the distribution system or to the transmission system at one of the following locations:

- Dufferin TS (preferred location)
- L13W and L18W (from Dufferin TS to Barlett JCT, must connect to both circuits)

The buildout up to (and including) 2041 meets the need until 2043.

Table 17 | Requirements for ESS to meet Leaside to Bridgman to Dufferin Need

Year	ESS Incremental Capacity Requirements (MW)	ESS Incremental Energy Storage Requirements (MWh)
2037	2	12
2038	4	40
2039	4	37
2040	7	69
2041	24	243
Total	**41**	**401**

This local ESS is expected to have a net system cost of up to $18 million, which accounts for the broader system benefit it enables through a reduction in overall provincial capacity needs. The combination of addressing local and provincial needs, along with using less land, make this option an attractive one for the Leaside to Bridgman to Dufferin need.

7.7.1.6 Recommendation for Leaside to Bridgman to Dufferin Circuits

The Technical Working Group recommends the following options to address the Leaside to Bridgman to Dufferin need:

- Increase transmission capacity to Dufferin TS
- Transfer of Dufferin TS load to upgraded Wiltshire TS
- Energy Storage Systems[22]

To address the upstream supply needs for Dufferin TS the IRRP recommends the cables supplying Dufferin TS be upgraded to fully utilize the capacity available at Dufferin TS. The ratings on the new cables should have similar ratings to the new C5E and C7E cables between Terauley TS and Esplanade TS. Demand in excess of the Dufferin TS station limit can then be transferred to an upgraded Wiltshire TS. These recommendations will be further studied in the upcoming RIP.

A ESS solution capable of meeting the incremental capacity and energy requirements is also recommended to alleviate upstream supply issues (from Leaside TS to Bridgman TS). Given the lead time available for the ESS to be in place, several procurement mechanisms (including future iterations of the IESO's Long-Term procurement) can be used to address both local and provincial

[22] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

supply constraints. The preferred location for ESS, either a large system or multiple smaller systems that are aggregated, is at or downstream (i.e., distribution-connected) from Dufferin TS.

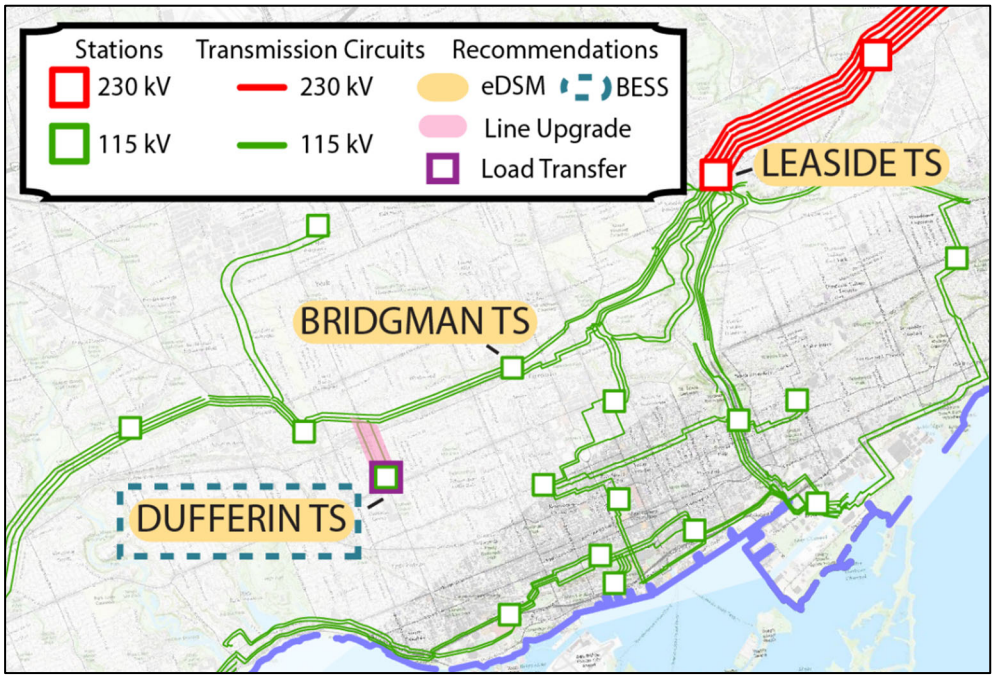
The IESO and Toronto Hydro will need to collaborate to scope the technical requirements, achievable implementation timelines, and decide on the most suitable procurement approaches. The IESO and Toronto Hydro will ensure the Technical Working Group is kept updated on progress and any challenges through annual Technical Working Group meetings.

A summary of the expected costs and lead times for the recommended wires options is provided in Table 18 below.

Table 18 | Recommended Wires Options to address Leaside to Bridgman to Dufferin Circuits

Recommendation	Capital Costs ($M CAD)	Lead Time
Increase transmission capacity to Dufferin TS	33	7 years
Transfer Dufferin TS load to upgraded Wiltshire TS	60	5 years

Figure 15 | Recommended Options for Leaside to Bridgman to Dufferin Area



7.7.2 Options for Addressing Leaside to Bloor to Hearn Circuits

7.7.2.1 Wires Option – Address End-of-Life on circuits from Leaside TS to Bloor JCT

Hydro One identified that the Leaside TS to Bloor JCT sections of the H1L and H3L 115 kV circuits will require asset renewal in the near-term. The IRRP analysis also identified capacity needs on the same sections of the line by 2036. This option is to renew this section of this line, bringing it up to a modern standard and providing an opportunity to increase the capacity limit of the lines.

7.7.2.2 Wires Option – Increase transmission capacity on circuits from Hearn SS to Basin TS

The need on the H1L and H3L circuits from Hearn SS to Basin TS is expected to coincide with the load growth at Basin TS from the expected Port Lands development (2041 and 2037 for reference and high electrification forecasts, respectively). This option involves reconductoring a short span of this 115 kV line (0.5 km) with higher capacity conductors with ratings equal or higher than the new Manby TS to Riverside JCT portion of K13J and K14J.

7.7.2.3 Non-wires Options – Incremental eDSM

The LAPS identified up to 16 MW of incremental eDSM potential that can be achieved by 2044 in the Leaside to Basin to Hearn area, specifically at Carlaw TS, Gerrard TS, and Basin TS. These incremental eDSM measures pass system cost effectiveness tests, meaning they provide both local and provincial system benefits.

7.7.2.4 Recommendation for Leaside to Bloor to Hearn Circuits

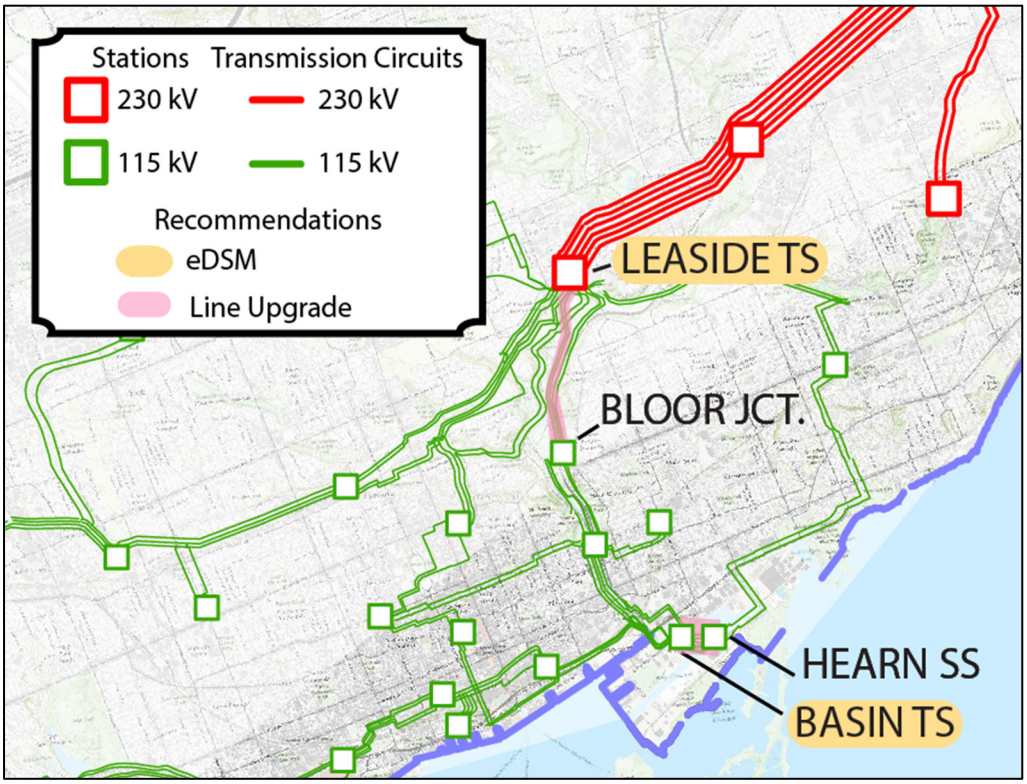
The Technical Working Group recommends that the following options be implemented to address the Leaside to Bloor to Hearn need:

- Increase transmission capacity on H1L and H3L circuits from Leaside TS to Bloor JCT and from Hearn SS to Basin TS.
- Incremental eDSM.

Due to the short span of the Hearn to Basin section (0.5 km) and the end-of-life needs on the Leaside to Bloor circuits, it is recommended that Hydro One investigate reconductoring the aforementioned sections with conductors having ampacity ratings equal to or higher than the new Manby TS to Riverside JCT portion of K13J and K14J. This upgrade will also enable more transfer of power from the Hearn SS and the recommended HVDC Third Supply. Incremental eDSM can help reduce the loading on the circuits, should any delays occur in the replacement of the circuit sections. The locations of transmission facilities from Leaside TS to Bloor, and Hearn SS to Basin TS, are shown in Figure 16.

This recommended wires-option is expected to cost approximately $25 Million and is expected to have a lead time of seven years.

Figure 16 | Recommended Options for Leaside to Bloor to Hearn Area



7.7.3 Options for Addressing Station Capacity Needs in Eastern Toronto

7.7.3.1 Scarboro TS, Warden TS, and Sheppard TS

The needs at Scarboro TS, Warden TS, and Sheppard TS are driven by local growth, specifically the Golden Mile Secondary Plan. As this Secondary Plan involves brand new communities, new transmission and distribution infrastructure will be needed to supply them. In their most recent rates application, Toronto Hydro proposed an additional DESN at Scarboro TS to increase capacity to the area to meet the demand growth from the Golden Mile Secondary Plan. This proposal has been accepted by the OEB.

The new DESN at Scarboro TS would also offload Warden and Sheppard TS, thereby ensuring these stations do not exceed their capacity limits. Over the long-term, a station capacity need at Sheppard TS may still arise. Toronto Hydro has proposed utilizing an unused winding at Sheppard TS to address long-term needs which will continue to be monitored. This recommended action is expected to cost $60 Million and is expected to have a lead time of seven years.

7.7.3.2 Glengrove TS

The need at Glengrove TS occurs in 2042 for the reference forecast and can come up as soon as 2035 in the high electrification scenario. Toronto Hydro identified that there may be opportunity to transfer load from Glengrove TS to Duplex TS. There is also limited opportunity for incremental eDSM (up to 4 MW by 2040) to meaningfully delay any upgrades.

Therefore, the Technical Working Group recommends that Toronto Hydro and Hydro One investigate the feasibility of load transfers from Glengrove TS to Duplex TS in the upcoming RIP. The Technical

Working Group will also continue to monitor load growth at Glengrove TS in upcoming cycles of regional planning.

7.7.3.3 Dufferin TS

The need at Dufferin TS occurs in 2040 for the reference forecast and can come up as soon as 2033 in the high electrification scenario. There is an opportunity to concurrently address station and supply capacity needs by placing the recommended ESS at Dufferin TS. This can defer the need at Dufferin TS to the end of the forecast period. There is some incremental eDSM potential at Dufferin TS (up to 7 MW by 2040) which can further alleviate station capacity needs in the area.

Therefore, the Technical Working Group reiterates the recommendation for the ESS to be connected to Dufferin TS. The Technical Working Group will also continue to monitor load growth at Dufferin TS in upcoming cycles of regional planning.

7.7.3.4 Basin TS

The need at Basin TS is heavily tied to the expected new development at the Port Lands, specifically the developments at Ookwemin Minising and McCleary Districts. The Technical Working Group received a study from the City of Toronto that details the load growth and potential for district energy systems to play an important role in meeting the area's energy needs. The study shows that district energy can potentially reduce the summer and winter peak demands. Despite this predicted demand reduction, a new station or expanded Basin TS will still be needed to supply new community growth and development in the area.

Therefore, the Technical Working Group recommends Hydro One investigate the feasibility of either expanding Basin TS or adding a new station in the area. With the input of the Technical Working Group, this station should be right-sized to meet the future needs of Basin TS after accounting for the impacts of the planned district energy system in the Port Lands, as well as updated information about the timing and magnitude of development. The City of Toronto will need to continue working closely with Toronto Hydro and Hydro One to finalize the site for a new or expanded Basin TS.

7.8 New Supply Options for Eastern Toronto

7.8.1 Need for Transmission Reinforcement

This need for transmission reinforcement was confirmed by assessing a suite of non-wires alternatives compared to the transmission option. Capacity needs were assessed on an hourly basis for the 20-year IRRP planning horizon and further modeled using an energy production simulation. This approach was taken to understand the timing, magnitude, and duration of peak demands on the existing system, and the total energy requirements to ensure local area reliability. Relying solely on locally sited renewable resources, both standalone and paired with energy storage, as well as a large standalone energy storage system (assumed to be ESS technology), was found to be not feasible to address the total energy need in East Toronto. A significant amount of land area would be required to site these resources at the scale needed to match the size of the need in eastern Toronto.

Other technically feasible local resource options such as utility-scale gas generation and small modular reactors (in combination with ESS) were ruled out due to community preferences and siting

challenges. Gas generation would be especially misaligned with the policy position from Toronto City Council. Similarly, incremental eDSM and DERs also cannot fully address the required need. However, both eDSM and DERs can help manage peak demand and, over time, reduce the size of the system need that must be met by other solutions. While these incremental measures could provide some local benefit while a transmission solution is being implemented, findings from the LAPS indicate the achievable potential of these local resources.[23]

While the PEC out-of-service scenario would drive an earlier need date, transmission reinforcement is still required by 2037 to address the capacity need forecasted to emerge in 2038.

Both during the IRRP development and in past transmission plans and studies, the IESO found that due to the built-up nature of the City of Toronto, options for siting new transmission facilities (both lines and stations) are extremely limited. The three possible transmission options studied for the IRRP reflects these limitations. These three options were developed with the objectives of being able to address the local capacity need, while reducing future reliance on PEC for local reliability.

All three options originate from east of the city. They either utilize existing transmission rights-of-way or utilize new paths that minimally impact existing land-uses.

7.8.2 Current Supply Constraints and Future Demand

Downtown Toronto is currently supplied by two transmission corridors: one from the west via Manby TS and one from the east via Leaside TS. A third transmission supply would support future growth and maintain system reliability in the downtown core. This provides an opportunity to address both resilience and capacity needs with a singular solution and was used as one of the considerations when choosing the recommended option for the third transmission line.

7.8.3 Overland Option: Expand 230 kV Leaside TS and New Supply from Cherrywood TS

This option involves expanding the Leaside TS by adding three new 230/115 kV autotransformers at Leaside TS, to complement the existing six, adding six new inline 230 kV circuit breakers between Cherrywood TS and Leaside TS and rebuilding a presently idled overhead transmission line between Cherrywood TS and Leaside TS. There is an idle transmission line along most of the 26 km distance between these two stations. A portion of this line is currently being used by Toronto Hydro for distribution.

This option requires Hydro One to expand the existing Leaside TS by redeveloping adjacent lands available to them starting in 2030,[24] and to rebuild and/or reconductor the existing transmission line structures between Cherrywood TS and Leaside TS. Most of this right-of-way is adjacent to homes, and it transects the Rouge National Urban Park. Some work to re-terminate the existing 230 kV circuits may be required to make this option feasible, as well as upgrades to portions of the 115 kV

[23] Small-scale behind-the-meter resources are not the only tools available for the IESO and Toronto Hydro to manage local demand and maintain local reliability. Larger, front-of-the-meter (FTM) generation resources can participate in ongoing and future IESO procurements; and the IESO is developing a Local Generation Program targeting smaller-scale FTM resources. There are also mitigation measures available in the operational timeframe, such as new and expanded Remedial Action Schemes, to manage a range of reliability risks. These types of measures are often deployed as interim measures while grid reinforcements are being planned or implemented.

[24] Pers. Comm. From Hydro One to the Technical Working Group.

transmission system between Leaside TS and Hearn SS. These 115 kV lines are aging, and upgrade work could be timed to coincide with the work needed to refurbish these facilities at their end-of-life.

7.8.4 Overland and Underground Option: Build a New 230 kV Transformer Station Downtown Supplied from Cherrywood TS

This option involves adding two 230/115 kV autotransformers at Hearn SS and building a double circuit 230 kV line between Cherrywood TS and Hearn SS by rebuilding about two-thirds of the existing idle line between Cherrywood TS and Scarboro TS. This option also requires reinforcing or expanding the existing overhead 230 kV transmission line from Scarboro TS to Warden TS, extending a new 230 kV line from Warden TS a further 3 km to Lumsden Junction, and finally constructing new underground 230 kV cables approximately 9 km to Hearn SS in the Port Lands. This option will require additional inline breakers on the Cherrywood TS to Leaside TS circuits, between Scarboro TS and Leaside TS, and additional 230 kV reconfiguration work between Scarboro TS and Warden TS to re-terminate existing circuits. This option would also allow the retirement of approximately 7 km of 115 kV cable sections of H7L and H11L between Hearn SS and Main TS.

7.8.5 Underwater Option: New HVDC Transmission Supplying Downtown from the East

The third option considered is a new high-voltage direct current (HVDC) link into the Port Lands in downtown Toronto from the bulk transmission network east of Toronto. Two potential points of origin were considered for this option where there is existing transmission infrastructure with available capacity east of Toronto near the Lake Ontario shoreline (Bowmanville SS and Pickering). Both high voltage alternating current (AC) and HVDC technologies were considered in the analysis.

Bowmanville SS was selected as the preferred point of origin because injecting bulk supply into Toronto from this location delivers additional benefits for the bulk network by bypassing Cherrywood TS altogether and freeing up additional capacity at the station to supply growth elsewhere in the Greater Toronto Area (GTA). HVDC technology was chosen over AC because it offers additional benefits and ancillary services, and becomes more cost-effective than AC for submarine cable lengths greater than approximately 50 km. The IESO has carried out a preliminary land review and assessed there is undeveloped land available to accommodate HVDC converter stations near the Bowmanville SS and the Hearn SS.

This HVDC Option involves installing approximately 65 km of submarine HVDC cables underneath Lake Ontario. Horizontal directional drilling is a common approach to make the transition from land to water while minimizing surface and sediment disruption. Voltage-source converter (VSC) stations, a key component to HVDC transmission, are a mature technology that continues to improve in key areas such as losses and compactness of the station footprint. A VSC station would need to be sited and constructed at each terminal end. Some additional work on the 115 kV system in the Port Lands in Toronto will be required to accommodate a higher power injection as compared to the injection through PEC, and inline breakers will need to be added to the Cherrywood TS to Leaside TS 230 kV transmission circuits to add further resiliency to the current supply to East Toronto.

7.9 Third Supply Options Analysis

To arrive at a recommendation, the IESO received information from the IRRP Technical Working Group, including exploratory cost estimates and preliminary project scope information for the overland and overland and underground transmission options. The IESO consulted with the transmission development community to obtain additional information for submarine HVDC technologies. These discussions focused on underwater HVDC facilities built in the last ten to 15 years and covered technical aspects of project planning, construction, operation and maintenance, environmental challenges and project economics. This research, extensive engagement, and the IESO's system studies have informed the detailed evaluation of the three transmission options summarized in this section.

The planning considerations factored into the assessment of the transmission options are introduced below, and each is summarized in the sub-sections that follow.

- **Reliability performance –** Ability to supply Toronto's future demand in accordance with the established reliability criteria for electric power systems, without reliance on PEC.
- **System resilience** – Impact on the power system's ability to withstand or recover from major events such as a loss of Manby TS or Leaside TS, and the flexibility to support a range of possible futures.
- **Bulk power system impact –** Benefits for the upstream bulk transmission network.
- **Implementation complexity –** Impacts on land-use and ability to manage potential risks throughout development and implementation of the option.
- **Cost-effectiveness for ratepayers –** cost effectiveness of the option in providing power reliably and safely to consumers.

7.9.1 Reliability Performance

7.9.1.1 Load Meeting Capability

The performance of each transmission option was studied in terms of its ability to supply Toronto's forecasted electrical demand. Each option provides a substantial increase in load meeting capability in Toronto and can meet the identified supply capacity needs.

The HVDC Option was shown to provide the largest increase to the system's load meeting capability. With the inclusion of incremental eDSM and/or local DERs, an integrated solution comprising the HVDC line and additional local measures can also meet needs driven by the high electrification forecast. In addition to offloading the transformers at Leaside TS, a capacity injection at Hearn SS would also offload the transmission system further upstream including the transformers at Cherrywood TS.

By comparison, the Leaside TS expansion option provides enough incremental new capacity to defer these system needs to 2042; and the combined overhead and underground option to the Port Lands can defer these system needs to 2044 under the reference case forecast. These options would require additional eDSM and/or DERs to meet these needs further into the future and additional transmission reinforcement would be required sooner to equal the additional load meeting capability of the HVDC Option.

7.9.1.2 Ancillary Services – Voltage Control

The VSC station technology that accompanies the implementation of an HVDC transmission line can provide specific reliability benefits through dynamic reactive power, providing voltage control and maintaining energy flows independent of power system conditions. Voltage control is critical in reducing risk of voltage collapse that could result in blackouts on a local or system-wide level. Specifically, in this case, the location of a VSC station near the Hearn SS is expected to provide reactive power support where it is needed within the load centre, and near Bowmanville SS, close to the Darlington Nuclear complex. This benefit is expected be quantified in further studies of the option as part of the detailed design process. Even if the underwater cable portion is out of service, the VSC stations can operate in STATCOM mode to continue to regulate voltage and support grid stability.

Reducing reliance on PEC also means losing the voltage support capabilities currently provided by the facility. HVDC with VSC technology can provide this voltage support. Neither of the AC options can provide this service.

7.9.2 System Resilience Benefits

7.9.2.1 Supply Diversity

The theme of resilience has consistently been raised by stakeholders as an objective of electricity planning. This reflects local concerns about climate change, aging infrastructure, and the impact of major events like the loss of Manby TS supply due to flooding that occurred in July 2024 and previously in July 2013. The three transmission options were reviewed in terms of their ability to deliver improved system resilience. While system resilience itself is not easily measured, incremental improvement to resilience is partly a function of the diversity of supply to an area, and the degree to which the different sources of supply can support each other during system outages.

The root of this issue is the reliance of Toronto's dense urban centre on two radial 230 kV transmission paths, Manby TS and Leaside TS, each with limited ability to back up the other. Leaside TS is reliant on a single radial 230 kV supply path from Cherrywood TS. A loss of Leaside TS can interrupt supply to half of the central 115 kV system, and a loss of Cherrywood TS can interrupt supply to this area plus a large part of the remaining eastern half of the city including East York and a significant portion of Scarborough.

The HVDC Option would bring a new, geographically and electrically separated source of supply directly into the urban centre. It has the capacity to replace PEC as a local source of supply, while adding redundancy in the event of transmission outages. Major events such as the 2024 flooding event at Manby TS that disconnected about 900 MW of load, and the similar 2013 event that disconnected about 3,800 MW of load impacted hundreds of thousands of customers. Toronto has experienced at least three 1-in-100-year rainfall events since 2005, and, due to the aging network and increasing frequency of extreme weather, both planned maintenance and the likelihood of unplanned outages are expected to increase into the future. If an event of a similar magnitude to the two Manby TS outages interrupted supply from Leaside TS for an eight-hour period, the economic consequences could be in the order of $400 million.[25]

[25] Based on an assumed load interruption of 900 MW for an eight-hour period, using a Value of Lost Load calculator recommended in the Ontario Energy Board's Vulnerability Assessment & System Hardening Report.

A new diversified supply source can provide better continuity of supply and better load restoration capability in East Toronto during and/or after major events, should one impact supply from Leaside TS or Cherrywood TS. Additionally, with minimal upgrades to the 115 kV system connecting the Manby TS (western) and Leaside TS (eastern) sectors, the supply to a large portion of the financial district in Downtown Toronto could be transferred to the new third supply source. This would extend the reliability benefits from East Toronto into the western Toronto Manby TS sector. These benefits include reducing the loading on Manby TS, and potentially deferring other future system upgrades needed to ensure reliability.

Lastly, as the HVDC cables would be submerged, they will be more immune to the effects of extreme weather compared to overhead transmission.

The Leaside TS expansion option does not provide the same level of system resilience benefit that a true third point of supply to the downtown can provide. Like the HVDC Option, with additional 115 kV system reinforcements, an expanded Leaside TS could facilitate increased load transfers from Leaside TS to Manby TS and provide some co-benefits for the Manby TS sector. The combined overhead and underground option to the Port Lands also provides some of the same benefits for reliability and system resilience. However, this option results in the East Toronto supply remaining reliant on supply from Cherrywood TS, and potentially vulnerable to major events impacting Cherrywood TS and multi-element contingencies impacting the Cherrywood TS to Leaside TS transmission corridor.

7.9.2.2 Operational Flexibility

The power flows across HVDC transmission systems are highly controllable, as the technology allows grid operators to dial the flow up or down, in either direction, across the line independent from the interconnected AC grid. This operational flexibility is beneficial under normal operation as demand in Toronto fluctuates through the day, as well as during periods of maintenance and/or outages on other parts of the local 115 kV transmission system.

Neither of the AC transmission options allows for comparable level of controllability, and therefore neither option provides system operators an equivalent level of real-time operational flexibility. In addition, because of this bi-directional control, the HVDC Option provides flexibility over a longer timeframe, making it compatible with a range of possible futures. For example, functioning as a transmission infeed to the city, the line benefits a future Toronto in which the city remains at a supply deficit and maintains a strong reliance on the interconnected grid for local electricity supply. Conversely, if a long-term future scenario unfolds with high penetration of local DERs (including storage), the flows across the HVDC line could be reversed to export power to the provincial grid.

HVDC technology contributes very little to fault current levels on the surrounding AC transmission system.[26] High fault current levels have been a limiting factor on the amount of DERs that can be integrated into Toronto's legacy 115 kV system, and while actions have been undertaken over many years to increase equipment ratings, this issue persists today. As HVDC lines and converter stations contribute very little fault current compared to AC transmission and synchronous generators (such as

[26] "Fault current" refers to extremely high magnitude of current that flows through a circuit during a fault, such as a short circuit or a line to ground fault. These fault currents can be significantly higher than the normal operating current of the system, and must be managed within the capabilities of the equipment to avoid causing severe damage to equipment and disrupting power supply.

PEC), the HVDC Option can contribute to alleviating technical barriers to higher DER penetration rates in the City of Toronto. These benefits will be evaluated through subsequent planning and short circuit studies and through preliminary project scoping and development.

7.9.2.3 Ancillary Services – Black-start Capability

Black start refers to the process of re-energizing a power system following a full or partial outage event without requiring additional power from the grid. In the case of a high impact, low probability event (e.g., complete loss of Leaside supply), power can be restored to the city through the HVDC cable. It therefore can play a critical part in improving restoration times in the event of a loss of supply from other sources.

Neither of the AC options can provide this service, and this is not a service that PEC currently provides. For the HVDC Option to provide this service, it would need to be intentionally scoped into the project design and built into the cost.

7.9.3 Bulk Power System Impact

7.9.3.1 Benefit to Cherrywood TS and 500 kV Network

Only the HVDC Option that originates to the east of Toronto can provide benefits to the bulk power system in addition to the Toronto local area. Cherrywood TS is the main bulk point of supply into the Eastern Toronto system, and it also acts as a critical bulk supply hub interconnecting Pickering Nuclear Generation and linking the GTA to Eastern Ontario. It is already one of the most heavily loaded bulk stations in the GTA. As the HVDC Option would bypass Cherrywood TS by providing a new path into the downtown core, it can reduce bulk congestion and defer the forecasted need to increase transformation capacity at the station. It may also defer or avoid the need for new 500 kV transmission from Cherrywood TS to Parkway TS in addition to additional 500 kV transformation capacity. This frees up the existing bulk transmission assets to supply additional load growth not only in Toronto but also in the Regions of Durham and York and surrounding areas. And by alleviating congestion on the bulk system east of Toronto, the new supply path into the load centre can also allow more generation to connect in the east, which is currently limited due to limitations on the current transmission interface governing power flows from east to west in the GTA.

The full scope of these bulk system benefits is being assessed as part of the South and Central Bulk Study and will continue to be assessed in subsequent bulk studies. If a 500 kV station and/or new 500 kV lines can be avoided, the ratepayer savings could be in the order of $100 million to $300 million or more (this preliminary estimate will be refined in subsequent studies). Neither of the AC options can provide similar benefits to the broader provincial bulk transmission network outside of the Toronto local area.

7.9.4 Implementation Complexity

7.9.4.1 Land-use Impacts

As the HVDC Option is expected to be built under Lake Ontario, with HVDC converter stations enclosed in buildings sited on presently vacant land and/or former industrial sites, it has the least land-use impact among the three options. All options will require a similar amount of land area for

stations. The IESO learned through engaging with HVDC transmission system owner-operators that horizontal directional drilling is a common method of making the land-water transition, which would have no surface impact beyond the construction phase. As compared to the AC options, less coordination to navigate through built-up areas would be required during construction and for routine maintenance or repair. Horizontal directional drilling, as an alternative to trenching methods, can avoid disturbing contaminated near-shore sediments in Toronto's inner harbour and is a method that has been successfully used in Lake Ontario.[27]

Both AC options would require construction through heavily built-up urban areas and would disturb existing secondary uses (e.g., community gardens, recreation, active transportation corridors). A significant amount of effort and investment has been made in the Meadoway project on portions of the existing Gatineau transmission corridor from Cherrywood TS. This corridor also crosses the Rouge National Urban Park. Delays may occur to manage the reconfiguration and outages of multiple key circuits supplying East Toronto as would be expected for any construction within the existing Cherrywood TS to Leaside TS corridor.

7.9.4.2 Project Development Challenges

The underwater HVDC transmission line would be the first of its kind in Ontario. There will be challenges associated with the novelty of the technology and its application as an underwater cable. Key project development steps including environmental and regulatory approvals and permitting, including provincial and federal environmental assessments. Environmental assessments may be coordinated so that a single environmental assessment meets the legal requirements of both jurisdictions.[28]

Through engagements, the IESO learned that there is a wealth of worldwide experience building similar projects and interest in developing transmission systems in Ontario. HVDC technology is the most common means of interconnecting offshore wind projects to the electricity grid and for building interties between jurisdictions over various distances up to hundreds of kilometers apart. Several similar projects are in the presently under construction worldwide. The IESO is confident, based on this growing volume of experience planning and executing similar projects, that implementation challenges can be effectively managed.

HVDC technology is currently in high demand, and there are a limited number of original equipment manufacturers (OEMs) that are commercially producing cables and VSC station components. The IESO learned that there are factory production queues for equipment, and due to bespoke nature of HVDC technology solutions, it is advantageous for developers to secure their slots in the production queue as early as possible. Once in a queue, production timelines can be three to four years (current estimate, as of August 2025), during which time the developer can continue to proceed with obtaining the various approvals and permits. For Toronto's third supply, there is time to meet the in-service date as long as implementation, concurrent with further community engagement and project scoping, continues without significant delay following the IRRP publication.

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[27] For example, the pipe connecting to Hydrostor's compressed air energy storage pilot was installed by directionally drilling approximately 1 km into Lake Ontario at depths up to 45m deep.

[28] Canadian Environmental Assessment Act, 2012. Requests must be made formally and approved by the federal Minister. Separate provincial and federal decisions are still required for the substituted process.

7.9.5 Cost Effectiveness

7.9.5.1 Cost of the Three Options

All three transmission options are major infrastructure investments, and all are estimated to cost in the order of $1 billion to $1.5 billion. The HVDC Option, based on a combination of sources, is estimated to cost approximately $1.5 billion, with a range of uncertainty equivalent to a Class 5 "exploratory" cost estimate.[29] The final cost will depend largely on the specific technical and design attributes of the project. For example, a bipole line will cost more than a symmetrical monopole line,[30] while offering a higher level of redundancy in the event of a cable fault.

Hydro One provided preliminary cost estimates for the AC alternatives which indicate that these options have a lesser upfront capital cost than the HVDC Option. Hydro One also indicated that these estimates are preliminary and lack defined uncertainty ranges.

As the HVDC and the two AC options have very different performance attributes and deliver different benefits both for Toronto customers and provincial ratepayers, it is not appropriate to select the preferred option based on the initial cost alone. At the same time, many of the additional benefits the HVDC Option provides are challenging to express quantitatively, including the provision of voltage support, operational flexibility, compatibility with a range of uncertain futures, potential for black-start capability, and land-use impacts. The bulk system benefit to ratepayers of the HVDC Option could be several hundred million dollars, which alone brings the cost of HVDC much closer to the other two options. And while extreme weather-related major events are still relatively rare, occurring about once per decade, the resilience benefit of the HVDC Option for reducing the impact and improving restoration following these events is significant. On balance, the IESO is confident the underwater HVDC Option provides positive benefits to ratepayers and the community, relative to the understood costs.

7.9.5.2 Realizing the Value of Long-term Transmission Investments

Over the last 20 years, while making investments in Toronto's 115 kV system, Hydro One has taken advantage of opportunities to upgrade 115 kV transmission equipment to a 230 kV design standard. For example, the John TS to Esplanade TS underground cable, the cable replacements between Riverside Junction and Strachan TS, and the Terauley TS to Esplanade TS underground cable (presently under construction) have all been built to a 230 kV standard. These enabling investments were undertaken to work toward a future operating voltage conversion from 115 kV to 230 kV in parts of the downtown core.

The HVDC Option preserves the optionality to convert parts of the downtown transmission system to 230 kV operation. The combined overland and underground option terminating in the Port Lands would also provides this potential benefit, but the overland option that reinforces the supply via Leaside TS does not.

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[29] Expected accuracy range from a low of -20% to -50% to a high of +30% to +100%. This is an industry standard estimate of the typical low and high ranges based on the maturity level of the project definition. The expected accuracy narrows as the project scope is further defined in the later stages of project development.

[30] HVDC systems can be configured as monopole (one conductor with ground or sea return) or bipole (two conductors, positive and negative). Bipole usually offers better reliability.

7.9.6 Recommended New Supply for Eastern Toronto

The IESO's recommendation for the preferred third transmission option is the underwater HVDC Option. This option addresses the long-term supply capacity need in East Toronto that exists with or without PEC in-service. When interconnected with the bulk transmission network at Bowmanville SS, it also delivers broader bulk system benefits. The HVDC technology provides additional reliability and resilience benefits to Toronto, including:

- Accommodating the highest incremental demand growth among the three options,
- Improved supply diversity and system resilience by introducing a true third supply path into the downtown core,
- Bulk reinforcement, deferral, enables system resources east of Toronto
- Ability to control power flows independent of conditions on the rest of the IESO-controlled grid,
- Additional ancillary services such as voltage control and black-start capability (e.g., ability to restore power following a local blackout), and
- Improved system performance and load restoration following major events beyond the normal planning criteria for the electric power system (e.g., events such as a complete loss of Manby TS[31] or Leaside TS).

The proposed connection points of the HVDC Option are shown for illustrative purposes in Figure 17. The project developer would be responsible for leading the design, undertaking route studies, establishing the route, seeking approvals, and constructing the facilities.

[31] Examples of such events include the July 2013 and July 2024 floods that both led to loss of Manby TS supply.

Figure 17 | Illustrative Map of the Toronto Area Showing the HVDC Option



Table 19 provides a summary of all three options for a new supply to Toronto.

Table 19 | Summary of Three New Supply Options to Toronto

	Option 1: Overhead	Option 2: Overhead + Underground	Option 3: Underwater (Recommended Option)
Estimated Capital Cost	$800 million	$900 million	$1.5 billion
Avoided Bulk System Reinforcements	N/A	N/A	Up to $300 million[32]
Year of Growth Enabled	2042	2044	Beyond 2044 (past the IRRP study timeline)
Load Meeting Capability (MW)	3,350	3,400	>3,400
$/MW Capacity Enabled	$1.5 million[33]	$1.5 million	$1.7 million[34]

[32] Preliminary estimate – the bulk system benefits are being evaluated in the South and Central Bulk Study.
[33] Includes preliminary cost estimate of bulk system reinforcements avoided by the HVDC Option.
[34] Does not consider the value of other local system benefits, including voltage support, black-start capability, or improved system resilience.

	Option 1: Overhead	Option 2: Overhead + Underground	Option 3: Underwater (Recommended Option)
System Resilience	Similar to today: two supply points	Moderate improvement: new supply to downtown, still reliant on Cherrywood TS	Significant improvement: new supply from a separate bulk connection
Other System Benefits	None	None	Local voltage support Relieves Cherrywood TS Enables more generation to connect in eastern Ontario
Other Development Considerations	Proximity to housing Potential conflict with Meadoway secondary land-use on corridor and Rouge National Urban Park	Underground facilities through built-up areas technically challenging; feasibility not certain	Bespoke equipment with production queues Lack of Ontario transmitter experience building HVDC and long underwater systems

7.9.7 Compatibility with Large ESS in the Port Lands

The IESO's technical studies found that injecting more than 900 MW at the Hearn site can contribute to thermal exceedances on parts of the 115 kV system under certain conditions. This presents challenges with co-locating additional transmission-connected resources (such as a large ESS[35]) in the same location as the HVDC Option. This creates a potential congestion issue when the transmission system is injecting into this location at the same time the ESS is discharging into the system. Therefore, with the HVDC Option, siting a large ESS connected to the Hearn SS may not be technically and economically feasible in the long-term. A smaller size energy storage system may be feasible. The Toronto IRRP has identified other suitable location for ESS, as noted in Sections 7.6.1.5 and 7.7.1.5.

7.9.8 Addressing Resilience of Toronto's Electricity System

7.9.8.1 Increasing Resilience through the HVDC Option

The recommended HVDC option will increase the diversity of supply to downtown Toronto in addition to enabling demand growth over the next 20 years. One of the most significant contributions of the HVDC option to system resilience is the introduction of a third, geographically and electrically distinct supply path into Toronto's urban core. Currently, the city relies heavily on two radial 230 kV transmission paths, Manby TS and Leaside TS, both of which have limited ability to provide emergency supply should one suffer a complete loss of supply. This configuration has proven vulnerable during extreme weather events, such as the 2013 and 2024 floods that disrupted supply from Manby TS, affecting hundreds of thousands of customers. During these events, the limited

[35] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

ability to resupply Manby TS from Leaside TS, even with PEC in-service, impacted the duration and severity of the outage.

The HVDC line bypasses Cherrywood TS and injects power directly into the downtown core via Hearn SS. This reduces dependency on the Cherrywood to Leaside corridor, mitigating the risk of cascading failures, and ensures continuity of supply during outages or emergencies for customers in eastern Toronto. It also improves the ability for the City's eastern supply to accommodate loads supplied by Manby TS should a loss of supply event occur in the western Toronto area. In effect, this third point of supply will enable faster restoration of service in the event of major outages.

Increasing frequency of extreme weather events pose serious risks to the electricity system. The HVDC cables, being submerged under Lake Ontario, are inherently more resilient to surface-level disruptions such as wind, ice storms, and flooding. This physical separation from urban infrastructure and environmental hazards significantly lowers the risk of damage, making the system more robust in the face of climate change.

HVDC technology also offers additional operational flexibility. Unlike AC systems, HVDC allows grid operators to control power flows independently of the rest of the grid. This controllability is crucial for managing fluctuating demand, scheduling maintenance, and responding to both planned and unplanned outages. Additionally, the HVDC system can be designed to include black-start capability, allowing it to re-energize the grid after a complete outage without relying on external power sources. This feature is not available in the existing AC options or through PEC, making HVDC a critical asset for emergency restoration and system recovery.

7.9.8.2 Climate Vulnerability Study

To account for climate risk in future system planning studies of Toronto's electricity system, the IESO will undertake a desktop study of climate vulnerabilities as part of ongoing planning. This study will assess climate change-related risks at key points of the electricity system across Toronto. The study is intended to equip planners with insights to determine the scope of extreme contingencies to be assessed in future studies.

The study will involve a comprehensive GIS-based analysis of historical and projected climate data including temperature, precipitation, and flooding trends. It will incorporate data from sources such as Environment and Climate Change Canada, the Climate Atlas of Canada, and regional conservation authorities. By modeling future scenarios under different emissions pathway scenarios, the study will also help planners anticipate how climate risks may evolve over time and affect system performance.

This information is particularly valuable for the IRRP process, which seeks to balance reliability, cost-effectiveness, and resilience. For example, insights from this study can inform decisions about where to prioritize upgrades, reinforce vulnerable assets, or deploy non-wires alternatives like DERs and energy storage. It can also support transmission planning, such as the proposed HVDC line to downtown Toronto, by identifying climate-resilient routing options and station siting considerations.

Moreover, the study's emphasis on visual mapping and trend analysis enhances transparency and engagement. It enables planners, municipalities, and Indigenous communities to better understand the risks and participate meaningfully in shaping resilient energy solutions.

In summary, this climate vulnerability study will provide the IESO with a data-driven foundation for carrying out subsequent planning studies to strengthen Toronto's electricity system against future

climate impacts. It ensures that regional plans are informed by localized risk assessments, enabling proactive, resilient, and adaptive infrastructure planning for a rapidly changing environment.

7.9.8.3 Extreme Contingencies Assessment

Extreme contingencies are high-impact, low-frequency events that could severely disrupt Toronto's electricity supply. Studies of this nature involve identifying system vulnerabilities and mitigating measures to address the risk of extreme contingencies. The recommendations in this IRRP, as described in this report, will help mitigate the risk of some extreme contingencies, but the outlook for demand growth and threat of extreme weather events will likely cause new system vulnerabilities to emerge. Therefore, the IESO will work with Toronto Hydro and Hydro One to assess the scope and timing of an updated extreme contingencies assessment. The results of this work will inform future regional planning cycles. The results of an extreme contingencies assessment are not typically made public because they can contain detailed information about system vulnerabilities that could pose security risks if disclosed.

8 South and Central Bulk Study

IESO is currently undertaking a bulk system study focused on the Southwestern and Central regions of Ontario, particularly along the Windsor to Hamilton corridor as well as the urban centers in the GTA.

The driver of the South and Central Bulk Study is to support economic growth in Southwestern Ontario and the GTA and enable new supply resources by:

- Confirming the transmission reinforcements required to enable connection of the small modular reactor (SMR) project at Darlington Nuclear Generating Station and expanded nuclear supply at Bruce.
- Determining the transmission upgrades needed to allow decreased reliance on emitting resources at York Energy Center in the York region, PEC in Toronto, Halton Hills generating station in GTA west and Sithe Goreway generating station in Brampton.
- Determining the transmission needed to enable reliable supply in high growth and economic development areas including the GTA and the Windsor to Hamilton corridor.
- Identifying new corridors required for future transmission reinforcements.

The Bulk Study has been carried out in coordination with the Toronto IRRP to integrate options to enable growth in the city and deliver new supply. Some of the key linkages from the bulk study to this IRRP are as follows:

- The buildout of a new double circuit 500 kV line from Bowmanville SS west towards the GTA will enable the connection of the SMR project and increase supply from Eastern Ontario towards the GTA and Southwestern Ontario. This reinforcement from the east will help redistribute load between heavily utilized GTA bulk stations at Cherrywood, Parkway and Claireville which currently supply Toronto along with York and Durham Regions and the western GTA.
- The HVDC third supply to Toronto is also expected to have bulk impacts as it will be another major supply from the east towards the city, providing an alternate independent route to meet the city's growing demand. The feasibility of this option was considered at both the regional and bulk system level. The Bulk Study also examined how the third supply to Toronto would impact how and where the required 500 kV reinforcement from Bowmanville gets terminated in the GTA.

The South and Central Bulk Study will be published in early 2026.

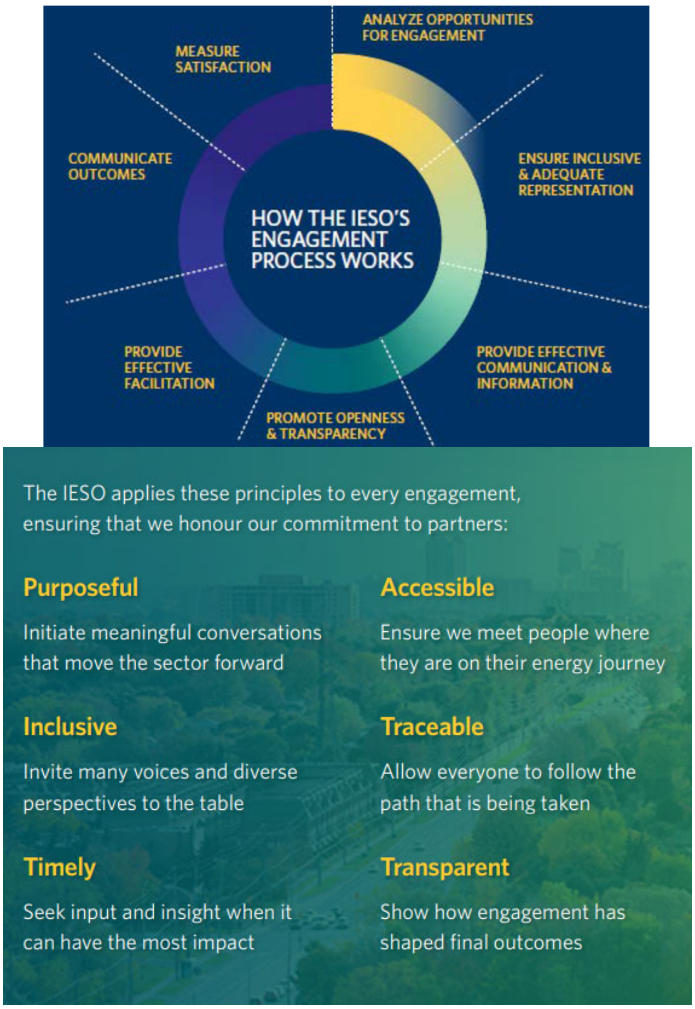
9 Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the Toronto IRRP.

9.1 Engagement Principles

The IESO's External Relations Engagement Framework and Indigenous Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 18 | The IESO's Engagement Principles



9.2 Engagement Tactics

To ensure that the Plan reflects the needs of Indigenous communities, municipalities, stakeholders, communities, market participants, customers and the general public, engagement involved:

- Leveraging the Toronto engagement webpage to post updated information, engagement opportunities, webinar materials, feedback received and the IESO response to feedback, as well as supplementary data and information.
- Targeted one-on-one discussions with Indigenous communities and the City of Toronto to help inform the engagement approach and to ensure that the communities' identified needs are considered.
- Hosted a series of public webinars at major milestones in the development of the plan to share details, understand feedback and answer questions.
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.
- A new PoweringGTA.ca website sharing details of active electricity plans within the GTA, including Toronto.
- Social media content on the IESO's LinkedIn and Instagram accounts to increase awareness of the planning efforts underway.

9.3 Engagement Approach

The engagement for the Toronto IRRP provided valuable insights into the local drivers and pockets of growth, priorities for the City of Toronto, community preferences, and the community vision for the future of Toronto. These insights shaped the development of the Plan and informed an integrated regional resource plan for the City of Toronto that is best suited to meet Toronto's unique and growing needs.

The IESO led an engagement strategy that included targeted one-on-one discussions with the City of Toronto and Indigenous communities, hosted technical briefings with communities as well as 6 public webinars to share information and solicit written feedback from interested rights holders and stakeholders. The purpose of each engagement opportunity was to build awareness and education of the regional planning process, provide updates and information pursuant to the Plan's development, and enable informed and meaningful community and stakeholder feedback. Outcomes of targeted community discussions and stakeholder feedback helped to inform and guide the development of the Plan at each key milestone.

To support the analysis of non-wire options, the IESO retained a consultant to develop a Local Achievable Potential Study (LAPS) to identify opportunities for incremental energy savings through energy efficiency, behind-the-meter distributed energy resources, and demand response. Engagement for the LAPS was included as part of the Toronto IRRP engagement approach.

Public webinars received high registration and were attended by a diverse group of interested stakeholders including the City of Toronto, Indigenous communities, government, industry, environmental associations, and community organizations. Written feedback was invited following each webinar. The six milestones of engagement, and which point feedback was invited, included:

1. Draft scoping outcome assessment report to share the planning approach before commencing the full IRRP study
2. Draft IRRP engagement plan, and draft electricity demand forecast for the region
3. Identified electricity needs for the region and introduction of the Local Achievable Potential Study
4. Results of the options screening for wire and non-wire options to meet the identified needs
5. Draft results for the Local Achievable Potential Study
6. Analysis of options and draft IRRP recommendations

Overarching themes of feedback heard during the development of the IRRP primarily focused on:

- Phase-out of PEC, and avoid new gas generation
- Community preference for non-wire options to meet electricity needs
- Enhanced transparency for data/information and decision-making rationale
- Alignment with City of Toronto decarbonization initiatives such as TransformTO
- Recognition of the need for a third supply line; coupled with requests for more information on the evaluation of options, impacts of routing options, and concern it would bring nuclear energy into the city

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations. A summary of the engagement milestones is described below.

9.3.1 Scoping Assessment

The IESO held preliminary discussions with the City of Toronto to help inform the engagement approach for the third round of planning, and to strengthen relationships and dialogue in this region that would inform the development of the Plan at each milestone. Engagement started with the draft Scoping Assessment Outcome Report for the Toronto Region. An invitation was sent to the City of Toronto, Indigenous communities, other stakeholders, and to the Toronto subscription list to announce the commencement of a new planning cycle and invite interested parties to provide input on the draft Toronto Region Scoping Assessment Outcome Report. A public webinar was held on February 16, 2023, to provide an overview of the regional electricity planning process and the scoping assessment, and to seek input. The final Scoping Assessment Outcome Report was posted on March 21, 2023, identifying the need for a coordinated regional planning approach through the development of an IRRP.

The key themes of feedback received during the scoping assessment milestone included study considerations for modelling extreme weather events, coordination with third party electricity demand studies (i.e., Port Lands DER study), opportunities to facilitate DERs, inclusion of a diversified electric and low-carbon gas scenario, and coordination with institutional customers to factor in their electrification plans into the regional forecast. The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.2 Demand Forecast

Following the finalization of the Scoping Assessment, the Technical Working Group began the development of Toronto's electricity demand forecast. IRRP recommendations are typically driven by

the reference demand forecast, which includes firm loads (current and planned), organic growth, residential, electrification and energy plans, and development plans. The Technical Working Group also developed a high electrification scenario to test potential demand growth that is less certain, assuming higher electrification adoption rates. The IESO sought input from the City of Toronto to identify drivers and pockets of growth, decarbonization and electrification initiatives.

To enable meaningful feedback and promote transparency, the IESO publicly posted a detailed forecasting methodology document and load forecast data tables to the engagement website early in the engagement process for stakeholder consideration. On April 16, 2024, the IESO hosted a public webinar to share the draft reference and high electrification scenarios, drivers of growth, draft engagement plan, and to seek stakeholder feedback. Feedback was received from 20 stakeholders, ranging from requests for information on methodology, requests for specific data and assumptions, inquiries on alignment with City of Toronto net zero plans, and requests that non-wires be considered in the Plan's development. Feedback on the draft engagement plan included enhanced collaboration with Indigenous communities and stakeholders throughout the planning process to produce better outcomes. The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.3 Electricity Needs

During this milestone, the IESO identified that the growing demand for electricity is causing significant electricity infrastructure needs across the western, northern, and eastern parts of the city. The IESO hosted a public webinar on December 5, 2024, to share the specific station and supply capacity needs in each area, detailing that a mix of large-scale wire and non-wire solutions would be required to meet the growing demand. The IESO further shared that reducing reliance on PEC amid growing demand for electricity would introduce large capacity needs.

During the webinar, the Local Achievable Potential Study (LAPS) was introduced to stakeholders as a tool to inform the non-wire analysis milestone in the Plan. The IESO shared the scope, methodology, and data inputs of the LAPS, and requested feedback from stakeholders.

The IESO received feedback from 21 stakeholders on the electricity needs and the LAPS methodology and scope. Feedback at this stage included additional requests for improved transparency of the demand forecast, support for the scenario without PEC, recommendations to close the facility, consideration of non-wires options to meet needs (including reconsidering offshore wind as an option), and feedback for the LAPS scope and methodology. The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.4 Options Screening

During this milestone, the IESO completed the options screening for the wire and non-wire solutions to meet needs across the city. The IESO hosted a public webinar on July 10, 2025, to share the screening criteria, and outcomes of the screening process for each need. Generally, wire options were screened-in as a solution to meet the needs, and non-wire options were screened-in in combination with wire options. The IESO also shared the three potential options for the third supply line in the webinar. The IESO collected written feedback and received 30 feedback submissions.

Feedback on the options screening included continued advocacy that non-wire solutions should play a key role in the Plan, and requests for more information on the analysis of the non-wire solutions

including land-use requirements and capacity. The IESO also heard that alignment of the Plan with decarbonization initiatives such as TransformTO and phase out of PEC with a committed timeline was important to many stakeholders.

Feedback specific to the third supply line demonstrated general support for the need for the third transmission supply line. City of Toronto staff shared general support for the transmission expansion and emphasized accelerating DER deployment for a future without PEC, the need for transparent route selection and stakeholder engagement, and minimizing land disruption and aligning with redevelopment priorities. Additional themes of feedback for the third supply line centered on concerns for prioritizing nuclear resources over the potential for renewable generation and impacts to lands and habitats. Feedback from Indigenous communities include concerns about potential impacts to environmental and archaeological sites, including along the shorelines. Technical briefings were provided to Indigenous communities to help address environmental concerns.

The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.5 Draft Results Local Achievable Potential Study

To further enhance and supplement the regional planning work underway for Toronto, the IESO conducted a local eDSM achievable potential (LAPS) study with consultant ICF International. The purpose of the study was to identify and quantify electricity energy savings potential, electricity demand savings potential and associated costs attainable through energy efficiency, demand response, and behind-the-meter DERs over a 20-year period of 2025 to 2045. To inform the development of the study, the IESO held a dedicated public webinar to share the draft results of the study and seek feedback.

The IESO received 11 feedback submissions from interested stakeholders. Key themes of feedback included:

- Opinion that customer program participation assumptions were too conservative
- Interest in district energy systems and front-of-the-meter wind, solar and energy storage (note that these front-of-meter resources have been considered in the Toronto IRRP but outside the LAPS reflecting the LAPS focus on customer-sited behind-the-meter resources).
- Inclusion of local health, economic and climate benefits of additional eDSM investments in the LAPS' cost-effectiveness analysis
- Comparison of draft results previous IESO-procured achievable potential studies and potential estimates of other parties
- Exclusion of vehicle-to-grid/building measures in the study

The IESO considered this feedback as part of the finalization of the Study, including in updates to customer program participation assumptions. The IESO addressed the exclusion of vehicle-to-grid/building measures in a separate memo posted with the draft results to the Toronto engagement website.

9.3.6 Options Analysis and Draft Recommendations

The final stage of engagement included the details of the options analysis and the draft recommendations for the Plan. The IESO hosted a public webinar on September 25, 2025 that provided an update on the Local Achievable Potential Study, shared details of the options analysis (including technical feasibility, ability to meet the need, cost, lead time, and other considerations), and the draft recommendations for each need in the west, north, and eastern parts of the City. The IESO also provided the details of the comparative analysis for each option for the third supply line, and the rationale for the preferred option in this final webinar.

The IESO made great efforts to release all publicly available information and data at key milestones for both the regional plan and the Local Achievable Potential Study to support the engagement process. To assist stakeholders in referencing all the available information, the IESO posted a Toronto Regional Plan Information Package in advance of this webinar, which can be viewed here.

The IESO received 15 feedback submissions on the options analysis and draft recommendations for the IRRP, including the preferred option for the third supply line. General feedback themes included the perspective that the IRRP showed a priority and overreliance on transmission infrastructure over non-wire options, desire for an electricity plan that sought to align with City of Toronto climate initiatives (including the phase out of PEC), support for draft recommendations to use load rebalancing opportunities, ESS, and eDSM where possible, and finally recommendations for implementation pathways for DERs and TENs. The City of Toronto commended the IESO for its transparent planning process and its commitment to modernizing regional energy planning by incorporating municipal input and evaluating innovative solutions like non-wires alternatives, demand-side management, and energy storage in the IRRP. Many stakeholders thanked the IESO for its efforts and due diligence in creating a comprehensive electricity plan.

Feedback on the third supply line included support for the need for the line and the value it will bring to the city. Stakeholders were interested to understand how the third supply line could support decarbonization efforts, such as helping to phase out PEC sooner and connecting to renewable generation outside the city. Some stakeholders shared concerns that the third supply line was prioritizing nuclear energy and untested SMR technology, and the source of nuclear was not in the interest of Canadians at this time.

9.4 Involving Municipalities in the Plan

The IESO engaged early and often with the City of Toronto to ensure that key local information about growth and development, energy-related plans, and environmental initiatives were taken into consideration in the development of this IRRP. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships and build trust, and provided opportunities for ongoing dialogue beyond this IRRP process. Additionally, the IESO led council outreach that included letters prepared for mayors and councillors, and one-on-one councillor meetings to provide elected officials with updates on electricity planning developments, and to provide an opportunity for discussion.

Through these discussions valuable feedback was received around growth and community preferences around solutions informing the IRRP, including:

- City of Toronto shared the drivers of load growth and pockets of high growth (i.e., TransformTO, Electric Vehicle Strategy, Secondary Plans, Green Bus Program, City of Toronto Official Plan) to be factored into the demand forecast scenarios and help to identify local needs and opportunities.
- The Technical Working Group leveraged ongoing City of Toronto studies into the IRRP (i.e., Downsview Airport site, Port Lands, Golden Mile Plan, electricity demand studies, and distributed energy resource analysis).
- City initiatives to decarbonize were contemplated at many levels, including for example, TransformTO and other electrification initiatives factored in the demand forecast. In response to the City Council request to align IRRP with City's 2040 target of net zero emissions the IESO included a scenario to understand timing and options for a future without PEC, and the IESO studied the ability of non-wire options to meet electricity needs.
- City perspectives on routing and siting of infrastructure for the third supply line that align with City plans, such as Port Lands redevelopment plans and potential for complementary energy storage.

9.5 Engaging with Indigenous Communities

To raise awareness and share information about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to the following Indigenous communities:

- **Mississaugas of the Credit First Nation**
  Toronto is situated within the lands covered by Treaty 13, signed with the Mississaugas of the Credit First Nation.
- **Alderville First Nation**
- **Beausoleil First Nation**
- **Chippewas of Georgina Island First Nation**
- **Chippewas of Rama First Nation**
- **Curve Lake First Nation**
- **Hiawatha First Nation**
- **Mississaugas of Scugog Island First Nation**
  The preceding seven communities are signatories to the Williams Treaties, which cover parts of the Toronto region. The Mississaugas of Scugog Island First Nation is a Williams Treaties First Nations member inclusive of the "Gunshot Treaty", which covers the north shore of Lake Ontario, beginning at the eastern boundary of the Toronto Purchase, within the City of Toronto.
- **Six Nations of the Grand River**
  The community is represented by the Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council.
- **Métis Nation of Ontario**

The IESO remains committed to an ongoing, meaningful dialogue with communities to help shape long-term planning in regions across Ontario. This engagement was part of a broader commitment to fostering respectful relationships, ensuring transparency, and supporting informed participation in regional energy planning. Throughout the development of this plan, the IESO's engagement with

Indigenous communities included extending the opportunity to meet one-on-one to address any inquiries or concerns about the IRRP, and the third supply option discussed in Section 7.8 specifically.

9.5.1 Indigenous Engagement Feedback

The following summarizes feedback received in writing and verbal communications with Indigenous communities. Feedback submitted to the IESO can be viewed on the Regional Electricity Planning - Toronto engagement webpage.

Mississaugas of the Credit First Nation (MCFN)

The IESO met with the Mississaugas of the Credit First Nation (MCFN) to provide an overview of the Toronto IRRP, including the region's electricity needs and the three supply line options under consideration. In addition to being treaty rights holders of land within the Toronto region under Treaty 13, the MCFN communicated that they submitted an aboriginal title claim to the water and waterbeds of Lake Ontario. The community has requested that Ontario pause review of that claim. This information may be relevant to the underwater transmission option (Option 3) as discussed in Section 7.8 (New Supply Options for Eastern Ontario), if pursued. The MCFN expressed interest in better understanding the potential environmental and archeological impacts of the underwater transmission option as well as the emergency repair and remediation options available. The MCFN have requested additional information and/or studies to support their review and feedback.

Mississaugas of Scugog Island First Nation (MSIFN)

The Mississaugas of Scugog Island First Nation (MSIFN) expressed a commitment to collaborative solutions that support reliable energy, honour their rights, and foster prosperity for the community. The MSIFN provided feedback on the proposed investments and recommendations contained in the IRRP, with a focus on the underwater transmission option (Option 3) as discussed in Section 7.8 (New Supply Options for Eastern Ontario). In particular, the MSIFN identified land and environmental concerns about the underwater transmission option, if pursued. The MSIFN also expressed an interest in ongoing participation and engagement in the regional planning process.

Hiawatha First Nation

The Hiawatha First Nation communicated concerns with environmental and archaeological sites, including along the shorelines, in a one-on-one meeting discussion. This information may be relevant to the underwater transmission option (Option 3) as discussed in Section 7.8 (New Supply Options for Eastern Ontario), if pursued.

Six Nations of the Grand River (SNGR)

The IESO met with Six Nations of the Grand River (SNGR) to present the Toronto IRRP, outlining the region's electricity needs and the three supply line options under review. SNGR expressed interest in remaining engaged in the IRRP process but did not provide feedback at this time.

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REGIONAL INFRASTRUCTURE PLAN REPORT

TORONTO

Regional Infrastructure Plan Report

Toronto

May 27, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Toronto Technical Working Group

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Disclaimer

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

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

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

Executive Summary

REGION **Toronto** (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: November 28, 2025 **END DATE:** May 27, 2026

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Toronto region, preceded by, the publication of Needs Assessment (NA) report in December 2022 by Hydro One followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in March 2023 and in October 2025 respectively, by the Independent Electricity System Operator (IESO).

Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs) and publishes a RIP report. The RIP report includes a discussion of all options and plans identified in earlier phases and recommends a preferred wires plan to address the near, medium, and long - term needs over a twenty-year study period.

The objectives and scope of the RIP are:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2026-2035) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identify any new need(s) over the 2026-2035 period that may have emerged since previous planning phases. Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.
- Consideration of long-term needs identified in the Toronto IRRP, Bulk system studies or as identified by the TWG.

The TWG agreed to adopt the IRRP load forecast for the RIP study because no material changes were identified. For shared stations that also serve Alectra or Elexicon, additional load has been incorporated into the forecasts based on inputs provided by the LDCs. Municipal plans were considered in developing the LDC forecasts, and additional municipal input on future load growth was obtained through the IRRP stakeholder engagement process.

The list of major infrastructure investments recommended by the TWG in the region for the next 10 years is given below. The needs include those previously identified in the NA and IRRP, as well as any new needs identified during the RIP phase, if any.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD
Asset Renewal Needs			
Basin TS	Transformers T3/T5 replacement*	Hydro One	2030
Manby TS	Autotransformers (T7, T9, T12) replacement, Step-down transformer (T13/T14) replacement*(NEW)	Hydro One	2030 2033
Leslie TS	Transformer T1, T4 replacement (T4 NEW)	Hydro One	2032
Dufferin TS	Transformer T2 replacement* (NEW)	Hydro One	2032
Cecil TS	115kV Switchgear replacement (NEW)	Hydro One	2032
Bermondsey TS	Transformers T3/T4 replacement	Hydro One	2033
Strachan TS	Transformers T13/T15 replacement*	Hydro One	2033
Agincourt TS	Transformers T5/T6 replacement (NEW)	Hydro One	2033
Terauley TS	Transformers T1/T2/T3/T4 replacement (NEW)	Hydro One	2033
Carlaw TS	Transformers T1/T2 replacement* (NEW)	Hydro One	2033
Rexdale TS	Transformer T2 replacement (NEW)	Hydro One	2033
John TS	Transformer T3 replacement* (NEW)	Hydro One	2033
Duplex TS	Transformers T1/T2 & T3/T4 replacement*	Hydro One	2034
Fairchild TS	Transformers T1 & T3/T4 replacement	Hydro One	2034
Warden TS	Transformer T4 replacement (NEW)	Hydro One	2035
Finch TS	Transformer T1 replacement (NEW)	Hydro One	2035
H1L/H3L/H6LC/H8LC	Leaside Jct. X Bloor St. Jct. – Overhead line section renewal	Hydro One	2031
L9C/L12C	Leaside TS X Balfour Jct. – Overhead line section renewal	Hydro One	2031
H1L/H3L & H2JK	Underground cable replacement (NEW)	Hydro One	2035

*Transformers to be replaced with higher rated standard units.

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M) [c]
Station Capacity Needs				
Bathurst TS & Finch TS	Connect Downsview MTS (Load Transfers to new Downsview MTS) - First DESN (Phase 1) - Second DESN (Phase 2)	THESL / Hydro One	 2033 2039	$135-155M[d]
Scarboro TS	Build third Scarboro TS DESN (Load Transfers to new Scarboro DESN)	Hydro One / THESL	2035	$55-65M
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	Hydro One / THESL	2035	$55-65M
Sheppard TS	Expand T1/T2 DESN using the idle windings	Hydro One / THESL	2029	$16M
Transformation Capacity Need				
Manby TS (West) Autotransformers	Load Transfer (Copeland T2/T4 to Leaside Supply) + Reliance on existing Manby Remedial Action Scheme	-	2026	-
Transmission Line Capacity Need				
Manby TS X Riverside Jct.: 115 kV Circuits	Upgrade capacity of 115 kV circuits	Hydro One	2029	$25M
Richview TS X Manby TS: 230 kV Circuits	230 kV Corridor Reinforcement	Hydro One	2032	N/A[b]

Notes:

a) The Planned In-Service dates are tentative and subject to change.
b) The recommended plan to address the Richview TS x Manby TS corridor need is expected by Q4 2026 as part of the GTA West IRRP.
c) Costs are tentative high-level budgetary planning estimates based on 2026 dollars and subject to change.
d) Property procurement costs not included.

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region (includes representatives from Hydro One Transmission, IESO and LDCs) and publishes a RIP report. The third cycle of the Regional Planning process for the Toronto region was initiated with the publication of Needs Assessment (NA) and the report was published in December 2022 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in March 2023 and in October 2025 respectively, by the Independent Electricity System Operator (IESO).

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium -term needs.

This report was prepared by the Toronto TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies (LDC), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1-1.

Table 1-1: Toronto region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission)
2	Independent Electricity System Operator (IESO)
3	Toronto Hydro-Electric System Limited (“THESL”)
4	Hydro One Networks Inc. (Distribution)
5	Alectra Utilities Corporation (“Alectra”)
6	Elexicon Energy Inc. (“Elexicon”)

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

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

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

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, Electricity Demand Side Management ("eDSM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2026-2035 identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2026-2035 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Toronto IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Electricity Demand Side Management ("eDSM"), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

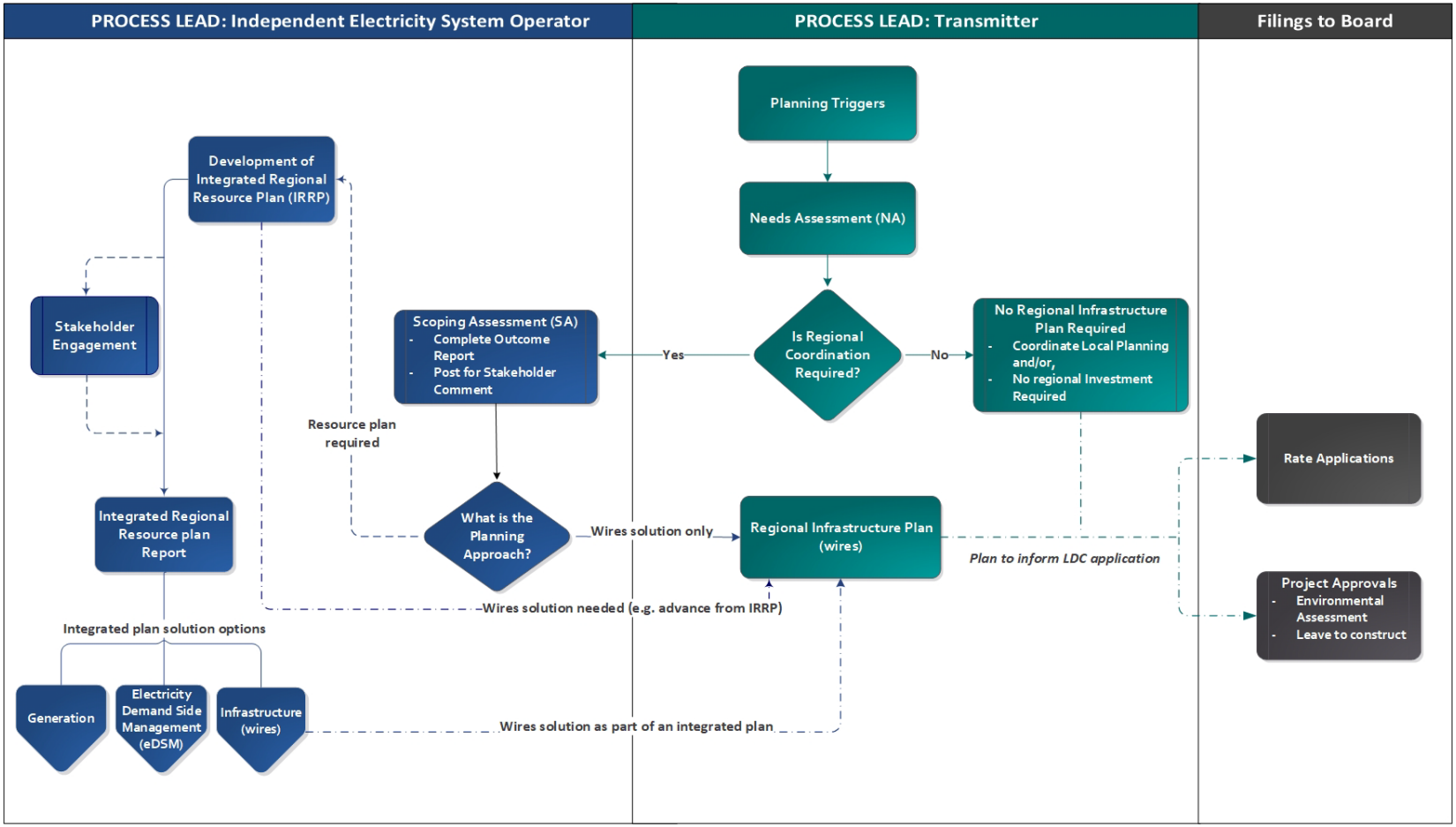
The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' eDSM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in the transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

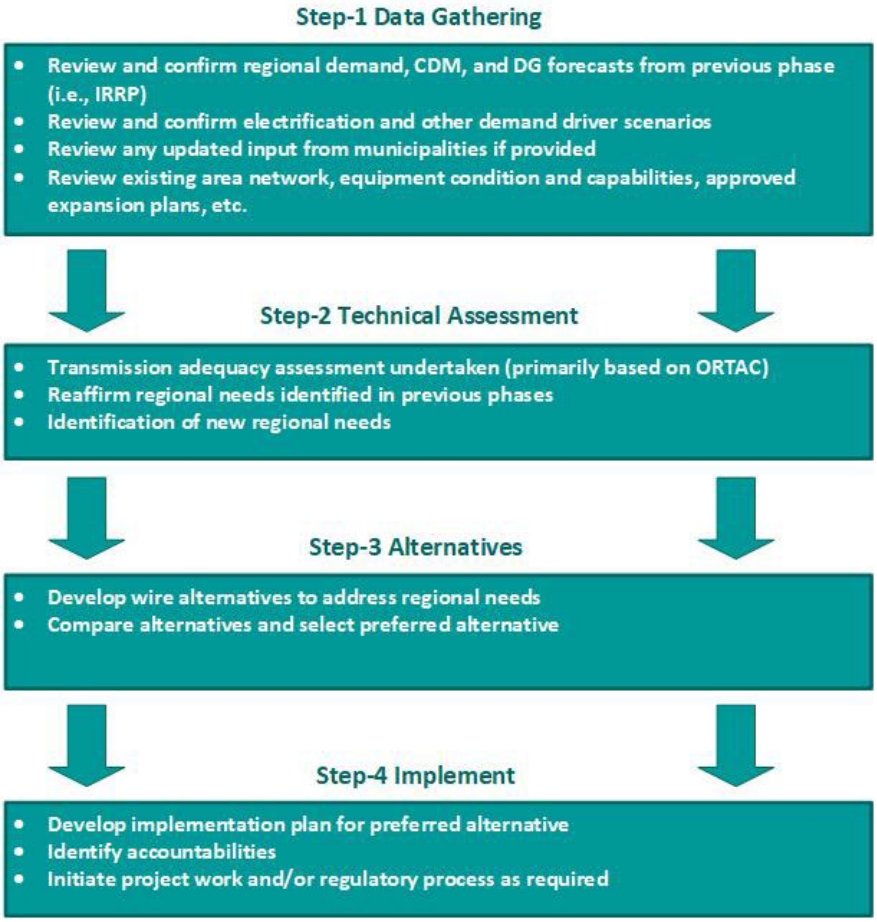
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure 3-1.

Figure 3-1: Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure 3-2: Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or eDSM programs. As agreed by TWG members, the load forecast from the Toronto IRRP was used for this RIP with the addition of the Alectra's and Elexicon's load which were not considered in the IRRP.

- Review and confirm electrification and other growth scenarios which affect the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment

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

3.2.3. Alternative Development

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

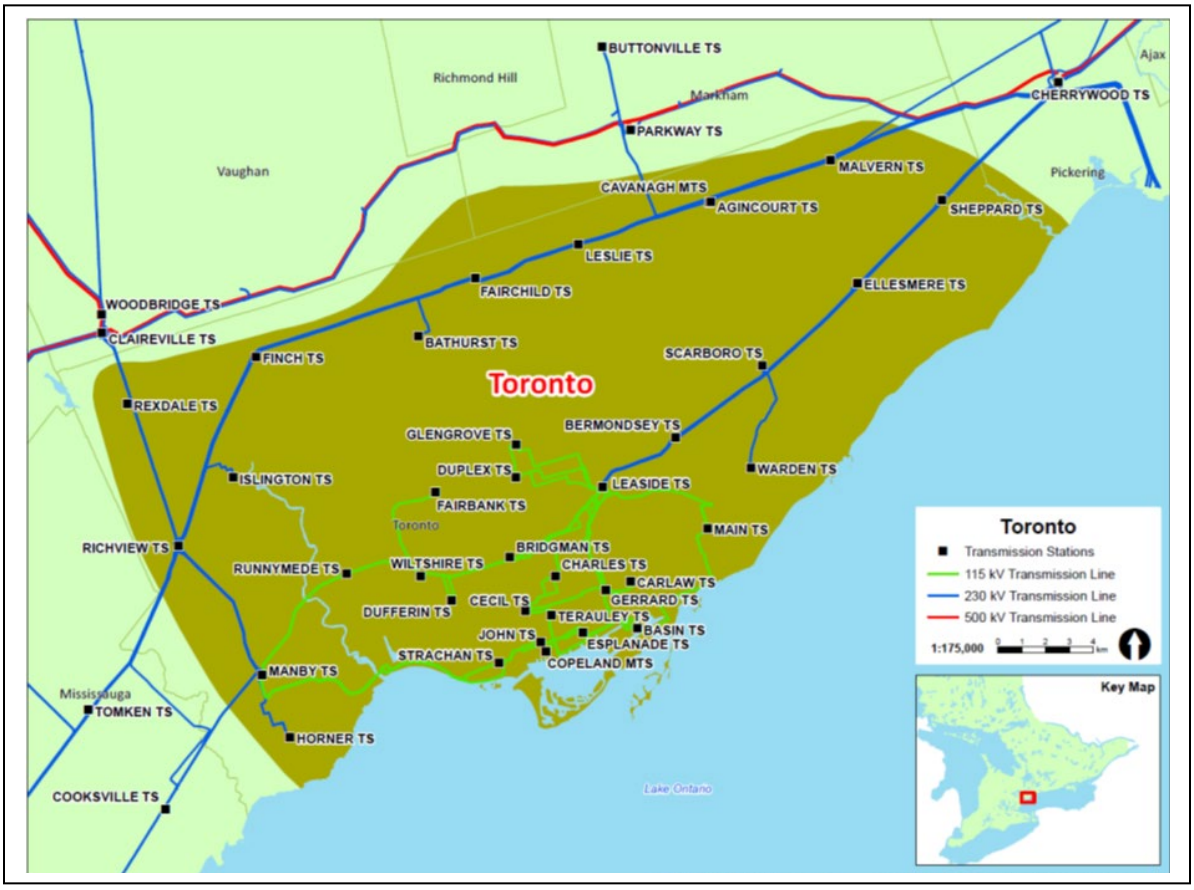
3.2.4. Implementation Plan

The fourth and last step is the development of the implementation plan for the preferred alternative, identify accountabilities and initiate project work or obtain permissions from the Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region covers the area roughly bordered geographically by Lake Ontario on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east. It includes the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Electrical supply to the region is provided from thirty-six (36) 230kV and 115kV step-down transformer stations. The boundaries of the Toronto region are shown in Figure 4-1 below.

Figure 4-1: Map of Toronto Regional Planning Area



As shown in Figure 4-2, the eastern, northern, and western parts of the Region are supplied by eighteen (18) 230/27.6kV step-down transformer stations. As shown in Figure 4-3, the central area is supplied by two (2) 230/115kV autotransformer stations (Leaside TS and Manby TS) and sixteen (16) 115/13.8kV and two (2) 115/27.6kV step-down transformer stations. The region is also supplied locally by Portlands Energy Centre ("PEC"), a 600 MW combined-cycle power generating station located in the Port Lands area of the

Toronto Waterfront via Hearn Switching Station ("SS"). The sum of 2024 non-coincident and coincident summer peak load of the Region were about 4,870 MW and 4,430 MW, respectively.

Figure 4-2: Geographical Area of East, North, and West 230 kV Area

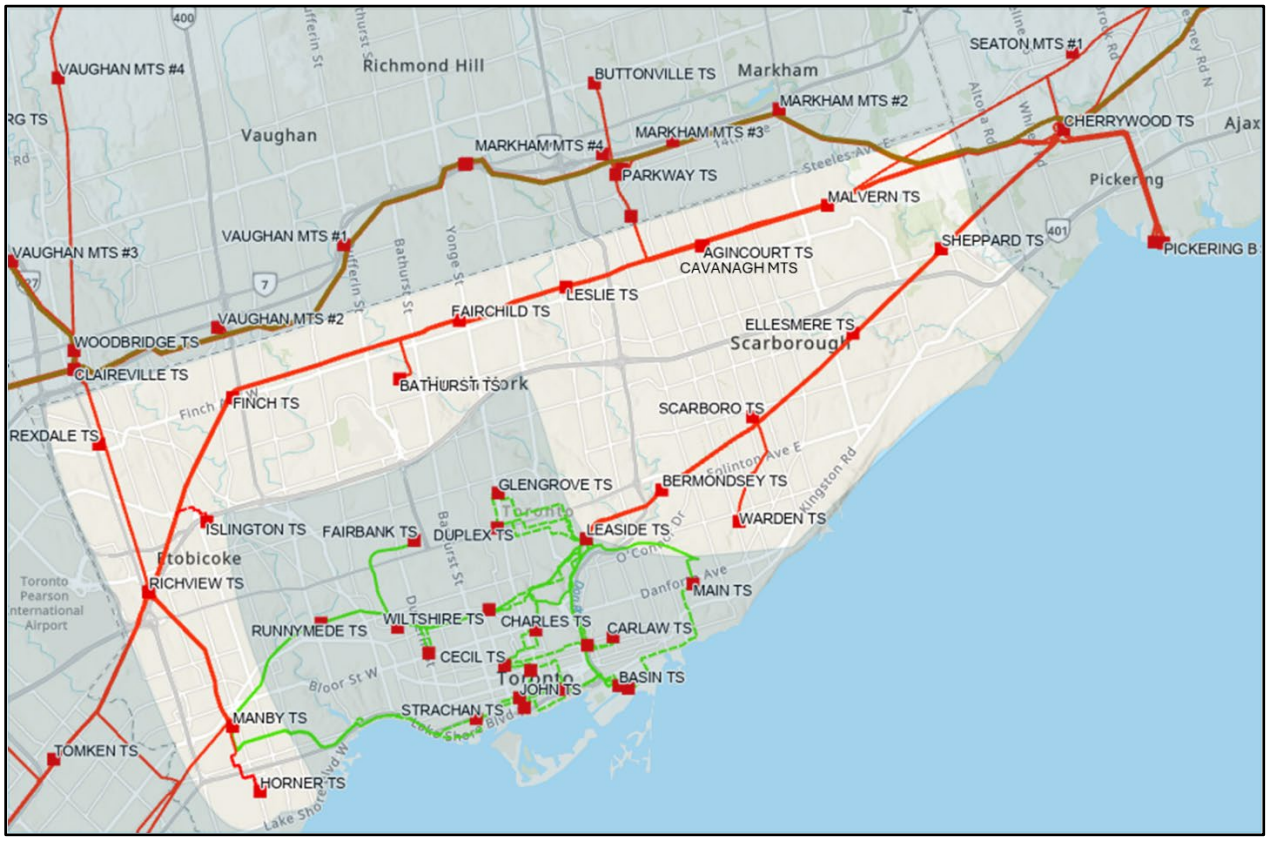


Figure 4-3: Geographical Area of Central 115 kV Area (Manby and Leaside)



Electricity demand in the region is projected to increase steadily over the forecast period, driven primarily by economic growth, electrification initiatives, customer connection activity, and municipal development plans. While the region has historically been summer-peaking, the forecast indicates a potential transition to winter-peaking by the early 2030s. The circuits and stations within the Toronto region are listed in Table 4-1 below:

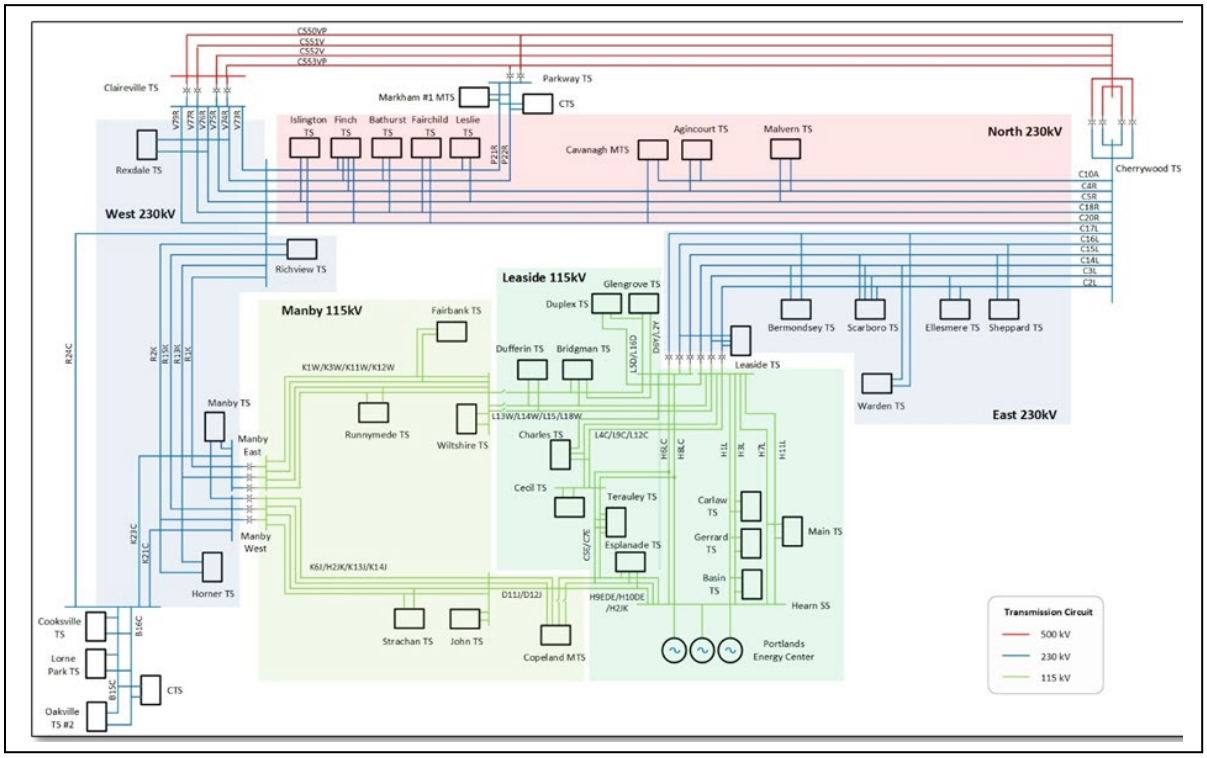
Table 4-1: Transmission Station and Circuits in the Toronto region

115kV Circuits	230kV Circuits	Transformer Stations	Generation Stations
K1W,K3W,K11W, K12W, K6J, K13J, K14J, H2JK, D11J, D12J, H9DE, H10DE, C5E, C7E, H6LC, H8LC, H1L, H3L, H7L, H11L, L13W, L14W, L15, L18W, L4C, L9C, L12C, L5D, L16D, L2Y, D6Y	R1K, R2K, R13K, R15K, R24C, K21C, K23C, C2L, C3L, C14L, C15L, C16L, C17L, C4R, C5R, C18R, C20R, C10A, P21R, P22R, V72R, V73R, V74R, V76R, V77R, V79R	Agincourt TS, Basin TS, Bathurst TS, Bermondsey TS, Bridgman TS, Carlaw TS, Cavanagh MTS, Cecil TS, Charles TS, Copeland MTS, Dufferin TS, Duplex TS, Ellesmere TS, Esplanade TS, Fairbank TS, Fairchild TS, Finch TS, Gerrard TS, Glengrove TS, Horner TS, Islington TS, John TS, Leaside TS*, Leslie TS, Main TS, Malvern TS, Manby TS*, Rexdale TS, Richview TS, Runnymede TS, Scarboro TS, Sheppard TS, Strachan TS, Terauley TS, Warden TS, Wiltshire TS	Portlands Energy Centre

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of Toronto region is shown in Figure 4-4 below.

Figure 4-4: Toronto Transmission Single Line Diagram



5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that were completed in past ten years or are currently underway is provided and is briefly discussed in the sub-sections. As part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the **Toronto region** to improve the supply capability and reliability.

Hydro One is the Transmission Asset Owners (TAO) in the region and has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Midtown Transmission Reinforcement Project (2016) – Covered replacement of the aging L14W underground cable and addition of a new 115 kV circuit between Leaside TS and Bridgman TS.
2. Runnymede TS DESN#2 and Manby TS to Wiltshire TS Circuits Upgrade Project (2018) – covered building of a second 50/83 MVA, 115/27.6 kV DESN at Runnymede TS and reinforcement of the Manby TS to Wiltshire TS 115 kV circuits to accommodate increasing load demand in the area.
3. Clare R. Copeland 115 kV Switching Station (2019) – Built to connect a new THESL owned 115/13.8 kV step-down transformer station (Copeland MTS) in Downtown Toronto.
4. Manby SPS Load Rejection (L/R) Scheme (2019) – Built to ensure that loading on in-service equipment at Manby TS is not exceeded for loss of two out of three autotransformers in the Manby East and Manby West switchyards.
5. John TS transformer replacements (2019-2021) – 115/13.8 kV 45/75 MVA transformers T1, T2, and T4 were replaced with new 60/100 MVA units based on asset condition assessment.
6. Sheppard TS DESN replacement (2021) – 230/27.6 kV 50/83 MVA transformers T3 and T4 were replaced with new same size units T5 and T6 based on asset condition assessment.
7. Strachan TS transformer replacement (2021) – 115/13.8 kV 40/67 MVA transformer T12 was replaced with new 60/100 MVA unit based on asset condition assessment.
8. Runnymede TS DESN replacement (2022) – 115/27.6 kV 58/93 MVA transformers T3 and T4 were replaced with new 50/83 MVA units T5 and T6 based on asset condition assessment.
9. Horner TS new DESN (2022) – covers construction of a second 75/125MVA, 230/28 kV DESN at the Horner TS site to meet the load growth in the southwest Toronto area.
10. Bridgman TS transformer replacements (2024) – 115/13.8 kV 40/67 MVA transformers T11, T12 and T13 and 45/75MVA transformer T14 were replaced with new 60/100 MVA units based on asset condition assessment.

11. Fairbank TS DESN replacement (2024) – 115/27.6 kV 50/83 MVA transformers T1, T2, T3 and T4 were replaced with new same size units T5, T6, T7 and T8 based on asset condition assessment.
12. Scarboro TS transformer replacement (2024) – 230/27.6 kV 75/125 MVA transformer T23 was replaced with new same size unit based on asset condition assessment.
13. Copeland MTS new DESN with spare transformer (2024) – THESL installed new 115/13.8 kV 60/100 MVA transformers T2, T4, T5 at Copeland MTS to meet increasing demand in Downtown Toronto.
14. John TS transformer replacements (2025) - 115/13.8 kV 75/125 MVA transformers T5 and T6 were replaced with new 60/100 MVA units based on asset condition assessment.

II. Following Major projects are underway:

1. Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley (2026) – A 2.5 km tunnel between Esplanade TS and Terauley TS is to be built.
2. Richview to Manby Corridor Reinforcement (R X K) Project (2026) – Adding a third 230 kV double-circuit line between Richview TS and Manby TS, aimed to increase the transmission line capacity between the two stations to meet forecast load demand in the southwest GTA.
3. Main TS transformer replacement (2026) – 115/13.8 kV 45/75 MVA transformers T3 and T4 are to be replaced with new 60/100 MVA units based on asset condition assessment.
4. Charles TS transformer replacements (2027) – 115/13.8 kV 45/75 MVA transformers T3 and T4 are to be replaced with new 60/100 MVA units based on asset condition assessment.
5. Strachan TS transformer replacement (2027) – 115/13.8 kV 45/75 MVA transformer T14 is to be replaced with new 60/100 MVA unit based on asset condition assessment.
6. Malvern TS transformer replacement (2027) – 230/27.6 kV 75/125 MVA transformer T3 is to be replaced with new same size unit based on asset condition assessment.

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

The major LDC in the Toronto region, THESL, has confirmed that there is no material change in the Toronto region IRRP Load Forecasts at this time and thus the IRRP forecasts were used in development of this Report. In addition, the other LDCs have also provided their load forecasts for the stations within the region that currently supply their customers, which were also considered in the development of this Report. TWG participants, including representatives from LDC's, the IESO and Hydro One, provided information and input for the IRRP and RIP load forecasts. Municipal plans were considered in developing the LDC forecasts, and additional municipal input on future load growth was obtained through the IRRP stakeholder engagement process.

During the study period, the load in the Toronto region is expected to grow at an average annual rate of approximately 2.5% in summer and 2.8% in winter from 2025 to 2044. The Region is summer peaking, however based on the forecast it is expected that the region will transition to winter-peaking in the near future. This shift is largely driven by electrified heating, which will significantly increase electricity demand during winter months.

Figure 6-1 & 6-2 show the Toronto region extreme summer/winter weather net coincident and non-coincident load forecast from 2025 to 2044. The load forecasts from the Toronto IRRP, along with the additional information for the shared stations, were used as agreed upon by the TWG.

The non-coincident and coincident reference forecasts for the individual stations in the region are available in Appendix A. These forecasts, along with the high-electrification forecasts in the IRRP, are used to determine any need in the region.

Figure 6-1: Toronto region summer/winter Coincident Net Peak Load Forecast

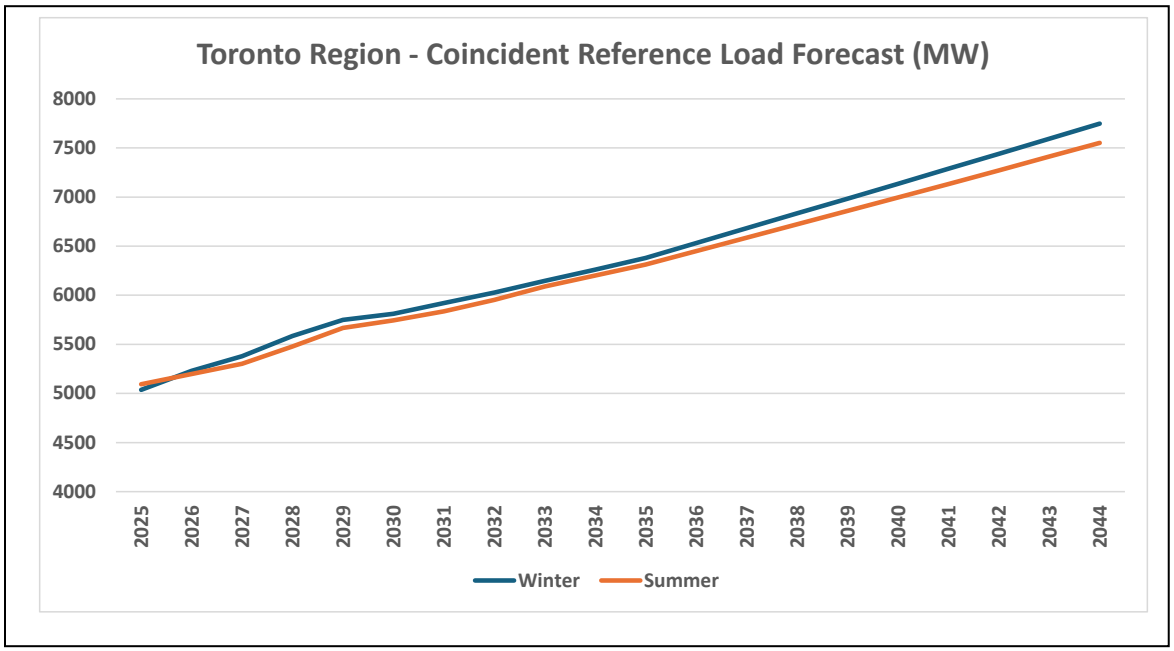
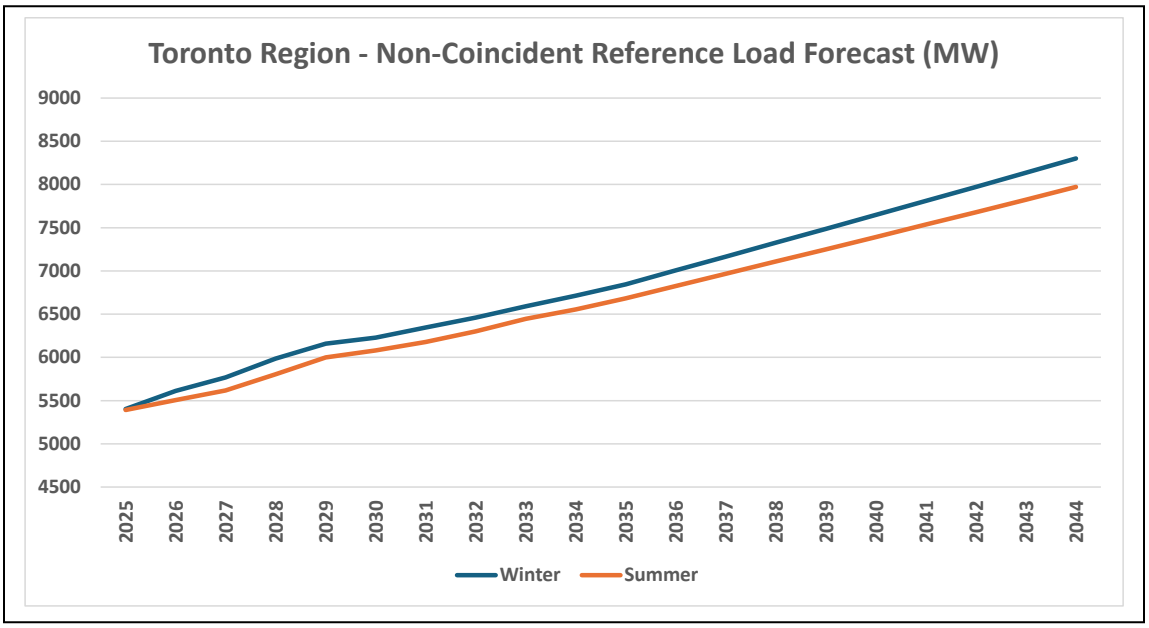


Figure 6-2: Toronto region summer/winter Non-coincident Net Peak Load Forecast



6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2025-2044.
- THESL has confirmed load forecasts up to 2044 in the area are the same as the IRRP. Alectra and Elexicon have provided load forecasts for the shared stations up to 2044.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is currently summer peaking but is expected to be winter peaking during the study period, so this assessment considers both summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 30°C ambient temperature.
- Adequacy assessment is conducted as per ORTAC. Enhanced criteria used in the IRRP were also considered in this report.[1]

[1] The ORTAC does not require double element contingency events to be evaluated for local area (non-bulk) transmission systems, unless the contingency propagates to a higher voltage level or causes a net load loss greater than 1,000 MW. However, the IRRP also evaluated double element contingencies for the local areas in Toronto region due to the social and economic importance of continuous electricity supply to the area.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Toronto region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed as per their respective in-service dates.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Toronto region Third cycle Needs Assessment Report, Completed in December 2022 by Hydro One
- Toronto region Third cycle Scoping Assessment Report, Completed in March 2023 by the IESO
- Toronto region Third cycle Integrated Regional Resource Plan Report, Completed in October 2025 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG have also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Toronto region. The complete list of major HV transmission equipment requiring replacement in the Toronto region is provided in Table 7-1 in this sub-section. Hydro One and THESL are the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:

    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 7-1: Major HV Transmission Asset assessed for Replacement in the region planned in next 10 years

Station/Circuit	Need Description	Planned ISD
Basin TS	Transformers T3/T5 replacement*	2030
Manby TS	Autotransformers (T7, T9, T12) replacement, Step-down transformer (T13/T14) replacement*	2030 2033
Leslie TS	Transformer T1, T4 replacement	2032
Dufferin TS	Transformer T2 replacement*	2032
Cecil TS	115kV Switchgear replacement	2032
Bermondsey TS	Transformers T3/T4 replacement	2033
Strachan TS	Transformers T13/T15 replacement*	2033
Agincourt TS	Transformers T5/T6 replacement	2033
Terauley TS	Transformers T1/T2/T3/T4 replacement	2033
Carlaw TS	Transformers T1/T2 replacement*	2033
Rexdale TS	Transformer T2 replacement	2033
John TS	Transformer T3 replacement*	2033
Duplex TS	Transformers T1/T2 & T3/T4 replacement*	2034
Fairchild TS	Transformers T1 & T3/T4 replacement	2034
Warden TS	Transformer T4 replacement	2035
Finch TS	Transformer T1 replacement	2035
H1L/H3L/H6LC/H8LC	Leaside Jct. X Bloor St. Jct. – Overhead line section renewal	2031
L9C/L12C	Leaside TS X Balfour Jct. – Overhead line section renewal	2031
H1L/H3L & H2JK	Underground cable replacement	2035

*Transformers to be replaced with higher rated standard units.

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

7.2. Station Capacity Needs

Over the study period 2025-2044 RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the Toronto region. The IRRP study had previously indicated that Bathurst TS and Scarboro TS require capacity relief within the 2026-2035 period. This RIP has further confirmed those needs. The need date for Sheppard TS and Finch TS capacity relief may also be advanced based on the load forecast considering the addition of Alectra's and Elexicon's load. The stations which require capacity relief during the 2026-2035 period are shown in Table 7-2 below. The need timeframe defines the time when the peak non-coincident reference load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 7-2: Toronto region Station Capacity Needs in next 10 years

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2025 Loading (MW) (Summer/Winter)	Ref. Forecast Need Date (Summer/Winter)
1	Bathurst TS	361 / 390	278 / 185	2035 / 2042
2	Scarboro TS	364 / 412	214 / 179	2035 / 2039
3	Basin TS	130 after asset renewal (existing LTR 88 / 104)	49 / 54	2035 / 2035
4	Sheppard TS	208 / 231	158 / 115	2029 / 2032
5	Finch TS	366 / 403	280 / 221	2033 / 2042

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transformation Capacity Needs

Over the study period 2025-2044 RIP reviewed the 230 kV to 115 kV transformation capacity needs within the Toronto region. The IRRP study had previously indicated that the following transformation capacity relief is required within the 2026-2035 period. This RIP has further confirmed this need as shown in Table 7-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) area limit.

Table 7-3: Toronto region Transformation Capacity Needs in next 10 years

Sr.no.	Station Name	Area Limit (MW) (Summer)	2024 Loading (MW) (Summer)	Ref. Forecast Need Date
1	Manby TS (West) Autotransformers	570 (470) (1)	358 (2)	2028 (3)

(1) Area limit of 570 MW is based on the loss of one autotransformer. Area limit of 470 MW is based on the loss of two autotransformers T1 and T2 and 150 MW of load shedding by Manby RAS after the loss of T1 and T2. The limit may increase after the most limiting autotransformer T12 is replaced.

(2) The 2024 summer loading is being used as John T5/T6 2025 loading data is currently missing.

(3) The 2028 need date is based on summer coincident reference forecast and an area limit of 470 MW. If control actions in between the loss of the first and second autotransformers are accounted for, the need date extends beyond 2044.

The need and the preferred solutions to address this need are discussed further in Section 8 of the report.

7.4. Transmission Line Capacity Needs

Over the study period 2025-2044 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Toronto region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the 2026-2035 period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 7-4 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 7-4: Toronto region Transmission Line Capacity Needs in next 10 years

Sr.no.	Name of Circuit	Name of Section	Area Limit (MW) Summer	2025 Summer loading (MW)	Need Date
1	K13J / K14J	Manby TS X Riverside Jct.	510 / 370 (1)	358 (2)	2026 (3)
2	R1K/R2K/R13K/R15K	Richview TS x Manby TS	1840 (4)	1560	2032 (4)

(1) An area limit of 510 MW is based on the loss of one circuit K13J or K14J. An area limit of 370 MW is based on the loss of two circuits simultaneously K13J and K6J / H2JK.

(2) The 2024 summer loading is being used as John T5/T6 2025 loading data is currently missing.

(3) 2026 need date is based on summer coincident reference forecast and area limit of 370 MW.

(4) The area limit and need date based on reference forecast were provided by the IRRP.

The needs and the preferred solutions to address these needs are discussed further in Section 8 of the report.

7.5. Long-Term Capacity Needs

Over the study period 2025-2044 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Toronto region. The IRRP study had previously indicated that the following longer term capacity needs in Table 7-5 below.

Table 7-5: Toronto region Long-Term Capacity Needs in next 10-20 years

Need Type	Long-Term Need	Timing
Station Capacity	Warden TS	2036
	Fairbank TS	2042
	Strachan TS	2039
	Dufferin TS	2040
	Glengrove TS	2042
	Manby DESNs	2043
	Fairchild TS	2040
	Leslie TS	2039
	Duplex TS	2042
	Main TS	2043
	Runnymede TS	2043
Transformation Capacity	Leaside TS Autotransformers	2036
	Manby TS (East) Autotransformers	2041
Line Capacity	K1W/K3W (St.Clair Ave. Jct. X Fairbank TS)	2036
	Leaside TS X Wiltshire TS: 115kV Circuits	2036
	H1L/H3L Capacity – (Leaside TS X Bloor Jct.) and (Hearn SS X Basin TS)	2036 /2041
	Cherrywood TS X Leaside TS: 230kV Circuits	2036

These needs are discussed further in Section 8 of the report, and they will be monitored and evaluated in future planning cycles due to the forecast uncertainty and the longer-term timing of need.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Toronto Region. These needs include those previously identified in the NA and IRRP for the Toronto Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region for the near- and mid-terms are summarized below in Table 8-1 below:

Table 8-1: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
Basin TS	Transformers T3/T5 replacement*	2030	8.1.1
Manby TS	Autotransformers (T7, T9, T12) replacement, Step-down transformer (T13/T14) replacement*	2030 2033	8.1.2
Leslie TS	Transformer T1, T4 replacement	2032	8.1.3
Dufferin TS	Transformer T2 replacement*	2032	8.1.4
Cecil TS	115kV Switchgear replacement	2032	8.1.5
Bermondsey TS	Transformers T3/T4 replacement	2033	8.1.6
Strachan TS	Transformers T13/T15 replacement*	2033	8.1.7
Agincourt TS	Transformers T5/T6 replacement	2033	8.1.8
Terauley TS	Transformers T1/T2/T3/T4 replacement	2033	8.1.9
Carlaw TS	Transformers T1/T2 replacement*	2033	8.1.10
Rexdale TS	Transformer T2 replacement	2033	8.1.11
John TS	Transformer T3 replacement*	2033	8.1.12
Duplex TS	Transformers T1/T2 & T3/T4 replacement*	2034	8.1.13
Fairchild TS	Transformers T1 & T3/T4 replacement	2034	8.1.14
Warden TS	Transformer T4 replacement	2035	8.1.15

Finch TS	Transformer T1 replacement	2035	8.1.16
H1L/H3L/H6LC/H8LC	Leaside Jct. X Bloor St. Jct. – Overhead line section renewal	2031	8.1.17
L9C/L12C	Leaside TS X Balfour Jct. – Overhead line section renewal	2031	8.1.18
H1L/H3L & H2JK	Underground cable replacement	2035	8.1.19
Station Capacity Needs			
Bathurst TS & Finch	Connect Downsview MTS and supply Bathurst load - First DESN (Phase 1) - Second DESN (Phase 2)	 2033 2039	8.2.1
Scarboro TS	Build third Scarboro TS DESN and supply Scarboro load	2035	8.2.2
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	2035	8.2.3
Sheppard TS	Expand T1/T2 DESN using the idle windings	2029	8.2.4
Transformation Capacity Needs			
Manby TS (West) Autotransformers	Area supply is limited by the Limited Time Rating of one autotransformer with 150 MW RAS, if considering the loss of two autotransformers	2028	8.3.1
Transmission Line Capacity Needs			
Manby TS X Riverside Jct.: 115kV Circuits	Upgrade capacity of 115kV circuits.	2026	8.4.1
Richview TS X Manby TS: 230 kV Circuits	230 kV Corridor Reinforcement	2032	8.4.2

*Transformers to be replaced with higher rated standard units.

The potential long-term needs in the 2036 – 2044 timeframe are discussed in Section 8.5.1 to Section 8.5.16 in this report.

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

8.1.1 Basin TS – T3/T5

The existing T3 and T5 transformers at Basin TS are 45/75 MVA units and are currently identified for replacement in 2030 based on asset condition assessment.

These units will be replaced with larger 60/100 MVA units to address asset renewal needs while also helping to address expected future station capacity needs. These replacement upgrades and other ancillary equipment renewals will contribute to increased capacity and maintaining supply reliability in the Basin TS area.

8.1.2 Manby TS – T7/T9/T12 & T13/T14

Several transformers at Manby TS are currently identified for replacement in the early 2030s based on asset condition assessments.

The existing T7, T9, and T12 autotransformers are 150/250 MVA units. These units will be replaced with like-for-like units to address asset renewal needs and contribute to maintaining reliability of supply to the Manby East and Manby West area.

The existing T13 and T14 transformers are 56/93 MVA units. These units will be replaced with the standard 75/125 MVA units to address asset renewal needs to maintain supply reliability in the local area and contribute to addressing expected future station capacity needs.

8.1.3 Leslie TS – T1/T4

The existing T1 and T4 transformers at Leslie TS are 75/125 MVA units and are currently identified for replacement in 2032 based on asset condition assessment.

The existing T1 transformer is a non-standard unit with dual LV voltage levels at 13.8 kV and 27.6 kV. As the 13.8 kV supply will no longer be required from Leslie TS, both T1 and T4 will be replaced with standard 230-27.6-27.6 kV 75/125 MVA units to address asset renewal needs. These replacements and other ancillary equipment renewals will support the ongoing supply reliability in the Leslie TS area. Following the replacement of the existing T2 with a standard unit, the 27.6 kV supply capability at Leslie TS is expected to increase.

8.1.4 Dufferin TS – T2

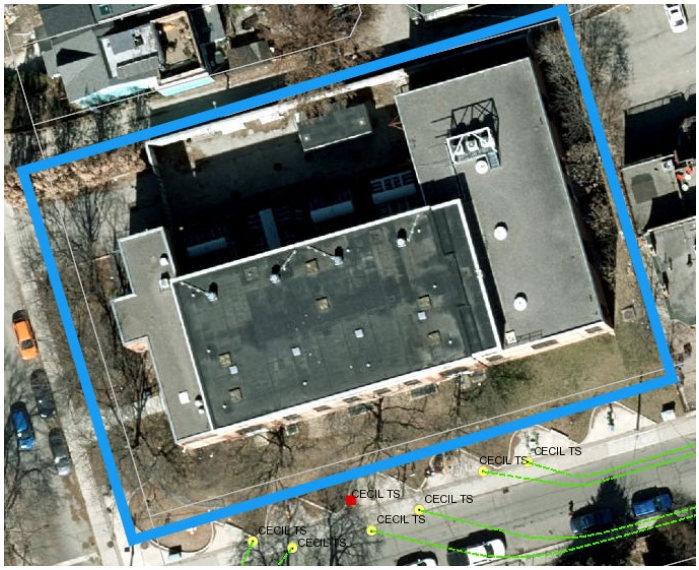
The existing T2 transformer at Dufferin TS is a 45/75 MVA unit and is currently identified for replacement in 2032 based on asset condition assessment.

This unit will be replaced with a 60/100 MVA unit to meet asset renewal requirements and align with the other units at Dufferin TS. This replacement will contribute to maintaining supply reliability in the Dufferin TS area.

8.1.5 Cecil TS – 115kV Switchgear

The existing Cecil TS 115kV gas-insulated switchgear (GIS) equipment includes eight 115kV breakers and associated ancillary switchgear equipment. This indoor GIS switchgear has been recommended for full replacement to address obsolescence and supportability issues that have started to become a risk from the perspective of maintainability, operability, and reliability.

Figure 8-1: Cecil TS located in Downtown Toronto



Alternative 1 – Standard In-situ Replacement: This alternative would include full replacement of the existing GIS switchgear in the same physical location with new switchgear of similar or better ratings. However, the existing space is very constrained and replacing equipment in-situ while maintaining operations would be a significant risk. As a result, this alternative is not considered feasible and is rejected.

Alternative 2 – Greenfield Replacements: This alternative would include full replacement of the existing GIS switchgear in a new physical location with new switchgear of similar or better ratings. This alternative would allow the switchgear to be replaced in a new greenfield location and minimize project execution risk and system operation risk. This alternative would address asset needs and maintain long-term supply reliability to customers in the region.

The recommended plan is to proceed with Alternative 2 to replace the existing GIS switchgear and maintain long-term supply reliability to customers in the region.

8.1.6 Bermondsey TS – T3/T4

The existing T3 and T4 transformers at Bermondsey TS are 75/125 MVA units and are currently identified for replacement in 2033 based on asset condition assessment.

These units will be replaced with like-for-like units to address asset renewal needs. These replacements and other ancillary equipment renewals will contribute to maintaining supply reliability in the Bermondsey TS area.

8.1.7 Strachan TS – T13/T15

The existing T13 and T15 transformers at Strachan TS are 45/75 MVA units and are currently identified for replacement in 2033 based on asset condition assessment.

These units will be replaced with larger 60/100 MVA units to address asset renewal needs while also helping to address expected future station capacity needs. These replacement upgrades and other ancillary equipment renewals will contribute to increased capacity and maintaining supply reliability in the Strachan TS area.

8.1.8 Agincourt TS – T5/T6

The existing T5 and T6 transformers at Agincourt TS are 75/125 MVA units and are currently identified for replacement in 2033 based on asset condition assessment.

These units will be replaced with like-for-like units to address asset renewal needs. These replacements and other ancillary equipment renewals will contribute to maintaining supply reliability in the Agincourt TS area.

8.1.9 Terauley TS – T1/T2/T3/T4

The existing T1, T2, T3, and T4 transformers at Terauley TS are 75/125 MVA units and are currently identified for replacement in 2033 based on asset condition assessment.

These units will be replaced with standard 60/100 MVA units to address asset renewal needs. These replacements and other ancillary equipment renewals will contribute to maintaining supply reliability in the Terauley TS area.

8.1.10 Carlaw TS – T1/T2

The existing T1 and T2 transformers at Carlaw TS are 45/75 MVA units and are currently identified for replacement in 2033 based on asset condition assessment.

These units will be replaced with larger 60/100 MVA units to address asset renewal needs while also helping to address any future station capacity needs. These replacement upgrades and other ancillary equipment renewals will contribute to increased capacity and maintaining supply reliability in the Carlaw TS area.

8.1.11 Rexdale TS – T2

The existing T2 transformer at Rexdale TS is a 75/125 MVA unit and is currently identified for replacement in 2033 based on asset condition assessment.

This unit will be replaced with a like-for-like unit to address asset renewal needs. This replacement and other ancillary equipment renewals will contribute to maintaining supply reliability in the Rexdale TS area.

8.1.12 John TS – T3

The existing T3 transformer at John TS is a 45/75 MVA unit and is currently identified for replacement in 2033 based on asset condition assessment.

This unit will be replaced with a larger 60/100 MVA unit aligning with other units at John TS to address asset renewal needs while also helping to address any future station capacity needs. This replacement upgrade and other ancillary equipment renewals will contribute to increased capacity and maintaining supply reliability in the John TS area.

8.1.13 Duplex TS – T1/T2/T3/T4

The existing T1, T2, T3, and T4 transformers at Duplex TS are 45/75 MVA units and are currently identified for replacement in 2034 based on asset condition assessment.

These units will be replaced with larger 60/100 MVA units to address asset renewal needs while also helping to address expected future station capacity needs. These replacement upgrades and other ancillary equipment renewals will contribute to increased capacity and maintaining supply reliability in the Duplex TS area.

8.1.14 Fairchild TS – T1/T3/T4

The existing T1, T3, and T4 transformers at Fairchild TS are 75/125 MVA units and are currently identified for replacement in 2034 based on asset condition assessment.

These units will be replaced with like-for-like units to address asset renewal needs. These replacements and other ancillary equipment renewals will contribute to maintaining supply reliability in the Fairchild TS area.

8.1.15 Warden TS – T4

The existing T4 transformer at Warden TS is a 75/125 MVA unit and is currently identified for replacement in 2035 based on asset condition assessment.

This unit will be replaced with a like-for-like unit to address asset renewal needs. This replacement and other ancillary equipment renewals will contribute to maintaining supply reliability in the Warden TS area.

8.1.16 Finch TS – T1

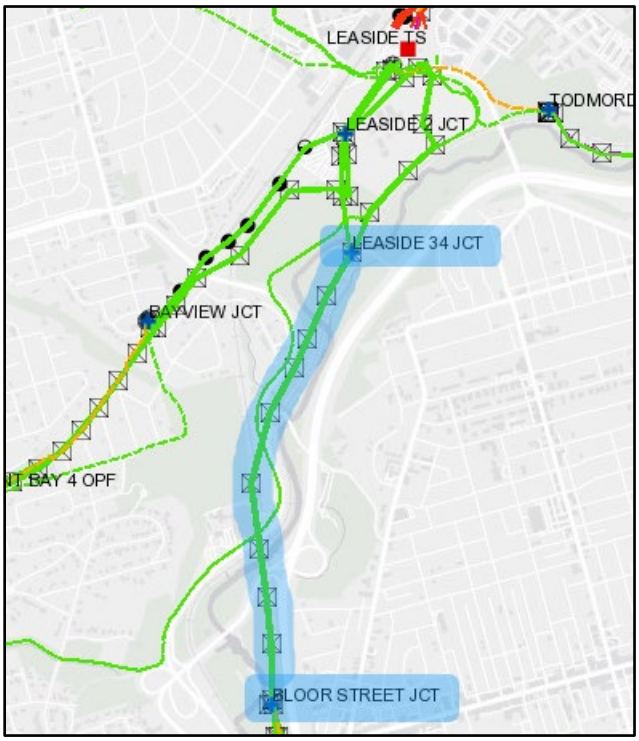
The existing T1 transformer at Finch TS is a 75/125 MVA unit and is currently identified for replacement in 2035 based on asset condition assessment.

This unit will be replaced with a like-for-like unit to address asset renewal needs. This replacement and other ancillary equipment renewals will contribute to maintaining supply reliability in the Finch TS area.

8.1.17 H1L/H3L/H6LC/H8LC – Leaside Jct. X Bloor St. Jct.

The 115 kV circuits H1L/H3L/H6LC/H8LC connect between the Leaside TS, Hearn SS and Cecil TS stations and supply step-down transformers at Basin TS, Gerrard TS, Carlaw TS, and Cecil TS. A 3 km overhead line section of these lines, between Leaside 34 Jct. and Bloor St. Jct., is predominantly steel lattice tower line. This 3 km line section between Leaside 34 Jct. and Bloor St. Jct. has been determined to require renewal. Figure 8-2 shows the Leaside 34 Jct. x Bloor St. Jct. line section of the H1L/H3L/H6LC/H8LC circuits.

Figure 8-2: H1L/H3L/H6LC/H8LC – Leaside 34 Jct. X Bloor St. Jct. Section



The following options were considered for this line section renewal:

Alternative 1 – Standard Renewal of Line Section: This alternative would prescribe a full refurbishment of the overhead line section and reconductor the section with new conductors on the existing towers. The ampacity recommendation in the IRRP will be considered and investigated during the project development stage. This alternative would address asset needs, improve line section capacity and minimize losses, and maintain long-term supply reliability to customers in the region.

Alternative 2 – Rebuild line section to 230 kV standard: This alternative would rebuild the line section to 230 kV standard and thereby allow the lines to potentially be operated at 230 kV in the future if all other sections were also upgraded. However, this alternative would be extremely costly and there are currently no plans to convert the other sections of these lines to higher voltages or to operate the lines at higher voltages. Therefore, this alternative is rejected.

The recommended plan is to proceed with Alternative 1 to most cost effectively renew the line section and maintain long-term supply reliability to customers in the region.

8.1.18 L9C/L12C – Leaside TS X Balfour Jct.

The 115 kV circuits L9C/L12C connect between the Leaside TS and Cecil TS stations and supply step-down transformers at Charles TS and Cecil TS. A 3.5 km overhead line section of these lines, between Leaside TS

and Balfour Jct., is predominantly steel lattice tower line. This 3.5 km line section between Leaside TS and Balfour Jct. has been determined to require renewal. Figure 8-3 shows the Leaside TS x Balfour Jct. line section of the L9C/L12C circuits.

Figure 8-3: L9C/L12C – Leaside TS X Balfour Jct. Section



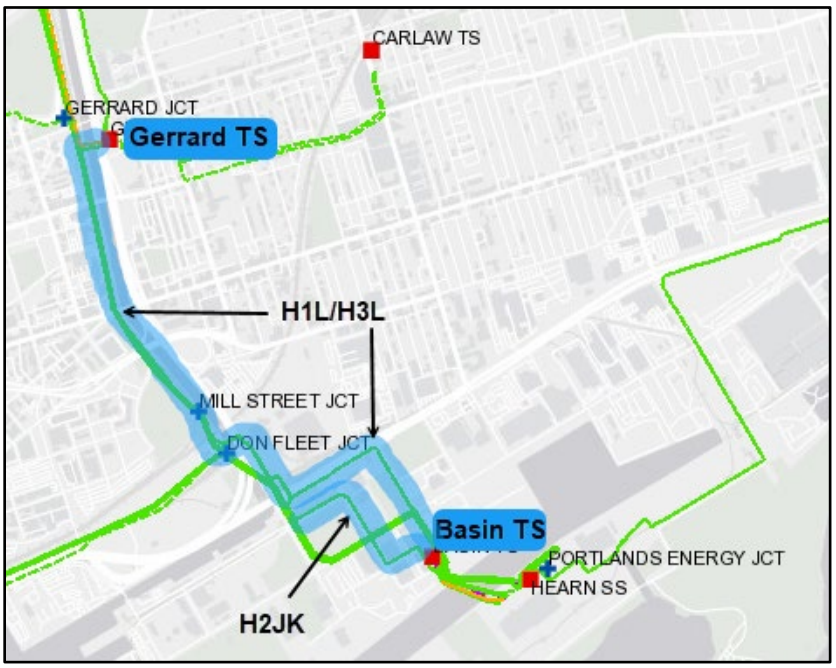
Preferred plan – Standard Renewal of Line Section: This would prescribe a full refurbishment of the overhead line section and reconductor the section with new conductors on the existing towers. The ampacity capability will be considered and investigated during the project development stage. This alternative would address asset needs, improve line section capacity and minimize losses, and maintain long-term supply reliability to customers in the region.

8.1.19 H1L/H3L & H2JK – Underground Cable Replacement

The 115 kV H1L/H3L circuits connect between the Leaside TS and Hearn SS stations and supply step-down transformers at Basin TS, Gerrard TS, and Carlaw TS. The 115 kV H2JK circuit connects between Hearn SS, John TS, and Manby TS with a normally open point at John TS. East of the John TS normally open point, H2JK primarily supplies Esplanade TS.

A 2.9 km underground cable section of H1L and H3L from Basin TS to Gerrard TS, and a 1.4 km underground cable section of H2JK from Basin TS to Don Fleet Jct. are 115 kV paper-insulated low-pressure oil-filled transmission cables. These cables parallel the Don River, are near Lake Ontario, and located in the Toronto Portlands. These cables are required to be replaced as verified through detailed condition assessments.

Figure 8-4: H1L/H3L – Basin TS X Gerrard TS Section; H2JK – Basin TS X Don Fleet Jct. Section



Preferred Plan – Replacement of Underground Cable Sections: This would prescribe a full replacement of the existing deteriorated oil-filled cables and ancillary equipment with oil-free cross-linked polyethylene (XLPE) cables and/or overhead lines with the largest feasible conductor sizes to minimize losses and improve capacity. This alternative would address asset renewal needs, improve line section capacity and minimize losses, and maintain long-term supply reliability to customers in the region.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2025-2044 for the 230kV and 115kV Transforming stations in the Toronto region using both the summer and winter peak load forecasts that were provided by the study team. This section describes the following Station capacity needs have been identified during the 2026-2035 period.

To address the station capacity needs, the recommendation of this planning cycle is a combination of new transformer stations and upgrades at existing stations. The RIP focuses on wire alternatives, however where possible non-wire alternatives are also considered as per the IRRP.

8.2.1 Bathurst TS & Finch TS – 230 kV / 27.6 kV

Significant load growth is anticipated in the Northwest Toronto area, particularly around Bathurst TS and Finch TS, primarily driven by the planned redevelopment of the Downsview area near Keele Street and Sheppard Avenue. Figure 8-5 shows the locations of Bathurst TS and Finch TS, along with the approximate area of the Downsview redevelopment plan.

Figure 8-5: Downsview Redevelopment Plan near Bathurst TS & Finch TS



Bathurst TS comprises two DESNs, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 361 MW. The station's 2025 actual non-coincident summer peak load was about 278 MW and is forecasted to be approximately 370 MW (net adjusted for extreme weather) or 102% of its LTR in 2035, based on summer non-coincident reference forecast.

Finch TS comprises two DESNs, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 366 MW. The station's 2025 actual non-coincident summer peak load was about 280 MW and is forecasted to be approximately 388 MW (net adjusted for extreme weather) or 106% of its LTR in 2035, based on summer non-coincident reference forecast [2].

To address a station capacity need of approximately 200-300 MW over the next 20 years, a new station or new DESN(s) will be required by 2035. THESL has proposed constructing a new Municipal Transformer

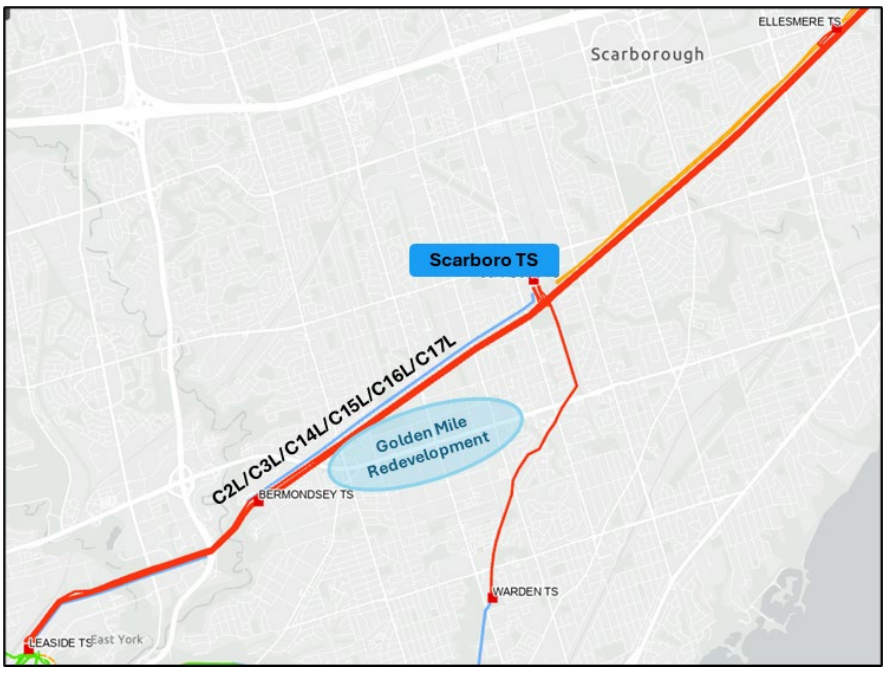
[2] Finch TS T1/T2 supply load for both THESL and Alectra. According to the IESO, Alectra's load was not included in the IRRP forecast. When Alectra's load is added, based on summer non-coincident reference forecast, the need date for station capacity relief at Finch TS advances from 2038 to 2033.

Station (“MTS”) in the vicinity of the Downsview area. Other alternatives, including building new DESN(s) at Bathurst TS and/or Finch TS, were considered. However, insufficient available space at or in proximity to the existing Bathurst TS property renders the addition of new DESN(s) infeasible. Furthermore, the location of Finch TS west of Highway 400 presents technical challenges associated with feeder crossings, making it a less favorable option for supporting the anticipated load growth in the Downsview area. According to the IRRP, the proposed new station with two DESNs can be connected to select Cherrywood TS x Richview TS circuit pairs, that are not on the same tower, along the Finch Corridor without the need for a switching station and without causing thermal overloads within the study period. Hydro One will continue to work closely with THESL in the coming years to support the connection of the new MTS.

8.2.2 Scarboro TS – 230 kV / 27.6 kV

Significant load growth is anticipated in the Scarborough area, particularly around Scarboro TS and Warden TS, primarily driven by the planned redevelopment of the Golden Mile along Eglinton Avenue East between Victoria Park Avenue and Birchmount Road. Figure 8-6 shows the location of Scarboro TS, along with the approximate area of the Golden Mile Secondary Plan.

Figure 8-6: Golden Mile Secondary Plan near Scarboro TS



Scarboro TS comprises two DESNs, T21/T22 (75/125 MVA) and T23/T24 (75/125 MVA), having a summer 10-Day LTR of 364 MW. The station’s 2025 actual non-coincident summer peak load was about 214 MW. Based on summer non-coincident reference forecast, Scarboro TS loading is forecasted to be

approximately 370 MW (net adjusted for extreme weather) by 2035 and over 500 MW by 2044. Its nearby station Warden TS is also forecasted to exceed its station capacity around 2036 and needs relief by transferring load to Scarboro TS. The other closest stations, Bermondsey TS and Ellesmere TS, are also projected to be loaded at about 75% and 100% of their station LTRs by 2044, respectively.

To address a station capacity need of approximately 150 MW over the next 20 years, a new station or DESN will be required by 2035. Spaces are available to accommodate an additional DESN at both the existing Scarboro TS and Warden TS properties. Scarboro TS is located adjacent to the Cherrywood to Leaside corridor, whereas Warden TS is supplied via a 4.5 km double-circuit overhead line tap from the same corridor. From a load reliability and operability perspective, building a new DESN at Scarboro TS represents the preferred alternative. Therefore, the TWG recommends that THESL and Hydro One keep monitoring the station loading and load forecast, and collaborate on the development of a third DESN at Scarboro TS in the next few years.

8.2.3 Basin TS – 115 kV / 13.8 kV

As described in Section 8.1.1, Basin TS currently comprises one DESN, T3/T5 (45/75 MVA), having a summer 10-Day LTR of 88 MW. These transformers will be replaced with 60/100 MVA units, tentatively by end of 2030. The Basin TS station capacity is expected to increase to approximately 130 MW and satisfy the need in the near to medium term. The station's 2025 actual non-coincident summer peak load was about 49 MW. Due to the City's development plan in the Port Lands area, the station loading is projected to reach 130 MW (net adjusted for extreme weather) by 2035, based on summer non-coincident reference forecast. Additional station capacity relief will be required by the end of the medium-term period or within the long-term planning horizon.

Hydro One and THESL have been continuously working with the City of Toronto on their relocation and/or reconfiguration request for the electricity infrastructure in the Port Lands area. While no updates are currently available, Hydro One and THESL will keep the TWG informed of any further developments. The TWG recommends that Hydro One and THESL maintain this collaboration with the City to finalize the site for a new or expanded Basin TS . The TWG will continue to monitor Basin TS loading and review the need in the next RP cycle.

8.2.4 Sheppard TS – 230 kV / 27.6 kV

Sheppard TS comprises two DESNs, T1/T2 (75/125 MVA units with idle winding) and T5/T6 (50/83 MVA units), having a summer 10-Day LTR of 208 MW. The station's 2025 actual non-coincident summer peak load was about 158 MW and is forecasted to be approximately 238 MW (net adjusted for extreme weather) or 114% of its station LTR in 2035, based on summer non-coincident reference forecast[3].

[3] Sheppard TS T5/T6 supply load for both THESL and Elexicon. According to the IESO, Elexicon's load was not included in the IRRP forecast. When Elexicon's load is added, based on summer non-coincident reference forecast, the need date for station capacity relief at Sheppard TS advances from 2038 to 2029.

To address this station capacity need, the TWG recommends utilizing the idle winding on transformers T1/T2. THESL and Hydro One are working together on the development of expanding the 27.6 kV switchyard. This investment is expected to increase the Sheppard TS station capacity by at least 60 MVA and meet the identified need through at least 2040 based on summer non-coincident reference forecast. The TWG further recommends ongoing monitoring and reassessment of Sheppard TS loading to determine any additional long-term needs in the next RP cycle.

8.3 Transformation Capacity Needs

A Transformation Capacity assessment was performed over the study period 2025-2044 for the 230 / 115 kV Manby and Leaside autotransformers in the Toronto region using both the summer and winter peak load forecasts that were provided by the study team. This section describes the following capacity need that has been identified during the 2026-2035 period.

To address the transformation capacity need, the recommendation from the IRRP is a combination of wire and non-wire solutions. The RIP focuses on wire alternatives.

8.3.1 Manby West – 230 / 115 kV Autotransformers

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

Manby West and Manby East autotransformers supply two distinct 115kV load pockets. Manby West autotransformers normally supply three downstream 115 / 13.8 kV step-down transformer stations: Strachan TS, John TS, and Copeland MTS. The Manby West autotransformers may also be used in emergency situations to supply Esplanade TS and/or Terauley TS, which are normally served by the Leaside 115 kV transmission network.

The actual 2024 summer coincident loading for the Manby West area was 358 MW. The area limit based on the loss of a single autotransformer at Manby West is 570 MW[4]. According to the summer coincident reference forecast, the projected area load remains within the autotransformer limit; however, under the high-electrification scenario, the area load is expected to exceed the limit by 2043.

Based on the enhanced reliability criteria aligning with the IRRP, the scenario where two autotransformers are lost simultaneously and only one remains in service is also evaluated. Under this condition, the area limit is reduced to 470 MW[5] with the presence of the existing Manby Remedial Action Scheme ("RAS") which allows up to 150 MW of load rejection when two out of the three autotransformers

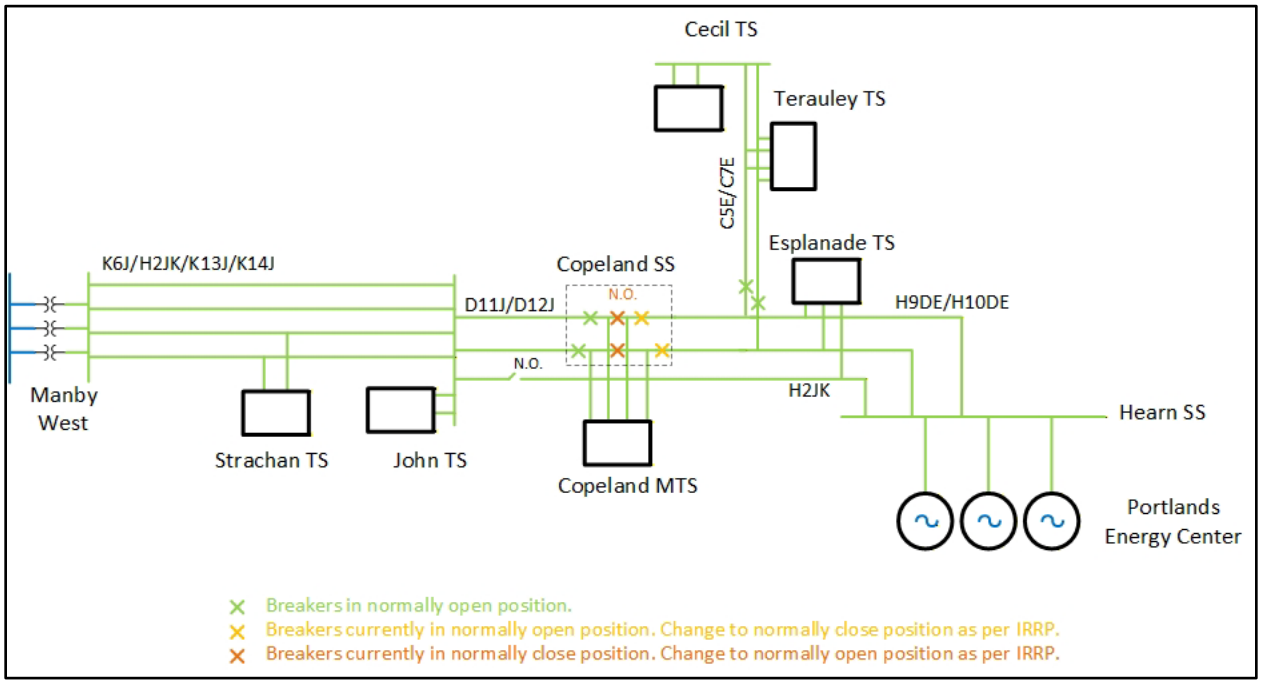
[4] The existing autotransformer T12 is currently the most limiting unit and is planned for replacement by 2030. Following the T12 replacement, the autotransformer limit is expected to increase.

are out of service at the same time. Based on the summer coincident reference forecast, the projected area load is expected to exceed this limit by 2028.

As outlined in the IRRP, the recommended plan to address this need includes the continued reliance on Manby RAS, permanent transfer of Copeland MTS T2/T4 to the Leaside supply, incremental electricity Demand Side Management ("eDSM"), and the potential connection of Energy Storage Systems ("ESS"). Based on the summer coincident reference forecast, the permanent transfer of Copeland MTS T2/T4 to the Leaside supply keeps the Manby West load under the 465 MW limit within the study period. Under the high-electrification forecast[5], the Many West load is expected to exceed the 465 MW limit by 2036. The potential non-wire solutions would further reduce the net load supplied by Manby West autotransformers and may also decrease the amount of load rejection required when two autotransformers are out simultaneously. The TWG recommends monitoring the demand growth in this area and revisiting this capacity need in the future regional planning cycle if the growth is significant.

Figure 8-7 shows the single line diagram of the Manby West area along with the partial transmission network of the Leaside / Hearn side. As recommended in the IRRP, Copeland T2/T4 is to be transferred to the Leaside / Hearn side by changing the normally open points at Copeland SS.

Figure 8-7: Permanent Transfer of Copeland T2/T4 to the Leaside Supply



[5] For the High Electrification forecast, please refer to https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/toronto-irrp-data-tables.xlsx

8.4 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2025-2044 for the 230kV and 115kV Transmission line circuits in the Toronto region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater to this need. The following line capacity needs have been identified during the 2026-2035 period.

8.4.1 K13J / K14J – 115 kV – Manby TS x Riverside Junction Overhead Line Upgrade

As described in Section 8.3.1, the Manby West autotransformers normally supply three downstream 115 / 13.8 kV step-down transformer stations: Strachan TS, John TS, and Copeland MTS. They may also be used in emergency situations to supply Esplanade TS and/or Terauley TS, which are normally served by the Leaside 115 kV transmission network. This supply is supported by a four-circuit corridor (K13J, K14J, K6J, and H2JK) between Manby West and John TS, as well as two underground cable circuits (D11J and D12J) from John TS to Copeland SS. The existing overhead sections of circuits K13J and K14J are the most limiting elements of the Manby West area supply.

The actual 2024 summer coincident loading for the Manby West area was 358 MW. The area limit based on the loss of a single circuit (K13J or K14J) is 510 MW. With Copeland T2/T4 supplied by Manby West, the projected area load is expected to exceed this limit by 2040 under the summer coincident reference forecast, and this need would shift into the near- to medium-term under the high-electrification scenario. If Copeland T2/T4 is permanently transferred to the Leaside supply as described in Section 8.3.1, the Manby West load is expected to remain within the limit under both the reference and high-electrification forecasts[6].

Based on the enhanced reliability criteria aligning with the IRRP, the scenarios involving the simultaneous loss of two circuits are also evaluated. Under this condition, the area limit decreases to 370 MW[7]. Based on the summer coincident reference forecast, the projected area load is expected to exceed this limit by 2026 when Copeland T2/T4 is supplied from Manby West. Even with the permanent transfer of Copeland T2/T4 to the Leaside supply, the need persists and is only deferred to 2027 when double-element contingencies without control actions are considered.

Given the importance of supply reliability for Downtown Toronto and the increasing difficulty in securing outages as load demand grows, the TWG recommends upgrading the 115 kV overhead sections of circuits

[6] For the High Electrification forecast, please refer to https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/toronto-irrp-data-tables.xlsx

[7] The most limiting scenario is the loss of two circuits K13J and K6J / H2JK simultaneously with no control actions considered.

K13J and K14J between Manby TS and Riverside Junction to at least match the ampacity of the other two circuits in the corridor (K6J and H2JK). The current planned in-service date of this line upgrade is Q2-Q3 2029.

8.4.2 R1K / R2K / R13K / R15K – 230 kV – Richview TS x Manby TS

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are four 230 kV circuits R1K, R2K, R13K, and R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS.

As recommended in the previous RP, this corridor requires reinforcement to increase transfer capability in support of continued load growth in these areas. The reinforcement will be implemented in two phases. Phase 1 involves constructing a new 230 kV double-circuit line within the existing corridor and forming two supercircuits, R2K and R15K. Phase 1 is expected to be completed by March 2026. Phase 2 will unbundle these supercircuits, with one new circuit connected to Manby West and the other to Manby East. At Richview TS, the new circuits will be tapped into two existing 230 kV circuits from Claireville TS. Phase 2 is anticipated to be completed around 2030.

As outlined in the IRRP, the post-reinforcement LMC will increase to around 1840 MW, and the area load is expected to reach this limit by 2032 based on the reference forecast, under a breaker failure contingency at Richview TS resulting in the loss of two of the three circuits between Richview TS and Manby West. The TWG recommends further evaluation of this need and options in the GTA West IRRP.

8.5 Long-Term Capacity Needs

Transmission system planning must consider potential long-term needs to help inform current and future planning actions. A number of potential longer term needs have been identified as noted in Table 7-5. These needs will continue to be monitored and evaluated as needed in future regional planning cycles. No planning action or investment is required at this time as long term forecasts are uncertain and subject to potential change and the timing of the needs are longer term. The sections below discuss these potential needs.

8.5.1 Warden TS Capacity

Warden TS is comprised of one DESN unit, T1/T2 (75/125 MVA units), that has a summer 10-Day LTR of approximately 182 MW. The IRRP observes potential future station capacity exceedances in the long-term beginning approximately in 2036. A new DESN station at Scarboro TS has been proposed to address the station capacity needs in the area (see Section 8.2.2) and will also allow load to be offloaded from Warden TS. No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.2 Fairbank TS Capacity

Fairbank TS consists of two DESN units, T5/T6 (50/83 MVA units) and T7/T8 (50/83 MVA units), that have a combined summer 10-Day LTR of approximately 222 MW. The IRRP observes potential future station capacity exceedances in the long-term beginning approximately in 2042. In addition, the Fairbank TS supply will also be limited to approximately 180 MW by the existing overhead line tap from St. Clair Ave. Jct. (see Section 8.5.14). The IRRP has proposed to address these long-term station and line capacity needs by transferring load from Fairbank TS to the new Downsview MTS (see Section 8.2.1). No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.3 Strachan TS Capacity

Strachan TS consists of two DESN units, T12/T14 (one 60/100 MVA unit; one 45/75 MVA unit) and T13/T15 (45/75 MVA units), that have a combined summer 10-Day LTR of approximately 171 MW. The IRRP observes potential future station capacity exceedances in the long-term beginning approximately in 2039. The currently anticipated solutions to manage potential future excess load include increased local electricity demand side management and upsizing transformers upon renewal replacement. No other investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.4 Dufferin TS Capacity

Dufferin TS consists of two DESN units, T1/T3 (60/100 MVA units) and T2/T4 (one 45/75 MVA unit; one 60/100 MVA unit), that have a combined summer 10-Day LTR of approximately 180 MW. The IRRP

observes potential future station capacity exceedances in the long-term beginning approximately in 2040. In addition, the Dufferin TS supply is currently limited to approximately 135 MW by the existing underground cable tap from Dufferin Jct. and Barlett Jct. (see Section 8.5.15). A combination of remedies including upgrading the Dufferin TS supply cables, load transfers, increased local energy storage systems, and upsizing transformers upon renewal replacement are currently considered as potential solutions to address possible future excess load. No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.5 Glengrove TS Capacity

Glengrove TS consists of two DESN units, T1/T3 (25/42 MVA units) and T2/T4 (25/42 MVA units), that have a combined summer 10-Day LTR of approximately 86 MW. The IRRP and RIP observe potential future station capacity exceedances in the long-term beginning approximately in 2042. The currently considered remedy is load transfer to Duplex TS, an adjacent load supply station, to address possible future excess load. No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.6 Manby TS DESN Switchyards Capacity

Manby TS consists of three DESN units, T13/T14 (56/93 MVA units), T3/T4 (25/42 MVA units), and T5/T6 (25/42 MVA units), that have a combined summer 10-Day LTR of approximately 226 MW. The IRRP and RIP observe potential future station capacity exceedances in the long-term beginning approximately in 2036. The currently anticipated solutions to manage potential future excess load include upsizing transformers via renewal and upgrade replacements (see Section 8.1.2). The LV switchyard supplied by T13 and T14 is also proposed to be reconfigured concurrently with the transformer replacements to enable future LV switchyard replacements at other DESNs and support long-term capacity growth. No other investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.7 Fairchild TS Capacity

Fairchild TS consists of two DESN units, T1/T2 (75/125 MVA units) and T3/T4 (75/125 MVA units), that have a combined summer 10-Day LTR of approximately 346 MW. With the added consideration of Alectra load, the RIP observes potential future station capacity exceedances in the long-term beginning approximately in 2040. It is currently anticipated that any potential future excess load will be able to be managed through load transfers as Fairchild TS is relatively near to the proposed new Downsview MTS area. No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.8 Leslie TS Capacity

Leslie TS consists of two DESN units, T1/T2 (75/125 MVA units) and T3/T4 (75/125 MVA units), that have a combined summer 10-Day LTR of approximately 323 MW. With the added consideration of Alectra load, the RIP observes potential future station capacity exceedances in the long-term beginning approximately

in 2039. It is currently anticipated that any potential future excess load can be managed primarily through improved capacity via transformer renewal and upgrade replacements (see Section 8.1.3). No other investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.9 Duplex TS Capacity

Duplex TS consists of two DESN units, T1/T2 (45/75 MVA units) and T3/T4 (45/75 MVA units), that have a combined summer 10-Day LTR of approximately 128 MW. The RIP observes potential future station capacity exceedances in the long-term beginning approximately in 2042. It is currently anticipated that any potential future excess load can be managed primarily through upsizing transformers via renewal replacements (see Section 8.1.13). No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.10 Main TS Capacity

Main TS consists of one DESN unit, T3/T4 (60/100 MVA units), that has a winter 10-Day LTR of approximately 117 MW. The RIP observes potential future station capacity exceedances in the long-term beginning approximately in 2043. It is currently anticipated that any potential future excess load can be managed primarily through renewal replacements of downstream 13.8 kV switchgear that will resolve capacity limitations. No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.11 Runnymede TS Capacity

Runnymede TS consists of two DESN units, T1/T2 (50/83 MVA units) and T5/T6 (50/83 MVA units), that have a combined winter 10-Day LTR of approximately 238 MW. The RIP observes potential future station capacity exceedances in the long-term beginning approximately in 2043. It is currently anticipated that any potential future excess load can be managed primarily through electricity demand side management measures. No investment or planning actions are required at this time, and the station and area needs will continue to be assessed in future planning cycles.

8.5.12 Cherrywood TS X Leaside TS – 230kV Circuits and Leaside TS Autotransformer Capacity

East Toronto is supplied from the east by six 230kV transmission lines that extend from Cherrywood TS to Leaside TS. The Cherrywood TS X Leaside TS lines directly supply six step-down transformer stations throughout Scarborough and East Toronto and also supply six 230/115 kV autotransformers (150/250 MVA units) at Leaside TS. The six Leaside TS autotransformers supply twelve step-down transformer stations via the Leaside 115 kV system.

The actual 2025 summer coincident peak load on the Cherrywood TS X Leaside TS lines was 2174 MW. Of the 2174 MW total, 1246 MW was supplied to the Leaside 115 kV system via the Leaside TS autotransformers. As outlined in the IRRP, the load meeting capability of the Cherrywood to Leaside lines is limited to approximately 2610 MW as a result of reaching voltage stability limits on the loss of two 230

kV supply circuits. Based on the summer reference load forecast, the Cherrywood to Leaside line loading is projected to reach this load level in approximately 2036.

The actions necessary to address the future long-term exceedances on the 230 kV supply lines and the Leaside autotransformers will be significant. As outlined in the IRRP, the recommended plan to address the Eastern Toronto needs is to introduce new supply. After assessing three distinct supply options, the IESO proposed a new underwater high-voltage direct current (HVDC) link between the Hearn SS area and the Bowmanville SS area as the preferred approach to provide new supply into the Eastern Toronto area. The HVDC link option will include extensive switchyard work at Hearn SS and Bowmanville SS as well as potentially new 230kV in-line breakers at Leaside TS on the Cherrywood TS X Leaside TS lines.

8.5.13 Manby East – 230 / 115 kV Autotransformers

As described in Section 8.3.1, Manby East comprises three 230 / 115 kV autotransformers (T7/T8/T9). They normally supply two 115 / 27.6 kV and one 115 / 13.8 kV step-down downstream transformer stations: Runnymede TS, Fairbank TS, and Wiltshire TS. The Manby East autotransformers may also be used in emergency situations to supply Dufferin TS and Bridgman TS, which are normally served by the Leaside 115 kV autotransformers.

The actual 2025 summer coincident loading for the Manby East area was 319 MW. The area limit based on the loss of a single autotransformer at Manby East is 560 MW[8]. According to the summer coincident reference forecast, the projected area load remains within the autotransformer limit during the study period.

Based on the enhanced criteria aligning with the IRRP, the scenario where two autotransformers are lost simultaneously and only one remains in service is also evaluated. Under this condition, the area limit is reduced to 460 MW with the presence of the existing Manby Remedial Action Scheme ("RAS") which allows up to 150 MW of load rejection when two out of the three autotransformers are out of service at the same time. Based on the summer coincident reference forecast, the projected area load is expected to exceed this limit by 2041.

As outlined in the IRRP, the recommended plan to address this need includes the continued reliance on Manby RAS, permanent load transfer from Fairbank TS to the new Downsview MTS, and incremental eDSM. Given that the planned autotransformer replacements may postpone the need (based on enhanced criteria aligning with the IRRP) to beyond 2044, the TWG recommends monitoring the demand growth in this area and revisiting this capacity need in the future regional planning.

8.5.14 K1W/K3W (St. Clair Ave. Jct. X Fairbank TS) Capacity

K1W and K3W 115 kV lines, extending between Manby TS (East) and Wiltshire TS, supply load to Fairbank TS and Wiltshire TS. Along this line, a 4.5 km tap from St. Clair Ave. Jct. to Fairbank TS supplies the Fairbank

[8] The existing autotransformer T7 is currently the most limiting unit and is planned for replacement by 2030. The other autotransformer T9 is also scheduled to be replaced at the same time. Following these replacements, the autotransformer limits are expected to increase.

TS. A portion of this line tap (~2.5 km) is currently planned to be relocated to accommodate new customer infrastructure.

The actual 2025 summer coincident peak load on the K1W/K3W line taps between St. Clair Ave. Jct. and Fairbank TS was approximately 122 MW. As noted in the IRRP, the load meeting capability of these line taps is approximately 180 MW based on the loss of one of the two circuits. It is currently anticipated and noted in the IRRP that the K1W/K3W line tap is projected to reach this load level in approximately 2036.

The current recommended plan to address this long-term need is to transfer load from Fairbank TS to the proposed Downsview MTS, as needed, to respect the limits of the K1W/K3W circuits. No investment or planning actions are required at this time, and the area supply needs will continue to be assessed in future planning cycles.

8.5.15 Leaside TS X Wiltshire TS – 115kV Circuits Capacity

The Leaside TS X Wiltshire TS corridor facilitates four 115 kV transmission lines (L13W, L14W, L18W, L15) that extend between Leaside TS and Wiltshire TS to supply load at Bridgman TS and Dufferin TS. Each line is comprised of a few distinct sections of either overhead conductors or underground cables. These lines are operated with the Wiltshire TS end normally open so they are, in effect, normally supplied radially from Leaside TS.

The actual 2025 summer coincident peak load on all L13W, L14W, L18W, L15 circuits was approximately 287 MW total. The L18W and L13W lines supply Dufferin TS via 1.3 km cable taps that have a load meeting capability to Dufferin TS of approximately 135 MW. These cable taps are known limitations and load level is managed accordingly to address this. Upgrading the capacity of these Dufferin TS cable taps would allow approximately 18 MW of additional Dufferin TS loading beyond which the main L13W line sections would start to become limiting. In the long term, as load growth at Bridgman TS and Dufferin TS evolves, sections of other lines may also reach limitations for certain contingencies.

As outlined in the IRRP and based on the load forecast that included the higher future Dufferin TS load, the plans to address the needs of this corridor currently include upgrading the capacity of the Dufferin TS supply cable taps, transferring load from the Dufferin TS load pocket to Wiltshire TS (assuming appropriately upgraded), and the installation of local energy storage systems. The TWG recommends monitoring the demand growth in this area and revisiting this capacity need in future regional planning cycles.

8.5.16 H1L/H3L Capacity – (Leaside TS X Bloor Jct.) and (Hearn SS X Basin TS) Sections

H1L and H3L 115 kV lines extend between Leaside TS and Hearn SS to supply load to Gerrard TS, Carlaw TS, and Basin TS. There are five distinct major line sections that make up the main path of each of these lines – two are overhead line sections; three are underground cable sections. The overhead line sections are the sections that may potentially experience capacity needs in the long-term.

The first overhead line section of H1L/H3L, from Leaside TS to Bloor St. Jct., may begin to experience capacity limitations in approximately 2036 when the Portlands Energy Centre G3 is unavailable and an n-2 contingency removes the H1L line, as noted in the IRRP. Similarly, the second overhead line section of

H1L/H3L, from Hearn SS to Basin TS, may begin to experience capacity limitations in approximately 2041 due to n-1 companion circuit outages.

The Leaside 34 Jct. x Bloor St. Jct. section of the H1L/H3L circuits is anticipated to be replaced by approximately 2031 due to asset renewal need. To address the long-term capacity need, the ampacity requirement identified in the IRRP will also be considered during the project development stage. For the Hearn SS X Basin TS section of the H1L/H3L circuits, the current recommended plan to address this long-term need is to reconductor the line section with higher ampacity conductors. No investment or planning actions are required at this time, and the area supply needs will continue to be assessed in future planning cycles.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for the Toronto region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon [2026-2035] are provided in Table 9-1 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9-1: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Budgetary Cost ($M) [c]
Asset Renewal Needs				
Basin TS	Transformers T3/T5 replacement*	Hydro One	2030	-
Manby TS	Autotransformers (T7, T9, T12) replacement, Step-down transformer (T13/T14) replacement*	Hydro One	2030 2033	
Leslie TS	Transformer T1, T4 replacement	Hydro One	2032	
Dufferin TS	Transformer T2 replacement*	Hydro One	2032	
Cecil TS	115kV Switchgear replacement	Hydro One	2032	
Bermondsey TS	Transformers T3/T4 replacement	Hydro One	2033	
Strachan TS	Transformers T13/T15 replacement*	Hydro One	2033	
Agincourt TS	Transformers T5/T6 replacement	Hydro One	2033	
Terauley TS	Transformers T1/T2/T3/T4 replacement	Hydro One	2033	
Carlaw TS	Transformers T1/T2 replacement*	Hydro One	2033	
Rexdale TS	Transformer T2 replacement	Hydro One	2033	
John TS	Transformer T3 replacement*	Hydro One	2033	
Duplex TS	Transformers T1/T2 & T3/T4 replacement*	Hydro One	2034	
Fairchild TS	Transformers T1 & T3/T4 replacement	Hydro One	2034	
Warden TS	Transformer T4 replacement	Hydro One	2035	
Finch TS	Transformer T1 replacement	Hydro One	2035	

H1L/H3L/H6LC/H8LC	Leaside Jct. X Bloor St. Jct. – Overhead line section renewal	Hydro One	2031	
L9C/L12C	Leaside TS X Balfour Jct. – Overhead line section renewal	Hydro One	2031	
H1L/H3L & H2JK	Underground cable replacement	Hydro One	2035	
Station Capacity Needs				
Bathurst TS & Finch TS	Connect Downsview MTS (Load Transfers to new Downsview MTS) - First DESN (Phase 1) - Second DESN (Phase 2)	THESL / Hydro One	 2033 2039	$135-155M[(d)]
Scarboro TS	Build third Scarboro TS DESN (Load Transfers to new Scarboro DESN)	Hydro One / THESL	2035	$55-65M
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	Hydro One / THESL	2035	$55-65M
Sheppard TS	Expand T1/T2 DESN using the idle windings	Hydro One / THESL	2029	$16M
Transformation Capacity Need				
Manby TS (West) Autotransformers	Load Transfer (Copeland T2/T4 to Leaside Supply) + Reliance on existing Manby Remedial Action Scheme	-	2026	-
Transmission Line Capacity Need				
Manby TS X Riverside Jct.: 115 kV Circuits	Upgrade capacity of 115 kV circuits	Hydro One	2029	$25M
Richview TS X Manby TS: 230 kV Circuits	230 kV Corridor Reinforcement	Hydro One	2032	N/A[(b)]

*Transformer units to be replaced with higher rated standard units.

Notes:

a) The Planned In-Service dates are tentative and subject to change.
b) The recommended plan to address the Richview TS x Manby TS corridor need is expected by Q4 2026 as part of the GTA West IRRP.
c) Costs are tentative high-level budgetary planning estimates based on 2026 dollars and subject to change.
d) Property procurement costs not included.

10. REFERENCES

[1] Hydro One, Toronto RIP - Report (2nd cycle), (published March 6, 2020)

[2] Hydro One, Toronto NA – Report (3rd cycle), (published December 19, 2022)

[3] Independent Electricity System Operator, Toronto SA – Report (3rd cycle), (published March 21, 2023)

[4] Independent Electricity System Operator, Toronto IRRP – Report (3rd Cycle), (published October 31, 2025)

[5] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 6.0 September 10, 2025)

[6] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[7] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. May 01, 2026)

[8] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Toronto Region – Summer Coincident – Reference Load Forecast

		Near to Medium-Term Forecast (MW)										Long-Term Forecast (MW)		
AREA & STATION	**LTR (MW)**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2040**	**2044**
NORTH 230kV	**1902**	**1389**	**1410**	**1430**	**1493**	**1517**	**1542**	**1573**	**1611**	**1648**	**1680**	**1728**	**1924**	**2119**
Agincourt TS	174	97	104	111	117	124	126	128	130	131	132	134	142	150
Bathurst TS	361	235	240	240	284	271	282	294	310	325	341	340	339	339
Cavanagh MTS	157	96	97	98	101	105	109	112	114	115	117	120	130	140
Downsview MTS		0	0	0	0	0	0	0	0	0	0	32	163	293
Fairchild TS	346	275	278	282	287	311	315	321	324	327	323	326	340	354
Finch TS	366	311	315	325	330	334	339	347	352	360	367	368	370	372
Leslie TS	323	257	259	256	254	251	249	247	256	265	274	280	306	331
Malvern TS	176	117	118	118	119	120	121	123	124	125	126	127	133	139
EAST 230kV	**1502**	**971**	**1009**	**1047**	**1064**	**1088**	**1122**	**1159**	**1198**	**1232**	**1266**	**1297**	**1420**	**1543**
Bermondsey TS	349	153	187	192	196	197	199	202	205	207	209	212	224	236
Ellesmere TS	189	143	142	150	152	153	155	158	160	162	163	166	175	185
Leaside TS	210	145	139	136	135	133	132	132	135	136	138	140	150	160
Scarboro TS	364	192	195	210	211	227	248	270	296	320	345	362	433	503
Sheppard TS	208	194	197	203	210	216	223	227	231	234	238	243	264	285
Warden TS	182	144	148	155	161	163	165	168	170	172	174	174	174	174
WEST 230kV	**1239**	**817**	**803**	**816**	**831**	**840**	**847**	**866**	**882**	**891**	**901**	**917**	**979**	**1041**
Horner TS	367	256	260	264	267	269	273	277	280	281	282	285	299	311
Manby TS	226	152	154	157	162	167	172	178	182	185	189	194	216	238
Rexdale TS	186	108	109	108	109	108	109	110	114	117	121	125	140	156
Richview TS	460	300	281	287	294	296	294	300	306	307	309	312	324	336
LEASIDE 115kV	**1804**	**1191**	**1182**	**1194**	**1213**	**1220**	**1237**	**1252**	**1290**	**1313**	**1327**	**1357**	**1476**	**1600**
Basin TS	88	57	52	56	65	69	80	85	106	116	125	134	170	206
Bridgman TS	191	130	129	126	125	124	122	119	119	120	118	120	127	138
Carlaw TS	74	46	37	36	35	35	35	35	36	37	38	40	47	55
Cecil TS	212	127	131	135	140	142	145	148	150	151	153	155	163	170
Charles TS	211	157	157	155	156	154	153	152	153	154	155	157	165	174
Dufferin TS	180	147	146	145	144	142	141	141	143	144	137	137	137	137
Duplex TS	128	82	83	86	88	91	93	96	98	100	102	106	122	138
Esplanade TS	186	109	106	108	110	111	113	117	120	121	123	125	132	139
Gerrard TS	128	63	63	64	64	64	64	65	66	66	67	69	74	79
Glengrove TS	86	61	62	62	62	62	62	63	64	66	68	70	78	86
Main TS	104	65	66	66	66	65	65	65	67	68	70	72	80	89
Terauley TS	216	146	149	155	157	160	163	167	169	170	171	173	182	191
MANBY E 115kV	**620**	**347**	**347**	**355**	**364**	**370**	**378**	**390**	**397**	**403**	**421**	**428**	**457**	**486**
Fairbank TS	222	152	149	151	155	157	161	166	168	170	165	165	165	165
Runnymede TS	220	119	122	125	129	133	135	139	143	146	159	162	173	185
Wiltshire TS	178	76	77	79	80	81	82	84	86	87	96	101	119	137
MANBY W 115kV	**715**	**423**	**429**	**471**	**474**	**479**	**482**	**484**	**483**	**485**	**488**	**493**	**510**	**534**
Copeland MTS	232	140	144	179	179	178	177	177	176	175	175	175	175	178
John TS	312	157	160	163	165	169	170	171	171	173	175	176	184	192
Strachan TS	171	125	126	130	130	132	134	136	136	137	138	142	152	164
Grand Total	**7783**	**5137**	**5181**	**5314**	**5438**	**5514**	**5608**	**5723**	**5860**	**5971**	**6083**	**6219**	**6766**	**7323**

Table A.2: Toronto Region – Winter Coincident – Reference Load Forecast

		Near to Medium-Term Forecast (MW)										Long-Term Forecast (MW)		
AREA & STATION	**LTR (MW)**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2040**	**2044**
NORTH 230kV	**2108**	**1342**	**1371**	**1394**	**1437**	**1465**	**1496**	**1521**	**1551**	**1581**	**1611**	**1658**	**1846**	**2035**
Agincourt TS	193	84	90	96	102	109	112	113	115	116	117	119	129	138
Bathurst TS	390	219	227	230	254	262	253	263	275	288	320	325	344	363
Cavanagh MTS	187	110	111	113	116	120	124	128	129	131	132	135	149	162
Downsview MTS		0	0	0	0	0	0	0	0	0	0	17	86	154
Fairchild TS	389	258	262	268	273	277	300	304	307	310	293	299	321	344
Finch TS	403	285	288	293	298	303	310	315	319	323	326	332	357	381
Leslie TS	357	278	283	282	283	283	286	285	292	300	308	315	342	370
Malvern TS	190	109	110	110	110	111	112	113	113	114	114	115	119	124
EAST 230kV	**1664**	**956**	**1010**	**1055**	**1072**	**1081**	**1114**	**1149**	**1183**	**1218**	**1250**	**1283**	**1415**	**1547**
Bermondsey TS	389	141	180	186	190	191	194	197	199	202	204	208	223	238
Ellesmere TS	206	139	139	147	148	149	152	154	155	157	158	161	172	184
Leaside TS	229	149	146	145	144	142	144	145	148	150	152	156	171	187
Scarboro TS	412	196	202	219	221	219	236	256	278	301	322	340	411	482
Sheppard TS	231	174	179	187	193	199	206	211	214	218	221	226	244	263
Warden TS	198	157	163	171	177	179	183	186	188	190	193	193	193	194
WEST 230kV	**1355**	**863**	**858**	**875**	**888**	**897**	**906**	**923**	**936**	**947**	**964**	**983**	**1057**	**1131**
Horner TS	394	263	270	275	278	280	286	290	294	296	298	302	322	341
Manby TS	252	147	151	155	159	164	169	175	178	181	184	191	218	245
Rexdale TS	200	111	112	113	113	113	114	115	118	121	124	128	144	160
Richview TS	509	341	324	332	338	340	337	343	347	348	358	361	373	385
LEASIDE 115kV	**1955**	**1289**	**1245**	**1265**	**1281**	**1290**	**1314**	**1329**	**1366**	**1393**	**1387**	**1421**	**1557**	**1697**
Basin TS	104	66	59	62	69	73	84	87	107	116	125	133	165	197
Bridgman TS	199	135	135	133	133	131	130	127	128	129	130	132	142	156
Carlaw TS	81	58	49	49	48	48	48	49	50	52	53	56	66	76
Cecil TS	220	130	119	124	128	129	131	133	135	136	137	138	146	153
Charles TS	221	171	173	173	173	172	173	172	173	174	174	177	189	200
Dufferin TS	203	161	163	164	165	164	165	167	170	173	145	144	144	143
Duplex TS	144	88	91	95	97	100	102	106	108	110	112	117	136	155
Esplanade TS	200	113	97	99	100	101	102	105	107	109	111	112	119	126
Gerrard TS	146	69	70	71	71	71	72	73	74	75	76	78	87	95
Glengrove TS	104	66	68	69	69	70	71	72	74	76	79	82	94	106
Main TS	117	76	78	79	80	80	81	82	84	86	88	92	106	120
Terauley TS	216	155	143	148	149	151	153	156	156	156	157	159	164	169
MANBY E 115kV	**676**	**356**	**361**	**371**	**379**	**387**	**397**	**409**	**416**	**426**	**466**	**479**	**530**	**581**
Fairbank TS	241	147	146	150	153	156	161	166	168	173	178	179	182	185
Runnymede TS	238	126	130	134	137	141	144	149	152	156	158	163	183	203
Wiltshire TS	198	83	85	88	89	90	91	94	96	97	130	137	165	193
MANBY W 115kV	**766**	**365**	**416**	**461**	**462**	**464**	**465**	**467**	**465**	**468**	**474**	**480**	**501**	**528**
Copeland MTS	244	74	131	167	167	165	163	163	162	161	161	160	159	161
John TS	326	150	153	157	158	159	159	160	158	160	163	164	174	185
Strachan TS	196	141	132	137	138	140	142	144	145	147	151	155	167	182
Grand Total	**8524**	**5170**	**5260**	**5421**	**5519**	**5583**	**5692**	**5798**	**5918**	**6032**	**6151**	**6302**	**6905**	**7520**

Table A.3: Toronto Region – Summer Non-Coincident – Reference Load Forecast

		Near to Medium-Term Forecast (MW)										Long-Term Forecast (MW)		
AREA & STATION	**LTR (MW)**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2040**	**2044**
NORTH 230kV	**1902**	**1480**	**1502**	**1523**	**1590**	**1614**	**1641**	**1674**	**1715**	**1745**	**1798**	**1847**	**2048**	**2248**
Agincourt TS	174	102	109	117	124	131	133	135	137	138	140	142	150	158
Bathurst TS	361	254	261	261	308	294	306	319	336	345	370	369	368	367
Cavanagh MTS	157	107	107	109	113	117	121	125	127	128	130	133	144	156
Downsview MTS		0	0	0	0	0	0	0	0	0	0	32	163	293
Fairchild TS	346	283	285	290	294	320	324	329	333	336	332	335	350	364
Finch TS	366	329	333	343	348	352	358	365	371	378	388	388	390	393
Leslie TS	323	276	278	274	273	269	267	265	275	284	302	309	337	364
Malvern TS	176	129	129	129	130	131	133	135	136	137	138	139	146	153
EAST 230kV	**1502**	**1021**	**1067**	**1106**	**1124**	**1150**	**1186**	**1225**	**1266**	**1303**	**1339**	**1370**	**1496**	**1622**
Bermondsey TS	349	171	212	217	222	223	225	229	232	234	236	240	253	267
Ellesmere TS	189	146	146	154	155	157	159	162	164	166	167	169	179	189
Leaside TS	210	153	148	145	143	141	140	140	143	144	146	149	159	169
Scarboro TS	364	207	210	227	227	245	267	291	319	345	371	389	459	529
Sheppard TS	208	194	197	203	210	216	223	228	231	234	238	243	265	287
Warden TS	182	150	154	161	167	169	171	175	177	179	180	180	181	181
WEST 230kV	**1239**	**899**	**887**	**902**	**919**	**929**	**937**	**957**	**973**	**983**	**986**	**1003**	**1072**	**1140**
Horner TS	367	262	266	270	273	275	279	283	286	287	288	292	305	318
Manby TS	226	177	178	183	189	194	200	207	212	215	219	226	251	276
Rexdale TS	186	118	119	119	119	119	119	121	125	128	132	137	154	171
Richview TS	460	343	324	331	339	342	339	346	351	353	346	349	362	375
LEASIDE 115kV	**1804**	**1231**	**1222**	**1234**	**1253**	**1260**	**1278**	**1293**	**1333**	**1357**	**1372**	**1403**	**1526**	**1654**
Basin TS	88	59	55	59	67	72	84	89	110	121	130	140	177	215
Bridgman TS	191	131	130	128	127	125	123	120	121	121	119	121	128	139
Carlaw TS	74	49	39	38	38	38	37	37	38	40	41	43	51	58
Cecil TS	212	131	135	139	145	147	150	152	155	156	157	160	168	176
Charles TS	211	162	162	160	161	159	158	157	158	159	159	162	170	179
Dufferin TS	180	151	150	149	148	146	145	144	146	148	141	141	140	140
Duplex TS	128	83	84	87	89	92	94	97	100	101	103	107	123	139
Esplanade TS	186	112	109	111	112	114	116	120	123	124	126	128	135	143
Gerrard TS	128	75	75	75	75	75	76	77	78	78	79	81	87	92
Glengrove TS	86	62	63	63	63	63	64	64	66	68	70	72	80	88
Main TS	104	68	68	68	68	68	67	68	69	70	72	74	83	92
Terauley TS	216	148	151	157	159	162	165	169	171	172	173	176	184	193
MANBY E 115kV	**620**	**373**	**373**	**381**	**391**	**398**	**406**	**419**	**426**	**432**	**452**	**460**	**491**	**522**
Fairbank TS	222	165	161	163	168	170	174	179	182	182	179	179	179	179
Runnymede TS	220	130	132	136	140	144	147	152	156	159	174	177	189	201
Wiltshire TS	178	79	80	82	83	84	85	88	89	91	100	105	124	142
MANBY W 115kV	**715**	**441**	**448**	**491**	**494**	**500**	**502**	**504**	**504**	**506**	**507**	**512**	**530**	**556**
Copeland MTS	232	143	147	183	183	182	181	181	180	179	179	179	179	182
John TS	312	167	170	173	175	179	181	182	182	183	184	185	193	202
Strachan TS	171	131	132	136	136	138	140	142	143	144	145	148	159	172
Grand Total	**7783**	**5445**	**5498**	**5638**	**5772**	**5851**	**5950**	**6072**	**6218**	**6326**	**6455**	**6596**	**7164**	**7742**

Table A.4: Toronto Region – Winter Non-Coincident – Reference Load Forecast

		Near to Medium-Term Forecast (MW)										Long-Term Forecast (MW)		
AREA & STATION	**LTR (MW)**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2040**	**2044**
NORTH 230kV	**2108**	**1470**	**1502**	**1527**	**1576**	**1608**	**1643**	**1671**	**1703**	**1736**	**1775**	**1825**	**2026**	**2227**
Agincourt TS	193	103	111	119	126	134	137	140	141	142	144	147	158	169
Bathurst TS	390	243	252	255	282	290	281	293	307	321	355	360	381	402
Cavanagh MTS	187	123	125	127	131	135	140	143	145	147	149	152	167	182
Downsview MTS		0	0	0	0	0	0	0	0	0	0	17	86	154
Fairchild TS	389	272	277	283	288	292	316	320	323	326	309	315	339	362
Finch TS	403	316	320	326	331	337	344	351	355	359	362	369	396	423
Leslie TS	357	293	298	297	298	299	302	301	309	317	332	339	369	398
Malvern TS	190	119	121	121	121	121	123	124	124	125	125	126	131	136
EAST 230kV	**1664**	**1020**	**1079**	**1126**	**1144**	**1153**	**1188**	**1225**	**1262**	**1299**	**1333**	**1367**	**1504**	**1641**
Bermondsey TS	389	150	192	199	203	204	207	210	213	215	218	222	238	254
Ellesmere TS	206	149	150	158	159	161	163	166	167	168	170	173	185	197
Leaside TS	229	157	153	152	151	150	151	153	156	158	160	164	180	197
Scarboro TS	412	211	218	236	237	236	254	275	299	323	346	364	434	505
Sheppard TS	231	194	199	207	214	220	228	233	236	240	244	249	270	291
Warden TS	198	160	166	174	180	182	185	189	191	193	196	196	196	197
WEST 230kV	**1355**	**931**	**926**	**945**	**959**	**969**	**979**	**997**	**1012**	**1023**	**1042**	**1063**	**1145**	**1227**
Horner TS	394	274	281	286	289	292	298	302	306	308	310	315	335	355
Manby TS	252	166	170	175	179	184	190	197	200	204	208	215	246	277
Rexdale TS	200	129	131	131	131	132	133	134	138	141	145	150	168	187
Richview TS	509	362	345	352	359	361	358	364	368	370	380	383	396	409
LEASIDE 115kV	**1955**	**1341**	**1292**	**1314**	**1331**	**1340**	**1365**	**1382**	**1421**	**1449**	**1444**	**1480**	**1623**	**1770**
Basin TS	104	72	64	68	76	80	91	95	117	127	136	145	180	216
Bridgman TS	199	139	138	137	136	135	134	131	132	133	133	136	147	161
Carlaw TS	81	61	52	52	51	51	52	52	53	55	56	59	70	81
Cecil TS	220	139	126	131	135	136	139	141	143	144	145	147	155	162
Charles TS	221	177	178	178	178	177	178	177	178	179	180	183	194	206
Dufferin TS	203	165	167	168	168	168	169	170	174	177	148	148	147	147
Duplex TS	144	89	92	96	98	100	103	106	109	111	113	118	137	156
Esplanade TS	200	119	101	104	104	105	107	110	113	114	116	118	125	132
Gerrard TS	146	80	80	81	81	82	83	84	85	86	87	90	99	108
Glengrove TS	104	67	69	70	71	71	72	73	75	78	80	83	96	108
Main TS	117	77	79	79	80	81	82	83	85	87	89	92	107	121
Terauley TS	216	158	145	150	151	153	155	158	158	159	160	161	166	172
MANBY E 115kV	**676**	**396**	**401**	**413**	**422**	**430**	**441**	**454**	**462**	**474**	**516**	**530**	**586**	**642**
Fairbank TS	241	158	157	161	165	168	173	178	180	186	192	192	196	199
Runnymede TS	238	153	157	162	166	170	174	179	183	187	190	196	220	244
Wiltshire TS	198	85	87	90	91	92	94	97	99	100	134	141	170	199
MANBY W 115kV	**766**	**396**	**449**	**496**	**497**	**500**	**501**	**503**	**502**	**505**	**506**	**512**	**535**	**565**
Copeland MTS	244	76	136	173	172	170	169	169	168	167	166	166	165	167
John TS	326	171	174	179	180	182	183	183	182	183	182	184	194	206
Strachan TS	196	148	139	144	145	147	149	152	152	155	159	163	176	192
Grand Total	**8524**	**5553**	**5649**	**5821**	**5929**	**5999**	**6117**	**6232**	**6362**	**6486**	**6616**	**6777**	**7419**	**8073**

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Agincourt TS T5/T6	230/27.6	C4R/C10A
2	Basin TS T3/T5	115/13.8	H3L/H1L
3	Bathurst TS T1/T2	230/27.6	P22R/C18R
4	Bathurst TS T3/T4	230/27.6	P22R/C18R
5	Bermondsey TS T1/T2	230/27.6	C17L/C14L
6	Bermondsey TS T3/T4	230/27.6	C17L/C14L
7	Bridgman TS T11/T12/T13/T14/T15	115/13.8	L14W/L15/L18W
8	Carlaw TS T1/T2	115/13.8	H1L/H3L
9	Cavanagh MTS T1/T2	230/27.6	C20R/C10A
10	Cecil TS T1/T2	115/13.8	Cecil Buses H & P
11	Cecil TS T3/T4	115/13.8	Cecil Buses P & H
12	Charles TS T1/T2	115/13.8	L4C/L9C
13	Charles TS T3/T4	115/13.8	L12C/L4C
14	Copeland MTS T1/T3	115/13.8	D11J/D12J
15	Copeland MTS T2/T4	115/13.8	D11J/D12J
16	Dufferin TS T1/T3	115/13.8	L13W/L18W
17	Dufferin TS T2/T4	115/13.8	L13W/L18W
18	Duplex TS T1/T2	115/13.8	L16D/L5D
19	Duplex TS T3/T4	115/13.8	L5D/L16D
20	Ellesmere TS T3/T4	230/27.6	C2L/C3L
21	Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
22	Fairbank TS T5/T6	115/27.6	K3W/K1W
23	Fairbank TS T7/T8	115/27.6	K3W/K1W
24	Fairchild TS T1/T2	230/27.6	C18R/C20R
25	Fairchild TS T3/T4	230/27.6	C18R/C20R
26	Finch TS T1/T2	230/27.6	C20R/P22R
27	Finch TS T3/T4	230/27.6	P21R/C4R
28	Gerrard TS T1/T2	115/13.8	H3L/H1L
29	Glengrove TS T1/T3	115/13.8	D6Y/L2Y
30	Glengrove TS T2/T4	115/13.8	D6Y/L2Y

31	Horner TS T3/T4	230/27.6	R15K/R2K
32	Horner TS T1/T2	230/27.6	R2K/R15K
33	Islington TS T1/T2	230/27.6	C5R/C20R
34	John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
35	John TS T5/T6	115/13.8	John Buses K1 & K4
36	Leaside TS T19/T20/T21 13.8	230/13.8	Leaside Buses HL2, HL3, HL16
37	Leaside TS T19/T20/T21 27.6	230/27.6	Leaside Buses HL2, HL3, HL16
38	Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
39	Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
40	Leslie TS T3/T4	230/27.6	P21R/C5R
41	Main TS T3/T4	115/13.8	H7L/H11L
42	Malvern TS T3/T4	230/27.6	C4R/C5R
43	Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
44	Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
45	Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
46	Rexdale TS T1/T2	230/27.6	V74R/V76R
47	Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
48	Richview TS T5/T6	230/27.6	V74R/V72R
49	Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
50	Runnymede TS T1/T2	115/27.6	K11W/K12W
51	Runnymede TS T5/T6	115/27.6	K12W/K11W
52	Scarboro TS T21/T22	230/27.6	C14L/C2L
53	Scarboro TS T23/T24	230/27.6	C15L/C3L
54	Sheppard TS T1/T2	230/27.6	C16L/C15L
55	Sheppard TS T5/T6	230/27.6	C15L/C16L
56	Strachan TS T12/T14	115/13.8	H2JK/K6J
57	Strachan TS T13/T15	115/13.8	K6J/H2JK
58	Terauley TS T1/T4	115/13.8	C7E/C5E
59	Terauley TS T2/T3	115/13.8	C7E/C5E
60	Warden TS T3/T4	230/27.6	C14L/C17L
61	Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
62	Wiltshire TS T2/T7	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Richview x Manby	R1K, R2K, R13K, R15K	230
2	Richview x Cooksville	R24C	230
3	Manby x Cooksville	K21C, K23C	230
4	Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
5	Cherrywood x Richview	C4R, C5R, C18R, C20R	230
6	Cherrywood x Agincourt	C10A	230
7	Parkway x Richview	P21R, P22R	230
8	Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
9	Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
10	Manby West x John	K6J, K13J, K14J	115
11	Manby West x John x Hearn	H2JK	115
12	John x Copeland	D11J, D12J	115
13	Copeland x Esplanade x Hearn	H9DE, H10DE	115
14	Esplanade x Cecil	C5E, C7E	115
15	Hearn x Cecil x Leaside	H6LC, H8LC	115
16	Hearn x Leaside	H1L, H3L, H7L, H11L	115
17	Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
18	Leaside x Charles	L4C	115
19	Leaside x Cecil	L9C, L12C	115
20	Leaside x Duplex	L5D, L16D	115
21	Leaside x Glengrove	L2Y	115
22	Duplex x Glengrove	D6Y	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Toronto Hydro-Electric System Limited ("THESL")
2	Hydro One Networks Inc. (Distribution)
3	Alectra Utilities Corporation ("Alectra")
4	Elexicon Energy Inc. ("Elexicon")

Appendix E: List of Municipalities in the Region

Sr. no.	Name of Municipality
1	City of Toronto

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	Electricity Demand Side Management
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria

PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station

Integrated Regional Resource Plan

Northwest Region
January 2023

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List of Acronyms

Acronym	Definition
APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTE	Long-term Emergency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station
ULTC	Under-Load Tap Changer

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Northwest region which included the following members:

Independent Electricity System Operator (IESO)

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

Sioux Lookout Hydro Inc.

Synergy North

The Working Group assessed the reliability of electricity supply to customers in the Northwest Region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options while maintaining flexibility to accommodate changes in key conditions over time.

The Northwest Working Group members agree with the Integrated Regional Resource Plan (IRRP)'s recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations. The Northwest Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Northwest region over the next 20 years from 2021 to 2040. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay. A geographic map of the Northwest region is shown in Figure 1-1. Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region encompasses the 230 kV circuits from the Manitoba interties in the west to Marathon TS in the east as well as the 115 kV sub-systems in between. A single line diagram of the electrical infrastructure in the region is shown in Figure 1-2.

Northwest regional electricity demand is winter peaking and, over the last five years, has grown on average by 1.1% per year. Electricity supply to the Northwest region is provided through the 230 kV East-West Tie circuits from Wawa TS, as well as from interconnections with Manitoba and Minnesota. Local generation in the region is predominantly hydroelectric and biomass-fueled.

The region's electricity is delivered by five local distribution companies (LDCs): Hydro One Networks Inc., Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., and Synergy North. Hydro One Networks is also the lead transmitter in the region for regional planning purposes. Note that three transmitters own assets in the Northwest region: Hydro One Networks, Nextbridge Infrastructure, and Wataynikaneyap Power. As the lead transmitter, Hydro One Networks coordinates the involvement of other transmitters as necessary. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and Hydro One Networks.

Development of the Northwest IRRP was initiated in Jan 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and the Scoping Assessment Outcome Report in Jan 2021 by the IESO.[1] The Scoping Assessment identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[1] The Needs Assessment can found on Hydro One's Northwest Ontario regional planning website and the Scoping Assessment Outcome Report can be found on the IESO's Northwest regional planning engagement website.

- Demand forecast scenarios, distributed generation assumptions, and conservation and demand management are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An update on the Supply to the Ring of Fire study is provided in Section 8
- A summary of engagement to date and the next steps are provided in Section 9; and
- The conclusion is provided in Section 10



Figure 1-1 | Geographic Map of the Northwest Region

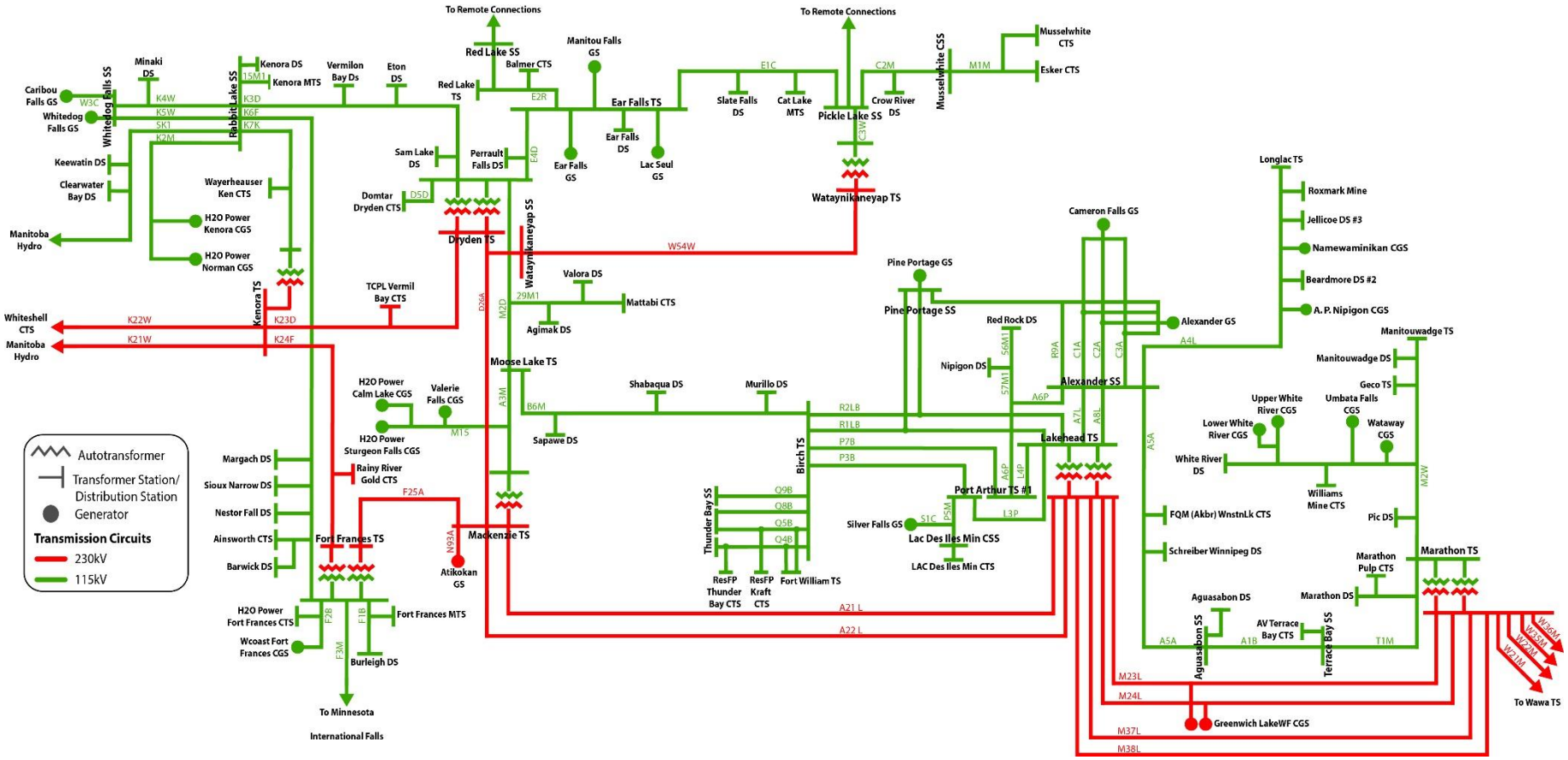


Figure 1-2 | Electricity Infrastructure in the Northwest Ontario Region

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Northwest region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through the application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic and feasible), and feedback from stakeholders.

There are several recent or ongoing transmission reinforcement projects in the Northwest region including the:

- East-West Tie Reinforcement (new double circuit 230 kV line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS),
- Waasigan Transmission Line Project (Phase 1 being a new double circuit 230 kV line from Lakehead TS to Mackenzie TS and Phase 2 being a new single circuit 230 kV line from Mackenzie TS to Dryden TS), and
- Wataynikaneyap Transmission Project (new single circuit 230 kV line from Dinorwic Junction near Dryden to Wataynikaneyap TS near Pickle Lake as well as 115 kV remote connection circuits north of Pickle Lake and Red Lake).

Taken together, these projects reinforce many of the 230 kV transmission paths in the region. With these reinforcement projects, the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs. There are no new transmission projects recommended as a result of this Northwest planning initiative.

Northwest electricity demand growth is driven by the mining sector which tends to add large incremental blocks of load, often with short lead times. Therefore, this IRRP also studied several high growth sensitivities beyond forecast demand levels to test the robustness of the plan.

The plan below is organized into two sections: near-/medium-term recommendations and ongoing monitoring. Near-/medium-term recommendations include actions or further studies to be undertaken by Working Group member(s) by a specified date. These recommendations address needs with a high level of forecast certainty and requires firm commitments in this cycle of regional planning. Ongoing monitoring activities address long-term needs or potential needs flagged in high growth sensitivities that may emerge but are not yet certain based on the latest electricity demand forecast. This approach ensures that the IRRP provides clear guidance on investments needed in the near future while remaining flexible to consider new information such as electrification, energy efficiency, and industrial/mining development plans.

2.1 Near-/Medium-Term Recommendations

The near- and medium-term recommendations are summarized in Table 2-1 and further discussed below.

Table 2-1 | Summary of Near- and Medium-Term Recommendations

Need/Subsystem	Recommendation	Lead Responsibility	Required By
Kenora MTS Station Capacity	Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO's Local Initiative Program and Synergy North will lead further non-wires analysis in local planning	Synergy North; IESO	2029
Crilly DS Station Capacity	NWAs not suitable; Hydro One Distribution will refine options for refurbishment or a new station in local planning	Hydro One Distribution	2027
Margach DS Station Capacity	NWAs not suitable; Hydro One Dx will install fan monitoring if growth materializes and monitor for additional growth that might necessitate a second transformer	Hydro One Distribution	2023
Fort Frances MTS Customer Reliability	Reconfiguration of Fort Frances TS to reduce supply interruptions to Fort Frances MTS during transmission system outages; Fort Frances Power and Hydro One Transmission will refine configuration in local planning	Fort Frances Power; Hydro One Transmission	As Soon as Practical
E1C Operation and High Voltage	With the new W54W circuit in-service, part of the Wataynikaneyap Transmission Project, E1C will be operated "normally open" and additional reactors will be installed at/near Pickle Lake SS to manage high voltages; Hydro One and IESO will collaborate in the Regional Infrastructure Plan to refine location of open point and reactor sizing	IESO Hydro One Transmission	As Soon as Practical

Note that all costs discussed below are planning-level estimates (-50% to +100%) provided for the purpose of comparing options. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

2.1.1 Kenora MTS Station Capacity

Kenora MTS is expected to reach capacity in 2029. There are no upstream supply constraints aside from the station capacity itself. The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits.[2] The wires options and distribution benefits are further discussed in Section 7.1.4.1. Based on the forecast hourly demand and associated energy-not-served profiles, three non-wires alternatives (NWAs) were identified including a 4 MW gas turbine facility, a 6-hour 4 MW battery, and a hybrid option of energy efficiency and demand response. The cost of these NWAs generally falls between the cost of expanding the existing station and a new station.[2] Therefore, the decision to pursue NWAs versus traditional wires options rests on distribution system benefits that can be realized by each option. NWA options analysis is further discussed in Section 7.1.4.2.

The technologies, regulatory framework, and protocols required to implement dispatchable NWAs to meet local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[3] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS.

Therefore, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[4] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

2.1.2 Crilly DS Station Capacity

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to

[2] The methodology for calculating cost estimates is set out in Section 7.1.1

[3] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[4] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to the existing reliance on backup generation. Distributed energy resources cannot remove the reliance on backup power and provide reliability comparable with other standard supply arrangements. Furthermore, the pool of customers served at Crilly DS is too small to target demand-modifying solutions such as energy efficiency and demand response. The IRRP recommends that Hydro One Distribution conducts local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost. Options considered thus far include:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),
- Rebuild Crilly DS at a different location as a 115/25 kV HVDS,
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS, or
- Replace Crilly DS with a 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

Wires options for Crilly DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.2. Hydro One Distribution should monitor load growth to determine when a firm commitment to refurbish/rebuild Crilly DS is required.

2.1.3 Margach Station Capacity

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS. Margach DS is approximately 10 km east of Kenora. Non-wires alternatives are not capable of addressing this large near-term step increase in demand.

The IRRP recommends that Hydro One distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service but no recommendation beyond the fan monitoring is required today. Wires options for Margach DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.3.

2.1.4 Fort Frances MTS Customer Reliability

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS. The two stations are located immediately across the

street from each other. Fort Frances TS is configured in a manner that would result in Fort Frances MTS supply interruptions during certain transmission outages. Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. While the station equipment has not yet reached end-of-life, most equipment has reached or exceeded its typical useful life (as defined in the OEB's Asset Depreciation Study[5]) and will need to be replaced gradually over the next 10-15 years. While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power which could quickly use up the remaining station capacity. Furthermore, 115 kV breakers at Fort Frances TS are also approaching end of life around 2027 which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS. Customer reliability, sustainment, and potential capacity needs are further discussed in Sections 6.2.2 and 0.

Fort Frances Power is developing a roadmap for Fort Frances MTS considering the replacement of aging assets, demand growth, and reliability improvements by reconfiguring supply from Fort Frances TS. Considering these needs simultaneously will ensure the most optimal and cost-effective outcome. Hydro One has proposed several Fort Frances TS reconfigurations that would incrementally improve customer reliability for Fort Frances TS and are further discussed in Section 7.2. The IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and refine a configuration in local planning.

2.1.5 E1C Operation and High Voltage

With the new 230 kV Wataynikaneyap circuit W54W in-service, operating circuit E1C closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W. The IRRP confirms that E1C should be operated normally open. This configuration is consistent with the 2015 North of Dryden IRRP.

With E1C operated normally open, high voltage arises due to line charging. Studies show that opening E1C closer to the Ear Falls TS end minimizes high voltage issues. Additionally, the IRRP recommends an additional reactor (approximately 10 MVar) at or near Pickle Lake SS.

E1C closed loop transfer limitations and E1C normally open high voltage issues are further discussed in Section 6.2.3. The IESO and Hydro One Transmission will collaborate in the Regional Infrastructure Plan to refine the location of the open point on E1C and the sizing of the reactor, considering asset conditions and costs.

[5] The OEB's Asset Depreciation Study can be found on the Ontario Energy Board's website.

2.2 Ongoing Monitoring

In addition to the needs addressed in the near- and medium-term plan above, there are several long-term or potential needs that may emerge over the forecast horizon. These needs will be monitored by the Working Group to determine when future planning studies should be triggered.

2.2.1 Station Capacity Needs Emerging in the Long-term

White Dog DS and Marathon DS are expected to reach capacity in 2032 and 2038 respectively. In both cases, current demand already exceeds 85% of the station capacity but forecast growth is modest over the forecast horizon. As with many stations across the Northwest, growth can materialize quickly if industrial development intensifies. Therefore, White Dog DS and Marathon DS should be monitored, and further planning activities should be triggered at least five years before anticipated capacity needs to enable consideration of non-wires alternatives. White Dog DS and Marathon DS station capacity needs are further discussed in Section 6.2.1.4 and 6.2.1.5.

2.2.2 Potential Growth in the Red Lake Area

The Red Lake area has significant mining activity and electricity demand is forecast to grow from 58 MW today to 70 MW by 2028. The W54W circuit recently completed as part of the Wataynikaneyap Transmission Project will help relieve constraints on the existing 115 kV circuits to Red Lake.

No capacity needs are anticipated based on the current demand forecast which was finalized by the end of 2021. However, the Working Group is aware of additional potential mining projects that are not captured in the current reference scenario demand forecast.[6] The timing and amount of load associated with these mines are not yet certain but, considering the typical size of new mining projects, remaining capacity in the Red Lake area can quickly be exhausted. Section 6.3.1 identifies the load meeting capability for the Red Lake area as well as constraints on the supply to Ear Falls and Dryden. Depending on the demand that materializes, bulk system enhancements beyond the scope of this IRRP (e.g., Waasigan Transmission Line Project Phase 2) may also be required.

The Working Group will monitor growth in the Red Lake area to determine when future planning activities should be triggered. The IESO will also continue to update the mining demand forecast, including mines in the Red Lake area, to inform ongoing bulk planning activities.

[6] As described in Section 5.4, for the purpose of this IRRP, the mining sector demand forecast was finalized by the end of 2021. The Working Group is aware of additional future mining projects that were either brought to the awareness of the Working Group after 2021 or were not yet certain enough for inclusion in the demand forecast. The IESO is updating the mining sector demand forecast by end of Q1 2023 and will provide updates to the Working Group to inform the Regional Infrastructure Plan.

2.2.3 Potential Growth in the Fort Frances Area

Several large industrial customers have expressed interest in connecting in the Fort Frances area; these customers' potential loads are not included in the current demand forecast. While the incremental electricity demand associated with these customers (approximately totalling 100 MW) may be significant, no firm commitments have been made.

No supply capacity needs are anticipated based on the current demand forecast. Section 6.3.2 identifies the load meeting capability of the Fort Frances area. The Working Group will monitor growth in the Fort Frances area to determine when future planning activities should be triggered.

2.3 Coordination with ongoing Bulk Planning and Project Implementation Activities

In April 2022, as part of the IESO's obligation to recommend the specific scope and timing of the Waasigan Transmission Line Project, the IESO recommended a staged approach for construction with Phase 1 (a new line from Thunder Bay to Atikokan) being placed in-service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the region, update the mining sector demand forecast and provide an update on the need for Phase 2 (a new line from Atikokan to Dryden) by Q2 2023.

The IESO is also conducting a Northern Ontario Voltage Study to identify reactive compensation needs across northern Ontario. There are several recently implemented or planned major transmission reinforcement projects in the north including the East-West Tie Reinforcement, Waasigan Transmission Line Project, Wataynikaneyap Transmission Project, and Northeast Bulk Plan recommendations.[7] These projects will impact the voltage characteristics across the northern bulk transmission system, including the Northwest region. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

The Waasigan Transmission Line Project and Northern Ontario Voltage Study are further described in Section 4.2. The IESO will continue to update the Working Group regarding ongoing bulk planning and project implementation developments for consideration in the Regional Infrastructure Plan.

In addition to the plans above, the IESO is carrying out a Supply to the Ring of Fire study in parallel with this IRRP. The preliminary findings are discussed in Section 8. The Supply to the Ring of Fire Study will continue in 2023 and the IESO will update the working group on findings for consideration in future regional planning activities.

[7] The Need for Northeast Bulk System Reinforcements report can found on the Northeast Bulk Planning webpage.

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 defined planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;

3. An Integrated Regional Resource Plan (IRRP), led by the IESO, proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A Regional Infrastructure Plan (RIP), led by the transmitter, provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

Regional planning is not the only type of electricity planning in Ontario. Other planning activities include bulk system planning, carried out by the IESO, and distribution system planning, carried out by LDCs. There are inherent overlaps in these three levels of electricity infrastructure planning.

The IESO completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. The IESO's Regional Planning Process Review report is posted on the IESO's website. Implementation of Regional Planning Process Review recommendations by the IESO, Ontario Energy Board, and its Regional Planning Process Advisory Board are ongoing.

3.2 The Northwest Region and IRRP Development

The process to develop the Northwest IRRP was initiated in January 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and Scoping Assessment Outcome Report in January 2021 by the IESO. As per the 18-month timeline, triggered by the publication of the Scoping Assessment Outcome Report, the original publication date for the Northwest IRRP was scheduled for July 13, 2022.

In April 2022, the IESO wrote to the Ontario Energy Board (OEB) to provide notice that the IESO required an additional six months to complete the IRRP. The IRRP's original scope was expanded to include additional key developments in the Northwest region. The expanded scope enabled more extensive stakeholder engagement, consideration of additional growth sensitivities, and better alignment with ongoing bulk studies across the Northwest and Northeast regions. Based on the IESO's estimate of the additional time required to incorporate the expanded scope, the new expected posting date for the Northwest IRRP was extended to January 13, 2023.

4. Background and Study Scope

This is the second cycle of regional planning for the Northwest region. In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (published January 2015)

A summary of each of the above IRRPs can be found in the 2021 Scoping Assessment Outcome Report[8]. The Scoping Assessment for this planning cycle recommended a single IRRP covering the entire Northwest region. This report presents an integrated regional electricity plan for the next 20-year period from 2021-2040.

Note that two new transmission system projects, the East-West Tie ("EWT") reinforcement and the Wataynikaneyap Transmission Project ("Watay Project") came into service during the current IRRP study. They were both assumed to be in-service for the purpose of this IRRP's technical assessments. The EWT reinforcement adds four new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS and W35M and W36M from Marathon TS to Wawa TS. The new EWT circuits were placed in service in March 2022. The Watay Project includes a new 230 kV circuit, W54W, between Watay 230/115 kV TS and Dinorwic Junction on circuit D26A, which runs between Dryden TS and Mackenzie TS. W54W was placed in service in August 2022. The Watay Project includes the connection of ten remote First Nation communities north of Pickle Lake (electrically supplied by Pickle Lake SS) and an additional seven remote First Nation communities north of Red Lake (electrically supplied by Red Lake SS). As of Q4 2022, work is still underway to connect Pickle Lake and Red Lake remote communities, but they were assumed to be in service for the purpose of this IRRP's technical assessments.

4.1 Study Scope

This IRRP identifies electricity needs in the Northwest Region and develops and recommends options to meet these needs. A list of transmission facilities included in the scope of this study can be found in Appendix C. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation, and demand management (CDM), distributed generation (DG), transmission and distribution system

[8] The 2021 Scoping Assessment Outcome Report can be downloaded from the Northwest Regional Planning engagement webpage.

capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

The Northwest IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, considering facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC, NERC, and NPCC criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
- Confirming identified end-of-life asset replacement needs and timing with LDCs and transmitters;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including conservation and demand management;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

For the Northwest IRRP, areas of interest with high growth potential beyond forecast demand levels were identified through stakeholder engagement. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.1.1 Scope of Regional Planning Regarding New Connections

The purpose of the IRRP is to identify and address reliability needs that require coordination between transmitters, distribution companies, and the IESO. In the Northwest region, growth is driven in large part by industrial customers, predominantly in the mining sector. A subset of these customers are not currently connected to the electricity grid but are pursuing grid connection in the near term. The IRRP used the best available information to accurately simulate the connection arrangement of future customers and projects. However, IRRP technical studies were focused on evaluating the overall adequacy of regional infrastructure to supply forecast demand rather than the capability to supply any specific new project. The IRRP

did not study the local connection requirements of any individual project unless there was an opportunity to align with broader regional needs.[9]

4.2 Parallel Bulk Planning Activities

The Waasigan Transmission Line Project and the Northern Ontario Voltage study are proceeding in parallel with this IRRP and the upcoming Regional Infrastructure Plan. Findings and recommendations from these bulk planning activities will inform ongoing regional planning activities.

4.2.1 Waasigan Transmission Line Project

The Waasigan Transmission Line Project ("Waasigan Project"), formally the Northwest Bulk Line, was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project to:

- Increase electricity supply to the region west of Thunder Bay;
- Provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- Enhance the potential for development and connection of renewable energy facilities.

The LTEPs divided the Waasigan Project into three phases:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an Order in Council, also in 2013, that amended Hydro One's license to develop and seek approval for the Waasigan Project according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 based on the timing of projected supply capacity needs and the risk of them materializing earlier. The IESO committed to ongoing monitoring to determine when construction of both Phase 1 and Phase 2 should begin and to confirm that they are the best course of action to meet the needs.

[9] Potential customers seeking connection should note that participation in the IRRP does not replace connection processes, namely Customer Impact Assessments (CIA) or System Impact Assessments (SIA). Furthermore, the absence of regional reliability needs identified through the IRRP in a particular area does not guarantee that connection requests in that area will be approved in a CIA or SIA.

In 2022, the IESO updated the demand forecast for the region west of Thunder Bay with information from the IRRP demand forecast and feedback from stakeholders. The mining sector demand forecast drove the majority of the demand growth and is further discussed in Section 5.4. The updated demand forecast showed a need for Phase 1 starting in 2025 and a temporary need for Phase 2 in 2026 and 2027, but not thereafter as some existing mining projects reach end of life. Therefore, the IESO recommended a staged approached for construction where Hydro One would construct the Project to meet near-term system capacity needs, with Phase 1 being placed in service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the Region and provide an update in Q2 2023 on the expected need date for Phase 2. This is a balanced approach to accommodate growth in a timely manner while managing ratepayer risks.

The IESO recognizes that a firm need for Phase 2 could materialize quickly given the potential for additional growth in the region. The IESO is currently in the process of updating the mining demand forecast to reflect additional information received over the past year since the last forecast iteration and to better capture future growth driven by electrification trends and government policy. The forecast update is expected to be completed in Q1 2023.

4.2.2 Northern Ontario Voltage Study

The IESO is conducting a Northern Ontario Voltage Study to identify reactive compensation needs across the bulk system in northern Ontario. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

4.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. The decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as they are the direct beneficiaries, or with the provincial and federal governments, to advance broader policy objectives.

Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with this IRRP to help inform government policy and potential customers seeking connection. This study outlines opportunities for alignment, updated high-level transmission supply cost estimates, updated avoided diesel system costs from connecting remote communities, and greenhouse gas reductions as a result of supplying remote communities and potential mines from the electricity grid instead of local generation. The preliminary findings are discussed in Section 8.

The study scope and timing of this ongoing study will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

5. Electricity Demand Forecast

This section describes the development of the demand forecast for the Northwest Region that underpins this IRRP. The 20-year forecast has three components:

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the Northwest and is based on information submitted by local distribution companies.
- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This is typically comprised of large industrial customers that have their own transformation station. The transmission-connected forecast is informed by direct engagement with customers.
- **Mining Sector**: The mining sector forecast captures electricity demand from both existing grid-connected and known future mining projects that are not yet grid-connected. The mining sector forecast is informed by data from government, industry publications, and engagement individual project proponents. Note that electricity demand from existing mining projects is also reflected in the above transmission- and distribution-connected forecast components. When the mining sector component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting

Each forecast component is described in detail below. Note that the forecasts in this section refer to the non-coincident peak demand forecast (i.e., the sum of each station's individual peak demand). Coincident forecasts (i.e., contribution of each station to the overall peak demand hour) for the subsystem in question are used for the purpose of identifying need dates and options analysis in Section 6 and 7. Coincident forecasts are found by applying a coincidence factor based on the contribution of each station to the subsystem's coincident peak over the past five years.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Northwest IRRP forecast was created prior to October 2022, the Ontario Energy Board has also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.[10]

[10] The Load Forecast Guideline can be found on the Ontario Energy Board's website.

5.1 Historical Demand

Figure 5-1 shows the net and gross historical demand over the last five years in the Northwest region. Distribution-connected customer historically make up approximately 55% of peak demand with the remainder made up of transmission-connected customers. Growth has been steady over the last five years, with an average annual demand growth rate of 1.1% and Northwest demand hovering just over 800 MW from 2018 through 2020. Northwestern Ontario is winter peaking, with the peak demand hour for each year typically occurring on winter evenings between 7 p.m. And 11 p.m.

Existing distributed generation resources historically contributed approximately 10-15 MW during peak demand conditions. This contribution was added back into the net demand forecast to arrive at the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast unless station-level adjustments were necessary to account for anomalous demand conditions on a case-by-case basis.

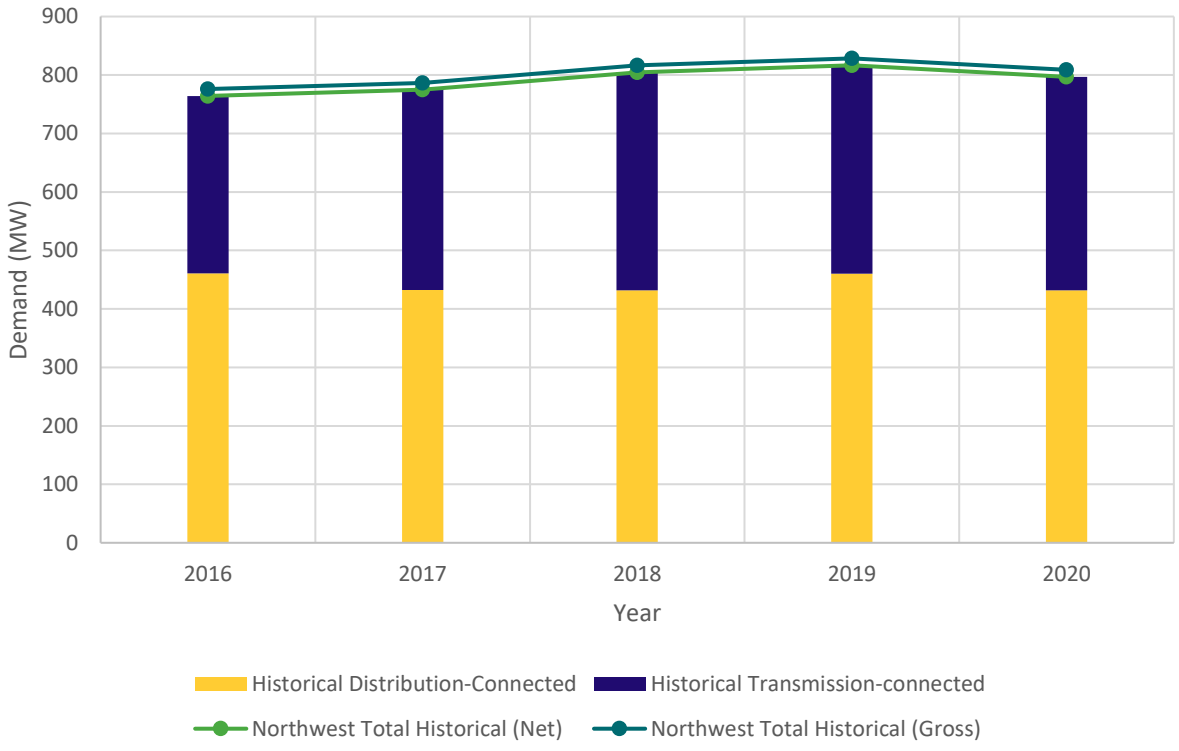


Figure 5-1 | 2016-2020 Historical Demand

5.2 Distribution-connected Forecast

The distribution-connected forecast component starts with a gross station-level demand forecast developed by local distribution companies for their service territory. The gross forecast was then modified to reflect the peak demand impacts of provincial conservation targets and distributed generation contracted through previous provincial programs such as FIT and microFIT[11] and adjusted to reflect extreme weather conditions to produce a reference scenario net forecast for planning assessments. Additional details related to the development of the distribution-connected demand forecast are provided in the sections below and in Appendix B.

5.2.1 Gross Local Distribution Company Forecast

Each participating local distribution company in the Northwest region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development and known connection applications within their service territories.

Note that the regional planning process relies on distributors to consider municipal and regional official plans and translate development plans into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities they serve. More details on each distributor's demand forecast assumptions can be found in Appendix B.2 to B.6. Distributors are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future distributed generation or new conservation measures which are accounted for by the IESO, as discussed in Section 5.2.2 and 5.2.3 below.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

[11] More information about the Feed-in Tariff can be found on the IESO's website.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

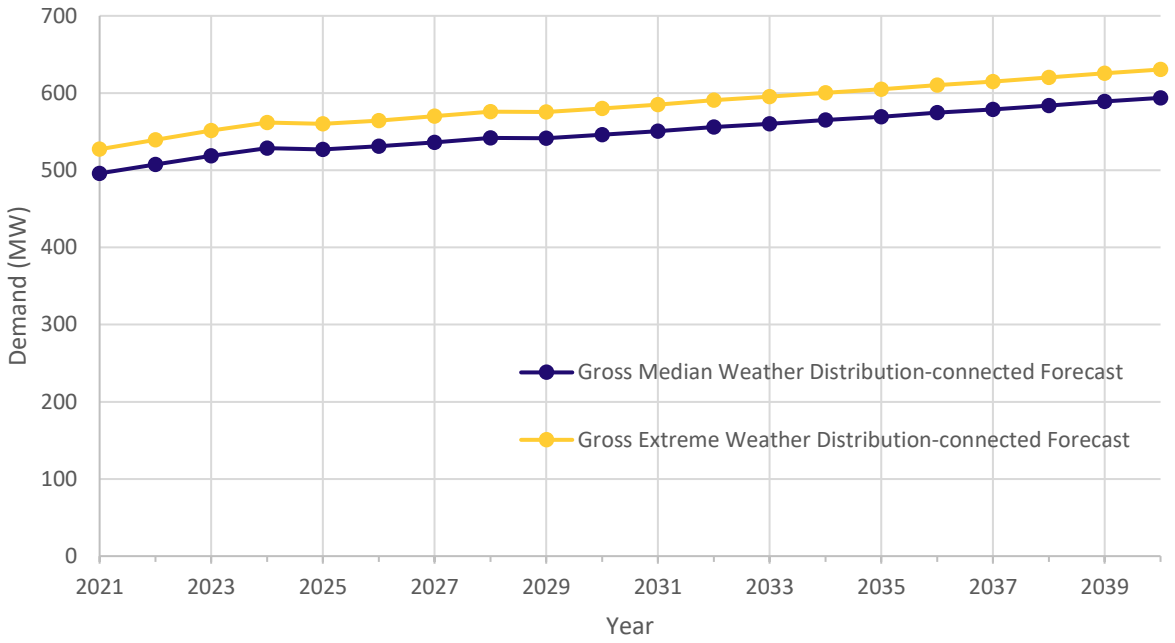


Figure 5-2 | Total Gross Median Weather Distribution-connected Forecast

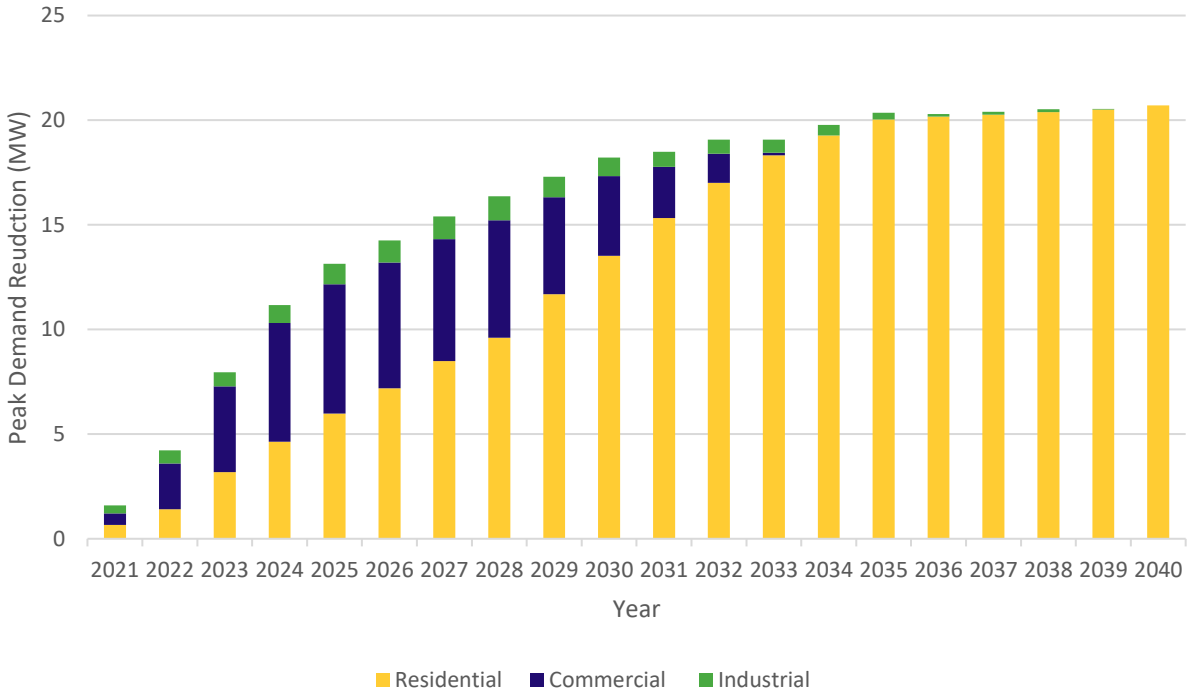
5.2.2 Contribution of Conservation to the Forecast

CDM is a clean and cost-effective resource that helps meet Ontario's electricity needs and is an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards is based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers, i.e., residential, commercial, and industrial consumers.

The estimates of demand reduction due to new program-related activities account for Ontario programs, federal programs that result in electricity savings in Ontario, and forecast future energy efficiency programs. The 2021 – 2024 CDM Framework is the central piece in which the IESO delivers programs on a province-wide basis to enable Ontario's electricity consumers to improve the energy efficiency of their homes, businesses, institutions, and industrial facilities.

Figure 5-3 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards and CDM programs) for residential, commercial, and industrial market segments. Additional details on the conservation forecast methodology are provided in Appendix B.9.



5.2.3 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, distributed generation in the Northwest region is also forecast to offset some peak demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed distributed generation capacity by fuel type and contribution factor assumptions can be found in Appendix B.10.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted distributed generation in the region (similar to the adjustment between net and gross historical demand described in Section 5.1 except with forward looking contracted distributed generation rather than existing distributed generation). Figure 5.5 shows the impact of distributed generation reducing the demand forecast. In the long term, the contribution of distributed generation is expected to diminish as these contracts expire. Note that any facilities without a contract with the IESO are not included in the distributed generation peak demand reduction forecast.

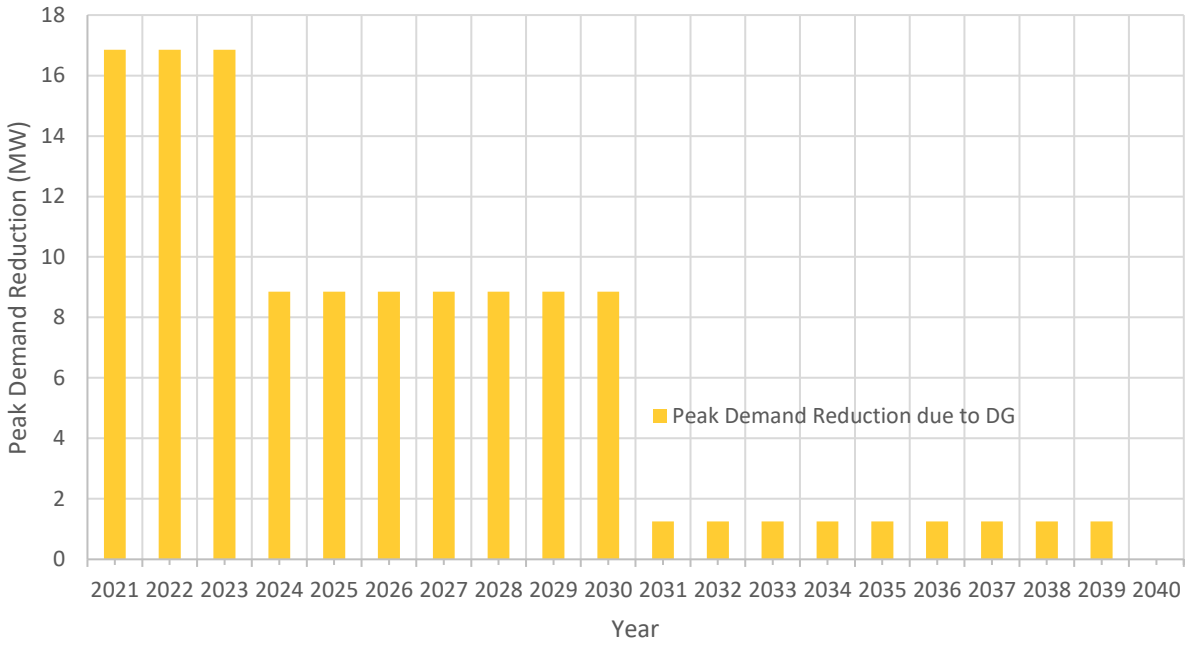


Figure 5-4 | Peak Demand Reduction to Demand Forecast due to Contracted Distributed Generation

5.3 Existing Transmission-connected Forecast

The Northwest region has fifteen customer transformer stations (CTS) that directly serve customers connected to the high-voltage transmission system. The IRRP relies on information from these customers to inform the transmission-connected forecast either directly through their account representative or through comments submitted through the IRRP engagement events. If, for a given station, no information about future demand changes is available, the default assumption is that demand at that station will remain the same as the average historical peak demand over the last five years. Figure 5-5 shows the total non-coincident transmission-connected customer demand forecast. The transmission-connected forecast is generally flat except for a few project expansions/retirements resulting in growth in 2026 and subsequent decline in 2028. Note that, unlike the distribution-connected forecast component, the transmission-connected component is not adjusted for extreme weather because industrial demand does not typically fluctuate with weather. Furthermore, while some customers have behind-the-meter generation facilities, they are not reflected in the forecast unless they are contracted with the IESO.

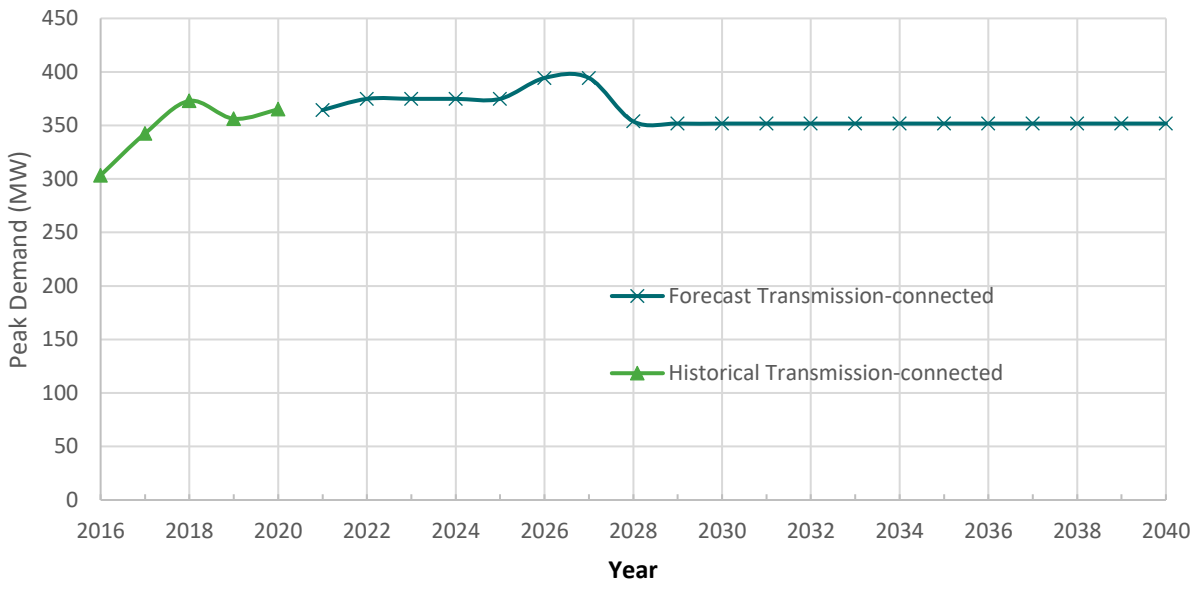


Figure 5-5 | Total Transmission-connected Demand Forecast

5.4 Mining Sector Forecast

In addition to the distribution- and transmission-connected forecasts, expansion of existing mines and new mining projects connecting to the grid are expected to make up the majority of the overall electricity demand growth in the Northwest region. As of Q4 2021, the IESO was aware of more than 20 potential future mining projects in the Northwest region at various stages of planning and development that had known electricity demand forecasts and projected in-service dates. The IESO is also aware of at least ~7-10 projects that are under consideration but have not yet progressed far enough to have an in-service date or electrical demand forecast. Note that information about future mining projects changes frequently. The IESO solicited public feedback on the mining demand forecast and associated list of known mining projects in May 2021. For this IRRP, the mining forecast was considered finalized by the end of 2021 to allow sufficient time for technical assessments that depended on forecast inputs. The mining projects incorporated in the IRRP mining forecast are listed in Appendix B.7.

The mining forecast is project-based and built from the bottom up based on known mining exploration or projects collected from proponents, industry publications, utility companies, and government. Each project is assigned one of four "likelihood" factors ranging from "most likely" to "least likely" that represents the probability of its electricity demand materializing to enable the creation of scenarios that represent different potential future outcomes.

Table 5-1 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included
Reference	- Includes all demand in the low scenario plus the full undiscounted demand forecast from projects classified as "most likely" and "likely" - Aligned with 2021 Annual Planning Outlook[12] reference scenario
High	- Includes all known mining projects with each project's demand forecast discounted according to their likelihood classification: ○ "Most likely" project forecasts are not discounted ○ "Likely" project forecasts discounted to 80% of their full project demand ○ "Less likely" project forecasts discounted to 50% of their full project demand ○ "Least likely" project forecasts discounted to 20% of their full project demand - Aligned with 2021 Annual Planning Outlook high scenario

[12] The Annual Planning Outlook forecasts electricity demand, assesses the reliability of the electricity system, identifies capacity and energy needs, and explores the province's ability to meet them. The latest Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 5-1 above.

Figure 5-6 shows the low, reference, and high mining demand forecast scenarios. The total aggregate undiscounted (i.e., without consideration of likelihood factors) forecast demand from all known projects is also shown in a dashed line. Note that the total aggregate undiscounted forecast demand is not a realistic growth scenario since it is highly unlikely for all proposed mining projects to materialized. The undiscounted forecast is provided for transparency to illustrate the scale of potential demand growth considered in the low, reference, and high scenarios.

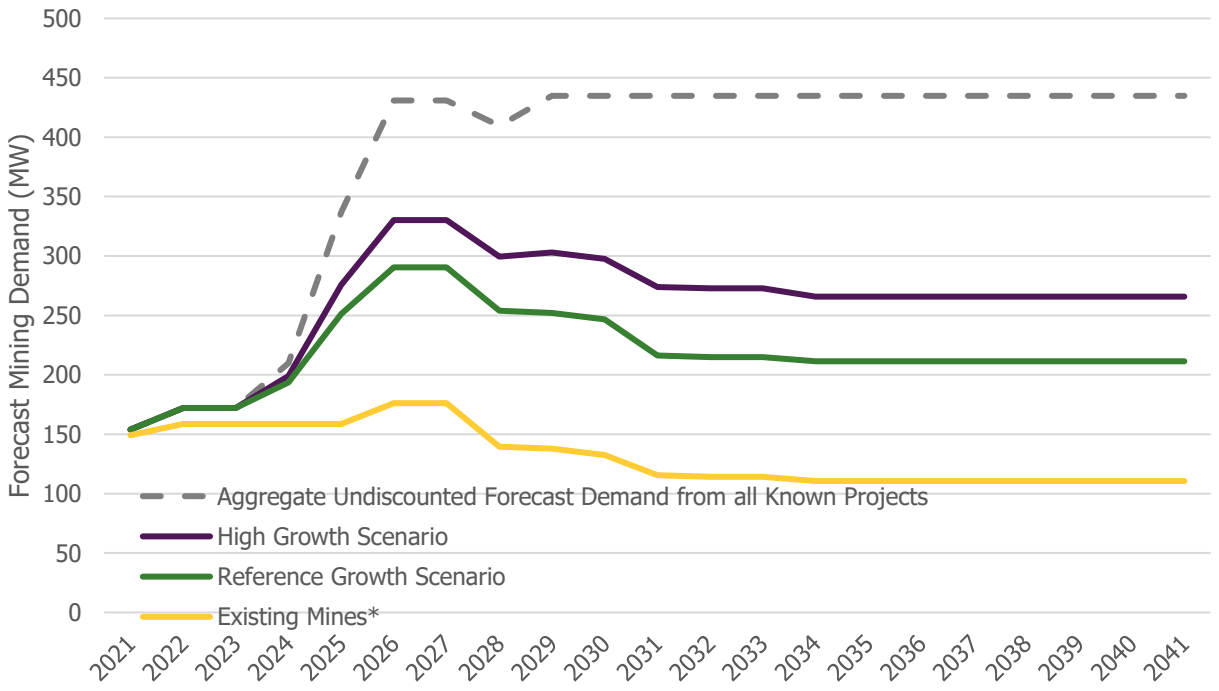


Figure 5-6 | Mining Demand Forecast

The mining sector already accounts for approximately 150 MW of demand today and is projected to grow to 290 MW by 2027 under the reference scenario. The low and high scenarios grow to 175 MW and 330 MW by 2027, respectively. Note that the IRRP does not provide disaggregated project-level forecast to preserve confidentiality.

Generally speaking, the existing mines (low) scenario informs local reliability needs that must be addressed even if no new mines materialize. The reference scenario informs the identification of needs that will likely arise and options to address those needs if/when mines materialize. Finally, the high scenario explores possible additional needs to test the robustness of the IRRP.

Note that in all scenarios, the mining forecast peaks in 2027 before declining for the remainder of the forecast horizon. This is a result of developing a project-based demand forecast as opposed to a top-line forecast for the mining sector as a whole. Information about existing and near-term projects are more readily available than information about long-term projects. Most known near- and mid-term new mining projects plan to come in-service by 2027. After 2027, demand begins to taper off as both existing and new mines reach the end of their planned operating life. The forecast scenarios do account for project extensions beyond their initial operating life but high uncertainty surrounding these extensions has meant that they were assigned low likelihood factors. In sum, the forecast performs well for predicting near- and medium-term mining growth but has less visibility of longer-term trends. Despite this shortcoming, a project-based demand forecast is more useful than a top-line forecast for the purpose of infrastructure planning. The project-based forecast provides relatively detailed information in the near- to mid-term when planning decisions must be made and provides critical geographic granularity necessary for transmission system studies.

5.5 Total Northwest Demand Forecast Scenarios

The total non-coincident Northwest demand forecast is shown in Figure 5-7 below. Note that when the mining forecast component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting. The reference scenario Northwest demand grows to 1060 MW by 2027. The low and high scenarios growing to 945 MW and 1100 MW by 2027, respectively. Note that the discontinuity between historical and forecast demand from 2020 to 2021 is partly due to the extreme weather correction applied to the distribution-connected forecast.

The IRRP reference forecast is approximately 20% higher than the Annual Planning Outlook forecast for the Northwest zone. This difference is in part due to the non-coincidence of the IRRP's station-level forecast; the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest. The sum of regional planning forecasts is also generally higher than their bulk planning counterparts since regional forecasts capture potential growth at a greater granularity not all of which may materialize when aggregated at a larger geographic scale.

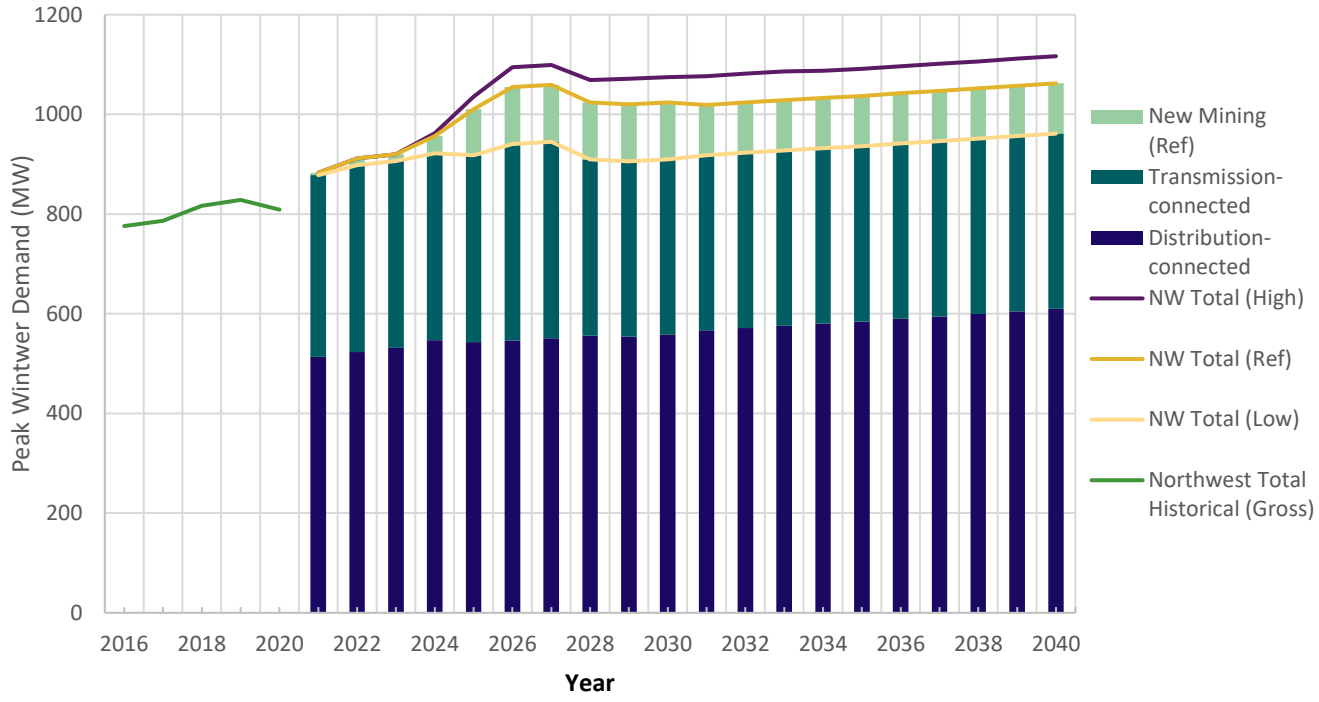


Figure 5-7 | Total Northwest Demand Forecast

5.6 Demand Profiling – Kenora MTS

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for stations or groups of stations with identified needs can be developed to characterize their needs with finer granularity. This is typically undertaken to inform an analysis of potential non-wires alternatives.

For this IRRP, hourly demand profiles were developed for Kenora MTS where a firm station capacity need was identified for which non-wires alternatives are promising. The Kenora MTS hourly demand profiles can be found in Appendix D.2. There were no other needs identified in this IRRP which could be addressed by non-wires alternatives.

Hourly demand profiles are created by first training a multiple linear regression model with historical data and then repeatedly applying the model under different weather/calendar variable permutations to forecast a range of possible future hourly profiles. The profiles are then ranked based on their median energy values. The median profile is scaled to match the peak demand forecast in each year and used to size and simulate non-wires alternatives as described in Section 7.1. A more fulsome description of the demand profiling methodology can be found in Appendix D.1.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Further, this data is only used to select suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of the implementation of the plan.

6. Needs

This section summarizes the needs identified through the IRRP process. Taking into account committed transmission projects identified through bulk planning processes (i.e., the East West Tie expansion and the Waasigan transmission line), the Northwest region is generally adequate to support forecast electricity demand growth. The needs identified in the IRRP deal with localized supply to various pockets of demand in the Northwest as well as high-growth scenarios in areas identified as having strong future development potential.

This section is organized as follows:

- Section 6.1 summarizes the methodology for identifying needs,
- Section 6.2 describes firm station capacity and local operational needs (i.e., needs that would materialize under the reference forecast scenario), and
- Section 6.3 describes potential needs that may arise if higher than forecast growth materializes in select subsystems in the region.

Section 6.2.3 (E1C Operation and High Voltage Need), in addition to specifying the needs identified, will also discuss the recommended solutions since there are no "alternatives" that would normally be discussed in Section 7.

Note that bulk system needs are not in scope for the IRRP, which is focused on local reliability and ensuring that local/regional infrastructure can serve forecast demand. Nonetheless, this IRRP report flags any potential interactions between regional and bulk system needs.

6.1 Needs Assessment Methodology

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the Working Group identified electricity needs which generally fall into the following categories:

- **Station Capacity Needs** arise when the demand forecast exceeds the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service.[13] A transformer station can also be limited when downstream or upstream equipment (e.g., breakers, disconnect switches, low-voltage bus, or high voltage circuits) is undersized relative to the transformer rating.

- **Supply Capacity Needs** describe the electricity system's ability to provide continuous supply to a local area at peak demand. This is limited by the Load Meeting Capability (LMC) of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements (e.g., a transmission line, group of lines, or autotransformer) when subjected to contingencies and criteria prescribed by ORTAC and NERC/NPCC standards. LMC studies are conducted using power system simulation analysis. For the high growth sensitivities in Section 6.3, the LMCs for the subsystems in question are higher than the total forecast demand (both reference and high scenarios). Nonetheless, as these areas have been identified to have future development potential, the IRRP explores the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. Details regarding the power flow simulations, including the system topology and credible contingencies studied, can be found in Appendix C.

- **End-of-life Asset Refurbishment Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. Note that IRRPs do not typically study and make recommendations for all end-of-life needs[14] where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process. Instead, the IRRP focuses on a subset of end-of-life needs where there are interactions with other regional needs and where there may be opportunities to reconfigure or right-size assets. Therefore, in the sections below, end-of-life needs are described in conjunction with other needs where relevant.

[13] Some stations in the Northwest only have a single transformer in which case the transformer's LTR is the limiting element.
[14] A list of transmission assets reaching end-of-life can be found in the Needs Assessment.

- **Load Security and Restoration Needs** describe the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

6.2 Needs Identified

Table 6-1 summarizes the firm needs identified in this IRRP and are further discussed in the sections below. Note that the White Dog DS and Marathon DS station capacity needs occur in the long-term and are not further discussed in Section 7 since no firm recommendations are needed at this time.

Table 6-1 | Summary of Needs

Need	Need Description	Need Date
Fort Frances MTS Customer Reliability	Frequent loss of supply due to transmission outages; end-of-life assets at both Fort Frances TS and Fort Frances MTS	Today
E1C Operation	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	Today
Margach DS	Station step-down transformer capacity	2023
Crilly DS	Station step-down transformer capacity	2027
Kenora MTS	Station step-down transformer capacity	2029
White Dog DS	Station step-down transformer capacity	2032
Marathon DS	Station step-down transformer capacity	2038

6.2.1 Station Capacity Needs

6.2.1.1 Margach DS

Margach DS is approximately 10 km east of Kenora. Margach DS has an LTR of 10.4 MW and historical demand has been stable at just under 10 MW. As shown in Figure 6-1, Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS.

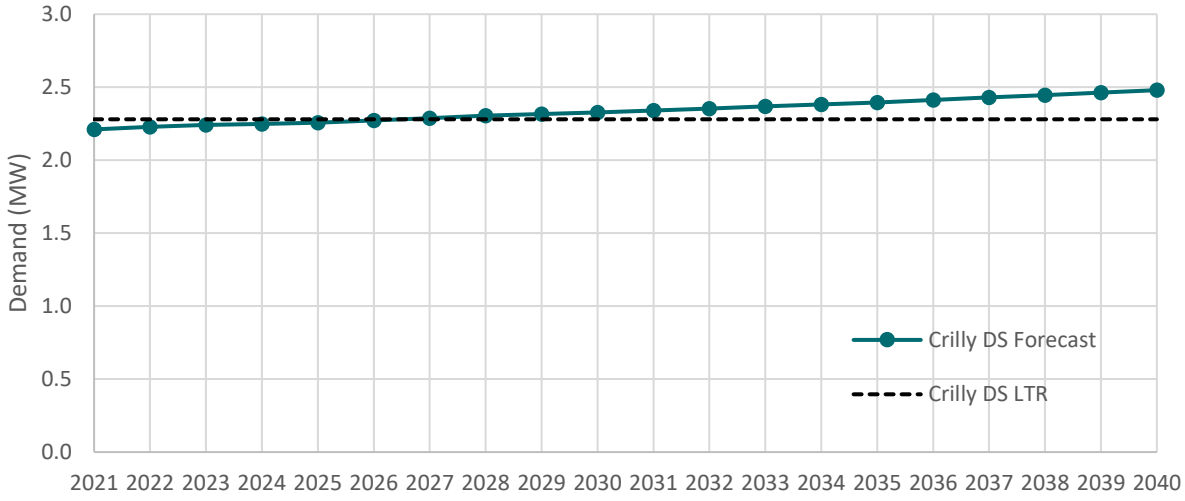


Figure 6-1 | Margach DS Forecast

6.2.1.2 Crilly DS

Crilly DS is a small (~2.2 MW LTR) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Crilly DS is expected to reach capacity in 2027 due to incremental growth in the community as shown in Figure 6-2.

6.2.1.3 Kenora MTS

Kenora MTS serves the City of Kenora and has a LTR of 23.4 MW. Synergy North has received inquiries from potential customers seeking new connections, including a new 4 MW project, but no formal agreements have been finalized. While these projects have not been included in the forecast, a relatively high annual growth rate of 1.25% was applied to account for the high degree of development interest.

Figure 6-2 | Crilly DS Forecast

Kenora MTS is expected to reach capacity in 2029 as shown in Figure 6-3.

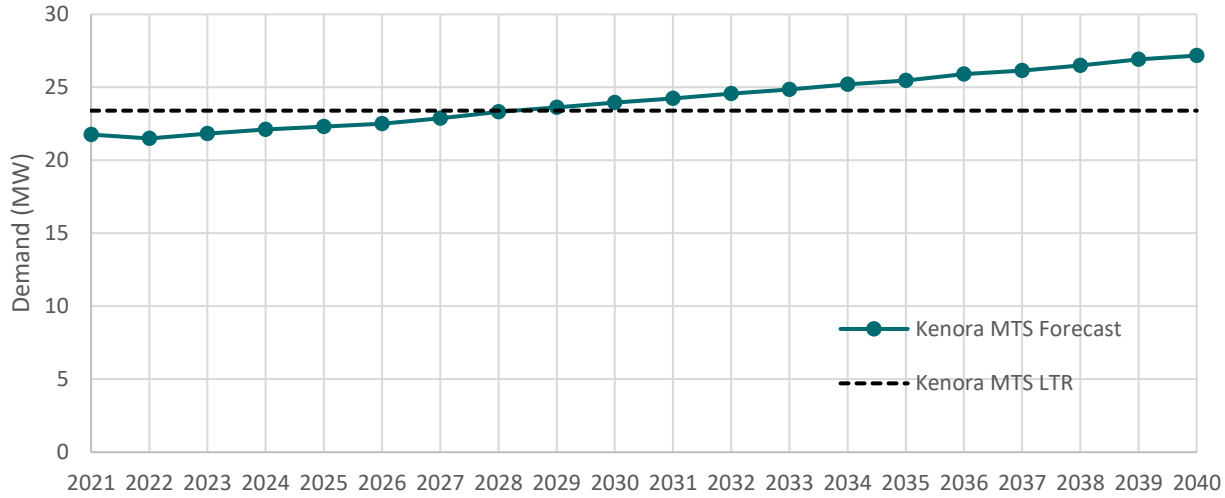


Figure 6-3 | Kenora MTS Forecast

6.2.1.4 White Dog DS

White Dog DS is located approximately 50 km northwest of Kenora and has a LTR of 2.9 MW. White Dog DS demand is expected to grow relatively quickly at an average rate of 1.3% annually due to growth in the community. White Dog DS is expected to reach capacity in 2032 as shown in Figure 6-4.

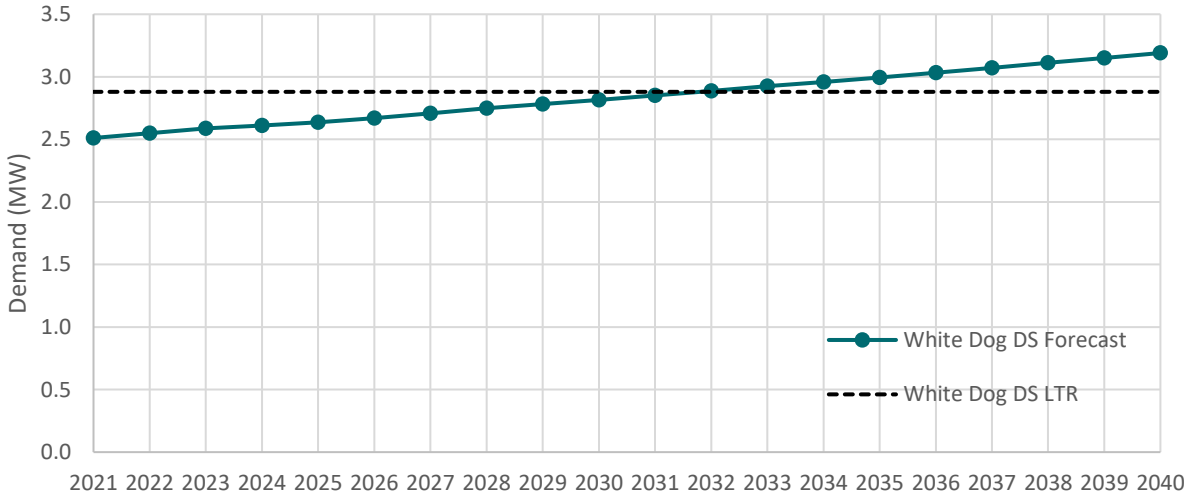


Figure 6-4 | White Dog DS Forecast

6.2.1.5 Marathon DS

Marathon DS serves the Town of Marathon and has a LTR of 10.4 MW. Growth is expected to be moderate and stable at an average annual growth rate of 0.9%. Marathon DS is expected to reach capacity in 2038 as shown in Figure 6-5.

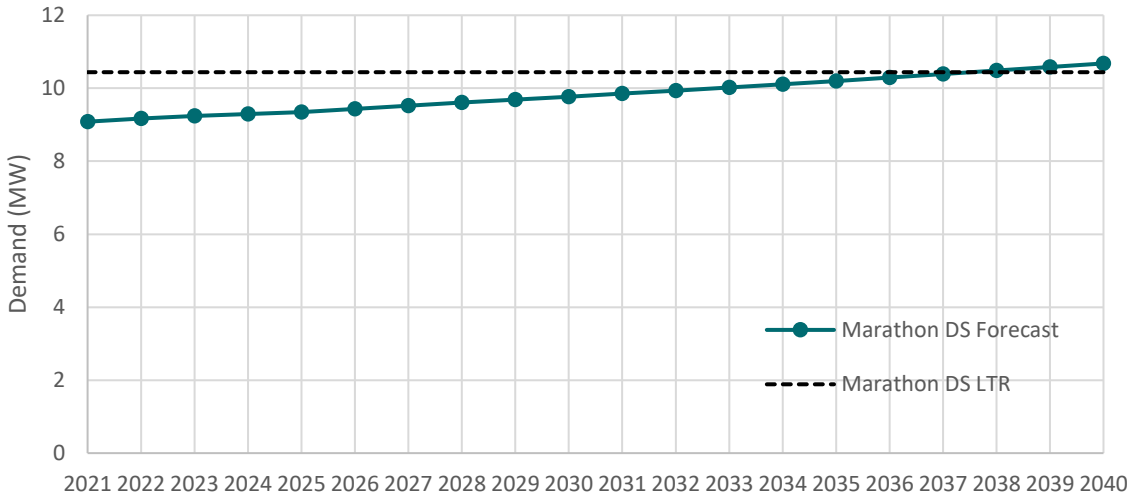


Figure 6-5 | Marathon DS Forecast

6.2.2 Fort Frances Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies the Town of Fort Frances, is supplied via a single circuit 115 kV line, F1B, from the nearby Fort Frances TS. The two stations are located across the street from each other as shown in Figure 6-6. Fort Frances MTS experiences outages semi-annually to accommodate planned maintenance outages on F1B. Despite there being two step-down transformers at Fort Frances MTS, the single circuit supply configuration results in community-wide power outages since there is no redundant supply path to the station.

Historically, outage durations ranges from 4 to 8 hours and impact critical loads such as the regional hospital and local health clinics. Customers have raised concerns with interruptions to surgery schedules and vaccine spoilage due to the loss of refrigeration. Power outages also disrupt other commercial and residential customers. Customer surveys conducted by Fort Frances Power suggest that customers can tolerate short outages but are increasing sensitive to prolonged outages. Of the 10 causes of distribution system customer interruptions tracked by the Ontario Energy Board, loss of transmission supply accounts for 90% of Fort Frances Power's customer interruptions over the last 10 years.

Note that this customer reliability issue does not violate ORTAC load security and restoration criteria due to the relatively low total demand served at Fort Frances MTS. Fort Frances MTS serves approximately 16 MW of load today and is expected to grow to 18 MW by the end of the forecast horizon.[15] Load security criteria limits the total amount of demand interrupted with any single element out of service to 150 MW. For loads under 150 MW, load restoration criteria only require that service is restored within 8 hours. Despite compliance with ORTAC criteria, the Fort Frances MTS supply configuration is still highly disruptive for customers and could potentially be improved with relatively low-cost solutions given the proximity to Fort Frances TS.

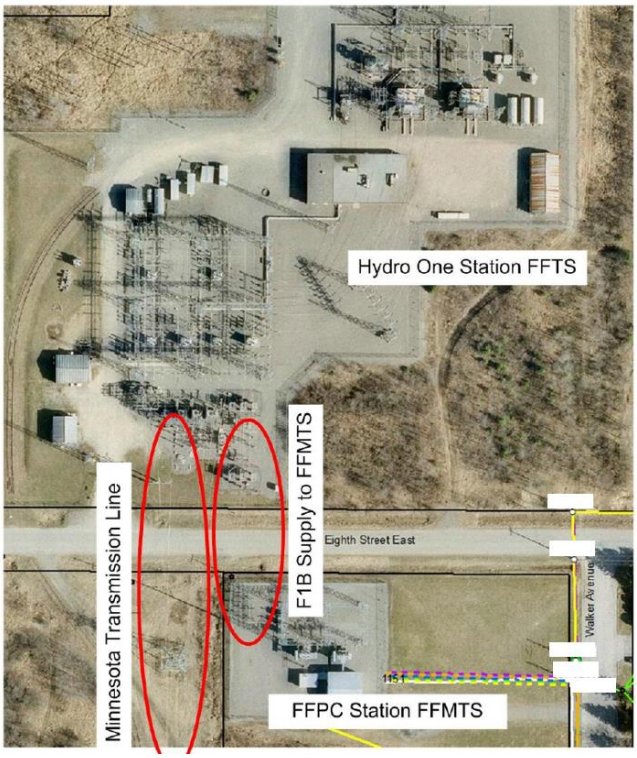


Figure 6-6 | Overhead view of Fort Frances TS (labeled as FFTS) and Fort Frances MTS (labeled as FFMTS)

[15] While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power that could quickly use up the remaining station capacity if they commit. This is further discussed in Section 6.3.2.

Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. The OEB's Asset Depreciation Study defines minimum, typical, and maximum useful life for a variety of electricity system assets. Apart from the main station breaker, which was replaced in 2019, all equipment at Fort Frances MTS is between its typical and maximum useful life. Furthermore, Fort Frances TS 115 kV breakers are also approaching end of life around 2027, which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS.

6.2.3 E1C Operations and High Voltage Need

This section discusses the E1C operations with the new 230 kV Wataynikaneyap circuit, W54W, in service. W54W was first energized in Aug 2022. However, C3W, a short 30 m circuit between Wataynikaneyap TS and Pickle Lake SS, is still operated normally open. Therefore, W54W is not yet connected to the existing 115 kV circuits from Ear Falls TS to Pickle Lake SS and Musselwhite CSS (E1C, C2M, and M1M). C3W will be operated closed in the near future so that W54W can help support demand growth on C2M. This is consistent with the IESO's original recommended scope for the Wataynikaneyap Transmission Project in 2016.[16] For the purposes of this IRRP report, W54W being "in-service," refers to the final state with C3W closed. A single-line diagram of the area is shown in Figure 6-7.

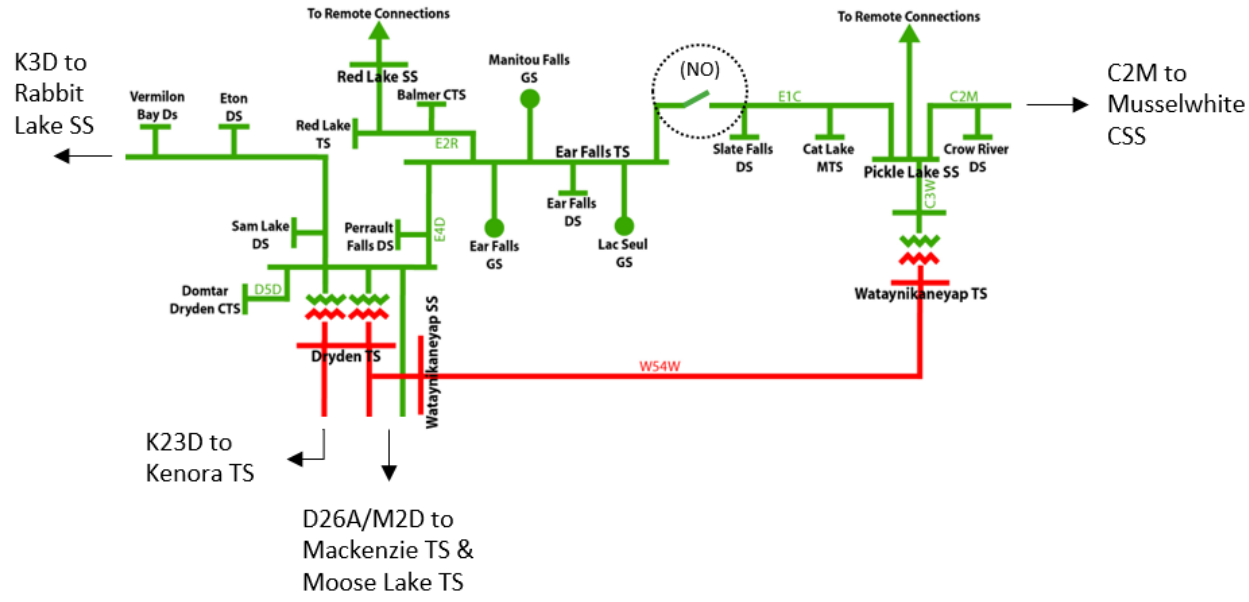


Figure 6-7 | Simplified Single Line Diagram of the Dryden and Pickle Lake Areas with Potential Normally Open Point

[16] The IESO's 2016 Recommended Scope of the new Line to Pickle Lake and Support Scope for the Remotes Connection Project is available on the Ontario Energy Board's priority transmission projects webpage.

With W54W in-service and connected to E1C via C3W, operating circuit E1C normally closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W as documented in the 2016 W54W System Impact Assessment (SIA) report.[17] When operating with the E4D-E1C-W54W loop closed, loads in the Ear Falls area will remain connected through E1C via the 230 kV path following the loss of E4D. Post-contingency voltage collapse limits the E4D+W54W flow to 57 MW which is insufficient for supplying existing demand in the Ear Falls, Red Lake, and Pickle Lake areas. The SIA notes that E1C must be opened pre-contingency as a mitigating control action when flow exceeds 57 MW and that this could occur multiple times per day at existing demand levels.

Furthermore, the SIA found that with the E4D-E1C-W54W loop closed, the Manitou Falls and Ear Falls hydro generators would remain connected to the grid following the loss of E4D, which causes transient instability when the post-contingency flow on the E1C exceeds 30 MW. To ensure that transient stability of the generators is maintained, pre-contingency generation levels would need to be reduced such that post-contingency flow on E1C does not exceed 30 MW. This reduction of transfer capability on E1C not only violates ORTAC Section 4.1, which limits reduction in transfer capability that results from a new connection, but would bottle hydro-electric generation that is otherwise available to provide capacity to the Northwest system. Therefore, the SIA recommended that the E4D-E1C-W54W loop should be opened pre-contingency to prevent pre-contingency generation reductions.

Due to these documented issues, this IRRP reaffirms that E1C should be operated normally open once W54W is in-service with C3W closed. This configuration resolves the violations described above and the resulting system is adequate to serve forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas. This configuration is consistent with the recommended scope for W54W (which was referred to as the "Line to Pickle Lake") in the 2015 North of Dryden IRRP. Note that operating E1C normally open enables W54W to relieve E4D which allows W54W to serve the dual purposes of improving the load meeting capability of both the Pickle Lake and Ear Falls/Red Lake areas. This was an important consideration that contributed to the recommendation for W54W.

However, with E1C operated normally open, another problem emerges. High voltage violations (voltages exceeding 127 kV) occur post-contingency under light load conditions. High voltages occur on the line end open of E1C and either Pickle Lake SS or Ear Falls TS depending on where the open point on E1C is located. High voltage violations are less severe when opening E1C near Ear Falls TS compared to near Pickle Lake SS. When E1C is open near Ear Falls TS, the most critical contingency is the loss of one of the existing 20 MVar reactors at Wataynikaneyap TS. The high voltage violations can be addressed by installing an additional 10 MVar reactor at or near Pickle Lake SS. The post-contingency voltages at nearby stations with and without this

[17] The 2016 W54W System Impact Assessment report is available on the IESO's Application Status webpage by searching for SIA ID 2016-567.

additional 10 MVar reactor are shown in Table 6-2. The post-contingency voltages exceed 127 kV at the E1C open line end and Pickle Lake SS for the loss of the existing 20 MVar reactor at Wataynikaneyap TS. Post-contingency voltages are maintained below 127 kV with the additional 10 MVar reactor.

Table 6-2 | Post-contingency Voltages with and without Additional 10 MVar Reactor at Pickle Lake SS with E1C Normally Open at Ear Falls TS

Bus/ Station Name	Post-contingency voltage (kV)	Post-contingency voltage (kV) with additional 10 MVar Reactor at Pickle Lake SS
E1C LEO	**130.7**	123.3
Pickle Lake 115	**127.7**	120.6
Watay 115	126	120.1
Watay SS 230	238	235.5
Dinorwic 230	237.8	235.6
Mackenzie 230	244.8	244
Musselwhite 115	120	115.1

The IRRP recommends that the IESO and Hydro One collaborate in the Regional Infrastructure Plan refine the location of the E1C open point and associated reactive compensation devices required. The E1C open point can be fine-tuned to minimize high voltages. The open point on E1C should consider the location and condition of existing switches as well as their accessibility for restoration purposes should E1C be needed to partially restore loads following a W54W or D26A contingency.

Furthermore, the Regional Infrastructure Plan should consider the installation of a voltage-based automatic switching scheme for the reactors at Pickle Lake SS, Wataynikaneyap TS, and Dinorwic Jct similar to existing switching schemes at other stations across the Northwest region. Voltage-based automatic switching would improve the transmission system's operational flexibility, help manage high voltage conditions currently experienced across the Northwest and help reduce post-contingency high voltages to the acceptable continuous maximum voltage within 30 minutes. Potential interactions with the existing Northwest reactor switching scheme should be considered as this scheme is developed.

6.3 Potential Needs and High Sensitivities

No firm regional supply capacity needs were identified in the Northwest in either the reference or high forecast scenarios. However, most of the growth in the Northwest is driven by large mining and industrial development which can add large, incremental blocks of demand with minimal lead time that can quickly use up remaining supply capacity. Through engagement with development proponents and stakeholders, the Working Group identified two areas in the Northwest, the Dryden/Ear Falls/Red Lake area and the Fort Frances area, where there is particularly strong development interest and where the existing transmission system, although adequate for current forecast scenarios, may become constrained if all known proposed projects materialize.

For these two areas, the IRRP studied high growth sensitivities to quantify the load meeting capability and identify the limiting phenomena on the existing system. This was accomplished by adding hypothetical loads at existing stations/busses to simulate new developments and increasing the hypothetical load until a planning standards violation was observed.

As discussed in Section 4.1, the IRRP did not study local connection requirements of any individual project. The purpose of the high growth sensitivity studies is to quantify system limitations so that growth can be more effectively monitored between regional planning cycles and future planning activities can be initiated in a timely manner if growth materializes. Regardless of the availability of regional supply capacity identified in the IRRP, customers seeking connection may be subject to additional requirements and limitations specified in Customer Impact Assessments (CIA) or System Impact Assessments (SIA).

6.3.1 Dryden/Ear Falls/Red Lake Load Meeting Capability

The Dryden/Ear Falls/Red Lake area hosts significant mining activity today. It includes the 115 kV system supplied from the Dryden TS autotransformers, circuit K3D from Rabbit Lake SS, and M2D from Moose Lake TS. The recently completed 230 kV Wataynikaneyap Transmission Project line W54W will help relieve constraints on the 115 kV circuit E4D, once the recommendations in section 6.2.3 are implemented, and no incremental capacity needs are anticipated in this area based on the current demand forecast.[18]

The area's load meeting capability (LMC) is a function of three nested local constraints as shown in Figure 6-8:

(1) Supply to the Red Lake subsystem including: Red Lake TS, Balmer CTS, and Red Lake remote communities

[18] Consistent with the recommendation in Section 2.1.5 (E1C Operation and High Voltage) and the needs discussed in Section 6.2.3, the IRRP technical studies assumes that E1C will be operated normally open at Ear Falls TS.

(2) Supply to the Ear Falls subsystem including: Ear Falls DS, Perrault Falls DS, and the Red Lake subsystem described above

(3) Supply to the Dryden subsystem including: Sam Lake DS, Eton Ds, Vermilion Bay DS, Domtar Dryden CTS, and the Ear Falls subsystem described above

An implication of this "nesting" is that, depending on where new loads connect, they could contribute to one or more subsystem needs. For example, a load connecting close to Dryden would contribute to needs in the Dryden subsystem only, whereas a load connecting at Red Lake would contribute to potential needs in all three subsystems.

The supply capacity in these subsystems may be further constrained by bulk system limitations on the 230 kV supply to the area West of Thunder Bay. Bulk system limitations are outside the scope of regional planning and will be addressed by the Waasigan Transmission Line Project.

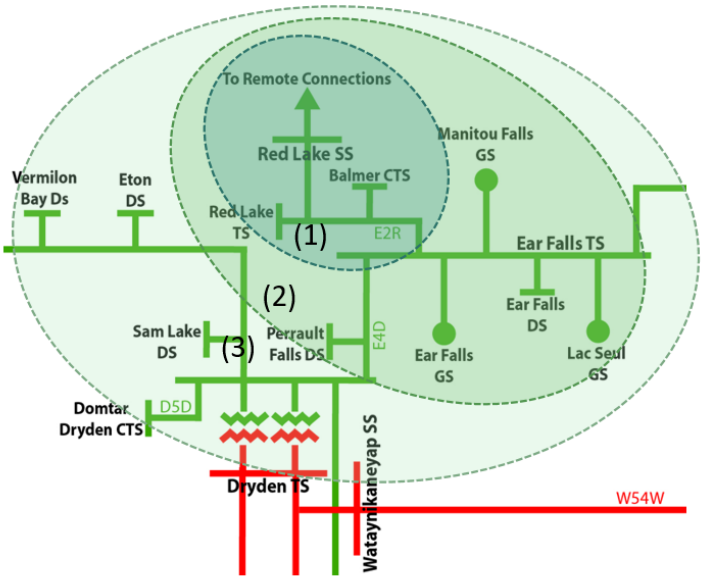


Figure 6-8 | Dryden/Ear Falls/Red Lake Nested Subsystems

Depending on which subsystem was being tested, the load meeting capabilities were derived by adding new hypothetical loads at Red Lake TS, Ear Falls TS, or the 115 kV bus at Dryden TS until a limiting phenomenon was encountered. The load meeting capabilities and the most limiting phenomenon or season for each subsystem is summarized in Table 6-3 and further described below. Note that, since the Northwest region is winter peaking, the IRRP forecast was developed for winter peak demand. However, since the Ear Falls and Red Lake subsystems can be thermally constrained, a summer peak forecast was also developed using the historical ratio between each station's summer and winter peaks.

Table 6-3 | Summary of Dryden/Ear Falls/Red Lake Load Meeting Capabilities

Subsystem	Load Meeting Capability	2032 Reference Peak Demand Forecast	2040 Reference Peak Demand Forecast
1. Red Lake	74 MW (summer thermal limitation)	61 MW summer peak	67 MW summer peak
2. Ear Falls	90 MW (summer thermal limitation)	67 MW summer peak	74 MW summer peak
3. Dryden	160 MW [19](summer/winter voltage decline)	129 MW winter peak	140 MW winter peak

6.3.1.1 Red Lake Subsystem

The Red Lake subsystem load meeting capability is limited in the summer by pre-contingency thermal overload of circuit E2R. The E2R continuous summer rating is 421 A which translates to a load meeting capability of approximately 74 MW.

The winter load meeting capability is higher than the summer capability. The winter load meeting capability is limited to 93 MW due to E2R pre-contingency thermal and voltage limitations. The winter E2R continuous winter rating is 528 A which translates to a load meeting capability of approximately 93 MW. 93 MW of load also causes pre-contingency voltage decline at Red Lake TS (i.e., voltages are under 113 kV). Note that the pre-contingency voltage limitation can be mitigated by installing appropriately sized voltage devices at the connection point of any new load. All load meeting capabilities described for the Red Lake and Dryden subsystems below assume that any new load will be accompanied by voltage devices to maintain adequate voltage performance at the point of connection.

Figure 6-9 below shows the Red Lake subsystem summer and winter peak demand forecast and associated load meeting capabilities.

The summer thermal limitation on E2R could be addressed by upgrading to higher rated conductors. There are several conductor options available with summer continuous ratings ranging from 590 A to 740 A.

[19] This LMC is significant higher than the existing Dryden Area Inflow (DAI) limit in existing System Control Orders documentation. This difference is mainly due to topology changes (i.e. new W54W). The IRRP sensitivity study also assumes that new loads will connect with appropriate voltage control devices installed at the point of connection which alleviates previously documented low voltage issues.

Upgrading to 740 A conductors would result in a summer load meeting capability of approximately 130 MW. Note that upgrading to higher rated conductors would also necessitate replacing existing structures to increase their height so that the conductors can be operated at a higher temperature. Furthermore, Red Lake TS would need an alternative supply while work on E2R is carried out. Upgrading E2R would cost approximately $23M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[20] The cost difference between different conductor choices is relatively insignificant. Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

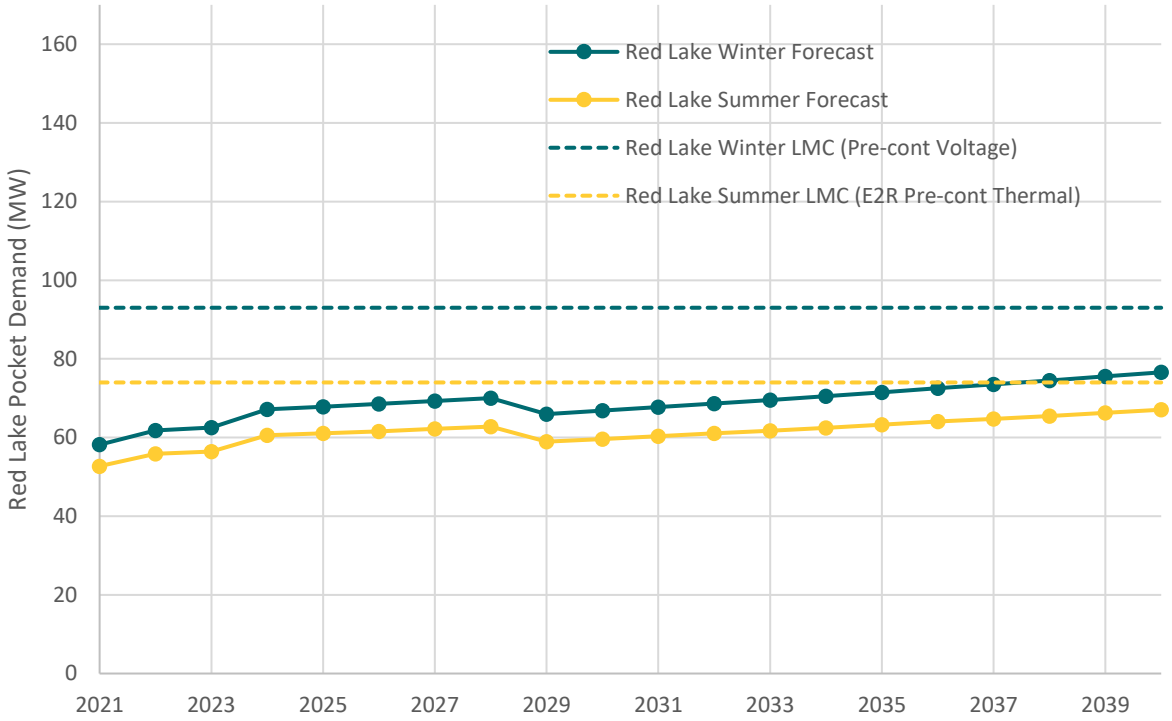


Figure 6-9 | Red Lake Subsystem Load Meeting Capabilities and Demand Forecast

E2R is approximately 75 years old. Hydro One anticipates that the average expected service life for the conductors is 90 years. The wood pole structures have a shorter expected service life at approximately 50 years. The end-of-life date for E2R will be based on actual asset conditions and no date has been determined for E2R as of 2022. If growth materializes, future planning

[20] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

studies should consider the cost of advancing E2R refurbishment as compared to alternatives such as local generation.

6.3.1.2 Ear Falls Subsystem

The Ear Falls subsystem load meeting capability is limited in the summer by E4D pre-contingency thermal overload. The E4D continuous summer rating is 410 A, which translates to approximately 72 MW. There is also a combined 18 MW of summer 98th percentile dependable hydro generation output from Ear Falls GS, Manitou Falls GS, and Lac Seul GS. Together the thermal capability and hydro generation results in a load meeting capability of approximately 90 MW.

Note that the winter load meeting capability is not expected to be limiting since it is significantly higher than the summer capability due to both the higher winter thermal rating of the circuit as well as higher dependable hydro generation output (approximately 64 MW of 98th percentile dependable hydro generation output).

Figure 6-10 below shows the Ear Falls subsystem summer demand forecast and load meeting capability.

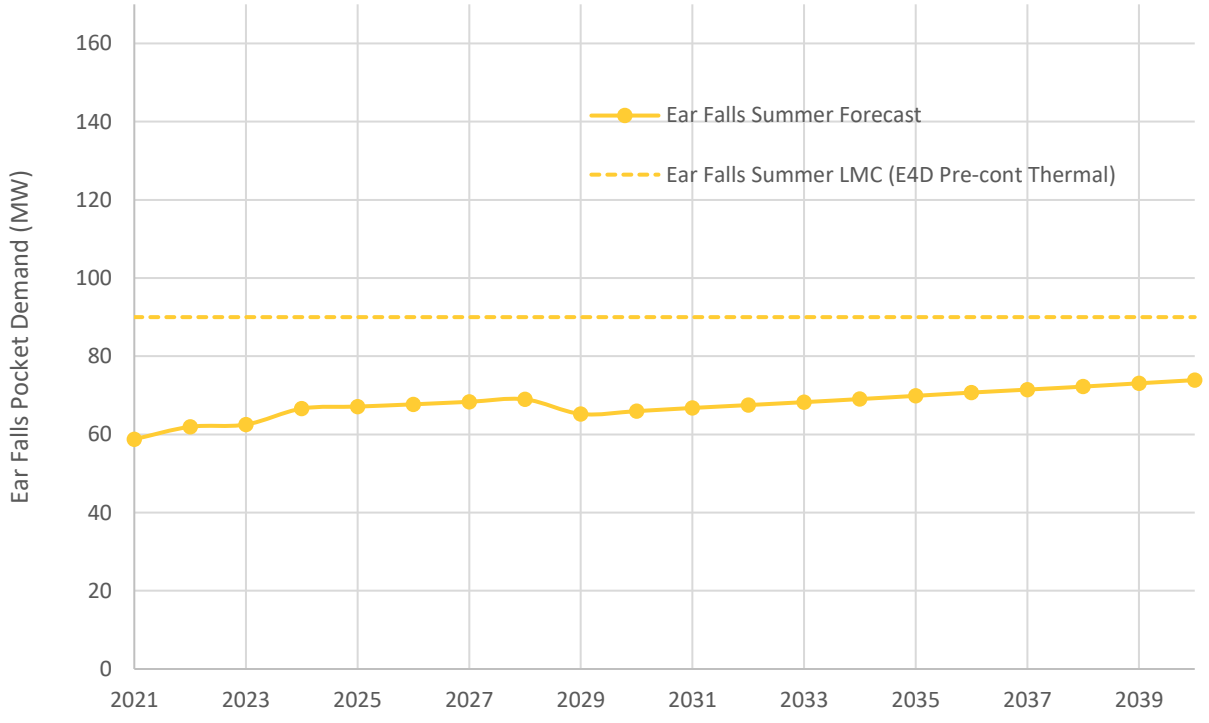


Figure 6-10 | Ear Falls Subsystem Load Meeting Capability and Demand Forecast

The summer load meeting capability for the Ear Falls subsystem can be increased to 130 MW by upgrading E4D with higher rated conductors (740 A summer continuous rating similar to conductors contemplated for E2R in the previous section). Upgrading E4D would cost approximately $35M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[21] Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. E4D is approximately the same age as E2R; future planning studies should also consider the cost of advancing E4D refurbishment as compared to alternatives such as local generation.

6.3.1.3 Dryden Subsystem

The Dryden subsystem load meeting capability is limited to 160 MW in both the summer and winter due to post-contingency voltage decline following the loss of D26A. When total demand in the Dryden subsystem exceeds 160 MW, the voltage decline at Dryden TS will exceed criteria (10% decline) as shown in Table 6-4. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

Table 6-4 | Post-Contingency (D26A N-1) Voltage Change (160 MW Dryden Subsystem Total Demand)

Station	Pre-Cont Voltage	Post-Cont (Pre-ULTC) Voltage	Post-Cont (Post-ULTC) Voltage
Mackenzie TS	247 kV	242 kV	239 kV
Dryden TS	237 kV	216 kV	214 kV (10% decline)
Kenora TS	243 kV	229 kV	230 kV
Fort Frances TS	244 kV	229 kV	231 kV

Dryden TS post-contingency voltage decline will no longer be limiting once Phase 2 of the Waasigan Transmission Line Project is built since it will provide a redundant path from Mackenzie TS to Dryden TS parallel to D26A. Without Phase 2, the post-contingency voltage decline could be addressed by a dynamic voltage device at Dryden TS, but this was not further studied since the device requirements would depend on the connection arrangement and characteristics of future loads.

[21] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

Note that the D26A + K23D N-1-1 contingency results in more severe voltage decline but could be addressed by a load rejection scheme since special protection systems are permitted by ORTAC for outage conditions.

Figure 6-11 shows the Dryden subsystem summer and winter peak demand forecast and associated load meeting capabilities.

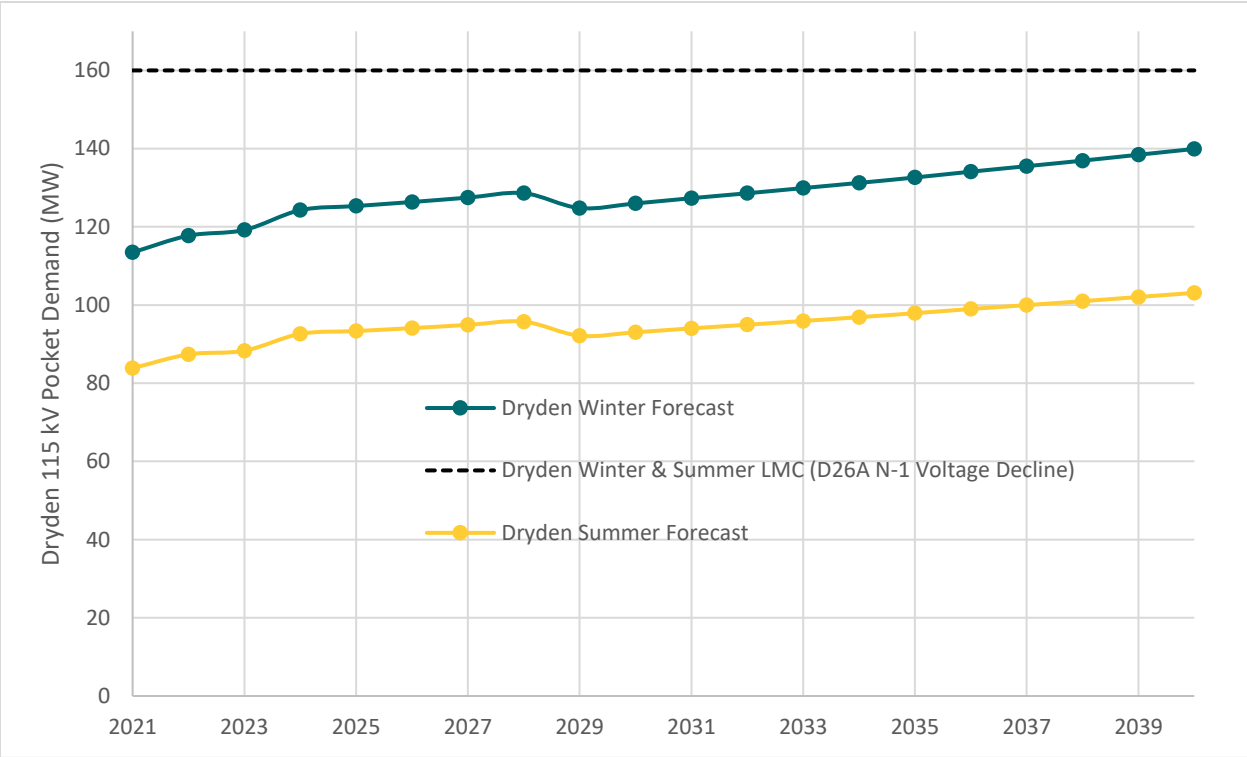


Figure 6-11 | Dryden Subsystem Load Meeting Capabilities and Demand Forecast

6.3.2 Fort Frances Load Meeting Capability

The Fort Frances area includes the 115 kV system supplied from the Fort Frances TS autotransformers and circuit K6F from Rabbit Lake SS as shown in Figure 6-13. For this high-growth sensitivity study, the Fort Frances area includes Fort Frances MTS, Burleigh DS, and a new hypothetical load connected directly to the 115 kV bus at Fort Frances TS. The stations connected to K6F do not materially impact the load meeting capability of the Fort Frances area.

Forecast demand in the Fort Frances area is relatively modest and is expected to grow from 21 MW today to 23 MW in 2040. However, the Working Group is aware of multiple inquiries from potential large new customers seeking connection in the Fort Frances area. Their combined load exceeds 100 MW but there is a high degree of uncertainty in whether their developments will proceed and where they may choose to connect to the grid. Some potential customers are also considering connection points in other parts of the province.

The Fort Frances load meeting capability is limited to 82 MW inclusive of approximately 3 MW of 98th percentile winter dependable hydro generation output from Fort Frances GS. This load meeting capability is the maximum total amount of load that can be served at Fort Frances MTS, Burleigh DS, and a new hypothetical load directly served on the Fort Frances TS 115 kV bus. It does not include load served on K6F. To achieve this load meeting capability, two new 25 MVar capacitor banks are assumed to be installed on the Fort Frances TS 115 kV bus to manage pre-contingency voltages. The load meeting capability is limited by post-contingency voltage decline on the Fort Frances TS 115 kV bus following the loss of F25A as shown in Table 6-5. The F25A contingency has a significant impact on 115 kV bus voltages because it removes one of the Fort Frances TS transformers (and the existing capacitor bank on its tertiary winding) by configuration. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

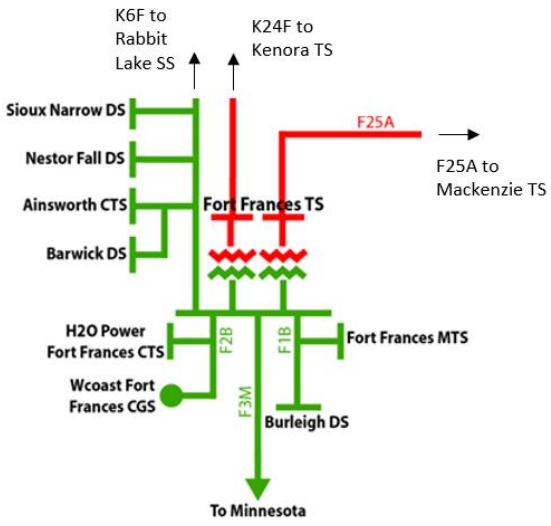


Figure 6-12 | Fort Frances Subsystem

Figure 6-13 below shows the Fort Frances subsystem winter peak demand forecast and associated load meeting capability.

Table 6-5 | Post-Contingency (F25A N-1) Voltage Change (82 MW Fort Frances Subsystem Total Demand)

Station/Bus	Pre-Cont Voltage	Post-Cont Pre-ULTC Voltage	Post-Cont Post-ULTC Voltage
Fort Frances TS (230 kV)	240 kV	234 kV	228 kV
Fort Frances TS (115 kV)	123 kV	110 kV (10% decline)	116 kV

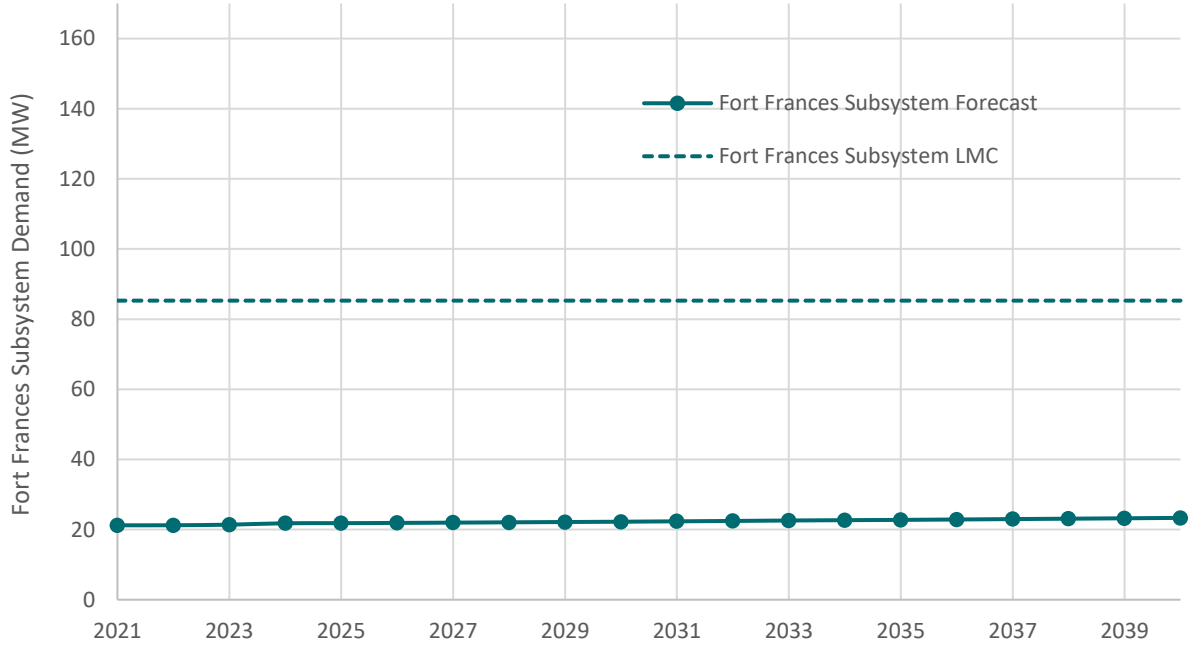


Figure 6-13 | Fort Frances Subsystem Load Meeting Capability and Demand Forecast

7. Options Considered and Recommendations

This section describes the options considered and recommendations to address the near- to medium-term needs identified in section 6. This section is organized as follows:

Section 7.1 describes the options considered for the Margach DS, Crilly DS, and Kenora MTS station capacity needs. This includes a discussion of how each station capacity need was screened for non-wires alternative suitability and, where there were promising non-wires opportunities, the options considered and financial analysis.

Section 7.2 explores configuration options to improve customer reliability at Fort Frances TS. These options will inform the Regional Infrastructure Plan where a final configuration will be chosen.

Note that the recommendation for the E1C operations and high voltage need can be found in Section 6.2.3 and will not be further discussed in this section.

7.1 Options and Recommendations for Station Capacity Needs

7.1.1 Methodology and Options Considered

There are two approaches for addressing station capacity needs:

- Build new infrastructure to increase station capacity. This is commonly referred to as a "wires" option and typically entails upsizing the existing station (e.g., replacing transformers with higher rated transformers or adding additional transformers) or building a new station to supply incremental demand growth. Wires options may also include modifications to or the addition of other power system equipment such as voltage regulation devices, switches, or breakers.

- Install or implement measures to reduce net peak demand to maintain loading within existing station capacity. This is commonly referred to as a "non-wires" alternative and can include options like energy storage, local distributed generation, demand response, conservation and demand management, or any combination of the above. Note that centrally delivered energy efficiency measures under the 2021-2024 Conservation and Demand Management framework are already included in the load forecast, as discussed in Section 5.2.2. Additional conservation and demand management can be considered as a non-wires alternative.

While wires options typically provide a step-change increase in capacity and are available in all hours, non-wires alternatives are more targeted and must account for the frequency and duration of the capacity need in addition to its magnitude. Therefore, identifying suitable technology types, sizing options, and simulating their discounted cash flows are significantly more complex for non-wires alternatives than wires options.

Non-wires alternatives are not suitable for all station capacity needs and there are often qualitative factors that rule out the use of non-wires alternatives. Before carrying out options analysis, a screening process is first applied to determine the suitability of non-wires alternatives for each need that considers the characteristics of the demand growth, the technical feasibility of non-wires alternatives to address the limiting phenomena, and any additional factors that would complicate or facilitate the implementation of non-wires alternatives. For stations where non-wires alternatives are suitable, the IRRP carries out options analysis as described below.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Note that the error margin in cost estimates is significant at the planning stage (-50% to +100%); they are only intended to enable comparison between options during the IRRP. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. Wires option costs can be reviewed in the Regional Infrastructure Plan before implementation work begins and the Working Group will revisit recommendations if cost estimates differ significantly. Actual non-wires alternative costs can also vary significantly from the benchmark estimates used in the IRRP depending on local market constraints at the time of implementation. The entity responsible for implementing the non-wires alternative (for station capacity needs, this will typically be the local distribution company) will only implement the alternative if it remains cost effective. Subsequent regional planning activities will be triggered if future costs differ significantly from those in the current IRRP.

For non-wires options, upfront capital and operating costs are compiled to calculate the levelized unit energy cost ($/MW-year). Similarly, an annual revenue requirement ($/year) is compiled for wires options. For each option, a discounted cash flow model is created which includes the levelized unit energy cost or annual revenue requirement as well as bulk system energy and capacity costs where applicable. Note that, in order to enable an apples-to-apples comparison, the discounted cash flow for the non-wires options includes a credit for the bulk system capacity value it provides. The discounted cash flow model for all options is compiled over the lifespan of the longest option considered (typically 70 years for wires options). The net present value (in 2021 CAD dollars) of these cash flows are the primary basis through which options are compared.

A list of the assumptions made in the economic analysis can be found in Appendix E.

7.1.2 Options and Recommendation for Crilly DS

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (LTR of ~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power whenever Sturgeon Falls is on outage. Furthermore, the existing station equipment will reach end-of-life over the next ~10 years and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to three factors. First, non-wires alternatives will not be able to eliminate nor reduce existing reliance on backup generation. Load modifying non-wires alternatives (e.g., energy efficiency measures or demand response) could potentially reduce peak demand and overall energy consumption but, when transmission supply is interrupted due to Sturgeon Falls outages, they cannot replace the need for backup generation. Similarly, distributed energy resources can reduce peak demand below the station LTR but, during outages, the distribution system served by Crilly DS must still rely on backup diesel generation. Frequent reliance on backup diesel generation results in poor reliability and is technically challenging due to difficulties in staying connected and maintaining power quality when supplying loads on a long single-phase distribution line. The long-term solution for Crilly DS station capacity should ideally provide reliability on par with other single circuit supply stations (where regular supply interruptions are not required for generator maintenance outages).

Second, structures and equipment at Crilly DS are approaching end-of-life in the near future. While the specific end-of-life dates vary based on asset conditions, existing structures and equipment are expected to require refurbishment/replacement over the next 10 years. Even if non-wires alternatives can address overloads due to incremental growth above the current station capacity, the station must still be rebuilt/refurbished at end-of-life.

Third, Crilly DS serves a small pool of customers (approximately 500 homes and businesses) in a remote location. This customer pool is too small to cost-effectively target energy efficiency or demand response measures since the overhead costs will likely be prohibitive compared to the potential savings in deferred or upsized infrastructure. Furthermore, while voluntary energy efficiency and demand response programs can produce predictable results when applied over large populations, the demand savings when targeted to a small group of customers is unreliable.

Since non-wires alternatives are not suitable for Crilly DS, Hydro One Distribution is considering the follow wires options:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),

- Rebuild Crilly DS at a different location as a 115/25 kV HVDS (close to the existing station/supply point),
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS (connected to F25A closer to the community served by Crilly DS), or
- Replace Crilly DS with 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

The cost of these wires options ranges from $7.5-15M (including line work required for connection) and will address both the station capacity and end-of-life needs. Refurbishing Crilly DS at its current location is likely the least costly option but is undesirable due to the continued reliance on backup power. Furthermore, the incremental capacity that can be accommodated at the existing location may be limited due to the space constraints. Rebuilding Crilly DS as a full HVDS (either at 115 kV or 230 kV) would offer the best reliability and performance but also at the greatest cost. Replacing Crilly DS with a padmount transformer may be a more cost-effective option but there are still technical hurdles to be further investigated such as the ability for 115 kV protections to be accommodated within a padmount configuration.

Since non-wires alternatives are not suitable and there are no upstream supply capacity needs that require further regional coordination, the IRRP recommends that Hydro One Distribution conduct local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost.

7.1.3 Options and Recommendation for Margach DS

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied from a nearby CTS. Margach DS is approximately 10 km east of Kenora.

Non-wires alternatives are not suitable for addressing the Margach DS station capacity need due to the timing and magnitude of the demand increase. Resupplying the large industrial customer causes the forecast demand at Margach DS to jump by 40% from 2022 to 2023. Energy efficiency measures are typically only feasible if the demand exceeding station capacity is a small percentage of the total demand in each year. Similarly, historical zonal demand response auction data indicates that demand response is only feasible to reduce peak demand levels by single digit percentages. While distributed generation can technically be sized to accommodate any demand growth (within station short circuit and thermal limitations) this would functionally be the same as the new customer self-generating rather than seeking grid supply and is unlikely to be cost effective. The near-term timing of the demand growth is also problematic for implementing non-wires alternatives since many of the technical and regulatory barriers for implementing non-wires alternatives are still being tested.

The IRRP recommends that Hydro One Distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. Installing fan monitoring is an inexpensive method to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers. The cost of installing fan monitoring is in the range of $1-1.5M compared to the cost of adding a new transformer which would be greater than $3M. Fan monitoring will increase the station capacity from approximately 10 MW today to 16 MW.

If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service, but no recommendation beyond the fan monitoring is required based on the current forecast.

7.1.4 Options and Recommendations for Kenora MTS

Kenora MTS serves the City of Kenora and is expected to reach capacity in 2029 with a moderate annual growth rate of 1.25%. The station has an LTR of 23.4 MW and demand will exceed the LTR by approximately 4 MW by the end of the forecast horizon (2040).

Non-wires alternatives are promising for addressing the Kenora MTS station capacity need. The magnitude of the need relative to the total demand is moderate which makes targeting load modifying non-wires alternatives like energy efficiency and demand response feasible. The timing of the need is in the mid-term, so the forecast confidence is reasonably high while still having adequate lead time to demonstrate the efficacy of relatively untested non-wires alternatives and navigate technical and regulatory barriers. The timing of the need also means that lessons learned from the IESO's York Region Non-Wires Alternative Demonstration Project can be leveraged for implementing non-wires alternatives for Kenora MTS.

The following subsections discuss the wires options for Kenora MTS, non-wires alternatives, and recommendations.

7.1.4.1 Wires Options

There are two high-level wires options:

- Expand Kenora MTS with an additional transformer and associated protections, control, and structures at a cost of approximately $5M. This can be accommodated on existing land owned by the distributor, Synergy North, within the station. This option assumes that feeder loads can be rebalanced and servicing these loads on existing distribution system infrastructure is possible.

- Construct a new substation located across the city from the existing station at a cost of approximately $30M. The new station would be supplied from Rabbit Lake SS.

The existing Kenora MTS station is located on the northern edge of the city. The proposed new substation would be located on the far west side of the city and, in addition to addressing station capacity needs, would provide substantial distribution system benefits by reducing the length of feeders required to reach customers and improving voltage and frequency regulation. The long feeders to the western parts of the system currently experience voltage and frequency issues especially during outages requiring parts of the distribution system to be resupplied from alternate feeders. Synergy North is also aware of significant development interest along the western outskirts of the city, but no formal agreements have been finalized. A new station would provide a supply point close to these customers and improve distribution system performance.

A new station would also provide a redundant transmission supply point that is connected to a different bus/breaker at Rabbit Lake SS than the existing station. If a new station is built, the distribution system could be designed with tie points and reclosers to enhance the overall reliability across Kenora.

The distribution system benefits above have only been qualitatively described in the IRRP. As discussed in the following subsections, the cost effectiveness of the non-wires alternatives may hinge on whether they can provide similar distribution system benefits as a new station. Future analysis by Synergy North should further quantify the value of these benefits.

7.1.4.2 Non-wires Alternatives

Three non-wires alternatives for Kenora MTS were identified and sized according to the characteristics of the hourly demand profile described in Section 5.6:

- A 4 MW gas generation facility (aero engine). The cost estimate for gas generation is based on the IESO's internal benchmark cost reports. To estimate its contribution to provincial system adequacy, its effective capacity was assumed to be 93% of its installed capacity, which is the lesser of its unforced capacity and the zonal capacity maximums reported in the 2021 IESO Annual Planning Outlook.[22]

- A 6-hour 4 MW (24 MWh) battery. The cost estimate for battery storage is based on data from the National Renewable Energy Laboratory. Note that local generation (e.g., wind or solar) was not required to complement the battery due to the relatively low energy requirement (i.e., the battery can be recharged from existing grid power when it is not needed).

[22] The 2021 Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

- A combination of energy efficiency measures and demand response. The availability and cost of incremental energy efficiency measures (i.e., in addition to the conservation and demand management programs already included in the demand forecast) are based on the IESO's 2019 Conservation Achievable Potential Study[23]. The 2019 Achievable Potential Study and incremental energy efficiency savings for Kenora MTS are further described in Appendix E. Demand response costs are estimated from average capacity auction values from 2018-2021 for the Northwest zone.

The net present value (NPV) of each wires and non-wires alternative's cost is shown in Table 7-1. The NPV includes the levelized unit energy cost as well as bulk system energy and capacity costs and benefits associated with each option over a 45-year asset life (which is typical for station equipment).

Table 7-1 | Kenora MTS Wires and Non-wires Alternative Costs

Option	Cost NPV ($2021 Real)
Expand Kenora MTS	$4 M
New Station	$25 M
4 MW Gas Generation	$22 M[24]
24 MWh Battery Storage	$10 M[24]
Combination of Energy Efficiency and Demand Response	$1-9 M[25]

7.1.4.3 Recommendation

The cost of the non-wires alternatives generally falls between the cost of expanding the existing station and a new station (which also improves reliability and performance on the distribution system). Therefore, the decision to pursue non-wires alternatives versus traditional wires options rests on distribution system benefits that can be realized by each option. For example, battery storage can be sited on the distribution system such that it improves voltage regulation along lengthy feeders. If the value of the distribution system benefits is greater than the cost difference between the battery and station expansion, the battery may be the most cost-effective solution for ratepayers overall.

[23] The 2019 Conservation Achievable Potential Study can be found on the IESO's website.
[24] Assumes full (unforced capacity) credit for system capacity value. Actual cost could be higher depending on the deliverability of the NWA resource.
[25] Cost ranges from $1-9 M depending on whether the energy efficiency measures are part of provincially cost-effective CDM (i.e implemented through the IESO's Local Initiative Program) or if they are incremental to provincially cost-effective CDM.

The technologies, regulatory framework, and protocols required to implement dispatchable non-wires alternatives (e.g., batteries, gas generation, or demand response) for the purpose of meeting local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[26] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Region Pilot and further refine the procurement and operation of non-wires alternatives for Kenora MTS.

Since there are no upstream constraints on the transmission system requiring further regional coordination, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement non-wires alternatives if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[27] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program become available. In addition to the energy efficiency measures that may result from the IESO's Local Initiative Program, Synergy North may also use the Ontario Energy Board's Conservation and Demand Management Guidelines[28] to leverage distribution rates for non-wires alternatives.

7.2 Options for Improving Customer Reliability at Fort Frances TS

As discussed in Section 2.1.4, the IRRP will not make a specific recommendation for improving customer reliability since Fort Frances Power's roadmap for Fort Frances MTS is still under development. However, this section will document the options considered during the IRRP process and the IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and select a preferred option in local planning.

The Fort Frances TS 115 kV station layout and connection to Fort Frances MTS is shown in Figure 7-1. The 115 kV side of Fort Frances TS is comprised of a 6-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B, and F1B. Fort Frances MTS is currently connected to the L1-bus (which connects to F1B) and is physically located immediately adjacent to Fort Frances TS. Transmission outages to F1B and the L1 bus have accounted for 90% of Fort Frances Power's customer interruptions over the last 10 years. Therefore, Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

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[26] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[27] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

[28] More information about the Conservation and Demand Management Guidelines is available on the OEB's website (link).

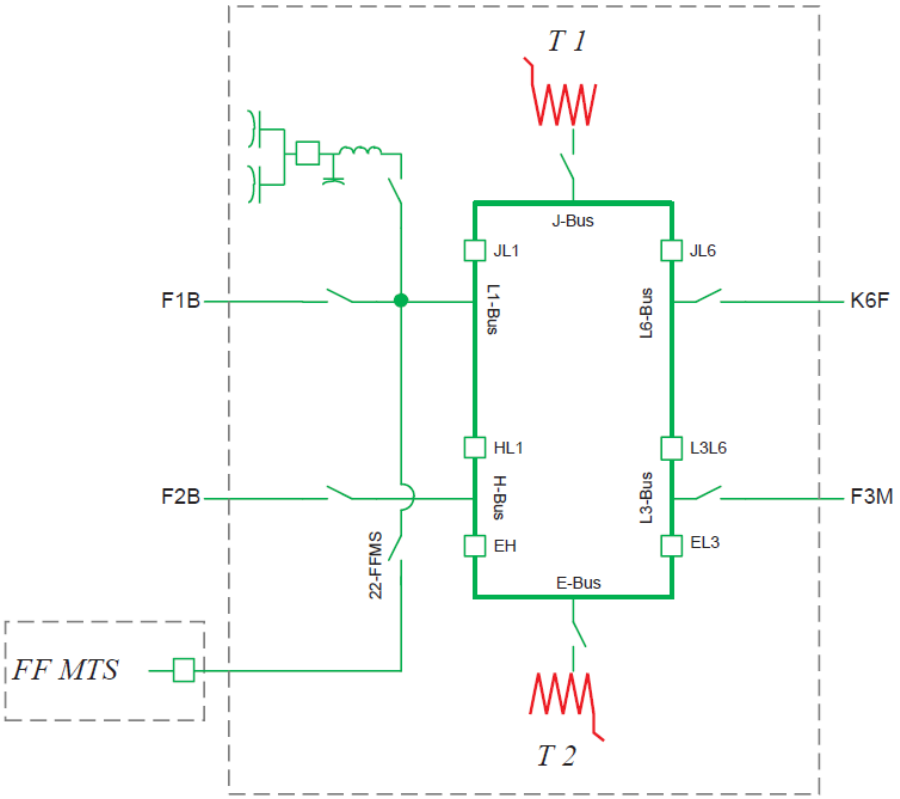


Figure 7-1 | Fort Frances TS 115 kV Single Line Diagram

The following options, in order of increasing complexity and cost, were contemplated:

- Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.
- Install a new 115 kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit.

- Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

8. Supply to the Ring of Fire

The Ring of Fire is a remote area covering 5000 km^2 located 500 km north of Thunder Bay with rich deposits of critical minerals.[29] There is strong interest in developing mining activities in this area, however as it is located far from established infrastructure, it is currently without all-season road access or grid power supply. Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning for Northwest Ontario. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with the ongoing Northwest IRRP. This report provides an update on preliminary findings as of Q4 2022 including:

- Transmission supply options and high-level cost estimates;
- Key opportunities for alignment that should be considered in the decision to pursue transmission supply to the Ring of Fire as well as its routing and connection point;
- Avoided diesel system costs from connecting remote communities to the grid via a transmission line to the Ring of Fire; and
- Greenhouse gas reductions associated with connecting remote communities and Ring of Fire mines to the grid, as opposed to self generation.

Note that the decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as the direct beneficiaries of such a project, and with the provincial and federal governments to advance broader policy objectives. The purpose of the renewed Supply to the Ring of Fire study is to help inform government policy and potential customers seeking connection.

8.1 Background

A map of the Ring of Fire area and nearby features of interest are shown in Figure 8-1. Interest in developing the Ring of Fire has varied over the years and there is a high degree of uncertainty in the eventual mining sector electrical demand that may materialize. However, with the current focus on developing critical minerals to support decarbonisation, interest in developing the Ring of Fire area is growing.

[29] Ontario's critical mineral list can be found in the 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

In addition to potential mining loads, there are five off-grid Matawa First Nation communities in the vicinity of the Ring of Fire. These communities rely on diesel generation systems that are expensive to operate, produce environmental pollutants, and may constrain the communities' growth. Enabling grid supply for these communities is an important factor contributing to the overall rationale for transmission supply to the Ring of Fire. The transmission supply routing and connection point to the existing electricity system should also consider the significant potential for hydro generation in the area which may be able to connect to the grid via the transmission line to the Ring of Fire.

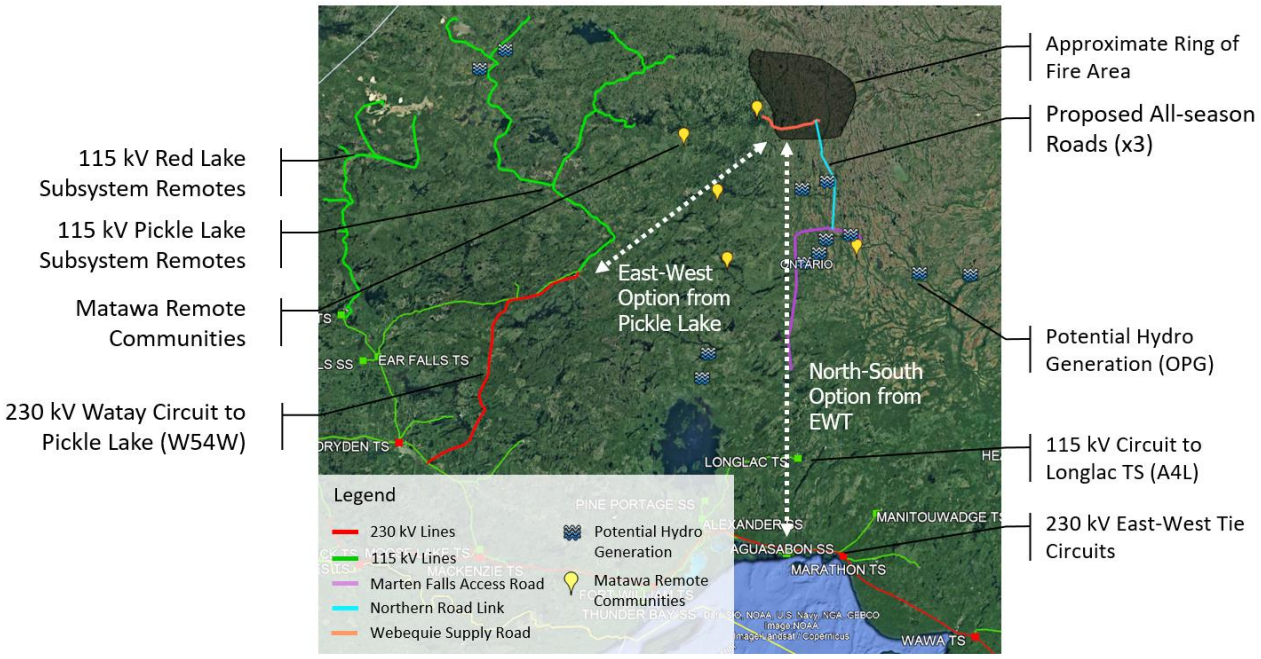


Figure 8-1 | Ring of Fire and Surrounding Area Map

Transmission supply to the Ring of Fire was contemplated in the 2015 North of Dryden IRRP and the 2016 Greenstone-Marathon IRRP. The North of Dryden IRRP outlined potential transmission supply options with the goal of connecting remote communities as well as serving mining electricity demand at the Ring of Fire if it were to materialize. This plan contemplated reinforcing the existing transmission system from the Dryden area to Pickle Lake and building a new transmission line from Pickle Lake to the Ring of Fire. The North of Dryden IRRP, in conjunction with the 2014 Remote Connection Plan, culminated in the indigenous-led Wataynikaneyap Transmission Project.

The Wataynikaneyap Transmission Project includes a new 230 kV line from Dinorwic Junction (near Dryden) to Pickle Lake as well as 115 kV transmission lines extending north of Pickle Lake and Red Lake to connect remote communities. The Matawa area remote communities chose not to participate in the Wataynikaneyap Transmission Project and no transmission lines were built from Pickle Lake to the Matawa communities or the Ring of Fire. This transmission supply option to the Ring of Fire is referred to as the East-West option in Figure 8-1.

The Greenstone-Marathon IRRP extended this analysis to consider potential cost optimization opportunities between new customers in the Greenstone area and remote communities/mines at the Ring of Fire. This entailed a North-South transmission supply option extending from the existing East-West Tie circuits northwards through Greenstone (which is electrically supplied from Longlac TS) and onwards to the Ring of Fire. The largest new customer in the Greenstone area at the time choose to self-generate instead of pursuing transmission supply and the North-South transmission supply option did not proceed.

To date, there have been no firm commitments from customers seeking transmission connection in the Ring of Fire area.

8.2 Policy Drivers and Demand Forecast

Enabling development in the Ring of Fire area is an important policy objective for the provincial government. Ontario's Critical Mining Strategy[30] identifies the Ring of Fire as a "priority project" and a "transformative opportunity for unlocking multi-generational development of critical minerals." The strategy also highlights the importance of Ontario's relatively clean electricity system for enabling development of lower-emissions mining compared to other jurisdictions.

The province has also expressed support for a "Corridor to Prosperity" comprised of three proposed all-season roads led by First Nations partners that connects to the existing highway system and extends northwards towards the Ring of Fire. These proposed roads include the Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link. The proposed roads are at various stages in their provincial and federal Environmental and Impact Assessments. Taken together, they would provide a continuous all-season transportation corridor to the Ring of Fire that would be necessary to facilitate mining development. Ontario has committed $1 billion to support these road infrastructure projects on the basis that federal contributions will match provincial commitments.

There is a high degree of uncertainty in terms of both the magnitude and timing of mining electricity demand at the Ring of Fire. The IESO's latest mining demand forecast includes approximately 30 MW of electricity demand associated with two proposed mining projects. The 2015/6 IRRP forecasts included up to 70 MW of demand at the Ring of Fire but some proponents have since walked away from their development plans. If transmission and

[30] The 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

transportation infrastructure were developed, mining demand would almost certainly be much higher than currently forecast. As of January 2022, there are approximately 26,000 active mining claims held by 15 companies in the Ring of Fire. The IESO will continue monitoring development plans and intends to update the mining forecast in Q1 2023 to better capture Ring of Fire growth scenarios.

The five Matawa area remote communities have a total demand of approximately 4 MW today and are forecast to grow at 4% per year.[31] This forecast was last updated in 2019 and will be updated as new information becomes available.

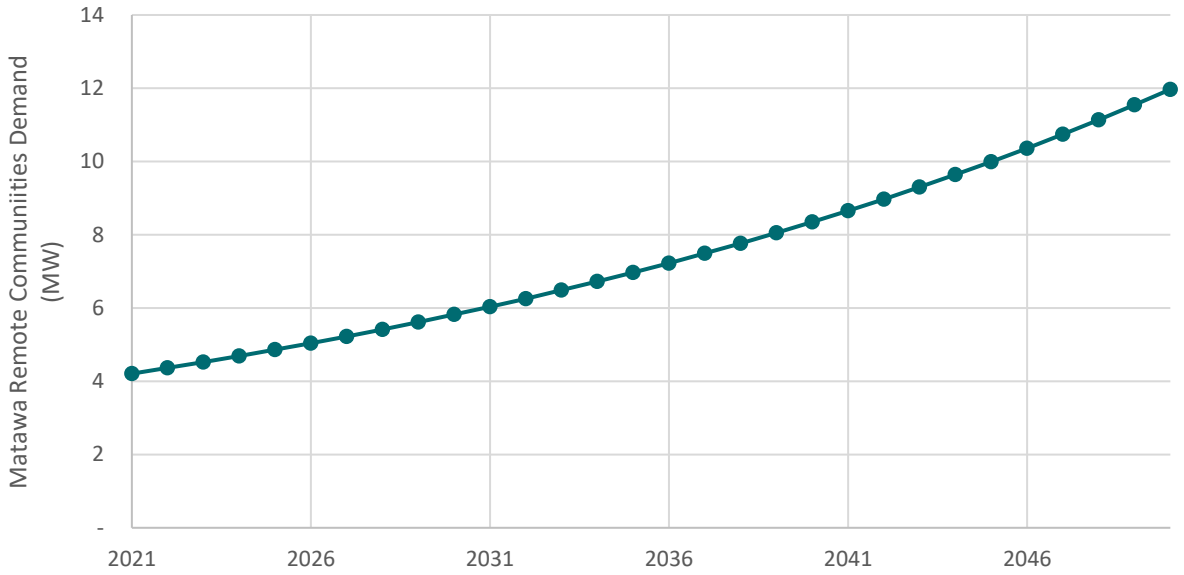


Figure 8-2 | Matawa Remote Communities Demand Forecast

[31]The forecast 4% growth rate reflects potential demand growth if the remote communities are grid connected and no longer constrained by diesel supply capacity.

8.3 Transmission Supply Options and Cost Estimates

As discussed in Section 8.1, at a high level, there are two transmission supply options to the Ring of Fire that could be pursued: a North-South option connecting to the East-West Tie circuits between Marathon and Thunder bay and an East-West option connecting to the new Wataynikaneyap TS near Pickle Lake. The conceptual electrical elements of each option are listed in Table 8-1. Note that at this stage, no detailed engineering design or routing work has been performed. The transmission options are presented here for discussion purposes and to facilitate high-level cost estimation (-50% to +100%).

The North-South option is estimated to cost between $860M and $1.08B while the East-West option is estimated to cost between $600M and $780M ($2022 real, overnight capital cost). The cost ranges reflect uncertainty in the final station configurations as well as in the per unit (km) cost of transmission lines which can vary depending on the technology type and geography. These cost estimates are not inclusive of step-down transformer stations at the loads themselves nor reactive compensation devices which will depend on the magnitude of the demand. Note that material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

Table 8-1 | Ring of Fire Transmission Option Conceptual Elements

Transmission Supply Option	Element #	Description	Length (km)	Cost ($2022 real)
North-South	1	230 kV single circuit line from East-West Tie circuits to Longlac	120	$170-215M
	2	New stations at East-West Tie connection point[32] and Longlac (to enable connection to A4L);	N/A	$115-125M
	3	230 kV single circuit line from Longlac to McFaulds Lake; roughly parallel to proposed roads	410	$575-740M
East-West	1	230 kV single circuit line from Wataynikaneyap TS near Pickle Lake to McFaulds Lake; roughly along route envisioned in the 2014 Remote Connection Plan	370	$580-745M
	2	Wataynikaneyap TS modifications	N/A	$20-30M

[32] Connecting the Ring of Fire line directly to East-West Tie lines between Lakehead TS and Marathon TS minimizes costs since it is the closest 230 kV supply point to the Ring of Fire. However, connecting to only one (or any subset) of the four parallel East-West Tie lines will unbalance flows between Marathon TS and Lakehead TS and may decrease the overall transfer capability of the East-West Tie. Future studies should weigh the costs and benefits of connecting to either Lakehead TS or Marathon TS versus a new junction and/or switching station on the East-West Tie.

While the East-West option is less expensive than the North-South option, it would provide less incremental capacity to supply load and would also increase exposure to outages. The load meeting capability for a radial expansion of the transmission system like the Ring of Fire is typically constrained by thermal, voltage, and load security limits. The thermal rating of a 230 kV single circuit line is unlikely to be constraining; as an example, a single East-West Tie circuit has a continuous rating of approximately 320 MW in the summer and 390 MW in the winter. This far exceeds the current known mining and remote community demand forecast. Voltage limits can be managed by installing voltage regulation devices at the loads and can be sized according to the expected demand, however this would add incremental cost and operational complexity. Load security limits, however, may become the most limiting factor depending on future mining developments.

Ontario Resource and Transmission Assessment Criteria (ORTAC) Section 7.1 load security criteria specifies the maximum amount of load that can be interrupted after certain contingencies. For the loss of a single element (i.e. single circuit supply to the Ring of Fire), no more than 150 MW may be interrupted. This limits the total load served on the North-South option to 150 MW. The East-West option is connected downstream of the new single circuit Wataynikaneyap line (W54W). The total load served by W54W is also limited to 150 MW including the all existing loads and their growth, new mining customers along W54W, and the Ring of Fire and Matawa communities. Existing load served on W54W totals approximately 45 MW today and is expected to grow to 80 MW by 2040. While the remaining room is sufficient for serving the currently forecast demand at the Ring of Fire (30 MW mining plus Matawa area communities), it leaves relatively little room to accommodate additional development. Furthermore, the IESO is aware of several additional mining projects potentially seeking connection along W54W. While these projects are not yet certain enough to be included in the IRRP reference forecast, they could significantly reduce the available capacity for growth at the Ring of Fire.

While not addressed by ORTAC criteria, another consideration is the level of exposure to outages. The East-West option would involve connecting the Ring of Fire and Matawa communities to a radial system that already spans several hundred kilometers of transmission lines (W54W and D26A). Each time any part of this system is faulted (e.g., in an electrical storm or fire), the whole system is removed from service until the fault can be addressed. By comparison, the North-South option can be connected to the East-West Tie (or nearby station) which are more robust and has redundant supply.

Due to the uncertainty in future mining developments, it is too early to rule out the East-West option at this time. However, the potential capacity constraints and customer reliability impacts related to the East-West option should be considered when selecting a preferred transmission option. The next section discusses opportunities for alignment and further considerations that may impact the preferred transmission option.

8.4 Opportunities for Alignment

A decision to pursue transmission supply to the Ring of Fire, and decisions on its preferred routing, should consider alignment with four opportunities in addition to supplying mining demand at the Ring of Fire:

- Supplying Matawa Remote Communities
- Enabling potential hydro generation
- Improving supply to Longlac
- Co-locating with transportation corridor

These opportunities for alignment are discussed in turn below.

8.4.1 Supplying Matawa Remote Communities

There are five Matawa indigenous remote communities in the vicinity of the Ring of Fire:

- Webequie
- Nibinamik
- Neskantaga
- Marten Falls
- Eabametoong

These communities were previously identified as economic for grid connection in the 2014 Remote Connection Plan but elected not to participate in the Wataynikaneyap Transmission Project. The 2014 Remote Connection Plan found that it was more cost-effective to supply the communities via a single circuit 115 kV transmission line (either from Pickle Lake or the East-West Tie circuits) than continued reliance on off-grid diesel generation systems. Transmission supply to the Ring of Fire could also enable connection of the Matawa remote communities. Both the North-South and East-West transmission options would serve this purpose. Updated potential avoided diesel generation system costs are discussed in Section 8.4.2.

Note that the decision to pursuing grid connection is up to the communities. The IESO will continue to engage with the Matawa communities to inform future studies. Furthermore, grid connection of remote communities does not preclude local energy projects such as the installation of distributed generation and storage. The IESO continues to support broad equitable participation in Ontario's energy sector through its Energy Support Programs including

the Indigenous Energy Projects (IEP) Program[33] which provides funding support to First Nation and Metis communities to assess and develop energy projects and partnerships.

8.4.2 Enabling Hydro Generation

In Jan 2022, the Ontario government asked Ontario Power Generation to examine opportunities for new hydroelectric development in northern Ontario. New hydroelectric generation could address the growing long-term electricity needs forecast for the province, with the potential for economic benefits for local and Indigenous communities in the north. Ontario Power Generation has shared this work with the Ministry of Energy and the IESO so that it can be considered as part of the IESO's work towards developing an achievable pathway to zero emissions in the electricity sector. Development of transmission supply to the Ring of Fire should consider the connection of potential hydro generation in the area.

There is significant hydroelectric generation potential in the vicinity of the Ring of Fire. Due to the geographic distribution of these potential generation facilities, the North-South transmission option is better suited than the East-West option to connect these facilities on the way to the Ring of Fire. Furthermore, the North-South option connects to a more robust point in the bulk transmission system which may result in fewer deliverability constraints and lower overall losses. The Ring of Fire North-South transmission line is not necessarily the optimal connection point for potential hydro generation near the Ring of Fire. Other connection options, to Pinard TS for example, may reduce the overall bulk system reinforcements needed to deliver the hydro generation capacity to southern Ontario. However, connecting to the Ring of Fire transmission line could significantly reduce the length of connection lines required for these potential hydro generators and future studies should consider the synergies between Ring of Fire transmission supply and enabling the connection of potential hydro generation.

8.4.3 Improving Supply to Longlac

The existing radial 115 kV circuit, A4L, to Longlac TS is near capacity and customers have expressed concern about poor reliability due to long and frequent outages. While no firm growth plans or new customer connection requests were received during this IRRP, there continues to be a high degree of interest for mining and industrial developments in the Greenstone and Geraldton areas supplied by A4L. There are also existing customers along A4L who have elected to self-generate rather than connect to the transmission system due to capacity constraints.

A4L refurbishment is underway and distance-to-fault relays have been installed which should decrease the frequency of outages and improve restoration times. However, these improvements do not increase the load meeting capability on A4L and, as with many other areas in the Northwest region, growth can materialize quickly.

[33] For more information, please visit the Indigenous Energy Projects Program webpage.

The North-South transmission option passes directly by Longlac TS and could help increase capacity and provide a secondary supply path to further improve reliability. The North-South option conceptual elements in Table 8-1 includes a 230/115 kV transformer station at Longlac for this purpose. Note that the East-West option is not suitable for reinforcing Longlac.

8.4.4 Co-locating with Transportation Corridor

The proposed Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link will provide a continuous all-season transportation corridor to the Ring of Fire. While detailed routing has not yet been performed, the North-South transmission option is well aligned with the proposed roads. The line length determined for the North-South option in Table 8-1 assumes that the transmission corridor runs parallel to the proposed roads wherever possible but the potential cost savings associate with colocation has not been factored into the transmission cost estimate yet. This likely overestimates the cost of the North-South transmission option compared to the East-West option; future studies should conduct more detailed engineering design and routing analysis to better quantify the benefits of colocation.

Co-locating linear infrastructure is consistent with provincial policy as articulated in Section 1.6.8 of the 2020 Provincial Policy Statement[34] and may help reduce environmental impacts. The roads would also provide easier access to the transmission line which could simplify construction as well ongoing operation and maintenance. Note that there are no proposed all-season roads along the East-West option route.

8.5 Avoided Matawa Communities Diesel System Costs

The Matawa remote communities are currently supplied by remote on-site diesel generation which is costly to operate. Up to 70% of the fuel must be flown in when winter roads are not available contributing to high costs and increased emissions from fuel transport. The costs of supplying electricity from remote diesel generation systems versus the grid over the first 20 years of transmission connection are shown in Figure 8-3. The net present value of remote diesel generation costs is estimated to be $446M over this period, while serving the same load from the provincial grid is estimated to be roughly $35M.[35] These net present values are expressed in real dollars in the year when transmission connection is hypothetically brought in-service. For the purpose of this assessment, it was assumed that transmission connection occurs in 2030 given the typical 7-year lead time of new transmission projects.

[34] The 2020 Provincial Policy Statement can be found on the Ontario government's Land Use Planning webpage.

[35] The cost of serving loads on the provincial grid is solely based on the system's marginal cost of energy. It does not include cost of transmission connection itself. Connecting remote communities is one of multiple potential benefits (other benefits include supplying mining loads and enabling hydro generation) that contribute towards a rationale for transmission supply. The cost of transmission supply should be compared against this full suite of benefits.

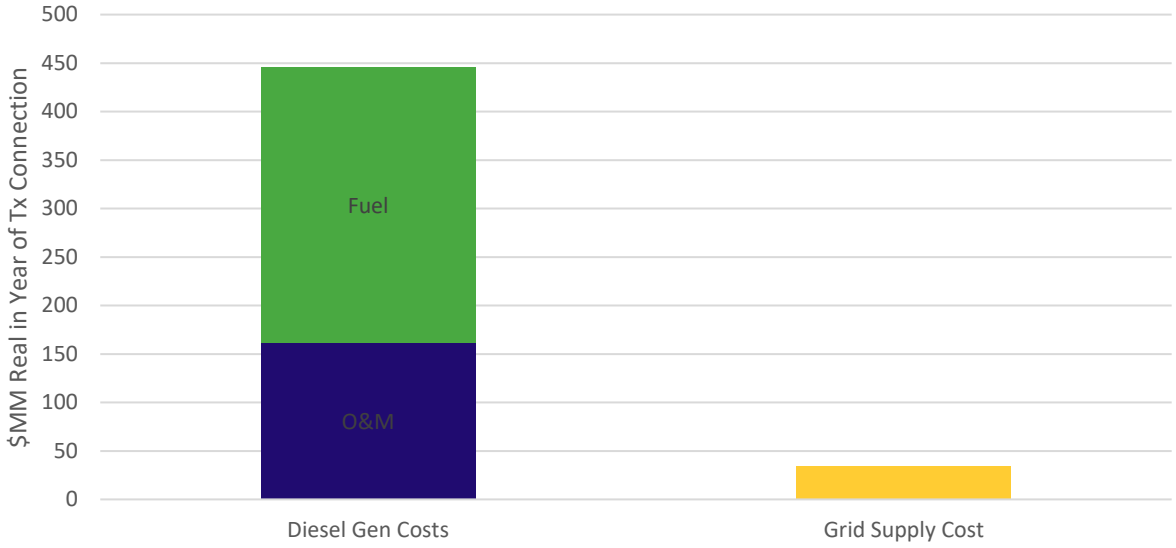


Figure 8-3 | NPV of Electricity Supply Costs from Diesel Generation versus the Provincial Grid for Matawa Remote Communities over the First 20 Years of Grid Connection

The cost of continuing to supply electricity to the remote Matawa communities by local diesel generation was estimated using the IESO's internal fuel forecast and aggregated cost data for remote communities served by Hydro One Remote Communities.[36] Generally speaking, economic and cost assumptions were consistent with the 2014 Remote Connection Plan adjusted for inflation. The cost of supplying electricity from local diesel generation is comprised of two components:

- Fuel costs including the cost for the fuel itself, winter road/air transportation, and the cost of carbon;
- Operating and maintenance costs estimated from historical revenue requirement and rate application regulatory submissions as a percentage of fuel costs.

[36] Not all Matawa communities are served by Hydro One Remote Communities. For communities served by Independent Power Authorities for which cost data was not directly available, system costs were estimated based the size of their load and Hydro One Remote Communities' system costs.

Of the $446M net present value, $284M is associated with fuel costs and $162M with operating and maintenance costs. Note that this cost estimate does not include the capital costs associated with expanding existing diesel systems to meet future capacity growth. This enables an apples-to-apples comparison with the cost of grid electricity which also did not include the incremental resource capacity cost of serving the newly connected remote communities. Furthermore, since the incremental capacity requirement is dependent on the year in which transmission connection occurs and the system needs/market conditions in the period following grid connection, capital costs associated with this capacity cannot be accurately calculated today. Future studies should refine the consideration of capacity costs when there is more certainty on when transmission supply will proceed.

The cost of serving Matawa remote communities should they be connected to the provincial electricity grid was based on the system marginal cost forecast in the 2021 Annual Planning Outlook.

8.6 Avoided Greenhouse Gas (GHG) Emissions

Avoided GHG emissions was estimated for the Matawa communities and the future mining load through the comparison of emissions on the electricity system (consistent with the 2021 Annual Planning Outlook emission rate per MWh) versus diesel generation for remote communities and natural gas generation for mining loads.[37]

The GHG reduction associated with connecting Matawa communities depends on the forecast demand levels and growth rate when transmission connection occurs. Consistent with the diesel system cost savings estimates in the previous section, transmission connection was assumed to occur in 2030. On average, over the first 20 years of transmission connection (i.e. 2030-2049), GHG reductions are expected to be approximately 27,000 tCO2e per year.

The GHG reduction associated with mining loads depends on the amount of demand that materializes. As discussed in Section 8.2, there is a high degree of uncertainty in terms of both the magnitude and timing of this demand. For illustrative purposes, if 30 MW of demand materializes (consistent with demand from known projects), GHG reductions would total 68,000 tCO2e per year. If 70 MW of demand materializes (consistent with demand from the 2015 IRRP forecasts), GHG reductions would total 160,000 tCO2e per year. The true avoided GHG emissions associated with connecting mining loads instead of on-site generation could be much higher given the large number of active mining claims in the Ring of Fire.

[37] The natural gas generation was assumed to be a combined cycle gas turbine (CCGT) facility with a heat rate of 7.265 MW/MMbtu and a natural gas emission intensity of 53.157 kgCO2e/MMbtu. For diesel generation emissions, the Hydro One Remote Communities fleet average generator efficiency and a diesel emission intensity of 75.22 kgCO2e/MMbtu was assumed.

8.7 Next Steps

The sections above provide an overview of preliminary findings to date of the Supply to the Ring of Fire Study and highlights some areas of uncertainty that will require further investigation. The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope, timing, and engagement process will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

9. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for this Northwest IRRP.

9.1 Engagement Principles

The IESO's engagement principles[38] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

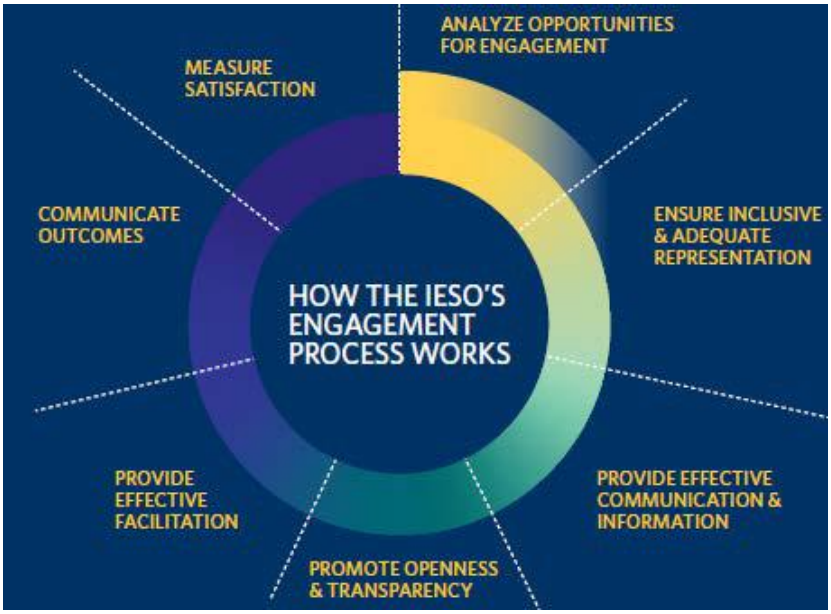


Figure 9-1 | IESO's Engagement Principles

[38] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

9.2 Creating an Engagement Approach for the Northwest

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage[39] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted discussions sessions;
- Face-to-face meetings; and
- One-on-one outreach with specific communities and stakeholders to ensure that their identified needs are considered (see Sections 9.4 and 9.5).

[39] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-Northwest-Ontario

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, leveraging existing relationships built through the previous planning cycle. This started with the Scoping Assessment Outcome Report for the Northwest region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the Northwest Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to ensure that municipal energy planning, including the need to recognize climate change priorities, as well as economic development and industrial growth (including forestry and mining) were in scope of the development of the IRRP. In addition, reliability remained a paramount concern within this region. Along with a response to the feedback received, the final Scoping Assessment was posted on January 13, 2021, which identified the need for a coordinated regional planning approach across the Northwest region – particularly important since the previous planning cycle targeted regional plans within five identified sub-regions.

Following the finalization of the Scoping Assessment, outreach then began with targeted municipalities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the Northwest planning region as well as all identified municipalities and Indigenous communities to ensure that all interested parties were made aware of this opportunity for input. Four public webinars were held at key stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on various components of the plan.

All these engagement sessions received strong participation with a cross-representation from stakeholders and community representatives. Feedback was received as a result each engagement meeting which was considered in each of the stages in the IRRP development.

The public webinars invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

In addition, three targeted discussions were held virtually to uncover specific feedback from communities and stakeholders on the following three topics:

1. Customer Reliability Concerns
2. Emerging Local Initiatives
3. Emerging Electricity Needs in the North of Dryden Area

Comments received during this engagement focused on the following major themes:

- Given the large geographic area for this planning region, consideration throughout the engagement should be given to targeted discussions to address local reliability and priorities. Education and support should be available to enable purposeful engagement for all interested parties
- Consideration in the demand forecast should be given to local developments, growth plans and climate change goals (i.e., electrification) – particularly in communities where capacity may be limited
- Non-wires alternatives should be considered to meet needs and, in particular, climate change priorities; existing resources in the region should be considered where contracts are due to expire
- Due consideration should be given to providing capacity for new commercial and industrial (mining and forestry) growth as well as electrification of existing industry
- Opportunities for future proponents to leverage existing partnerships or create new relationships among local and Indigenous communities to have due consideration of priorities and provide business prospects, where possible

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities as well as the members of the Northwest Regional Electricity Network.

Based on the discussions through the Northwest IRRP engagement initiative and broader network dialogue, there is a clear interest to further discuss the potential for development of the mining sector in this region and to look for alternative energy solutions to meet local needs, particularly as communities and industries shift towards electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts. To that end, ongoing discussions will continue through the IESO's Northwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and planning initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Northwest IRRP engagement webpage.

9.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with targeted municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; reliability concerns; and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities to provide input, the IESO invited Indigenous communities located in or near the Northwest region to participate in webinars that were held on:

- December 8, 2020
- May 20, 2021
- September 27, 2021
- November 2, 18, 29, 2021
- April 25 and 26, 2022
- November 3, 2022

The First Nation communities that were invited to the webinars were:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Couchiching
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort William
- Grassy Narrows
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Lac des Mille Lacs
- Lac La Croix

- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Mitaanjigamiing
- Muskrat Dam Lake
- Naicatchewenin
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- Nigigoonsiminikaaning
- Niisaachewan Anishinaabe Nation
- North Caribou Lake
- North Spirit Lake
- Northwest Angle No. 33
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Pays Plat
- Pikangikum
- Poplar Hill
- Rainy River
- Red Rock Indian Band
- Sachigo Lake
- Sandy Lake
- Seine River
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Whitesand
- Wunnumin Lake

The Métis communities that were invited to the webinars were:

- MNO Atikokan Métis Council
- MNO Greenstone Métis Council
- MNO Kenora Métis Council
- MNO Northwest Métis Council (Dryden)
- MNO Sunset Country Métis Council (Fort Frances)
- MNO Superior North Shore Métis Council (Terrace Bay)
- MNO Thunder Bay Métis Council
- Red Sky Independent Métis Nation

9.5.1 Information about Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective options after it has engaged with stakeholders and Indigenous communities and publishes recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement the recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report.

In instances where transmission is the recommended option, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then apply to the OEB for approval through a Leave to Construct hearing and, only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

There are no new transmission projects recommended as a result of this Northwest planning initiative.

10. Conclusion

The Northwest IRRP identifies electricity needs in the region over the 20-year period from 2021-2040, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

In the near term, the IRRP recommends new and/or upgraded stations to address station capacity needs at Crilly DS and Margach DS, further refinement of non-wires alternatives at Kenora MTS, reconfiguration of Fort Frances TS to improve customer reliability at Fort Frances MTS, and additional reactors at or near Pickle Lake SS to manage high voltages so that E1C can be operated normally open. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The IRRP recommends that the Working Group monitor growth, particularly in the Red Lake and Fort Frances areas. The IRRP studied high growth sensitivities to establish load meeting capabilities in these areas against which growth should be monitored to determine when future regional planning activities should be triggered. The IESO will update its mining sector demand forecast in early 2023 and provide updates to the Working Group. Electricity demand at White Dog DS and Marathon DS should also be monitored to confirm the timing of station capacity needs emerging in the 2030's. No firm recommendations are required for these potential long-term needs at this time.

The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope and timing will evolve with government policy direction and the IESO will share updates with the Working Group to inform upcoming regional planning activities.

The Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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REGIONAL INFRASTRUCTURE PLAN REPORT

Northwest Ontario

Regional Infrastructure Plan Report

[Northwest Ontario]

[Date: August 4, 2023]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Northwest Ontario Technical working group

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Disclaimer

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

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

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Executive Summary

REGION	Northwest Ontario Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: February 9, 2023	**END DATE:** August 4, 2023

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Northwest Region, preceded by, the publication of Needs Assessment (NA) report in July 2020 by Hydro One, followed by the Scoping Assessment (SA) in January 2021 & Integrated Regional Resource Plan (IRRP) in January 2023 published by the IESO respectively.

Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

2. OBJECTIVES AND SCOPE

Objectives:

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

Scope:

- A consolidated summary of needs and recommended plans for the region over a study period of 2023-2043 based on available information.
- A consolidated report of the needs and relevant wires plans to address near and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans in the near and medium-term to address these needs based on new and/or updated information.

- Consideration of long-term needs identified in the Northwest Ontario IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the Northwest Ontario region though a regional planning area map and a single line diagram. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River, and Thunder Bay. The region is comprised of 230kV circuits from the Manitoba interties in the west to Marathon TS in the east and 115kV sub-systems in between.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

This section provides a summary and brief description of all the projects completed in the past ten years or are currently underway.

I. Following Major projects were completed during the last ten years:

1. **Manitouwadge TS (2016)** – The 115/44kV, 5/7MVA T1 transformer was replaced with new 115/44kV 25/33/41.7 MVA unit.
2. **Dryden TS (2018)** – Five 115kV breakers and two 115/44kV, 11/15MVA transformers were replaced with new 115/44 kV 25/33/42MVA units.
3. **Lakehead TS (2017)** – Two 230/115kV autotransformers were replaced with new 230/115kV 150/200/250MVA units.
4. **Birch TS (2015)** – One 115/25kV transformer was replaced with a new 115/25kV 25/33/42MVA unit.
5. **Ear Falls TS (2022)** – Four 115kV breakers and one 115/13.2kV transformer was replaced with a new 115/13.2 kV 7.5/10/12.5MVA unit.
6. **East West Tie (2022)** – A 450 km, double-circuit, 230kV transmission line from Wawa TS to Lakehead TS was built with a connection approximately mid-way at Marathon TS.
7. **Wataynikaneyap Power Project Phase 1 (2022)** – A 300 km, single circuit, 230kV transmission line from Dinorwic to Pickle Lake, Ontario was built with a 230/115kV autotransformer, related switching facilities and necessary voltage control devices.

II. Following Major projects are underway:

1. **Rabbit Lake SS (2024-2027)** – Replace 115kV circuit breakers and associated equipment.
2. **Whitedog Falls SS (2025-2028)** – Replace 115kV circuit breakers and associated equipment.

3. **Mackenzie TS (2026-2029)** – Replace 230kV circuit breakers and associated equipment.
4. **Wawa TS (2026-2029)** – Replace two existing 230/115kV autotransformers with two new units; replace four 230kV and four 115kV circuit breakers.
5. **Wataynikaneyap Power Project Phase 2 (2022-2024 and beyond)** – Construct approximately 1438 km of 115kV, 44kV and 25kV transmission lines and twenty substations to connect 16 First Nations in two transmission subsystems.

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the Northwest Ontario Region is expected to grow at an average annual rate of approximately 2% in winter from 2023 to 2033. The Region is winter peaking so this assessment is based on winter peak loads.

The following other assumptions are made in this report.

- The study period for the RIP assessments covers near and medium-term. However, a longer term forecast up to 2043 is provided to identify long-term needs and align with the Northwest Ontario region IRRPs.
- LDCs reconfirmed load forecasts up to 2033. A longer term forecast up to 2040 is adopted with IRRP load forecast. The additional three years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR); or winter 10-day LTR if undergoing a winter season analysis.
- Bulk transmission line and auto-transformation capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Northwest Ontario Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. **Needs identified in the region**

a. **Asset Renewal for Major HV Transmission Equipment (Replace equipment identified in deterioration and technical obsolescence)**

- Rabbit Lake SS
- Whitedog Falls SS
- Mackenzie TS
- Wawa TS
- Marathon TS
- Lakehead TS
- Lakehead TS C8 Condenser
- Fort Frances TS
- Kenora TS

b. **Station Capacity**

- Margach DS
- Crilly DS
- White Dog DS
- White River DS
- Kenora MTS

c. **Transmission Line Capacity**

- E2R and E4D
- M2W

d. **System Reliability, Operation and Load restoration**

- Fort France MTS - Planned outages considering station single supply configuration
- E1C - Operation and High Voltage under a Normally-open configuration

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Northwest Ontario region. The needs include those previously identified in the NA and IRRP for the Northwest Ontario region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the Northwest Ontario region is given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Rabbit Lake SS	Replacement of the 115kV switchyard and its associated equipment	Hydro One Transmission	2024-2027	35.2
Whitedog Falls SS	Replacement of three 115kV breakers, DC station services and associated equipment	Hydro One Transmission	2025-2028	8.5
Mackenzie TS	Replacement of one 230/115kV autotransformer, five 230kV breakers, four switches, the AC station services and associated equipment	Hydro One Transmission	2025-2028	54.6
Wawa TS	Replacement of two 230/115kV autotransformer, associated breakers and equipment and station services	Hydro One Transmission	2026-2029	43.8
Marathon TS	Replacement of 230kV and 115kV breakers and associated equipment	Hydro One Transmission	2026-2029	14.6
Lakehead TS	Replacement of 230kV and 115kV breakers, the station services and associated equipment	Hydro One Transmission	2028-2031	41.5
Lakehead TS Condenser C8 Replacement	Replacement of the condenser C8 with a +60/- 40 MVAR STATCOM	Hydro One Transmission	2027	40.6
Fort Frances TS	Replacement of the 230kV breakers, associated equipment, and the station services	Hydro One Transmission	2029-2032	20.3
Kenora TS	Replacement of 230kV breakers, associated equipment, and the station services	Hydro One Transmission	2030-2033	17
Station Capacity Needs				
Margach DS	To be monitored and implemented in investment plan in 2025	Hydro One Distribution	2025	1

Crilly DS	To further assess the Alternative 1 and Alternative 2 from this RIP	Hydro One Distribution	NA	NA
White Dog DS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
White River DS	To be monitored and reviewed in the next planning cycle	Hydro One Distribution	NA	NA
Kenora MTS	To further assess the alternatives from this RIP; To be monitored and reviewed in next planning cycle	Synergy North	NA	NA
Transmission Line Capacity Needs				
E2R and E4D	To further evaluate the four alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	125-375
M2W	To further evaluate the two alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	TBD
System Reliability, Operation and Load restoration Needs				
Fort Frances MTS	Installation of a second breaker and switch in Fort Frances MTS to create a second supply to the MTS	Fort Frances Power	2026-2027	0.85
E1C Operation	To open E1C end at Ear Falls TS and installation of a 10 – 15 MVAR shunt reactor at Pickle Lake SS	Hydro One Transmission	2026-2027	20
Other Planning Considerations				
Fort Williams TS Shunt Capacitor Banks Replacement	Replacement of temporary capacitor banks with permanent units	Hydro One Transmission	2026-2027	6
Greenstone-Marathon Area System Needs	Further evaluation of the alternatives presented in the past IRRPs and RIP upon customers' requests	Hydro One Transmission and Proponent	TBD	TBD
Supply to the Ring of Fire	IESO to update Supply to the Ring of Fire study	IESO	TBD	TBD

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process where, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Northwest Ontario Region was initiated with the publication of Needs Assessment (NA) report in July 2020 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in January 2021 and in January 2023 published by the IESO respectively.

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

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

Table 1: Northwest Ontario Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Distribution)
2	Independent Electricity System Operator ("IESO")
3	Atikokan Hydro Inc.
4	Fort Frances Power Corporation
5	Sioux Lookout Hydro Inc.
6	Synergy North
7	Wataynikaneyap Power LP
8	NextBridge Infrastructure LP
9	Hydro One Networks Inc. (Transmission)

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans in the near and medium-term to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Northwest Ontario IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most

essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, Bulk System plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess, and document which of the needs

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendations to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the Independent Electricity System Operator (IESO) initiates the Scoping Assessment (SA) phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), Integrated Regional Resource Plan (IRRP) and/or Regional Infrastructure Plan (RIP).

The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the

region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in figure 1.

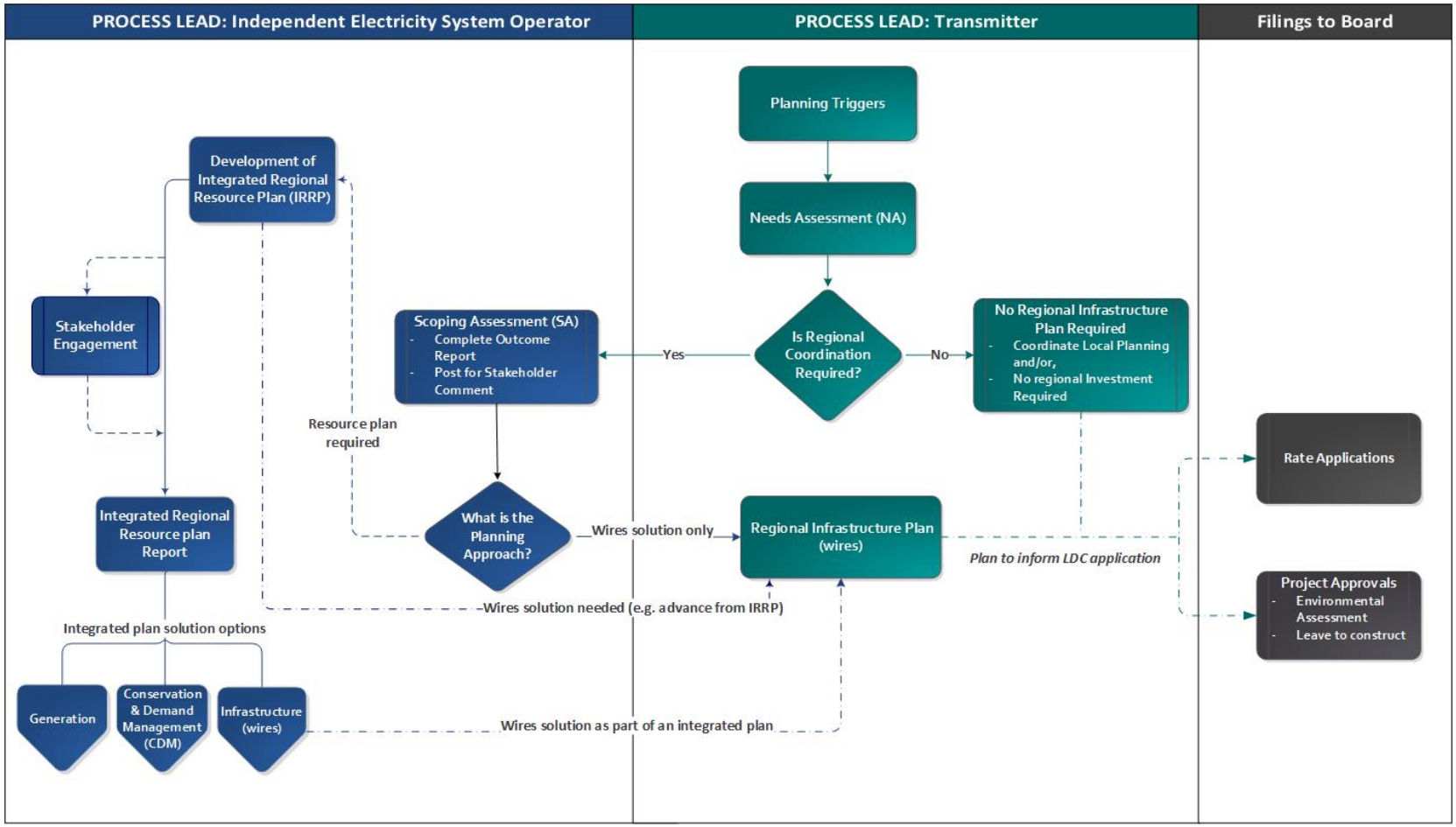


Figure 1: Regional Planning Process Flowchart

3.2 Regional Infrastructure Plan Methodology

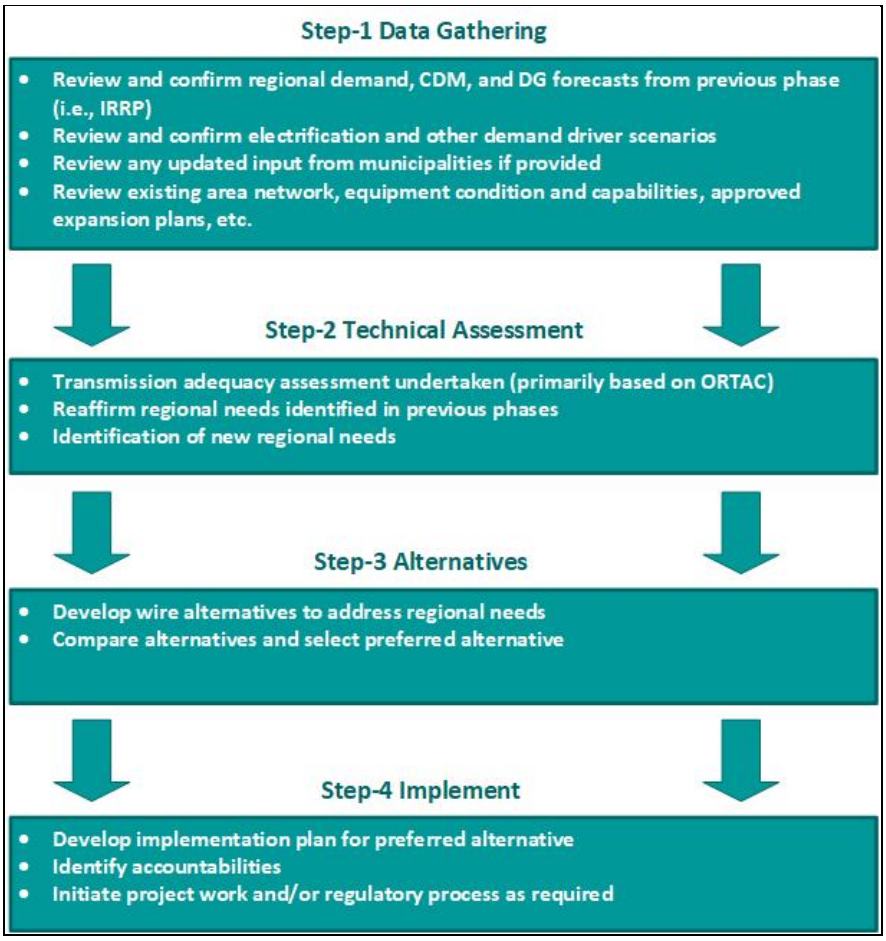


Figure 2: Regional Infrastructure Plan Methodology

Figure 2 above represents the four-step process of the Regional Infrastructure Plan which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.

- Review and confirm electrification and other growth scenarios which effects the projects recommended in in previous stages and also update the inputs provided by the Municipalities.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Northwest Ontario Region is roughly boarded by west of Hudson Bay and James Bay, North and West of the Lake Superior, and East of the Canadian province of Manitoba. The region consists of the districts of Thunder Bay, Kenora and Rainy River. Almost 54 percent of Region's entire population lives in Thunder Bay. The region accounts for approximately 60 percent of land area of the province and about two percent of Ontario's total population.

The geographical boundaries of the Northwest Ontario region are shown in Figure 3 below.



Figure 3: Map of Northwest Ontario Regional Planning Area

Bulk electrical supply to the Northwest Ontario region is provided through a combination of local generation stations connected to the 230kV and 115kV network, the East-West Tie transmission corridor and future Waasigan transmission line.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Synergy North, Sioux Lookout Hydro Inc., and Fort Frances Power Corporation. The LDCs receive power at the step-down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP. The January 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDCs. The January 2021 Northwest Region second cycle SA report prepared by IESO recommended a single IRRP covering the entire Northwest region. Subsequently, the January 2023 Northwest Ontario Region IRRP prepared by IESO considered the region as a whole.

4.1 North of Dryden Sub-Region

A radial single-circuit 115kV transmission line (“E4D”) and a new 230kV transmission line ("W54W”) supply electricity to the customers in the North of Dryden sub-region. The major supply stations for this sub-region are Dryden TS and Pickle Lake CTS, where the voltage is stepped down from the 230kV to 115kV at both stations, to serve local and industrial customers. Two of Wataynikaneyap Power’s 115kV transmission lines (WBC and WPQ) will supply two remote subsystems, north of Pickle Lake and Red Lake. Electricity demand in the North of Dryden sub-region is generally supplied by local hydroelectric generation.

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the North of Dryden Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations
• E4D • E2R • E1C • M1M • M3E • C3W • C2M • WBC** • WPQ**	• W54W	• Red Lake TS • Cat Lake MTS • Pickle Lake CTS* • Slate Falls DS • Perrault Falls DS • Crow River DS • Pickle Lake SS • Ear Falls TS • CTS1 • CTS2 • CTS3*	• Ear Falls GS (18.6MW) • Manitou Falls GS (72MW) • Lac Seul GS (12.5MW)

*Stations with Autotransformers installed

** Multiple Wataynikaneyap Power circuits and transformer stations are supplied radially from WBC (which connects to Pickle Lake CTS) and WPQ (which connects to E2R). See Appendices B & C for details.

4.2 Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station (“SS”). Located in the town of Marathon, Marathon TS connects the Northwest electrical system to the East Lake Superior electrical system at Wawa TS, with four 230kV lines - W21M, W22M, W35M and W36M. Marathon TS steps down 230kV to 115kV and supplies customers in the Town of Marathon, White River and Manitouwadge through a 115kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS in Thunder Bay Sub-Region.

The circuits and stations of the area are summarized in the Table 3 below:

Table 3: Transmission Station and Circuits in the Greenstone-Marathon Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations
• A1B • A5A • A4L • T1M • M2W	• W21M • W22M • W35M • W36M • M23L • M24L • M37L • M38L	• Marathon TS* • Longlac TS • Manitouwadge TS • Beardmore DS #2 • Jellicoe DS #3 • Manitouwadge DS #1 • Marathon DS • Pic DS • Schreiber Winnipeg DS • White River DS • CTS1 • CTS2 • CTS3 • CTS4 • CTS5	• CGS1 • CGS2 • CGS3 • CGS4 • CGS5 • CGS6

*Stations with Autotransformers installed

4.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230kV transmission system consisting of Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230kV to 115kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230kV transmission lines, K21W and K22W. Fort Frances TS steps down 230kV to 115kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115kV transmission line, F3M. Dryden TS steps down 230kV to 115kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230kV to 115kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities.

The circuits and stations of the area are summarized in the Table 4 below:

Table 4:Transmission Station and Circuits in the West of Thunder Bay Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations

• A3M • M1S • B6M • M2D • 29M1 • D5D • K3D • 15M1 • K6F • K7K • F2B • F3M • F1B • K4W • K5W • SK1 • K2M • W3C	• A21L • A22L • K22W • K21W • K23D • K24F • W54W • D26A • F25A • N93A	• Kenora TS* • Fort Frances TS* • Dryden TS* • Mackenzie TS* • Moose Lake TS • Barwick TS • Fort Frances MTS • Kenora MTS • Agimak DS • Burleigh DS • Clearwater Bay DS • Eton DS • Keewatin DS • Margach DS • Minaki DS • Nestor Falls DS • Sam Lake DS • Sapawe DS • Shabaqua DS • Sioux Narrows DS • Valora DS • Vermilion Bay DS • CTS1 • CTS2 • CTS3 • CTS4 • CTS5 • CTS6 • CTS7	• Atikokan GS (227MW) • Whitedog Falls GS (64.8MW) • Caribou Falls GS (70MW) • CGS1 • CGS2 • CGS3 • CGS4 • CGS5 • CGS6

*****Stations with Autotransformers installed

4.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230kV step-down transformation facility which steps down 230kV to 115kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115kV by three step-down transformer stations – Birch TS, Fort William TS, and

Port Arthur TS #1. Two parallel circuits A7L and A8L connect Lakehead TS to Alexander SS, which then interconnect Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS together.

The circuits and stations of the area are summarized in the Table 5 below:

Table 5: Transmission Station and Circuits in the Thunder Bay Sub-Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
• B5 • B9 • B14 • B15 • R2LB • R1LB • P7B • P3B • S1C • P5M • L3P • A6P • L4P • A7L • A8L	• A21L • A22L • M23L • M24L • M37L • M38L	• Lakehead TS* • Port Arthur TS #1 • Birch TS • Fort Williams TS • Murillo DS • Nipigon DS • Red Rock DS • CTS1 • CTS2 • CTS3	• Silver Falls GS (45MW) • Alexander GS (65.1MW) • Cameron Falls GS (70MW) • Pine Portage GS (143.9MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of Northwest Ontario region is shown in Figure 4 below.

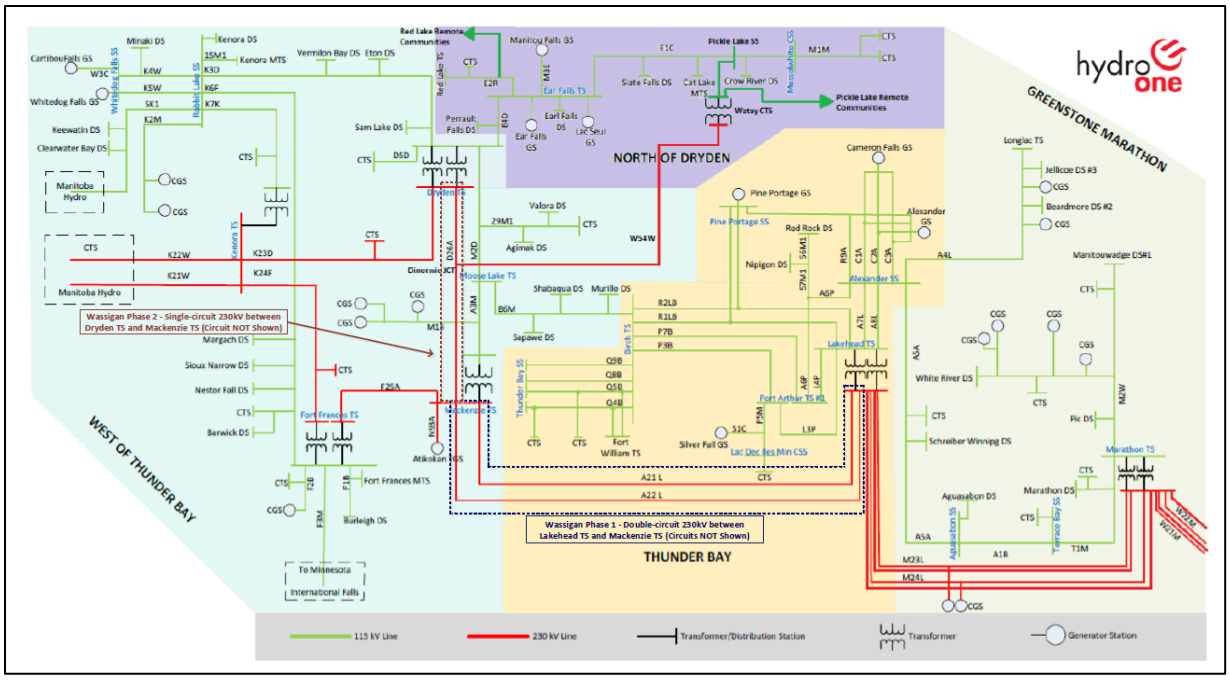


Figure 4: Northwest Ontario Transmission Single Line Diagram

4.5 New/Ongoing Transmission Line Projects Connect Sub-Regions

Below three recent/ongoing transmission projects in the Northwest regions reinforce the transmission corridors of the four sub-regions:

- East-West Tie Reinforcement
  - New double circuit 230kV line from Wawa TS to Lakehead TS in the Municipality of Shuniah, near Thunder Bay, Ontario, with a connection approximately mid-way at the Marathon TS.
- Waasigan Transmission Line Project
  - Phase 1 – New double circuit 230kV line from Lakehead TS to Mackenzie TS;
  - Phase 2 – New single circuit 230kV line from Mackenzie TS to Dryden TS.
- Wataynikaneyap Transmission Project
  - New single circuit 230kV line from Dinorwic Junction near Dryden to Pickle Lake CTS near Pickle Lake;
  - 115kV Remote connection subsystems north of Pickle Lake and Red Lake.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section, all projects that have been completed in the past ten years or currently are underway is provided and their scope of work is briefly discussed. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Northwest Region to improve the supply capability and reliability.

Hydro One, Next Bridge Infrastructure and Wataynikaneyap Power, three Transmission Asset Owners (TAO) in the region have undertaken execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

- **Manitouwadge TS (2016)** – The 115/44kV, 5/7 MVA T1 transformer was replaced with new 115/44kV 25/33/41.7 MVA unit.
- **Dryden TS (2018)** –Two 115/44kV, 11/15 MVA transformers were replaced with new 25/33/42 MVA units in addition to replacement of five 115kV breakers.
- **Lakehead TS (2017)** – Two 230/115kV autotransformers were replaced with new 230/115kV 150/200/250MVA units.
- **Birch TS (2015)** – One 115/25kV transformer was replaced with a new 115/25kV 25/33/42MVA unit.
- **Ear Falls TS (2022)** – One 115/13.2 kV transformer was replaced with a new 115/13.2 kV 7.5/10/12.5MVA unit in addition to replacement of four 115kV breakers.
- **East West Tie Reinforcement (2022)** – A 450 km, double-circuit, 230kV transmission line from Wawa TS to Lakehead TS was built with a connection approximately mid-way at Marathon TS.
- **Wataynikaneyap Power Project Phase 1 (2022)** – A 300 km, single circuit, 230kV transmission line from Dinorwic to Pickle Lake, Ontario was built with a 230/115kV autotransformer, related switching facilities and the necessary voltage control devices.

II. Following Major projects are underway:

- **Rabbit Lake SS (2024-2027)** –This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace identified 115kV circuit breakers, associated disconnect switches, instrument transformers and equipment protections. The scope of work also involves installing new AC station service, DC battery and PCT building.
- **Whitedog Falls SS (2025-2028)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace identified 115kV circuit

breakers and associated switches. The scope of work also involves replacing and upgrading DC station supply system.

- **Mackenzie TS (2025-2028)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace 230kV circuit breakers, select protections, and AC/DC station service systems. A new 115/44kV load facility at Mackenzie TS to replace the one at Moose Lake TS.

- **Wawa TS (2026-2029)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace two autotransformers rated 75/100/125MVA, 230/115kV, four 230kV circuit breakers, and four 115kV circuit breakers. The scope of work also includes replacing associated disconnect switches, protection equipment and the station service system.

- **Wataynikaneyap Power Project Phase 2 (2022-2024 and beyond)** – This investment, led by Wataynikaneyap Power, will construct approximately 1438 km of overhead 115kV, 44kV and 25 kV transmission lines and twenty substations to connect 16 First Nations in two transmission subsystems by 2024 (10 north of Pickle Lake and 6 north of Red Lake). The Red Lake subsystem is designed to connect a seventh First Nation beyond 2024.

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

After verification from the TWG participants, and as no material changes were identified, the Northwest Region IRRP Load Forecasts were used in development of this Report. TWG participants, including representatives from LDC's, Wataynikaneyap Power, IESO and Hydro One, provided information and input for the IRRP Load forecast, which also includes the inputs from the Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP).

During the study period, the load in the Northwest Ontario Region is expected to grow at an average annual rate of approximately 2% in winter from 2023-2033. The Region is winter peaking, so this assessment is based on winter peak loads.

Figure 5 shows the Northwest Region median winter weather net non-coincident load forecast from 2023-2033. Note that the non-coincident forecast is typically 10-15% higher than the coincident

forecast in the Northwest region. This assessment is based on non-coincident forecast. In the event that non-coincident load forecast identifies network element needs, a sensitivity study will be performed utilizing coincident load forecast. The load forecasts from the Northwest Ontario Region were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

The main factor contributing to the deviation between the load forecasts in the IRRP and the RIP is the mining sector forecast. In the IRRP, the mining forecast was considered final as of the end of 2021. However, after the completion of IRRP, IESO has provided an updated reference scenario for the mining forecast, accounting for potential future mining projects. As a result, this updated mining forecast contributes to the variation between the load forecasts in the IRRP and RIP beyond 2026.

Non-coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

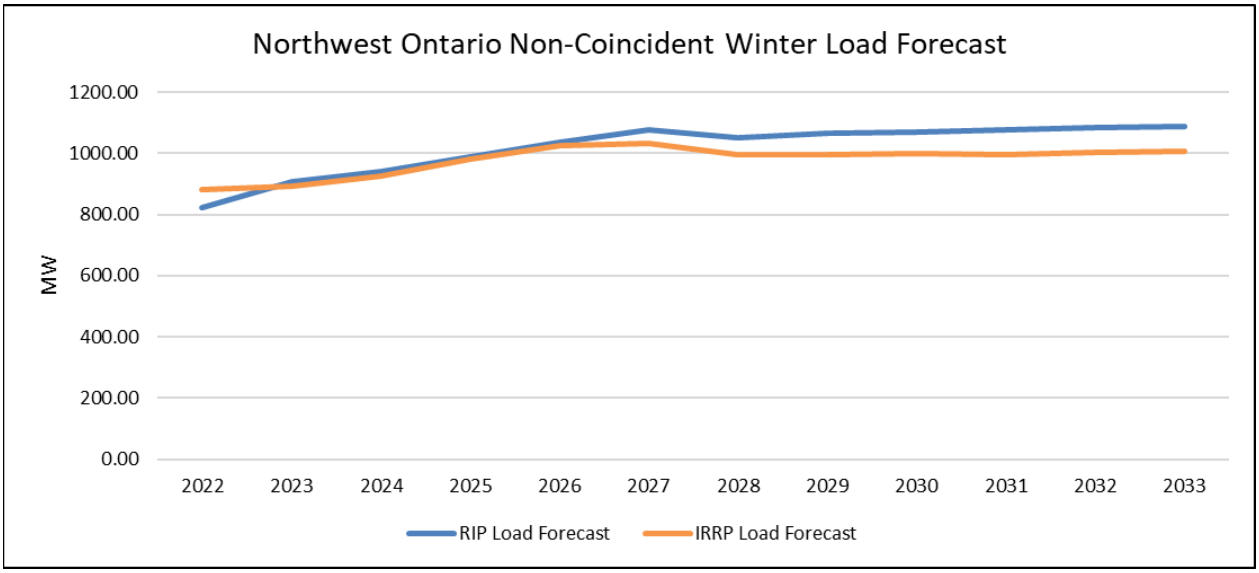


Figure 5: Northwest Ontario Region Winter Non-Coincident Net Peak Load Forecast

6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2033. However, a longer term forecast up to 2040 is provided to identify long-term needs and align with the Northwest region IRRPs.

- LDCs reconfirmed load forecasts up to 2033. A longer term forecast up to 2040 is adopted with IRRP load forecast. The additional three years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- This region is winter peaking, so this assessment is based on winter peak loads. However, since summer transmission line ratings are more constrained, Section 7.3 Transmission Line Capacity Needs is based on potential summer peak load demands.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) or by using the winter 10-day LTR if performing a winter season assessment.
- Bulk transmission line and auto-transformation capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Northwest Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Northwest Region Second Cycle Needs Assessment Report completed in July 2020 by Hydro One
- Northwest Region Second Cycle Scoping Assessment Report completed in January 2021 by the IESO
- Northwest Region Second Cycle Integrated Regional Resource Plan Report completed in January 2023 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Northwest Region. The complete list of major HV transmission equipment requiring replacement in the Northwest Region is provided in table 6 in this sub-section. Hydro One, Next Bridge Infrastructure and Wataynikaneyap Power are the Transmission Asset Owners (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Table 6: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Rabbit Lake SS	Replace equipment identified in deterioration and technical obsolescence	2024-2027
Whitedog Falls SS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2025-2028
Mackenzie TS	Replace equipment identified in deterioration and technical obsolescence	2025-2028
Wawa TS	Replace Equipment deterioration due to aging infrastructure	2026-2029
Marathon TS	Replace equipment identified in deterioration and technical obsolescence	2026-2029

Lakehead TS	Replace equipment identified in deterioration and technical obsolescence	2028-2031
Lakehead TS	Replace Condenser C8 identified in deterioration and technical obsolescence	2027
Fort Frances TS	Replace equipment identified in deterioration and technical obsolescence	2029-2032
Kenora TS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2030-2033

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

7.2. Station Capacity Needs

Over the study period 2023-2033 RIP reviewed the capacity of all the 230kV, 115kV Transforming stations and 115kV step down Distribution stations within the Northwest Ontario Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 7 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (winter) Limited Time ratings.

Table 7: Northwest Ontario Region Station Capacity Needs in the study period

Sr.no.	Station Name	Capacity (MVA)	2023 Historical Loading (MW)	Station 10 day LTR (MW)	Need Date
1	Margach DS	11.60	10.07	10.44	2023
2	Crilly DS	2.40	2.28	2.16	2027
3	White Dog DS	3.20	2.37	2.88	2027
4	White River DS	15.60	12.02	14.04	2029
5	Sam Lake DS	24.00	23.34	21.06	Now
6	Kenora MTS	26.00	19.13	23.40	2030

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period 2023-2033 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Northwest Region. The NA and IRRP studies had previously indicated that the following Transmission lines potentially require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 8 below. The mining sector load materialization timing drives the need timeframe. It defines when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time ratings.

Table 8: Northwest Ontario Region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Contingency	LTE Line Rating (Amps)	Need Date
1	E2R	Ear Falls TS – Red Lake TS	NA	421	TBD
2	E4D	Dryden TS – Ear Falls TS	NA	410	TBD
3	M2W	Pic JCT – Manitouwadge JCT	NA	290	TBD

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operational and Load restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of loss of 2 transmission elements.

Furthermore, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The IRRP studies had previously indicated that the following stations and transmission line require actions on system reliability and operational improvement. The RIP further confirms those needs with regards to System Reliability and Operation requirements.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

Table 9: Northwest Ontario Region System Reliability and Operational Needs in the study period

Station/Circuit	Need Description
Fort France MTS	Planned outages considering station single supply configuration
E1C	Operation and high voltage under a normally open configuration

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Northwest Ontario region. These needs include those previously identified in the NA and IRRP for the Northwest Ontario as well as any new needs identified during the RIP phase. All references to costs included in the alternative analysis are considered as planning allowances[2] and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 10 below:

Table 10: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
Rabbit Lake SS	Replace equipment identified in deterioration and technical obsolescence	2024-2027	8.1.1
Whitedog Falls SS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2025-2028	8.1.2
Mackenzie TS	Replace equipment identified in deterioration and technical obsolescence	2025-2028	8.1.3
Wawa TS	Replace Equipment deterioration due to aging infrastructure	2026-2029	8.1.4

[2] Allowances do not include real estate costs, environmental impacts and other costs not directly associated with the electrical infrastructure.

Marathon TS	Replace equipment identified in deterioration and technical obsolescence	2026-2029	8.1.5
Lakehead TS	Replace equipment identified in deterioration and technical obsolescence	2028-2031	8.1.6
Lakehead TS	Replace Condenser C8 identified in deterioration and technical obsolescence	2027	8.1.6
Fort Frances TS	Replace equipment identified in deterioration and technical obsolescence	2029-2032	8.1.7
Kenora TS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2030-2033	8.1.8
Station Capacity Needs			
Margach DS	Station Capacity Needs	2023	8.2.1
Crilly DS	Station Capacity Needs	2027	8.2.2
White Dog DS	Station Capacity Needs	2027	8.2.3
White River DS	Station Capacity Needs	2029	8.2.4
Sam Lake DS	Station Capacity Needs	Now	8.2.5
Kenora MTS	Station Capacity Needs	2030	8.2.6
Transmission Line Capacity Needs			
E2R	Capacity Needs of Section Ear Falls TS – Red Lake TS	TBD	8.3.1
E4D	Capacity Needs of Section Dryden TS – Ear Falls TS	TBD	8.3.1
M2W	Capacity Needs of Section Pic JCT – Manitouwadge JCT	TBD	8.3.2
System Reliability, Operational and Load restoration Needs			
Fort France MTS	The planned transmission outage caused customer interruptions due to the station's single supply configuration.	2023	8.4.1
E1C Operation and High Voltage	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	2023	8.4.2

Other Planning Considerations			
Fort William TS Shunt Capacitor Banks Replacement	Temporary capacitor banks to be replaced with permanent units	2026-2027	8.5.1

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

8.1.1. Rabbit Lake SS

Rabbit Lake SS, a North American Electric Reliability Corporation (NERC) Bulk Electrical System station, was originally built in 1956 and is located within the city limits of Kenora, Ontario. The switching station has six 115kV transmission lines connecting to three customer generating stations (CGSs) as well as Whitedog Falls SS, Kenora TS, Fort Frances TS, Dryden TS, and the interconnection with Manitoba Hydro. There are six 115kV oil circuit breakers and two 115kV SF6 circuit breakers in the yard.

Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence due to outdated design. The scope of work involves replacing 115kV circuit breakers, associated disconnect switches, instrument transformers and equipment protections. A New AC station service, DC battery and PCT building will also be installed.

This investment will help maintain the reliability of supply to area customers and reduce the risk of interruptions caused by station equipment failure. The project is currently planned to be completed in 2024-2027.

8.1.2. Whitedog Falls SS

Whitedog Falls Switching Station (SS) located approximately 80 km northwest of the City of Kenora, containing three 115kV circuits that terminate at the station with four circuit breakers, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence with little or no spare parts and manufacturer support. The scope of work involves replacing 115kV circuit breakers and associated disconnect switches. Replacement and upgrades of the DC station supply system will also be part of this investment,

This investment will help maintain the reliability of supply to area customers and reduce the risk of interruptions caused by station equipment failure. The project is currently planned to be completed in 2025-2028.

8.1.3. Mackenzie TS

Mackenzie TS is a 230/115kV station is located approximately 200 km west of Thunder Bay, Ontario. Mackenzie TS has six 230kV breakers which are about 46 years old. The station is a major station for Waasigan transmission line reinforcement project.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure and technical obsolescence with minimal spare parts and manufacturer support. The scope of work involves replacing the existing 230/115kV 75/125 MVA autotransformer with new 230/115kV 75/100/125 MVA. The project will also replace 230kV circuit breakers, select protections, and AC/DC station service systems. Hydro One has also planned to install a new 115/44 kV load facility at the station to replace the one at Moose Lake TS, optimizing the area supply configuration.

This investment will help maintain the reliability of supply to Atikokan Hydro customers and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2025-2028.

8.1.4. Wawa TS

Wawa TS is a 230/115kV transformer station, located southeast of the township of Wawa in northern Ontario. It was put in-service in 1969. The station is a major hub for connecting the Northeast, Northwest and Hydro One Sault Ste. Marie transmission systems. The existing autotransformers, oil circuit breakers, disconnect switches, protection and control, station service, and other ancillary facilities are in poor condition and in deterioration that require replacement to maintain the operability and reliability of the station.

Hydro One has plans to replace all deteriorated equipment at the station. The scope of work involves replacing two 239-121/13.9kV 75/100/125 MVA autotransformers, four 230kV circuit breakers, and four 115kV circuit breakers. In addition, the scope of work also includes replacing associated disconnect switches, protection equipment and station service system.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2026-2029.

8.1.5. Marathon TS

Marathon TS is a 230/115kV transformer station, located in the City of Marathon in northern Ontario. It was put in-service in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115kV oil circuit breakers at the station are about 40 years old, and three 230kV circuit breaker at the station are about 48 years old.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure to ensure the reliability of the transmission system and supply to customers. The scope of work involves replacing three 230kV circuit breakers with new SF6 breakers, and four 115kV circuit breakers with new SF6 breakers. The replacement of disconnect switches, protection equipment, and AC station service system will also be part of this investment.

In addition to component replacement. this project will separate and re-terminate two branches of 115kV circuit M2W. M2W is a radial transmission line consisting of two independent branches that merge into 1 switching position at the entry point of Marathon TS. To unbundle, Hydro One will install one additional 115kV circuit breaker with associated protections in order to create a new switching position at Marathon TS 115kV bus.

This investment at Marathon TS will improve transmission system reliability performance and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2026-2029.

8.1.6. Lakehead TS

Lakehead TS is a 230/115kV transformer station which was put in-service in 1955, located northeast of the city of Thunder Bay in norther Ontario. The station is critical to the transmission system of the Northwest, a major hub for East-West power transfer, and a major station for Waasigan transmission line reinforcement project. The station is classified as Bulk Electric System (BES) under NERC standards.

8.1.6.1 HV Component Replacement

Hydro One has plans to replace all station equipment identified in deterioration due to aging infrastructure to ensure the reliability of the transmission system and supply to the customers. The scope of work involves replacing high voltage circuit breakers with new SF6 breakers, replacing eight 115kV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2028-2031.

8.1.6.1 Condenser C8 Replacement

The transformers T7 and T8 at Lakehead TS are 239/121/13.9 kV 250 MVA autotransformers with primary and secondary windings connecting to the 230kV and 115kV systems, respectively. The tertiary windings of T7 and T8 are rated at 60MVA. In 2009, a -40/+60Mvar SVC replaced a poor condition condenser connected at T7 tertiary bus. The SVC consists of a 100Mvar TCR and a 60Mvar filter. A recent condition assessment has highlighted the poor condition and high risk of failure associated with C8, a synchronous condenser connected to T8's tertiary bus. To address this issue, Hydro One consulted with IESO to explore the options of maintaining the status quo, removing the condenser, or replacing it with appropriately sized equipment. The consideration of the need for condenser inertia was also part of the assessment.

Following discussions between IESO and Hydro One, it has been recognized that replacing C8 with a static synchronous compensator (STATCOM) is the preferred solution. To ensure optimal controller coordination, the recommended replacement strategy involves sourcing the STATCOM from the same vendor as the existing SVC. By installing a STATCOM with the same capacity and connecting it to the 13.8kV tertiary winding of transformer T8, effective voltage control of the 230kV bus at Lakehead can be achieved in coordination with the existing SVC at T7. This asset and infrastructure replacement will effectively mitigate the risks associated with equipment failure and enhance the overall reliability of the system. It's important to note that IESO is currently conducting further studies to assess the reactive power needs in northern Ontario.

8.1.7. Fort Frances TS

Fort Frances TS is in the Town of Fort Frances and was put in-service in 1947. Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service systems and protection equipment.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2029-2032.

8.1.8. Kenora TS

Kenora TS is a 230/115kV station in-service since 1972 and located in east side of Kenora City, Ontario. The station is critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure and technical obsolescence with minimal spare parts and manufacturer support. The scope of work involves replacing high voltage circuit breakers, protection equipment and replacing/upgrading AC/DC station service systems.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2030-2033.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2023-2033 for the 230kV ,115kV Transformer stations and 115kV step down Distribution stations in the Northwest Ontario Region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified in the during the study period:

8.2.1 Margach DS– 115kV – Distribution Station Step-Down Transformer Capacity Needs (2023)

Margach DS is approximately 10 km east of Kenora. Margach DS presently has two 115/ 26.5kV 7.5MVA transformers (T1/T2) with a winter LTR of 10.4MW. The historical demand at Margach DS has remained stable, consistently just below 10 MW. The station will exceed its normal supply capacity in 2023.

Table 11: Margach DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Margach DS	10.4	10.50	10.48	10.47	10.48	10.51	10.53	10.53	10.53	10.55	10.55	10.58

The following alternatives were considered to address Margach DS capacity need.

Alternative 1: Install Transformer Fan Monitoring.

Installing transformer fan monitoring is a relatively inexpensive solution to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers.

Alternative 2: Maintain Status Quo

Considering that the peak loading in 2022 was 9.96 MW and there is only anticipated natural residential load growth, maintaining the status quo is also considered a viable solution.

The LDC- Hydro One Distribution recommends alternative 2 as the preferred solution at the time of this RIP. Regarding alternative 1, the LDC has incorporated it into its investment plan with an anticipated implementation date in 2025. Given the gradual growth in station loading and the existing plan in place, the LDC will closely monitor the station's load and take necessary actions if required before 2025, ensuring a smooth transition to Alternative 1.

8.2.2 Crilly DS– 115kV – Distribution Station Step-Down Transformer Capacity Needs (2027)

Crilly DS is a small (~2.2 MW LTR) station supplied from 115kV transmission circuit M1S and has a 6.6 kV bus shared with Sturgeon Falls CGS, a small hydroelectric plant located approximately 50 km west of Atikokan. This legacy non-standard supply arrangement results in annual outages at Crilly DS during maintenance periods of the generator. Backup power from diesel generation is utilized when Sturgeon Falls is offline. Moreover, the station equipment is approaching its end-of-life, and limited space constraints limit refurbishment options on-site.

Crilly DS is expected to exceed its capacity in 2027 due to incremental growth in the community.

Table 12: Crilly DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Crilly DS	2.16	2.14	2.14	2.15	2.16	2.18	2.19	2.20	2.21	2.23	2.24	2.25

To address this capacity issue, the TWG has identified the following alternatives for consideration:

Alternative 1: Refurbish Crilly DS at the current location

This alternative is likely the least costly solution, but Crilly DS will still rely on backup power from diesel generation during outages at Sturgeon Falls CGS.

Alternative 2: Rebuild Crilly DS at a different location as a 115/25 kV HVDS

This alternative entails rebuilding Crilly DS at a different location, operating as a 115/25 kV HVDS station. The new site would be situated closer to the existing station and supplied by the 115kV transmission circuit M1S.

Alternative 3: Rebuild Crilly DS at a different location as a 230/25 kV TS (connected to F25A closer to the community served by Crilly DS)

This alternative will rebuild the station and operate it as a 230/25kV Transformer Station (TS).

Alternative 4: Replace Crilly DS with 115:25kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence)

This alternative requires further investigations on the feasibility of configuring the station with a padmount transformer.

Hydro One Distribution are considering all 4 alternatives. Due to the radial supply nature of M1S, reliability concerns can only be partially addressed by upgrading station assets at Crilly DS. Considering the timeline and the need for further assessment, the LDC has indicated that additional studies and investigations are required to evaluate the cost and benefits of all four alternatives before determining the preferred solution to address the station capacity needs projected for 2027. In the interim, the LDC will closely monitor the loading of Crilly DS and take appropriate actions if the load grows faster than forecasted. This

proactive approach will ensure that any capacity challenges are promptly addressed. By conducting thorough analyses and closely managing the station's loading, the LDC aims to make informed decisions and select the most suitable alternative to meet the future capacity requirements of Crilly DS.

8.2.3 Whitedog DS – 115kV - Distribution Station Step Down Transformer Capacity Need (2027)

Whitedog DS is a distribution station that receives its supply from the OPG Whitedog GS 13.8kV bus. The station is comprised of three 0.667MVA single-phase transformers, with an additional single-phase transformer serving as a spare. All the single-phase transformers in the station are 75 years old. Currently, Whitedog DS is connected to a single feeder (12.48kV) that supplies the Whitedog First Nation community.

Whitedog DS is expected to exceed its capacity in 2027 due to incremental growth in the community. Recently, the Whitedog First Nation also expressed plans for growth and expansion within their community and it is at the preliminary stage of development. To support this potential load growth, the capacity of the Whitedog DS station would need to be increased. In addition, OPG is planning system renewal work on this 13.8 kV bus and needs to coordinate scope and cost with the LDC if the connection is to be maintained.

Table 13: Whitedog DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Whitedog DS	2.88	2.80	2.82	2.85	2.87	2.92	2.95	2.99	3.01	3.05	3.07	3.11

To address this capacity issue, the TWG has identified the following tentative alternatives for consideration:

Alternative 1: Replace the existing transformers with a larger size

This alternative will allow Whitedog DS to remain connected to the OPG bus. But it involves expanding the existing site to accommodate larger-size transformers, which need OPG's approval since OPG owns the land. Additionally, OPG is in the process of refurbishing the Whitedog GS switchgear; if the DS is to remain connected to OPG, the scope of work is subject to coordination with OPG.

Alternative 2: Relocate Whitedog DS as a 115/12.48 kV DS

This alternative will relocate Whitedog DS with a larger size transformer to the Hydro One Whitedog Switching Station, connecting it to the transmission 115kV bus. This solution may require a small site expansion, which would necessitate approval from OPG.

Alternative 3: Maintain Status Quo

This alternative will not take action at this point and continue monitoring if the forecasted load growth materializes. This alternative requires the LDC to work with the generator to land on an amicable solution for the generator's system renewal work.

The LDC – Hydro One Distribution recommends alternative 3 maintaining the status quo for now. While the Whitedog First Nation has expressed plans for future growth, they are currently in the preliminary stage, indicating that the load demand increase might not materialize in the immediate future. Maintaining the status quo allows the LDC to closely monitor the actual load growth and assess its sustainability before committing to significant infrastructure changes. If the projected increase materializes, appropriate corrective actions will be taken. This approach ensures that the LDC can respond effectively to the evolving needs of the Whitedog First Nation while maintaining a reliable power supply to the community.

8.2.4 White River DS – 115kV - Distribution Station Step Down Transformer Capacity Need (2029)

White River DS is a 115/26.8 kV step down distribution station supplying the Town of White River. The station has two 7.5/10MVA transformers both in service serving the load with a LTR of 14.04MW. However, the station is lacking the provision of a spare transformer as a backup in the event of a failure. Currently, if one of the transformers fails, the load can be transferred to the remaining operational unit. With the projected load growth, White River DS's contingency capacity to fully restore the load following a contingency will be compromised, specifically, in the event of one transformer failure, the failed transformer's load cannot be offloaded to the other transformer at the station due to overloading as the load grows in the area. Hence, the station is expected to exceed the contingency capacity in 2029.

Table 14: White River DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
White River DS	14.04	13.42	13.51	13.69	13.80	13.91	14.00	14.09	14.18	14.27	14.35	14.44

To address this capacity issue, the TWG has identified the following tentative alternatives for consideration:

Alternative 1: Maintain Status Quo

This alternative will not take action at this point and continue monitoring if the forecasted load growth materializes.

Alternative 2: Install a MUS Facility

There is a tentative plan for the LDC to look into installing a MUS facility at the station; in such case, the station contingency capacity can be increased with the additional MUS facility. It is also recognized as the most cost-effective solution to address the need.

The LDC – Hydro One Distribution recommends alternative 1 to maintain the status quo as the preferred solution. Based on the load forecasts, White River DS will exceed contingency capacity in 2029. The next

cycle of regional planning will commence in 2025. It will allow the working group to reevaluate this need and confirm if the capacity needs at White River DS still holds in 2028. Should this be the case, the study group at that moment will decide the best course of action to fill this need.

8.2.5 Sam Lake DS – 115kV -Distribution Station Step Down Transformer Capacity Need (Now)

Sam Lake DS is a Hydro One Distribution owned 115/25kV High Voltage Distribution Station (HVDS) supplied from 115kV circuit K3D. The station is the sole supply for Sioux Lookout Hydro LDC. It contains two 115kV/25kV 15/20/25MVA transformers (T1 and T2) and only one of the transformers is in-service at any given time. The station is projected to exceed its normal supply capacity this year. A Local planning study[3]was conducted and was published in January 2023 with a TWG[4] recommended solution to address the need.

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Sam Lake DS	21.6	28.22	28.47	28.67	28.70	28.72	28.74	28.74	28.74	28.78	28.81	28.87

The following alternatives were considered by the TWG in the Local Planning study:

Alternative 1 – T1 and T2 Transformer both in service at Sam Lake DS

Currently, only one of the transformers is on load, while the other is a hot spare in case of a transformer contingency. Therefore, the additional capacity can be made available if both T1 and T2 are in service.

Alternative 2 – Install fan monitoring on T1 and T2 at Sam Lake DS

As discussed in section 2, T1 and T2 transformers at Sam Lake DS are currently equipped with unmonitored fans, and it is not reliable to load the transformers at the maximum fan-cooled rating without a fan monitoring system. Therefore, installing fan monitoring can increase the station capacity at Sam Lake DS.

Alternative 3 – Install an additional (3rd) transformer at Sam Lake DS

An additional transformer at Sam Lake DS can also increase the capacity at Sam Lake DS.

Alternative 4 – Construct a new 115kV/25kV station supplied from Hydro One's K3D Circuit

A new High Voltage Distribution Station (HVDS) can be built to increase the capacity of the area.

Alternative 5 – Construct a new 230kV/25kV station supplied from Wataynikaneyap transmission system

[3] Local Planning – Report (Sam Lake DS)
[4] Local Planning Technical Working Group Members: Hydro One Inc. (Transmission), Hydro One Inc. (Distribution) and Sioux Lookout Hydro.

A new station can be built and supplied from the new Wataynikaneyap 230kV system, which would bring in a new transmission supply and significantly improve the load supply diversity at the Sam Lake DS area in case of a K3D outage.

The TWG have conducted a coordinated review and evaluation of all the alternatives to address the local capacity need. The TWG recommended Alternative 2 – Install fan monitoring on T1 and T2 at Sam Lake DS. This alternative allows Hydro One Distribution and Sioux Lookout Hydro to address the capacity need in the timeframe required (based on the winter conservative load forecast) and maintain supply reliability to the Sam Lake area customers. This alternative is the lowest cost option and achieves the best balance between cost versus local system benefits.

8.2.6 Kenora MTS – 115kV - Transmission Station Capacity Need (2030)

Kenora MTS is currently equipped with 115/12.5 KV transformers T1, T2 and T4. T1 and T4 have a rating of 9/12 MVA, while T2 has a rating of 10/13/14 MVA. The station's total planning winter LTR is 23.4MW. Therefore, this station will exceed its normal supply capacity in 2030.

Table 15: Kenora MTS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Kenora MTS	23.4	21.4	21.7	21.9	22.1	22.5	22.9	23.2	23.5	23.8	24.1	24.4

Synergy North has received inquiries from potential customers seeking new connections, but formal agreements still need to be finalized. Although these new connection loads have not been incorporated into the forecast, an annual growth rate of 1.25% has been applied to account for the significant level of development interest. The following wires and non-wires alternative solutions are considered:

Alternative 1: Expand Kenora MTS with an Additional Transformer

Install an additional transformer and associated protections, control, and structures with an expansion of the existing station.

Alternative 2: Construct a new substation across the city from the existing station

The proposed new substation will be located on the city's west side. In addition to increasing the supply capacity, this solution will provide substantial distribution system benefits by reducing the feeder length required to reach the customers and improving the distribution system performance.

Alternative 3: Non-Wires Solutions

IRRP recommends three non-wire alternatives. A 4MW gas generation facility, a 6-hour 4MW (24MWh) battery, or a combination of energy efficiency measures and demand response are feasible options. This alternative will provide potential distribution benefits to the end customers.

Alternative 4: Maintain Status Quo

This alternative is considered based on the long-term horizon of the need. Kenora MTS will exceed station capacity in 2030 based on the load forecasts provided by the LDC. The next cycle of regional planning will commence in 2025 and will allow the working group to reevaluate this need and confirm if the station capacity need still holds true in 2028. Should this be the case, the TWG at that moment will decide the best course of actions to address this need.

The TWG recommends Alternative 4 as the preferred solution at this RIP. Considering the long-term outlook of the need, the LDC intends to move forward by retaining the services of a consultant to assist in understanding the pricing of each of the proposed alternatives. Prior to determining the preferred alternative an investigation of the total costs and benefits of each solution will be completed. The LDC does not intend to engage in any material investments prior to 2028 to mitigate the challenge of Kenora MTS reaching its thermal capacity, instead continued study and monitoring of load growth and customer connections is anticipated to trigger investment. To fully understand the preferred alternative and investment benefits, the LDC intends to incorporate and quantify the benefits of grid scale and behind-the-meter (BTM) energy storage solutions that may allow for access to many different services reducing the cost of reliable service to the City of Kenora.

Furthermore, the LDC recognizes that non-wires alternative could be developed in stages to reduce cost and align with the load growth as compared to a traditional wires investment (e.g., new substation.) This offers enhanced reliability for radially supplied customers that would otherwise not have effective options to improve their reliability, particularly for momentary outages.

The roadmap below has been prepared to ensure that the LDC remains well positioned to address the challenge with sufficient time for deployment and with the most cost-effective solution for its customers.

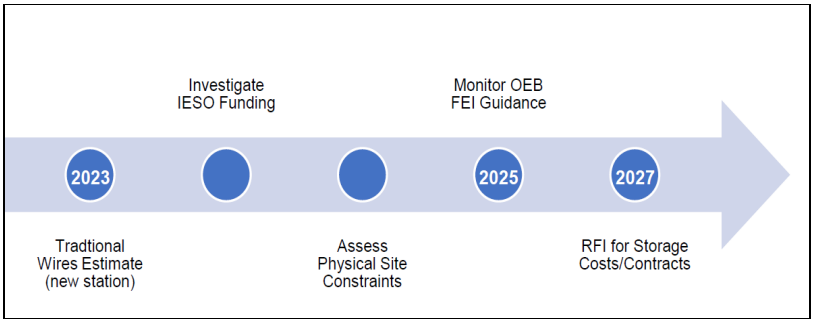


Figure 6: Kenora MTS Strategy Roadmap

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission

Lines Capacity Assessment was performed over the study period 2023-2033 for the 230kV and 115kV Transmission line circuits in the Northwest Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the Northwest region currently does not have a firm supply capacity need. But it is important to consider the potential impact of large mining and industrial developments that can quickly consume the remaining supply capacity with minimal lead time. After engaging with development proponents and stakeholders during the IRRP phase, the Technical Working Group (TWG) identified three potential transmission circuits, E4D, M2W and E2R, that may require additional supply capacity if all proposed projects materialize.

8.3.1 E4D and E2R – 115kV – Capacity Needs under Mining Sector Development

The E4D circuit supplies the Ear Falls and Red Lake area, while the E2R circuit serves the Red Lake area north of Dryden. The E4D circuit has a continuous summer rating of 410 A, equivalent to approximately 72 MW. Additionally, there is a combined 18 MW of dependable hydro generation output from three hydroelectric power stations. Considering the thermal capability and hydro generation, the load capability of the E4D circuit is approximately 90 MW during the summer. It is worth noting that the winter load meeting capability is expected to be higher due to the circuit's higher thermal rating and increased hydro generation output.

As for the E2R circuit, it has a continuous summer rating of 421 A, translating to a load meeting capability of approximately 74 MW. The E2R circuit's continuous winter rating is 528 A, resulting in a load meeting capability of approximately 93 MW due to pre-contingency thermal and voltage limitations, meaning a load of 93 MW also causes pre-contingency voltage declines at Red Lake TS.

The IRRP forecasts the summer peak demand of the E4D circuit to reach 67 MW in 2032, and the summer peak demand of the E2R circuit to reach 61 MW in the same year.

The system area map is shown below in Figure 7:



Figure 7: Dryden - Ear Falls - Red Lake Map

Considering the potential combined area load growth from mining and Wataynikaneyap Power customer connections, which could increase by 50-115 MW by 2028, a few mining and industrial customers are actively engaging with IESO and Hydro One Transmission to explore potential options to accommodate this load increase. As shown on Figures 8-11, four transmission alternatives have been proposed to address the capacity needs in the area. These options also require the installation of appropriately sized voltage devices to mitigate voltage performance criteria.

- Alternative 1 - Upgrade 115kV Circuit E4D and E2R:

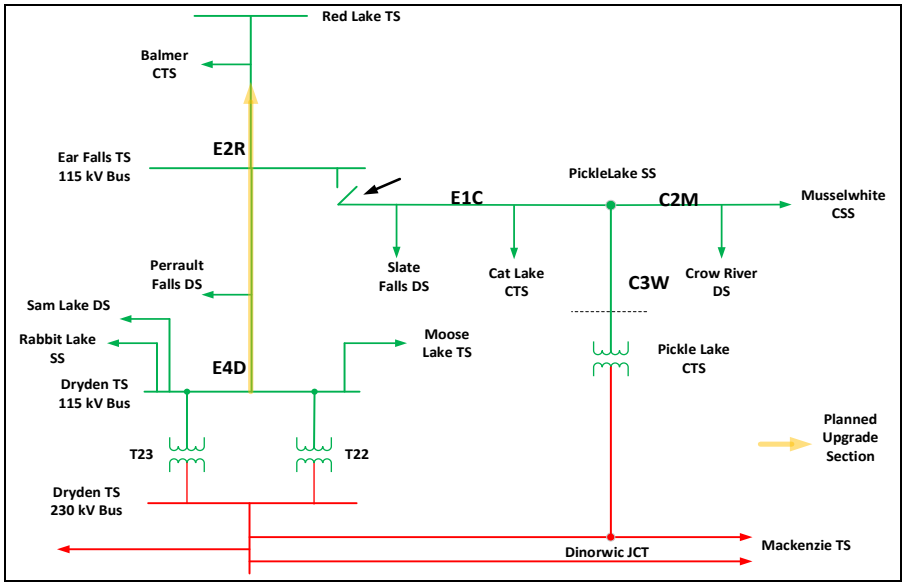


Figure 8: Alternative 1 Single Line Diagram - Upgrades on Existing Infrastructure

- Alternative 2 – Building a new 115kV Single Transmission Line from Dryden TS to Red Lake TS:

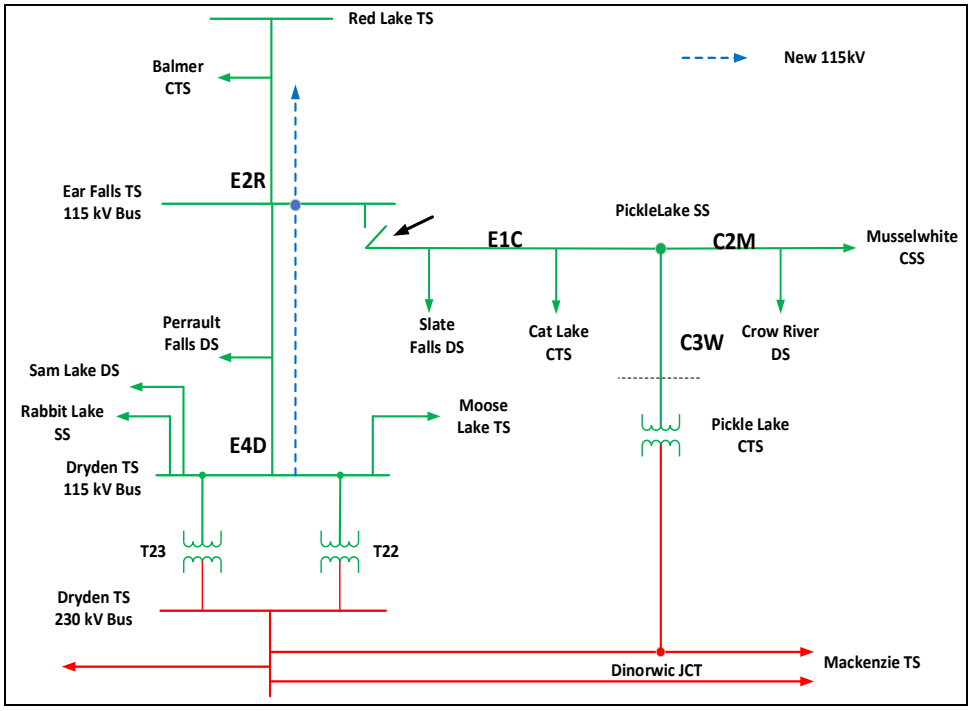


Figure 9: Alternative 2 Single Line Diagram – Building New 115kV Infrastructure

- Alternative 3 – Building a new 115kV Single Transmission Line from Ear Falls TS to Red Lake TS with E4D Upgrades:

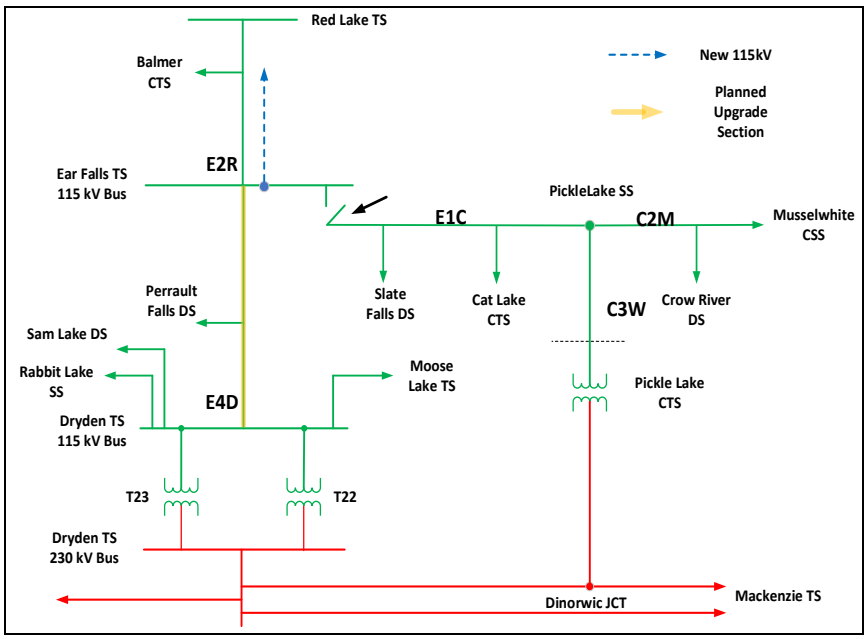


Figure 10: Alternative 3 Single Line Diagram - Building New 115kV Infrastructure and Upgrades on Existing Infrastructure

- Alternative 4 – Building a new 230kV Single Transmission Line from Dryden TS to Red Lake TS:

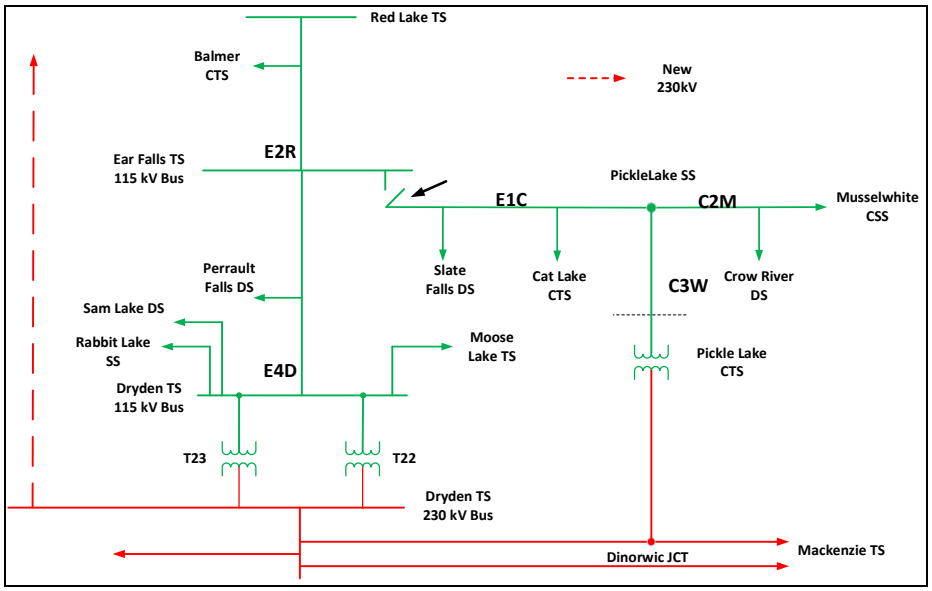


Figure 11: Alternative 4 Single Line Diagram - Building New 230kV Infrastructure

These options require the installation of appropriately sized voltage devices to mitigate pre-contingency voltage limitations. The planning allowance for these alternatives ranges from $125M to $375M, depending on the materialized load and the required infrastructure.

To determine the most cost-effective and beneficial solution to increase the area's load meeting capability, one of the project proponents has taken the lead in initiating a technical feasibility study with IESO and a physical feasibility study with Hydro One. These studies aim to thoroughly investigate the proposed alternatives and assess their economic viability and overall benefits. The goal is to identify the optimal solution that not only meets the area's increasing load demands but also ensures long-term reliability and system stability.

By conducting a detailed analysis and leveraging the expertise of Hydro One and IESO, it is expected to identify the most suitable course of action that maximizes cost-effectiveness and delivers significant value to all stakeholders in the area. The findings of this study will contribute to the decision-making process, enabling the selection of a preferred solution that aligns with the region's future growth plans.

8.3.2 M2W – 115kV – Capacity Needs under Mining Sector Development

The M2W circuit is a radial transmission line supplied from Marathon TS, consisting of two independent branches. One branch extends approximately 70 km in the north-east direction to Manitouwadge DS, while the other branch stretches eastward for about 100 km to White River DS.

There is a possible growing capacity need on the branch that leads towards Manitouwadge DS flagged by a customer connection application after the 2023 Northwest Ontario IRRP The section from Pic JCT to Manitouwadge JCT is the most constrained, with a continuous summer rating of 290 A, equivalent to approximately 57 MW. Recently, there has been significant interest from mining customers, with an anticipated growth of 30-80 MW by 2028. The 2022 summer peak demand on the M2W branch was 6.1 MW. Additionally, an industrial customer is planning a mining project of 50.9 MW by 2025-2026 on this branch. If the mining project proceeds as planned, the branch will start to experience capacity issues.

To address the potential need for additional capacity, the following alternatives are being considered:

- Alternative 1 - Upgrade the conductor and structures on the existing M2W circuit
- Alternative 2 - Building a new parallel 115kV circuit supplied from Marathon TS

Since the anticipated increase in mining sector load has not yet materialized, further assessment of the above alternatives for reinforcing the M2W circuit will be conducted to determine their cost and feasibility. These assessments will be undertaken in the event of a request from customers for additional load and upon reaching an agreement with them.

8.4 System Reliability, Operational and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has

been performed, considering the net coincident load forecast and the loss of one element over the study period 2023-2033 to cater this need**.** Based on the results, the following system reliability and operation needs have been identified for this Region.

8.4.1 Fort Frances MTS Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS via a single circuit 115kV line F1B. Line F1B extends approximately 20 km to the east of Fort Frances to also supply rural Hydro One LDC loads. The single circuit supply configuration results in Fort Frances MTS supply interruptions during certain transmission outages (planned and unplanned). Over the past 10 years, 90% of Fort Frances Power's customer interruptions is a due to transmission supply losses as reported by the Ontario Energy Board (OEB). Fort Frances LDC has indicated a reliability need due to the single circuit supply configuration as planned and unplanned outages causes community-wide power outages. Outage durations ranges from 4 to 8 hours with a total of 16MW load interrupted. Despite meeting the ORTAC criteria, the current supply configuration of the Fort Frances MTS remains highly disruptive for customers. However, considering the close proximity of Fort Frances MTS to Fort Frances TS, there is potential for cost-effective improvement solutions.

The two stations are located across the street from each other. Most of the Fort Frances MTS station equipment has exceeded their manufacture life span and will need to be replaced within the next 10-15 years. The current Fort Frances MTS station configuration also does not allow for any primary 115kV components to be isolated for maintenance purposes; therefore, the entire station must be de-energized to allow for primary components to be serviced or repaired. Considering all above, reconfiguration of the station will improve the supply interruptions for Fort Frances MTS.

The Fort Frances TS 115kV station layout and connection to Fort Frances MTS is shown in Figure 12. Fort Frances TS 115kV side is comprised of a six-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B and F1B. Fort Frances MTS is currently connected to the F1B circuit which connects to L1 bus. Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

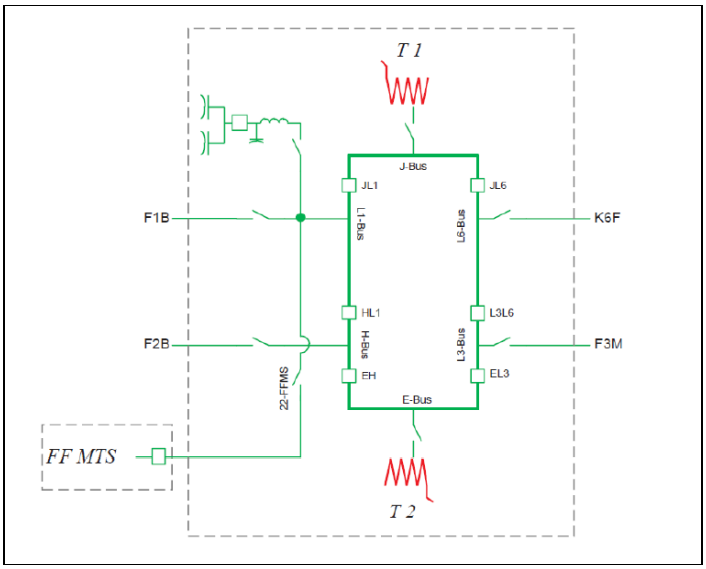


Figure 12: Fort France TS Single Line Diagram

Alternative 1:

Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.

Alternative 2:

Install a new 115kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit. This would still have the MTS on a single supply.

Alternative 3:

Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels and loop flows. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

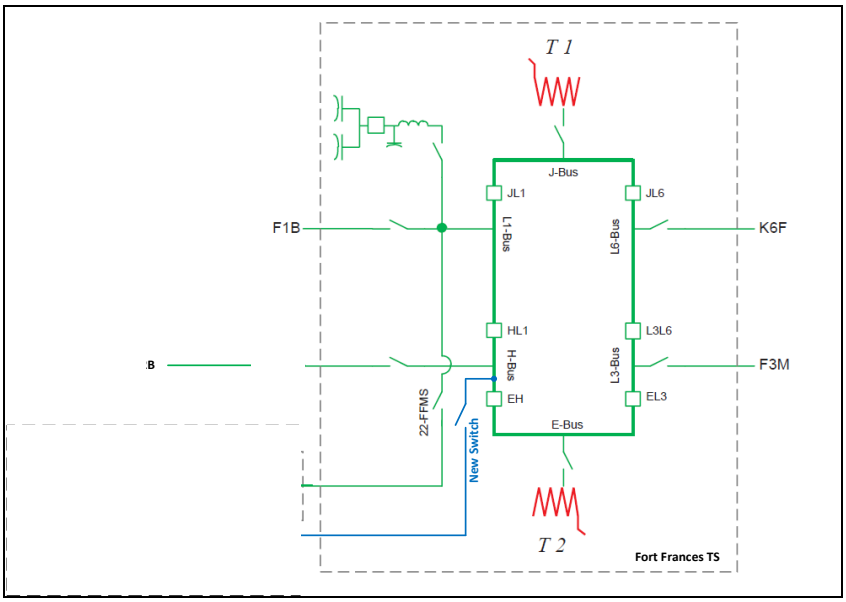


Figure 13: Fort Frances MTS Need Alternative 3

Alternative 4:

Install a second breaker and switch at Fort Frances MTS on the 115kV side, connecting it to 115kV circuit F2B via a drop feed. This creates a second supply for Fort Frances MTS, achieving full redundancy while tapping at a different location comparing to Alternative 3

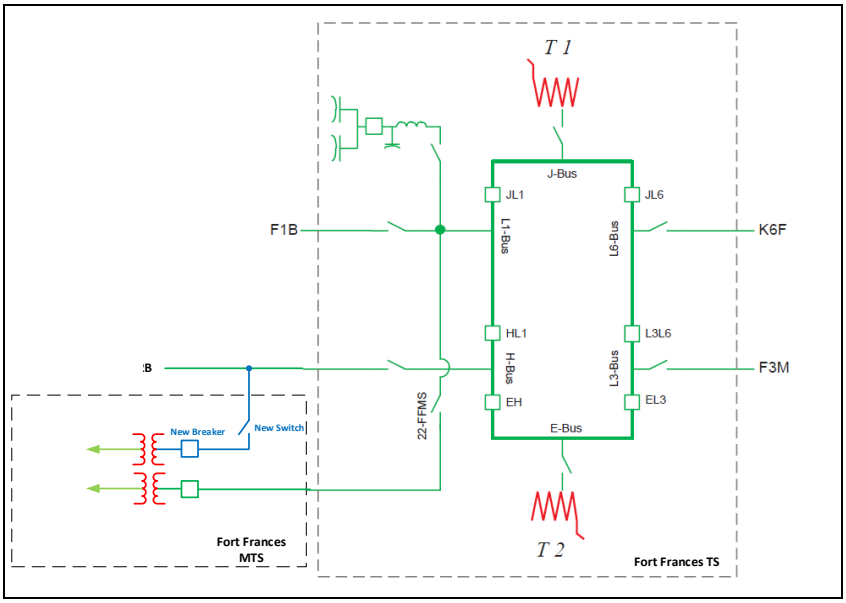


Figure 14: Fort Frances MTS Need Alternative 4

The LDC Fort Frances Power recommends alternative 4 as the optimal alternative for addressing the need. The interruptions caused by planned transmission supply outages can be effectively mitigated with the dual supply. This alternative also provides FFPC with the capability to isolate any primary station components for maintenance purposes without requiring a station-wide outage. Alternative 4 offers a robust station supply configuration that enhances reliability for current customers and accommodates potential significant load growth from industrial customers and electrification of the community. Fort Frances Power has started the preparation of the IESO SIA application package at the time of this RIP, and the project is planned for execution in the year 2026-2027. Additionally, the implementation of Alternative 4 will serve as a building block for the forthcoming Fort Frances MTS End-of-Life replacement project, contributing to its seamless execution.

8.4.2 E1C Operation and High Voltage Need

The Integrated Regional Resource Plan (IRRP), published in January 2023, identified operational challenges concerning the 115kV E1C transmission line. This line plays a critical role in the Pickle Lake area system, and its operational state significantly affects the system's overall performance. Two main challenges have been identified in the E1C operation. Limitations on supply capacity when E1C operates in a normally closed state and high voltage issues when it operates in a normally open state. A single line diagram of the area is presented in Figure 15.

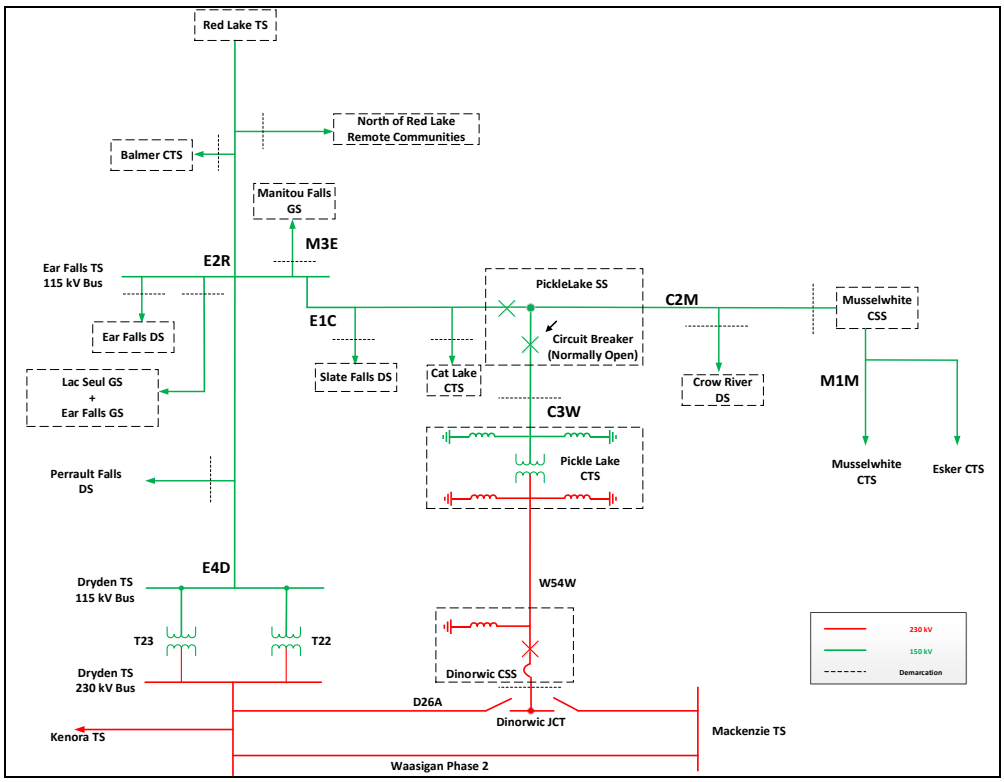


Figure 15: Dryden - Pickle Lake - Ear Falls - Red Lake Area Single Line Diagram

Operating the E1C in a closed state results in a loop configuration that restricts transfer capability through E4D and W54W, thereby limiting the area's overall potential for load increase. This limitation could potentially impact local business expansion. Moreover, if E4D were to fail, the local generations at Ear Falls TS would remain connected, potentially causing transient instability. To maintain system adequacy and meet forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas, it is crucial to introduce a normally open point on the E1C line end. This change would offload E4D and shift the loading on the Pickle Lake area to the newly installed 230kV transmission line W54W. However, operating E1C in an open state would lead to high voltage issues under light load conditions, regardless of the E1C end that is opened. To resolve this problem, the following alternatives are being considered.

Alternative 1: Installation of a Remote-Controlled Switch at a Mid-Point of E1C and Operate E1C Normally Open at the New Switch Location

While opening E1C mid-point reduces most high-voltage issues and provides for more capacity on the E4D by shifting load supply to W54W, it would require an upgraded or newly installed isolation switch capable of being remotely operated from the control center. Closing the switch may be required at times under light load conditions and with unexpected events, involving failure of transmission equipment in the Pickle Lake or Ear Falls areas, could trigger the need to revert to the operating configuration in the Pickle Lake area as illustrated in Figure 15. This involves closing the switch and opening the circuit breaker at Pickle Lake SS. While using an existing switch (with no remote-control capability and no on-load switching capability) will be implemented as an interim solution; this alternative, as a permanent solution, is associated with a planning allowance of approx. $6M and the effectiveness and reliability of communications to this very remote site is low. In addition, sourcing independent and reliable AC and DC supplies for the switch will be challenging and expensive. Therefore, this alternative is considered and rejected as a permanent solution.

Alternative 2: Opening E1C on the Pickle Lake SS Line End with Reactor Installations at Cat Lake MTS or Ear Falls TS

This alternative was discussed with the TWG and was compared with alternative 3.

Opening E1C at the Pickle Lake SS end leads to a voltage as high as 132 kV on the E1C line end near Pickle Lake SS under a light load pre-contingency condition. It also results in multiple post-contingency violations. Consequently, a 10-15 Mvar shunt reactor would need to be installed near Cat Lake MTS or Ear Falls TS to implement this solution. The Ear Falls location would require site expansion. It is unknown at this time the physical feasibility of installing a high voltage shunt reactor at the MTS. As the short circuit level at the MTS is low, at least two reactor installations would be required to comply with the 4% voltage change criteria when switching a reactive device. Planning allowance is approximated to be $20M for an Ear Falls installation.

Alternative 3: Opening E1C on the Ear Falls TS Line End with Reactor Installations at Pickle Lake SS

This alternative mirrors alternative 2 but opens the other end of E1C. High voltage violations are less severe in this configuration, with pre-contingency voltages in the area staying within the ORTAC limit. The most critical contingency is the loss of one of the existing 20 Mvar reactors at Pickle Lake CTS. The TWG

has confirmed that installing an additional 10 - 15 Mvar reactor at Pickle Lake SS would address the high voltage violation. Space is available at Pickle Lake SS for a reactor installation and the short circuit levels are sufficient at this station to require 1 reactive device in lieu of two smaller ones. Planning allowance is approximated to be $20M.

The TWG recommends Alternative 3 as the most effective solution. This approach only experiences high voltage violations under post-contingency scenarios, and the addition of a 10 -15 Mvar reactor can effectively mitigate these violations. Once this reactor is installed at Pickle Lake SS, the interim normally open point on E1C (mid-point) will be closed and the new normally open point made to be at Ear Falls TS; refer to Figure 16 for the recommended solution. Once the project is initiated, the TWG will investigate and refine the automatic reactor switching scheme recommended in IRRP.

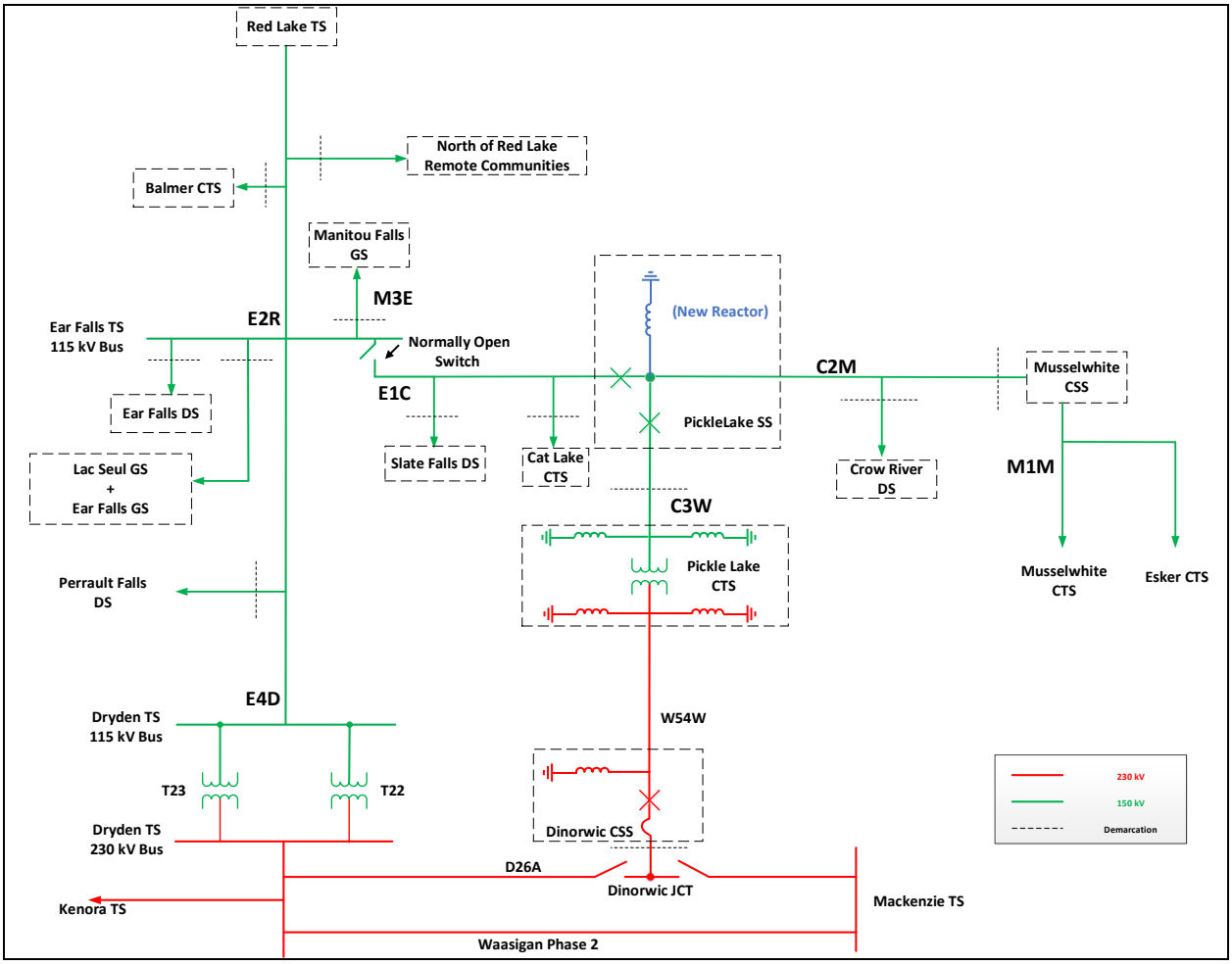


Figure 16: E1C Operation Recommended Solution

8.5 Other Planning Considerations

8.5.1 Fort William TS Shunt Capacitor Banks Replacement

Fort William TS, a step-down station in southeastern Thunder Bay, is supplied by 115kV transmission circuits B5 and B15, providing power to the suburban area. The station comprises of two 115/25 kV transformers with capacities of 50/66.6/83.3 MVA each. Additionally, Fort William TS relies on temporary capacitors on trailers, namely SC1 and SC2, which have been in service for a considerable period. SC1 and SC2 are rated at 14.88 Mvar and 15.77 Mvar respectively, operating at 25 kV. However, both capacitor banks have been assessed in poor conditions and as obsolete.

Presently, SC1 is scheduled for maintenance ensuring that SC1 remains available for service when needed. SC2 is in a significantly deteriorated condition, requiring extensive repairs both in terms of time and costs. It is crucial to address the concerns for supporting local loads and satisfying IESO's contingency planning criteria for both capacitor banks. Therefore, the following alternatives have been considered in this RIP:

Alternative 1: Maintain Status Quo

This alternative was considered and rejected as it does not address the deteriorated condition and the reliance on temporary mobile units, which could reduce supply reliability for customers.

Alternative 2: Refurbish the Existing Units

This alternative was considered and rejected due to the asset condition. SC2 has suffered damage with parts stolen and missing, making refurbishment a significant and non-economic investment with higher future maintenance requirements.

Alternative 3: Replacement for Both Units.

This alternative will provide new permanent shunt capacitors which are appropriately configured to ensure reliable supply to customers and fulfill system contingency planning criteria.

The TWG recommends alternative 3 as the preferred and cost-effective solution. Given the asset condition, refurbishing SC2 is not deemed worthwhile compared to the effort required for replacement. Recognizing the criticality of these units for local system reliability, Hydro One is initiating a project, with a planning allowance of $6M, to replace both units with similar equipment. Simultaneously, SC1 is scheduled for maintenance to ensure its functional operation until replacement.

By implementing alternative 3, Fort William TS will address the significant deteriorated assets issue, meet contingency planning criteria, and maintain a reliable power supply to customers.

8.5.2 Greenstone - Marathon Area System Needs

In Northwest Ontario, there continues to be interest in additional loads and generation connections in the Greenstone-Marathon sub-region. Alternatives presented in the past IRRPs, and RIPs remain valid. Further assessment of those alternatives for reinforcing the area will be conducted to determine their cost and feasibility. These assessments will be undertaken in the event of a request from customers for additional load and upon reaching an agreement with them.

8.5.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. As per the 2023 Northwest Ontario IRRP, there are a few options to energize the Ring of Fire area. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study to help inform government policy and potential customers seeking connection. Preliminary findings were included in the 2023 Northwest IRRP. The scope and timing of the IESO's ongoing study will evolve with government policy direction.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan report for Northwest Ontario region. The Major infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2033 are provided in Table 16 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 16: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Rabbit Lake SS	Replacement 115kV switchyard and associated equipment	Hydro One Transmission	2024-2027	$35.2M
Whitedog Falls SS	Replacement three 115kV breakers, DC station services and associated equipment	Hydro One Transmission	2025-2028	$8.5M
Mackenzie TS	Replacement of one 230/115kV autotransformer, five 230kV breakers, four switches, AC station services and associated equipment	Hydro One Transmission	2025-2028	$54.6M
Wawa TS	Replacement of one 230/115kV autotransformer, associated breakers and equipment and station services	Hydro One Transmission	2026-2029	$43.8M
Marathon TS	Replacement of 230kV and 115kV breakers and associated equipment	Hydro One Transmission	2026-2029	$14.6M
Lakehead TS	Replacement of 230kV and 115kV breakers, station services and associated equipment	Hydro One Transmission	2028-2031	$41.5M
Lakehead TS Condenser C8 Replacement	Replace Condenser C8 with a +60/-40 Mvar STATCOM	Hydro One Transmission	2027	$40.6M
Fort Frances TS	Replacement of 230kV breakers, associated equipment, and station services	Hydro One Transmission	2029-2032	$20.3M
Kenora TS	Replacement of 230kV breakers, associated equipment, and station services	Hydro One Transmission	2030-2033	$17M

Station Capacity Needs				
Margach DS	Monitor and implement investment plan in 2025	Hydro One Distribution	2025	$1M
Crilly DS	Further assess the Alternative 1 and Alternative 2 from this RIP	Hydro One Distribution	NA	NA
White Dog DS	Monitor and review in next planning cycle	Hydro One Distribution	NA	NA
White River DS	Monitor and review in next planning cycle	Hydro One Distribution	NA	NA
Kenora MTS	Further assess the alternatives from this RIP; monitor and review in next planning cycle	Synergy North	NA	NA
Sam Lake DS	Install fan monitoring – Refer to Local Planning for more detail	Hydro One Distribution and Sioux Lookout Hydro	2023	$1.5M
Transmission Line Capacity Needs				
E2R and E4D	Further evaluation on the four alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	$125M-375M
M2W	Further evaluation on the 2 alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	TBD
System Reliability, Operation and Load restoration Needs				
Fort Frances MTS	Install a second breaker and switch in Fort Frances MTS to create a second supply to the MTS	Fort Frances Power	2026-2027	$0.85M
E1C Operation	Open E1C end at Ear Falls TS and install a 10 – 15 MVAR shunt reactor at Pickle Lake SS	Hydro One Transmission	2026-2027	$20M
Other Planning Considerations				
Fort Williams TS Shunt Capacitor	Temporary capacitors to be replaced with permanent units	Hydro One Transmission	2026-2027	$6M

Banks Replacement				
Greenstone-Marathon Area System Needs	Further evaluation of the alternatives presented in the past IRRPs and RIP upon customers' requests	Hydro One Transmission and Proponent	TBD	TBD
Supply to the Ring of Fire	IESO to update Supply to the Ring of Fire study	IESO	TBD	TBD

Note:

a) The planned in-service dates are tentative and subject to change
b) Costs are based on budgetary planning estimates/allowance and excludes the cost for distribution infrastructure (if required)

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Winter Weather Adjusted Net Load Forecast

Table A.1: Northwest Ontario Region – Winter Non-Coincident- Net Load Forecast

Transformer Station Name	DESN ID	LTR (MVA)	LV Cap	LTR (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Agimak DS	T1/T2	12.0	N	10.80	5.14	5.15	5.18	5.24	5.30	5.36	5.43	5.49	5.57	5.64	5.72	5.90	5.95	6.01	6.06	6.12	6.17	6.23	6.32	6.39	6.46
Barwick DS	T1/T2	65.4	Y	62.13	27.61	27.58	27.69	27.86	28.02	28.19	28.35	28.51	28.71	28.79	29.00	23.68	23.88	24.07	24.26	24.45	24.64	24.84	24.12	23.85	23.58
Beardmore DS # 2	T2	12.0	N	10.80	1.67	1.62	1.62	1.64	1.65	1.66	1.75	1.75	1.71	1.72	1.74	1.69	1.70	1.72	1.73	1.74	1.75	1.77	1.77	1.78	1.78
Birch TS	T2/T3/T4	111.6	Y	106.02	74.30	74.25	73.91	73.83	74.12	74.63	74.71	74.79	75.26	75.77	76.10	78.77	79.05	79.46	79.82	80.23	80.68	81.03	81.24	81.72	82.20
Burleigh DS	31T1	11.6	N	10.44	4.70	5.12	5.12	5.13	5.15	5.17	5.18	5.19	5.21	5.22	5.24	5.65	5.68	5.71	5.73	5.76	5.79	5.82	5.91	5.96	6.02
Cat Lake MTS	T1	3.0	N	2.70	1.05	1.05	1.06	1.07	1.09	1.10	1.12	1.13	1.15	1.17	1.18	1.18	1.19	1.21	1.22	1.23	1.25	1.26	1.27	1.29	1.30
Clearwater Bay DS	40T1	10.4	N	9.36	6.37	6.36	6.36	6.37	6.39	6.41	6.41	6.41	6.42	6.43	6.44	7.17	7.21	7.24	7.27	7.30	7.33	7.36	7.43	7.50	7.57
Crilly DS (Sturgeon Falls CGS)	23T1	2.4	N	2.16	2.14	2.14	2.15	2.16	2.18	2.19	2.20	2.21	2.23	2.24	2.25	2.49	2.51	2.53	2.54	2.56	2.58	2.60	2.63	2.66	2.69
Crow River DS	21T1/21T2	11.6	N	10.44	3.32	3.32	3.33	3.35	3.37	3.39	3.42	3.44	3.46	3.49	3.52	3.62	3.64	3.66	3.68	3.71	3.73	3.75	3.78	3.81	3.84
Dryden TS	T4/T5	63.3	N	56.97	20.74	20.82	20.99	21.20	21.47	21.71	21.95	22.17	22.42	22.71	22.81	22.42	22.70	22.97	23.25	23.52	23.80	24.08	24.10	24.29	24.48
Ear Falls DS	T5	11.6	N	10.44	6.01	6.00	6.01	6.05	6.10	6.15	6.22	6.27	6.35	6.41	6.48	6.38	6.41	6.45	6.49	6.52	6.56	6.60	6.66	6.70	6.73
Eton DS	T1	12.0	N	10.80	4.13	4.14	4.15	4.16	4.18	4.20	4.21	4.21	4.22	4.23	4.25	4.72	4.75	4.79	4.82	4.85	4.88	4.91	4.95	5.01	5.06
Fort Frances MTS	T2/T3	26.6	N	23.94	16.23	16.20	16.21	16.27	16.33	16.39	16.46	16.53	16.63	16.72	16.83	17.79	17.88	17.97	18.06	18.15	18.24	18.33	18.48	18.62	18.77
Fort William TS	T5/T6	109.4	N	103.93	79.15	79.30	79.25	79.10	79.50	80.12	80.28	80.44	85.03	85.62	86.11	89.88	90.42	91.04	91.68	92.34	93.00	93.65	95.15	96.19	97.22
Jellico DS # 3	T1	2.4	N	2.16	0.71	0.71	0.71	0.71	0.71	0.72	0.72	0.73	0.73	0.74	0.75	0.75	0.75	0.75	0.76	0.76	0.76	0.77	0.77	0.78	0.78
Keewatin DS	T1	11.6	N	10.44	5.42	5.42	5.43	5.45	5.47	5.50	5.50	5.51	5.52	5.53	5.54	6.21	6.24	6.28	6.32	6.36	6.40	6.43	6.49	6.56	6.63
Kenora DS	T1	12.0	N	10.80	6.79	6.81	6.84	6.88	6.92	6.98	7.01	7.04	7.08	7.11	7.16	7.75	7.81	7.88	7.94	8.00	8.07	8.13	8.20	8.29	8.38
Kenora MTS	-	26.0	N	23.40	21.49	21.76	21.95	22.15	22.52	22.95	23.25	23.56	23.86	24.17	24.45	25.88	26.12	26.53	26.79	27.14	27.55	27.81	28.24	28.64	29.04
Longlac TS	T2	47.6	Y	45.22	21.45	21.39	15.80	15.97	16.15	16.33	16.58	16.80	17.08	17.33	17.59	17.38	17.52	17.67	17.81	17.95	18.09	18.24	17.35	17.32	17.29
Manitouwadge DS	19T1	9.6	N	8.64	1.40	1.39	1.40	1.40	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.60	1.60	1.61	1.62	1.63	1.64	1.64	1.66	1.68	1.69
Manitouwadge TS	T1	41.7	N	37.53	10.34	18.84	18.92	19.11	19.32	19.54	19.82	20.09	20.41	20.69	21.00	19.94	20.09	20.25	20.41	20.56	20.72	20.88	22.04	22.30	22.57
Marathon DS	2375T1	11.6	N	10.44	8.11	8.15	8.19	8.26	8.34	8.41	8.48	8.54	8.61	8.68	8.76	10.49	10.59	10.69	10.80	10.90	11.00	11.10	11.34	11.55	11.76
Margach DS	T2	11.6	N	10.44	10.50	10.48	10.47	10.48	10.51	10.53	10.53	10.53	10.55	10.55	10.61	15.33	15.39	15.45	15.51	15.57	15.63	15.68	16.28	16.68	17.08
Minaki DS	T1	12.0	N	10.80	0.87	1.70	1.69	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.82	1.83	1.83	1.84	1.84	1.85	1.85	1.95	1.98	2.00
Moose Lake TS	T2/T3	12.2	N	10.98	7.78	7.73	7.78	7.77	7.76	7.76	7.76	7.75	7.76	7.77	7.78	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.71	7.71
Murillo DS*	T1/T2	13.0	N	11.70	19.55	19.56	19.58	19.63	19.69	19.76	19.76	19.76	19.77	19.78	19.80	21.27	21.34	21.40	21.45	21.50	21.55	21.59	21.78	21.93	22.08
Nestor Falls DS	T1	11.6	N	10.44	3.75	3.75	3.75	3.76	3.77	3.78	3.79	3.79	3.80	3.81	3.83	4.21	4.22	4.24	4.26	4.28	4.30	4.32	4.36	4.40	4.44
Nipigon DS	24T1	11.6	N	10.44	4.07	4.09	4.11	4.14	4.18	4.22	4.26	4.30	4.34	4.38	4.43	4.57	4.61	4.65	4.69	4.73	4.77	4.81	4.86	4.90	4.95
Perrault Falls	36T1	11.6	N	10.44	0.52	0.52	0.53	0.53	0.53	0.54	0.54	0.55	0.55	0.56	0.56	0.59	0.59	0.60	0.60	0.61	0.61	0.62	0.62	0.63	0.64
Pic DS	1504T2	12.0	N	10.80	8.07	13.27	13.28	13.31	13.34	9.13	9.15	9.17	9.20	9.23	9.26	6.80	6.84	6.89	6.93	6.97	7.02	7.06	5.74	5.38	5.02
Port Arthur TS	T1/T2	61.4	N	55.26	36.98	37.10	37.02	37.39	37.73	38.17	38.37	38.61	38.58	39.00	38.91	41.45	41.39	41.86	41.83	42.06	42.55	42.52	43.12	43.50	43.88
Red Lake TS	T3/T4	61.5	Y	58.43	31.04	33.98	34.32	34.69	35.09	35.47	30.75	31.23	31.77	32.23	32.67	31.73	32.14	32.54	32.95	33.36	33.78	34.19	32.82	32.81	32.79
Redrock DS	33TT1	9.6	N	8.64	4.51	4.49	4.49	4.50	4.51	4.53	4.53	4.54	4.55	4.56	4.58	4.12	4.14	4.15	4.16	4.18	4.19	4.21	4.14	4.11	4.08
Sam Lake DS	2501T1/2501T2	24.0	N	21.60	28.22	28.47	28.67	28.70	28.72	28.74	28.74	28.74	28.78	28.81	28.87	30.53	30.64	30.74	30.86	30.97	31.08	31.19	31.33	31.52	31.71
Sapawe DS	11T1/11T2	4.8	N	4.32	4.50	4.51	4.52	4.54	4.57	4.60	4.62	4.64	4.66	4.68	4.71	4.90	4.93	4.97	5.00	5.04	5.07	5.11	5.13	5.17	5.20
Schreiber Winnipeg DS	34T1	9.6	N	8.64	5.80	5.81	5.83	5.87	5.91	5.95	5.98	6.01	6.04	6.08	6.12	6.83	6.88	6.93	6.98	7.03	7.08	7.14	7.23	7.32	7.41
Shabaqua DS	32T1	9.6	N	8.64	3.32	3.32	3.32	3.33	3.35	3.36	3.37	3.39	3.40	3.42	3.44	3.69	3.71	3.73	3.75	3.77	3.78	3.80	3.84	3.87	3.91
Sioux Narrow DS	27T1	12.0	N	10.80	5.01	5.01	5.01	5.03	5.05	5.07	5.08	5.09	5.11	5.12	5.14	5.66	5.69	5.72	5.75	5.78	5.80	5.83	5.89	5.95	6.01
Slate Falls DS	T1	4.7	N	4.23	0.77	0.77	0.77	0.77	0.78	0.78	0.79	0.79	0.80	0.80	0.81	0.84	0.85	0.85	0.86	0.86	0.87	0.88	0.88	0.89	0.90
Valora DS	30T1	4.8	N	4.32	0.96	0.96	0.97	0.99	1.00	1.01	1.03	1.04	1.05	1.07	1.08	1.16	1.17	1.19	1.20	1.22	1.23	1.25	1.26	1.28	1.30
Vermillion Bay DS	31T1	9.6	N	8.64	2.65	2.66	2.68	2.70	2.73	2.75	2.78	2.80	2.83	2.85	2.88	2.85	2.87	2.90	2.93	2.96	2.99	3.01	3.02	3.04	3.06
White Dog DS	-	3.2	N	2.88	2.80	2.82	2.85	2.87	2.92	2.95	2.99	3.01	3.05	3.07	3.11	3.08	3.12	3.16	3.20	3.24	3.28	3.32	3.33	3.36	3.39
Whiteriver DS	36T1	15.6	N	14.04	13.42	13.51	13.69	13.80	13.91	14.00	14.09	14.18	14.27	14.35	14.44	12.15	12.23	12.31	12.39	12.47	12.54	12.62	12.42	12.32	12.22
Pickle Lake Cluster	-	-	-	-	9.57	9.85	10.14	10.43	10.74	11.06	11.39	11.73	12.08	12.44	12.81	13.19	13.59	14.13	14.70	15.29	15.90	16.53	17.20	17.88	18.60
Red Lake Cluster	-	-	-	-	9.93	10.24	10.57	10.90	11.24	11.60	11.97	12.35	12.74	13.15	13.57	14.01	14.46	15.04	15.64	16.26	16.91	17.59	18.29	19.02	19.79

Appendix B: Lists of Step-Down Transformer Stations

Sr.NO	Transformer Station	Voltage (kV)	Supply Circuit
1	EAR FALLS TS	115/44	M3E, E4D, E1C, E2R
2	RED LAKE TS	115/44	E2R
3	CAT LAKE MTS	115/25	E1C
4	CROW RIVER DS	115/25	C2M
5	PERRAULT FALLS DS	115/12.5	E4D
6	SLATE FALLS DS	115/24.9	E1C
7	LONGLAC TS	115/44	A4L
8	MANITOUWADGE TS	115/44	M2W
9	MARATHON TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
10	BEARDMORE DS #2	115/25	A4L
11	JELLICOE DS #3	115/12.5	A4L
12	MANITOUWADGE DS #1	115/12.5	M2W
13	MARATHON DS	115/25	T1M
14	PIC DS	115/25	M2W
15	SCHREIBER WINNIPEG DS	115/12.5	A5A
16	WHITE RIVER DS	115/25	M2W
17	BARWICK TS	115/44	K6F
18	DRYDEN TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
19	FORT FRANCES TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
20	KENORA TS	230/115	K24F, K7K, K21W, K23D, K22W
21	MACKENZIE TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
22	MOOSE LAKE TS	115/44	A3M, M1S, M2D, B6M
23	FORT FRANCES MTS	115/12.47	F1B
24	KENORA MTS	115/12.5	15M1
25	AGIMAK DS	115/25	29M1
26	BURLEIGH DS	115/12.5	F1B
27	CLEARWATER BAY DS	115/25	SK1
28	ETON DS	115/12.48	K3D

29	KEEWATIN DS	115/12.5	SK1
30	MARGACH DS	115/25	K6F
31	MINAKI DS	115/25	K4W
32	NESTOR FALLS DS	115/12.5	K6F
33	SAM LAKE DS	115/25	K3D
34	SAPAWE DS	115/12.5	B6M
35	SHABAQUA DS	115/12.5	B6M
36	SIOUX NARROWS DS	115/12.5	K6F
37	VALORA DS	115/25	29M1
38	VERMILION BAY DS	115/12.5	K3D
39	BIRCH TS	115/28.4	B9, P7B, B14, B5, R2LB, P3B, B15, R1LB, B6M
40	FORT WILLIAM TS	115/25	B5, B15
41	LAKEHEAD TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
42	PORT ARTHUR TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
43	MURILLO DS	115/25	B6M
44	NIPIGON DS	115/12.5	57M1
45	RED ROCK DS	115/12.5	56M1
46	Pickle Lake CTS	230/115	W54W
47	NORTH CARIBOU LAKE TS (D)	115/25	WCD
48	MUSKRAT DAM TS (E)	115/25	WDE
49	BEARSKIN LAKE TS (F)	115/25	WEF
50	SACHIGO LAKE TS (G)	115/25	WEG
51	KINGFISHER LAKE TS (J)	115/44/25	WCJ
52	WUNNUMIN LAKE TS (I)	44/25	WJI
53	WAWAKAPEWIN TS (K)	115/44/25	WJK
54	KASABONIKA LAKE TS (L)	44/25	WKL
55	KI-WAPEKEKA TS (M)	115/25	WKM
56	PIKANGIKUM TS (Q)	115/25	WPQ

57	POPLAR HILL TS (S)	115/25	WRS
58	DEER LAKE TS (U)	115/25	WTU
59	SANDY LAKE TS (W)	115/25	WZW
60	NORTH SPIRIT LAKE TS (V)	115/44/25	WZV
61	KEEWAYWIN TS (Y)	115/25	WVY

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Mackenzie x Dryden	D26A	230
2	Mackenzie x Fort Frances	F25A	230
3	Dryden x TCPL Vermill Bay x Kenora	K23D	230
4	Fort Frances x Kenora	K24F	230
5	Mackenzie x Marmion Lake x Atikokan	N93A	230
6	Kenora x Whiteshell (Manitoba Hydro)	K21W	230
7	Kenora x Whiteshell (Manitoba Hydro)	K22W	230
8	Mackenzie x Lakehead	A21L	230
9	Mackenzie x Lakehead	A22L	230
10	Marathon x Lakehead	M23L	230
11	Marathon x Lakehead	M24L	230
12	Marathon x Lakehead	M37L	230
13	Marathon x Lakehead	M38L	230
14	Wawa x Marathon	W21M	230
15	Wawa x Marathon	W22M	230
16	Wawa x Marathon	W35M	230
17	Wawa x Marathon	W36M	230
18	Dinorwic Jct x Pickle Lake	W54W	230
19	Kenora x Rabbit Lake	15M1	115
20	Ignace x Camp Lake x Valora x Mattabi	29M1	115
21	Mackenzie x Moose Lake	A3M	115
22	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	B6M	115
23	Dryden x Domtar Dryden	D5D	115
24	Fort Frances x Burleigh	F1B	115

25	Fort Frances x Internat Fls (Minnesota Power)	F3M	115
26	Kenora x Norman	K2M	115
27	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	K3D	115
28	White Dog x Minaki x Rabbit Lake	K4W	115
29	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	K6F	115
30	Kenora x Weyerhaeuser Ken x Rabbit Lake	K7K	115
31	Moose Lake x Valerie Falls x Mill Creek	M1S	115
32	Moose Lake x Ignace x Dryden	M2D	115
33	Rabbit Lake x Keewatin x Forgie	SK1	115
34	White Dog x Caribou Falls	W3C	115
35	Nipignon x Red Rock	56M1	115
36	Reserve x Nipignon	57M1	115
37	Alexander x Port Arthur	A6P	115
38	Lakehead x Port Arthur	L3P	115
39	Lakehead x Port Arthur	L4P	115
40	Port Arthur x Birch	P3B	115
41	Port Arthur x Birch	P7B	115
42	Port Arthur x Conmee	P5M	115
43	Thunder Bay x Birch	B9	115
44	Thunder Bay x Birch	B14	115
45	Thunder Bay x Birch	B5	115
46	Thunder Bay x Birch	B15	115
47	Lakehead x Pine Portage x Birch	R1LB	115
48	Lakehead x Pine Portage x Birch	R2LB	115
49	Silver Falls x Lac Des Iles x Conmee	S1C	115
50	Aguasabon x Terrace Bay	A1B	115

51	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	A4L	115
52	Alexander x Minnova x Schreiber x Aguasabon	A5A	115
53	Alexander x Cameron Falls	C1A	115
54	Alexander x Cameron Falls	C2A	115
55	Alexander x Cameron Falls	C3A	115
56	Upper White River x Lower White River	GA1	115
57	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	M2W	115
58	Alexander x Pine Portage	R9A	115
59	Ear Falls x Selco x Slate Falls x Cat Lake x Pickle Lake	E1C	115
60	Pickle Lake x Crow River x Musselwhite	C2M	115
61	Pickle Lake x Wataynikaneyap	C3W	115
62	Ear Falls x Balmer x Red Lake	E2R	115
63	Ear Falls x Scout Lake x Dryden	E4D	115
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Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Atikokan Hydro Inc.
2	Fort Frances Power Corporation
3	Hydro One Networks Inc. (Distribution)
4	Sioux Lookout Hydro Inc.
5	Synergy North

Appendix E: List of Districts[5] in the region

Sr. no.	Name of District
1	Kenora
2	Rainy River
3	Thunder Bay

[5] In Northern Ontario, Districts are in place of Municipalities.

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor

PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Northwest Region Integrated Regional Resource Plan Addendum

North of Dryden Sub-Region
August 2025

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List of Acronyms

APS	Achievable Potential Study
ATB	Annual Technology Baseline
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long-term Emergency
NERC	North American Electric Reliability Corporation
NOCS	Northern Ontario Connection Study
NOMA	Northwestern Ontario Municipal Association
NPCC	Northeast Power Coordinating Council
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
SIA	System Impact Assessment
TFS	Technical Feasibility Study
TS	Transformer Station
TWG	Technical Working Group
ULTC	Under-Load Tap Changer

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

This IRRP Addendum Report was prepared on behalf of the Technical Working Group (Working Group) of the North of Dryden sub-region which included the following members:

Independent Electricity System Operator (IESO)

Wataynikaneyap Power

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

The Working Group assessed the reliability of electricity supply to customers in the North of Dryden sub-region over a 25-year period beginning in 2025; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options while maintaining flexibility to accommodate changes in key conditions over time.

The North of Dryden Working Group members agree with the IRRP's Addendum recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

Executive Summary

The Northwest Integrated Regional Resource Plan (IRRP) Addendum addresses electricity system needs in the North of Dryden sub-region over a 25-year horizon, from 2025 to 2050. While the 2023 Northwest IRRP did not identify firm electricity needs in this sub-region, it acknowledged that new needs could emerge if growth in the mining sector materialized. In 2024, the IESO received further information indicating significant potential load growth tied to mining developments in the region. In response, the IESO initiated this Addendum study ahead of the standard five-year planning cycle to proactively assess system adequacy and ensure reliable electricity supply.

The North of Dryden sub-region includes Dryden, Ear Falls, Red Lake, and Pickle Lake, and encompasses 21 remote First Nation communities connected via the Wataynikaneyap transmission system. Electricity planning for the region is carried out by a Technical Working Group (TWG), which includes the Independent Electricity System Operator (IESO), licensed transmitters, and local distribution companies. In this sub-region, the TWG includes Hydro One Networks Inc. and Wataynikaneyap Power, who together support the development of coordinated solutions to meet emerging electricity needs.

Electricity demand in the region is forecasted to grow significantly, with peak demand increasing from approximately 120 MW in 2023 to over 420 MW under the reference scenario and up to 750 MW under extreme growth by 2050. This growth is primarily driven by mining sector expansion and community growth. The IRRP developed three demand scenarios; Reference, High, and Extreme to test system robustness and inform planning decisions.

The Addendum identifies near-, medium-, and long-term electricity system needs in the sub-region. The primary need in the sub-region is in the Red Lake area, where electricity demand is expected to exceed available supply capacity by 2028 due to thermal constraints on the existing 115 kV transmission corridors (E4D and E2R). These constraints are driven by sustained load growth, particularly from mining developments. In the Pickle Lake area, which is supplied by the 230 kV circuit W54W, the existing infrastructure has sufficient capacity to accommodate forecasted load growth under the reference scenario. However, additional voltage support will be required toward the end of the planning horizon to maintain system reliability and ensure compliance with planning criteria. This includes the installation of reactive compensation to address emerging voltage constraints and support future connections.

To address these needs, the TWG recommends reinforcing the existing 115 kV transmission corridor in the area. This includes two new 230 kV double-circuit transmission lines, one from Dryden TS to Ear Falls TS and the other from Ear Falls TS to Red Lake SS, along with four new 230/115 kV autotransformers and reactive compensation at Red Lake SS, Ear Falls TS, and Pickle Lake TS. The existing 115 kV circuits E4D and E2R will be reconfigured to operate normally open, providing backup supply during outages. This option meets all applicable planning criteria, addresses imminent connection needs in the Red Lake area, and reinforces the transmission system to support long-term growth and enable economic development across the North of Dryden sub-region. This option:

- Supports regional electricity needs through 2050 and beyond, across reference, high, and extreme demand scenarios.
- Enhances reliability and reduces the risk of load interruptions in the North of Dryden sub-region.
- Facilitates the connection of new resources including hydroelectric, biomass, and other generation by lowering connection costs and enabling power transfers to the broader grid.
- Strengthens system resilience and robustness while meeting all applicable planning criteria.
- Offers long-term cost efficiency, as building a double-circuit line upfront is significantly more economical than adding a parallel single-circuit line later.
- Minimizes environmental and land-use impacts by leveraging existing rights-of-way where feasible.

Non-wires alternatives (NWAs) were also evaluated, including natural gas, biomass, solar, wind, and battery energy storage systems. While some options offer system benefits, they face limitations in reliability and/or land use. Natural gas, while cost-competitive, presents challenges related to fuel supply, regulatory compliance, and community acceptance. Hybrid renewable options require extensive land and cannot serve all hourly load requirements. Ultimately, NWAs were deemed unsuitable as standalone solutions for the Red Lake area's long-term needs but may complement transmission investments in future planning cycles.

Extensive engagement was conducted with municipalities, Indigenous communities, industry stakeholders, and the public. Feedback emphasized support for the recommended transmission solution, concerns about transmission lead times, interest in enabling economic development, and the importance of respecting Indigenous land rights and ensuring meaningful participation. These insights were incorporated throughout the planning process.

In conclusion, the IRRP Addendum recommends Transmission Option 3 – Double Circuit as the preferred solution to meet electricity needs in the North of Dryden sub-region. This option supports regional growth and reliability through 2050 and beyond, aligns with planning criteria and stakeholder expectations, and enables future resource development and community expansion. The TWG will continue to monitor demand growth, particularly in Pickle Lake, and initiate further reinforcements as needed. The next cycle of regional planning for Northwest Ontario began in Q3 2025 and will build upon the findings of this Addendum.

1. Introduction

This Northwest Integrated Regional Resource Plan (IRRP) Addendum Study ("the Study") builds on the Independent Electricity System Operator's (IESO) 2023 Northwest IRRP, published in January 2023. This addendum study was initiated by the Technical Working Group (TWG) earlier than the mandated five-year cycle of regional planning to address emerging electricity needs in the North of Dryden sub-region, where growing demand is anticipated due to mining developments and community expansion. Its objective is to ensure that the transmission system can continue to reliably support future electricity requirements in this rapidly growing area.

The North of Dryden sub-region encompasses a large geographic area extending north from Dryden through Ear Falls, Red Lake, and Pickle Lake, reaching as far as Sachigo Lake in the northwest and Big Trout Lake in the northeast. It includes the recently completed Wataynikaneyap transmission system, which connects 17 remote First Nation communities. This sub-region spans parts of the Robinson-Superior Treaty area, First Nation Treaty areas 3, 5, and 9, as well as Regions 1 and 2 of the Métis Nation of Ontario (MNO), and includes a total of 21 remote communities.

For planning purposes, the region is defined by its electrical infrastructure rather than geographic boundaries. It is supplied by 230 kV and 115 kV circuits extending east from Kenora and north from Atikokan, and includes the 230/115 kV systems located north of Dryden. A geographic map and single line diagram illustrating the sub-region's infrastructure are provided in Figure 1.1 and Figure 1.2 respectively.

Four local distribution companies (LDCs) serve the area: Hydro One Networks Inc., Atikokan Hydro Inc., and Fort Frances Power Corporation. Transmission assets in the region are owned by two licensed transmitters: Hydro One Networks Inc. and Wataynikaneyap Power. This IRRP Addendum was prepared by the IESO on behalf of a Working Group composed of these LDCs and transmitters.

This Addendum follows from the previous regional planning cycle, where Hydro One published its Needs Assessment in July 2020[1] and the IESO issued the Scoping Assessment Outcome Report in January 2021[2]. The Northwest IRRP was released in January 2023[3] and the Northwest Regional Infrastructure Plan (RIP)[4] was published in August 2023. This Addendum supplements the 2023 Northwest IRRP and does not replace or supersede its findings.

[1] NW 2023 Needs Assessment Report can be found on Hydro One's Northwest Ontario regional planning website.
[2] NW 2023 Scoping Assessment Outcome Report can be found on IESO's Northwest regional planning engagement website.
[3] Northwest (NW) 2023 Integrated Regional Resource Plan can be found on IESO's Northwest regional planning engagement website.
[4] Northwest Regional Infrastructure Plan (RIP) 2023 can be found on Hydro One's Northwest regional planning engagement website.

Figure 1.1 | Geographic Map of the North of Dryden Sub-Region

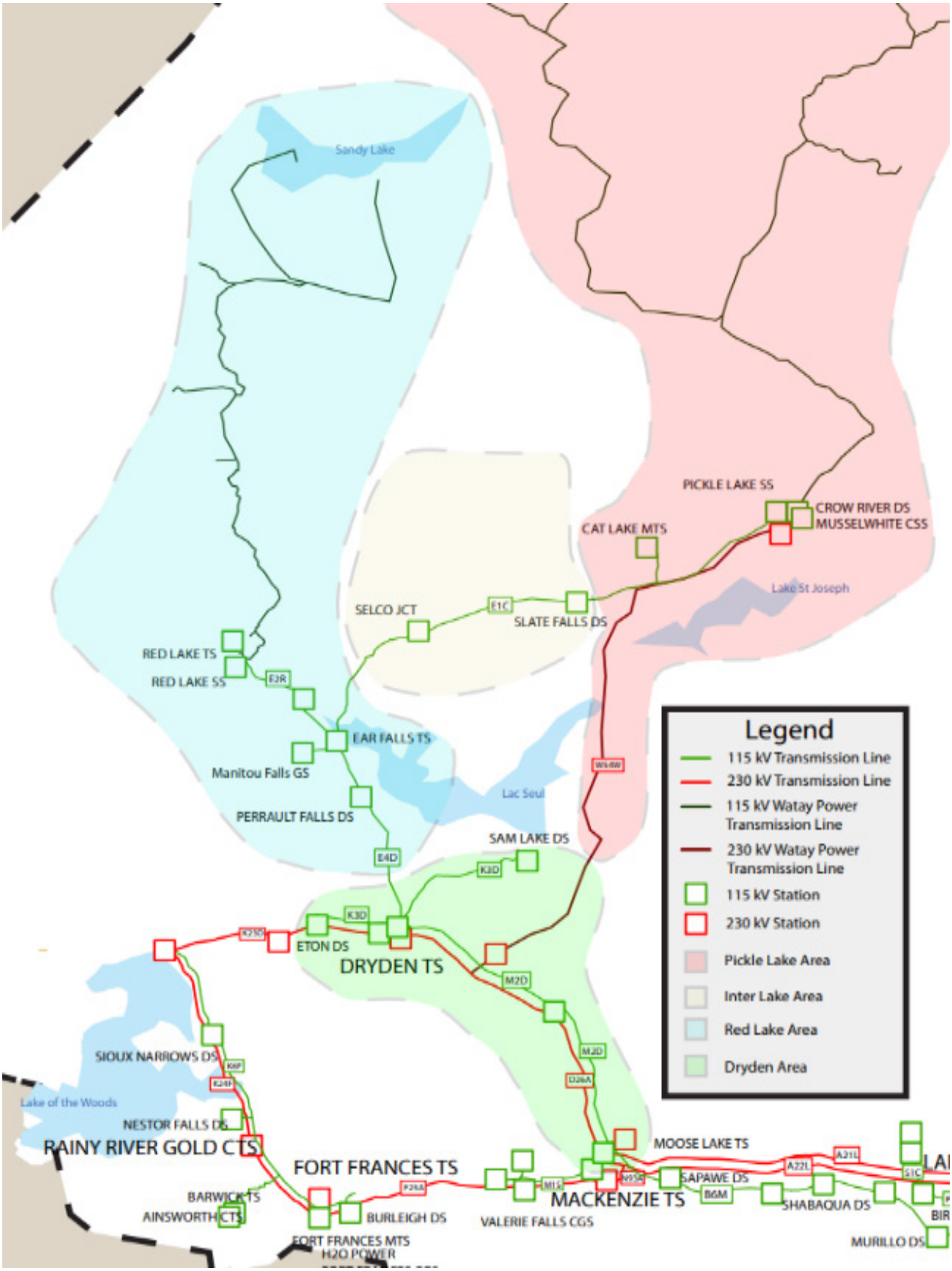
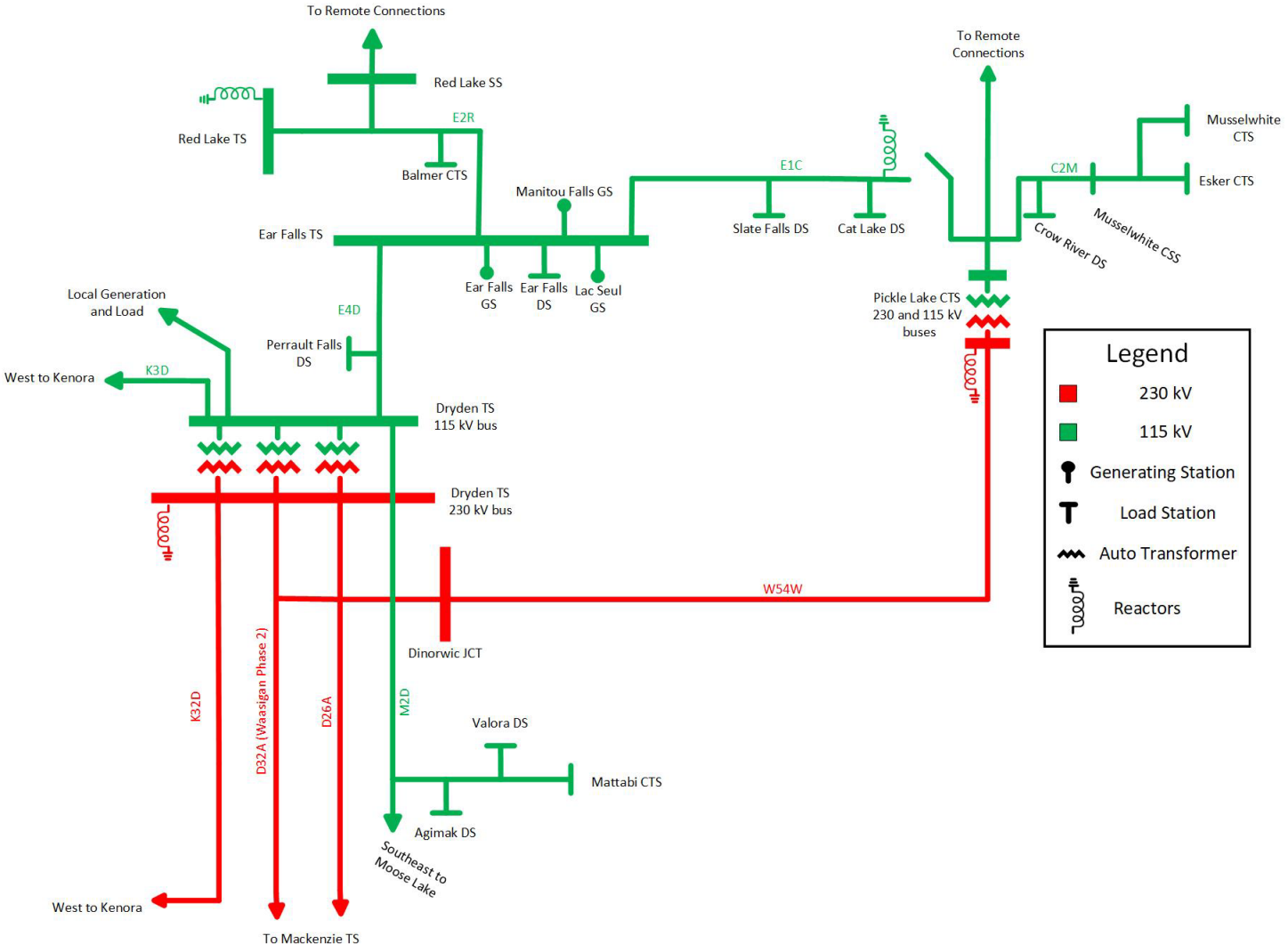


Figure 1.2 | Current Electricity Infrastructure in the North of Dryden Sub-Region



2. The Integrated Regional Resource Plan Addendum

This IRRP Addendum outlines recommended actions to address the electricity needs of the North of Dryden sub-region over the next 25 years. These recommendations are informed by projected electricity demand growth and assessed against the capabilities of the existing transmission infrastructure. The analysis is guided by the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards established by the North American Electric Reliability Corporation (NERC). Each recommendation has been evaluated based on system reliability, cost-effectiveness, technical feasibility, optimal use of existing infrastructure where practical, and stakeholder input.

Several major transmission reinforcement projects in the Northwest region are foundational to enabling future development in the North of Dryden sub-region:

- **East-West Tie Reinforcement:** A new double-circuit 230 kV transmission line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS. In service since 2022.
- Waasigan Transmission Line Project:
    - *Phase 1* – A new double-circuit 230 kV line from Lakehead TS to Mackenzie TS (under construction; expected in-service December 2025).
    - *Phase 2* – A new single-circuit 230 kV line from Mackenzie TS to Dryden TS (expected in-service December 2027).
- **Wataynikaneyap Transmission Project:** A new single-circuit 230 kV line from Dinorwic Junction (near Dryden) to Wataynikaneyap TS (near Pickle Lake), along with associated 115 kV circuits connecting remote communities north of Pickle Lake and Red Lake. In service as of 2025.
- **Pickle Lake Shunt Reactor Project:** Installation of a 115 kV line shunt reactor at Pickle Lake SS to moderate voltage and enable a normally open point on circuit E1C. Expected in-service October 2026.

With the East-West Tie and Wataynikaneyap projects already in service, and the Waasigan Transmission Line progressing toward completion, these reinforcements collectively strengthen the 230 kV backbone across the Northwest. These upstream enhancements position the system to accommodate targeted investments within the North of Dryden sub-region, supporting future load growth tied to industrial and community expansion.

Electricity demand in the sub-region is expected to increase significantly, primarily driven by mining and industrial activity. These developments can result in large, step-changes in demand with relatively short lead times, presenting challenges for long-term transmission planning. To address this, the IRRP considered high-growth demand scenarios to test the robustness and adaptability of the plan under more aggressive assumptions.

This plan is organized into two components:

- **Near- and Medium-Term Recommendations:** Actions and studies to be undertaken by Working Group members within specified timeframes. These actions address needs with high forecast certainty and require committed action during this planning cycle.
- **Ongoing Monitoring:** Activities to track long-term or potential needs that may emerge under high-growth scenarios but remain uncertain in the current forecast. These include monitoring electrification trends, energy efficiency performance, and updates to industrial or mining development plans.

This phased approach ensures that immediate system needs are addressed while maintaining flexibility to adapt as new information becomes available.

2.1 Near- and Medium-Term Recommendations

This section summarizes the electricity system needs identified in the Study and the recommended actions to address them.

2.1.1 Red Lake Area Supply Capacity Need

Electricity demand in the Red Lake area is expected to exceed available supply capacity by 2028, driven by sustained growth. Under the reference forecast, capacity needs are projected to rise from 40 MW in 2028 to 115 MW by 2050. The current system is constrained during summer conditions due to pre-contingency thermal limits on the 115 kV circuits E4D (Dryden to Ear Falls) and E2R (Ear Falls to Red Lake). Load forecasts for the Red Lake Area under reference, high-growth, and extreme-growth scenarios are provided in Figure 6.5. These recommendations are based on the reference forecast.

Transmission reinforcement options were assessed, ranging from targeted upgrades along the Dryden–Ear Falls–Red Lake corridor (estimated capital cost: $800–$1,000 million) to broader incremental reinforcements extending through the Dryden–Pickle Lake–Ear Falls corridor (estimated cost: $2,500 million), which would also enhance supply capacity for the Pickle Lake area. These options and their benefits are discussed further in Section 7.

Several non-wires alternatives (NWAs) were evaluated, including:

- 130 MW natural gas fired generating resource
- 130 MW biomass fired generating resource
- A hybrid resource consisting of 400 MW battery storage, 4,000 MW solar, and 150 MW wind

However, these NWA were found unsuitable as stand-alone solutions due to technical and reliability constraints:

1. The 115 kV network's ~80 MW capacity limits the ability to host large, centralized resources, requiring fragmented siting and connections.
2. The single-circuit configuration of transmission lines introduces unacceptable reliability risks under ORTAC load security criteria, particularly as demand approaches 150 MW by 2040 under the reference scenario which could occur earlier if mining developments materialize sooner.

Therefore, to address the supply capacity needs in the Red Lake area, the IRRP recommends the following transmission investments:

- Hydro One Transmission to:
- Construct two new double-circuit 230 kV transmission lines: one from Dryden TS to Ear Falls TS, and another from Ear Falls TS to Red Lake SS.
- Install two new 250 MVA 230/115 kV autotransformers at Ear Falls TS.
- Reconfigure existing 115 kV circuits E4D and E2R to operate normally open, allowing them to serve as backup supply during outages.
- Wataynikaneyap Power to:
- Install two new 250 MVA 230/115 kV autotransformers at Red Lake SS.

While NWAs are not viable as primary solutions, they may offer supply diversity and resilience. The IRRP therefore recommends that the IESO explore cost-effective supply resources to complement these transmission reinforcements during the next Northwest Ontario IRRP cycle, expected to begin later this year.

2.1.2 Pickle Lake Area Supply Capacity Need

The current load meeting capability (LMC) of the Pickle Lake area is approximately 125 MW, constrained by pre-contingency voltage limits as defined by ORTAC. Voltage sensitivity analysis under the reference load growth scenario indicates that these criteria will be violated at Pickle Lake TS by 2043, limiting the area to supply further demand. To address this, capacitive compensation will be required to support future load connections.

However, rather than waiting until 2043, the IRRP recommends advancing the installation of a 40 MVar capacitor bank at Pickle Lake TS. This proactive step will not only mitigate the anticipated voltage deficiencies but also deliver near-term benefits by improving operability during outages and supporting load restoration efforts. The region currently faces reliability challenges due to limited remote operational capability and the absence of backup supply, which increases restoration time and complexity. The capacitor bank will help alleviate these issues by enhancing voltage stability and reactive support under contingency conditions.

Under N-1 conditions, ORTAC load security criteria limit interruptible load to 150 MW. While the reference scenario remains within this threshold, the high-growth scenario exceeds it by 2030. Load forecasts under reference, high-growth, and extreme-growth scenarios are shown in Figure 6-2-2. Recommendations in this section are based on the reference scenario.

Looking ahead, the plan recommends that the TWG continue to monitor demand growth and explore reinforcement options for the corridor between Pickle Lake and Red Lake. This would further improve backup supply capability and overall reliability in the region.

Near- and medium-term recommendations are summarized in Table 2.1 and discussed further in Section 7.

Table 2.1 | Summary of Near- and Medium-Term Recommendations

Need/Subsystem	Recommendation	Lead Responsibility	Implementation
Red Lake Area Supply Capacity	Reinforce the existing 115 kV E2R and E4D transmission corridors. Hydro One Transmission will construct two new double-circuit 230 kV transmission lines: one from Dryden TS to Ear Falls TS, and another from Ear Falls TS to Red Lake SS. Hydro One will install two new 250 MVA 230/115 kV autotransformers at Ear Falls TS, and Wataynikaneyap Power will install two new 250 MVA 230/115 kV autotransformers at Red Lake SS. Upon completion, the existing 115 kV circuits E4D and E2R will operate in a normally open configuration and serve as backup supply during outages. Hydro One and IESO will collaborate to refine location of open points.	Hydro One; Watay Power	Hydro One to determine in-service date reflecting urgency of 2028 need date.
Pickle Lake Area Supply Capacity	Install a 40 MVar capacitor at Pickle Lake TS to address voltage concerns. Monitor demand growth and trigger planning to evaluate reinforcing the corridor between Pickle Lake and Red Lake to ensure adequate backup supply and system resilience.	Hydro One; Watay Power	2030

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, electricity planning at the regional level is carried out through a structured regional planning process. This process assesses the interconnected electricity needs of a region, defined by shared supply infrastructure over the near, medium, and long term, and results in a coordinated plan to ensure reliable and cost-effective electricity supply.

A regional plan considers existing infrastructure, forecast growth, and customer reliability expectations. It evaluates potential solutions and recommends actions to address identified needs.

The current regional planning framework was formalized by the Ontario Energy Board (OEB) in 2013 and operates on a five-year cycle for each of the province's 21 defined planning regions. The process is carried out by the IESO in collaboration with licensed transmitters and local distribution companies (LDCs) within each region. It consists of four key components:

1. **Needs Assessment** – Led by the region's lead transmitter, this initial screening identifies electricity needs and determines whether regional coordination is required.
2. **Scoping Assessment** – Led by the IESO, this step defines the appropriate planning approach and the scope of any recommended planning activities.
3. **Integrated Regional Resource Plan (IRRP)** – Led by the IESO, the IRRP proposes coordinated solutions to meet identified needs.
4. **Regional Infrastructure Plan (RIP)** – Led by the lead transmitter, the RIP provides further detail on recommended wires solutions.

Additional information on the regional planning process and the IESO's planning approach is available in Appendix A of the 2023 Northwest IRRP.

Regional planning is one of several planning activities in Ontario's electricity sector. Bulk system planning, led by the IESO, and distribution system planning, led by LDCs, also play key roles. While each planning level has distinct objectives, there are natural overlaps among them, particularly in areas where infrastructure and customer needs intersect.

3.2 The Northwest Region and IRRP Addendum Development

The Northwest IRRP was initiated in January 2021, following Hydro One's Needs Assessment in July 2020 and the IESO's Scoping Assessment Outcome Report in January 2021. In alignment with the standard 18-month IRRP timeline, the original publication was scheduled for July 13, 2022. However, in April 2022, the IESO requested a six-month extension from the OEB to incorporate key developments in the region. This extension allowed for more comprehensive engagement, consideration of additional growth scenarios, and improved coordination with ongoing bulk system studies across both the Northwest and Northeast.

As part of the IRRP, the IESO identified several sub-regions for continued monitoring, including the North of Dryden area. In response to significant load growth and new developments in this sub-region, the IESO initiated an IRRP Addendum in August 2024 to evaluate options for maintaining reliable electricity supply.

4. Background and Study Scope

During the first cycle of regional planning, the Northwest region was divided into four sub-regions, each with its own Integrated Regional Resource Plan (IRRP):

- **North of Dryden** (published January 2015)[5]
- **Greenstone-Marathon** (published June 2016)[6]
- **West of Thunder Bay** (published July 2016)[7]
- **Thunder Bay** (published December 2016)[8]

In the second cycle, these sub-regions were considered collectively within the broader context of Northwestern Ontario, culminating in the publication of the 2023 Northwest IRRP. The third cycle of regional planning for the Northwest region commenced in Q3 2025.

4.1 Study Scope

This IRRP Addendum addresses emerging electricity needs in the North of Dryden sub-region and evaluates supply options to meet these needs, identifying the most effective solution. The plan was developed by the IESO in collaboration with the Technical Working Group (TWG) and incorporates:

- Forecast electricity demand growth
- Conservation and demand management (CDM)
- Distributed generation (DG)
- Transmission and distribution system capabilities
- Relevant community plans
- Equipment end-of-life considerations
- Developments in the bulk transmission system

[5] North of Dryden IRRP can be found on IESO's North of Dryden regional planning engagement website.
[6] Greenstone-Marathon IRRP can be found on IESO's Greenstone-Marathon regional planning engagement website.
[7] West of Thunder Bay IRRP can be found on IESO's West of Thunder Bay regional planning engagement website.
[8] Thunder Bay IRRP can be found on IESO's Thunder Bay regional planning engagement website.

The IRRP Addendum was guided by the following planning steps:

- Developing a 25-year electricity demand forecast and identifying system needs over that horizon
- Assessing the load meeting capability (LMC) and reliability of the existing transmission system, including facility ratings, transformer performance, local generation, and reactive power devices
- Applying contingency-based assessments and reliability standards from ORTAC, NERC, and NPCC (where applicable)
- Confirming end-of-life asset replacement needs and timing with transmitters and LDCs
- Identifying and evaluating alternatives to address system needs, including generation, transmission, distribution, and non-wires solutions such as CDM
- Conducting sensitivity analyses for areas with high growth potential to test the robustness and flexibility of proposed solutions
- Engaging with communities to understand needs and explore alternatives
- Evaluating options to address near- and long-term needs
- Communicating findings, conclusions, and recommendations in a comprehensive plan

4.1.1 Scope of Regional Planning regarding New Connections

Growth in the North of Dryden sub-region is primarily driven by industrial customers, particularly in the mining sector. While many of these customers are not yet connected to the electricity grid but have expressed interest in doing so. This Study also incorporates the latest demand growth forecasts from the municipalities and Indigenous communities and enables future growth. This Study used the best available information to simulate potential future connection configurations.

Rather than evaluating the capability to supply each individual project, the Study focused on assessing the overall adequacy of regional infrastructure to meet projected demand. Local connection requirements for specific projects were only considered where they aligned with broader regional needs[9].

4.2 Parallel Planning Activities

Several planning initiatives are underway in parallel with this IRRP Addendum, including the Northern Ontario Bulk Study and the Northern Ontario Connection Study (NOCS). These efforts are expected to inform and complement regional planning activities.

[9] Participation in the IRRP does not replace the formal connection processes required for new customers, including Customer Impact Assessments (CIA) and System Impact Assessments (SIA). Additionally, the absence of identified regional reliability needs in a specific area through the IRRP does not guarantee approval of future connection requests through CIA or SIA processes.

4.2.1 Northern Ontario Bulk Study

The IESO initiated the Northern Ontario Bulk Study to address several key objectives:

- Responding to increasing electricity demand in Northern Ontario, driven by mining developments, electrification of metal production, and broader industrial electrification
- Supporting province-wide demand growth, which requires new supply resources and expanded transmission capacity to enable bulk transfers across Ontario
- Advancing the Government of Ontario's Critical Minerals Strategy and Powering Ontario's Growth report by unlocking economic opportunities and enabling resource development in Northern Ontario

The study is evaluating transmission options to reinforce the supply corridor between southern and northern Ontario and exploring new supply resources in the North to meet higher demand growth.

4.2.2 Northern Ontario Connection Study

The IESO is conducting the Northern Ontario Connection Study in response to a request from the Government of Ontario to develop supply options in Northwest Ontario that will:

- Connect remote First Nations communities currently reliant on diesel generation
- Improve reliability for grid-connected First Nations communities
- Support critical minerals mining development
- Enable new hydro and renewable resource development

Further engagement for NOCS is planned for late spring/summer 2025, with the study expected to conclude in Q3 2025.

5. Electricity Demand Forecast

This section outlines the development of the demand forecast for the North of Dryden sub-region. While IRRPs typically use a 20-year planning horizon, a 25-year forecast was developed for this Addendum to capture the full impact of anticipated mining activity in the area.

The forecast consists of three components: distribution-connected demand, transmission-connected demand, and a focused mining sector forecast. The mining sector forecast is integrated within the transmission-connected category but also presented separately to highlight future incremental demand.

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the North of Dryden sub-region and is based on information submitted by local distribution companies (LDC). The regional planning process relies on LDCs to consider municipal and regional official plans and First Nations development plans and translate them into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities they serve.
- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This typically consists of large industrial customers that have their own transformation station. The transmission-connected forecast is informed by direct engagement with customers.
- **Mining Sector**: The mining sector forecast captures electricity demand from both existing grid-connected and known future mining projects that are not yet grid-connected. The mining sector forecast is informed by data from government, industry publications, and engagement with individual project proponents, municipal energy committees, and task forces (i.e., Northwestern Ontario Municipal Association [NOMA]). Note that electricity demand from existing mining projects is also reflected in the above transmission- and distribution-connected forecast components. When the mining sector component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting

All forecasts in this section refer to non-coincident peak demand, meaning the sum of each station's individual peak demand. Each component is described in further detail below.

5.1 Historical Demand

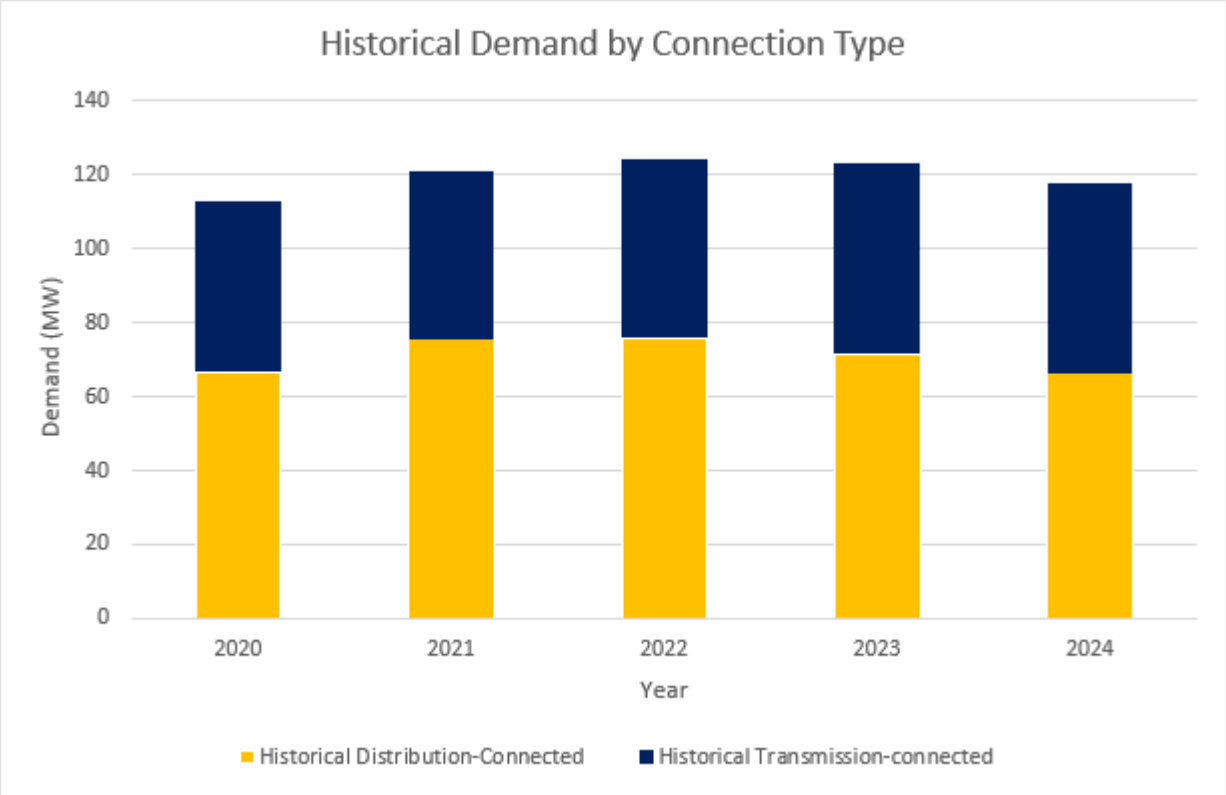
Figure 5.1 illustrates net and gross historical demand over the past five years in the North of Dryden sub-region. Historically, distribution-connected customers have accounted for approximately 60% of peak demand, with the remainder served through transmission connections.

Demand growth was steady through 2022, tapering slightly into 2024, with an average annual growth rate of 0.9%. Peak demand in the sub-region has hovered just above 120 MW from 2021 to 2023.

The North of Dryden sub-region is winter peaking, with annual peak demand typically occurring on winter evenings between 7:00 p.m. and 8:00 p.m.

Distributed generation has historically contributed about 10–15 MW during peak conditions. This contribution was added to the net demand forecast to derive the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast, with station-level adjustments made where anomalous conditions were identified.

Figure 5.1 | 2020–2024 Historical Demand



5.2 Distribution-connected Forecast

To develop the distribution-connected forecast, each LDC prepared a gross station-level demand forecast for its service territory (see Section 5.2.1). These forecasts were then adjusted to reflect:

- The impact of provincial conservation targets
- Distributed generation contracted through programs such as FIT and microFIT.[10]

[10] More information about the Feed-in Tariff can be found on the IESO's website.

- Extreme weather conditions

The result is a reference scenario forecast that accounts for expected peak demand under typical operating conditions.

5.2.1 Gross Local Distribution Company Forecast

Each participating LDC developed gross demand forecasts at the station level, or at the station bus level for multi-bus stations, based on their understanding of local development plans and customer engagement. These forecasts incorporate anticipated changes in consumer demand due to efficiency improvements and rising electricity prices (i.e., "natural conservation"), but exclude impacts from future distributed generation or new conservation measures, which are accounted for separately by the IESO.

From these forecasts, demand growth from new developments and known connection applications was identified. The compiled distribution-connected forecasts were then adjusted for extreme weather conditions, as shown in Figure 5.2. This gross forecast includes residential loads and distribution-connected mining loads under the reference scenario.

Figure 5.2 | Total Gross Median and Extreme Weather Distribution-connected Forecast

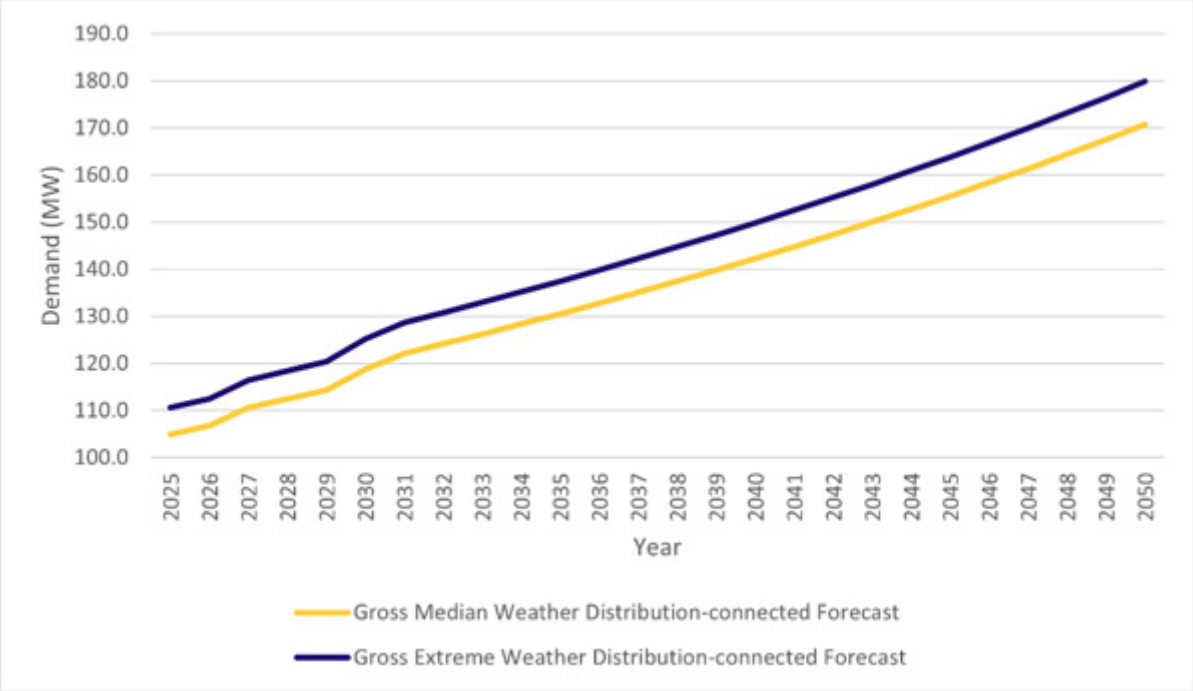
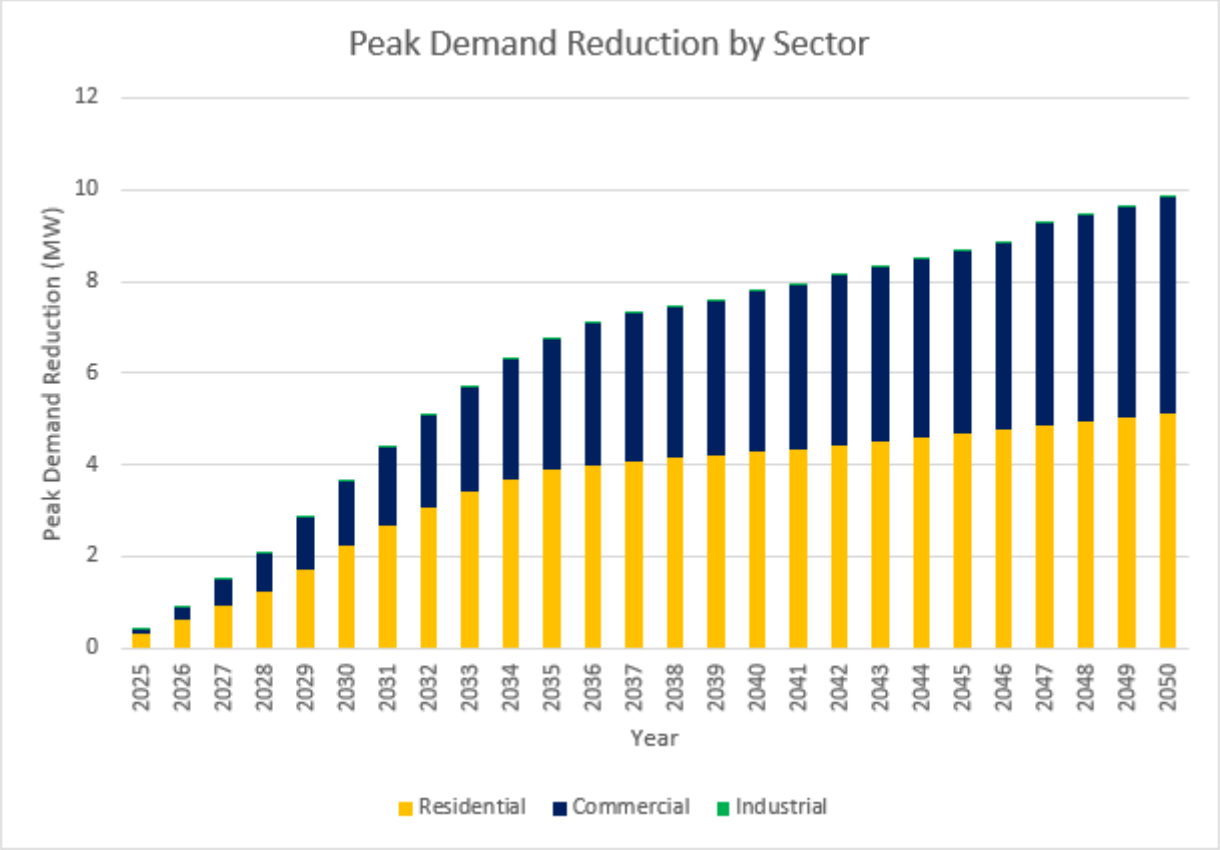


Figure 5.3 | Contribution of Conservation to Forecast



5.2.2 Contribution of Conservation to the Forecast

Electricity Demand-Side Management (eDSM), previously known as Conservation and Demand Management (CDM), is a clean and cost-effective resource that helps meet the province's electricity needs. The 2025–2036 Electricity Demand-Side Management (eDSM) Framework, which expands on the foundation laid by the 2021–2024 Conservation and Demand Management (CDM) Framework, is a large initiative led by the IESO that aims to reduce electricity demand and improve system efficiency. Electricity Demand-Side Management is achieved through the delivery of programs and collaboration with local distribution companies and partners which contributes to electricity savings in Ontario. This framework enables the IESO to optimize the full value of demand-side management in a variety of ways allowing consumers on a province-wide basis to save on energy costs in their homes, businesses, institutions, and industrial facilities and add more flexibility to regional tailoring and innovation to respond to evolving grid needs.

Figure 5.3 shows the total contribution of conservation to the forecast and is divided into three sectors such as residential, commercial, and industrial.

5.3 Transmission-connected Forecast

The North of Dryden sub-region includes several customer transformer stations (CTS) that directly serve large industrial customers connected to the high-voltage transmission system, such as mining operations. Expansion of existing mines and the development of new projects are expected to be the primary drivers of electricity demand growth in the sub-region.

To support planning, the IESO developed a mining sector forecast that incorporates multiple potential future mining projects at various stages of development. This forecast is based on information gathered from project proponents, industry publications, stakeholders, utilities, and government sources. Unlike the distribution-connected forecast, the mining forecast was not adjusted for extreme weather, as industrial demand in this sub-region is generally not sensitive to weather.

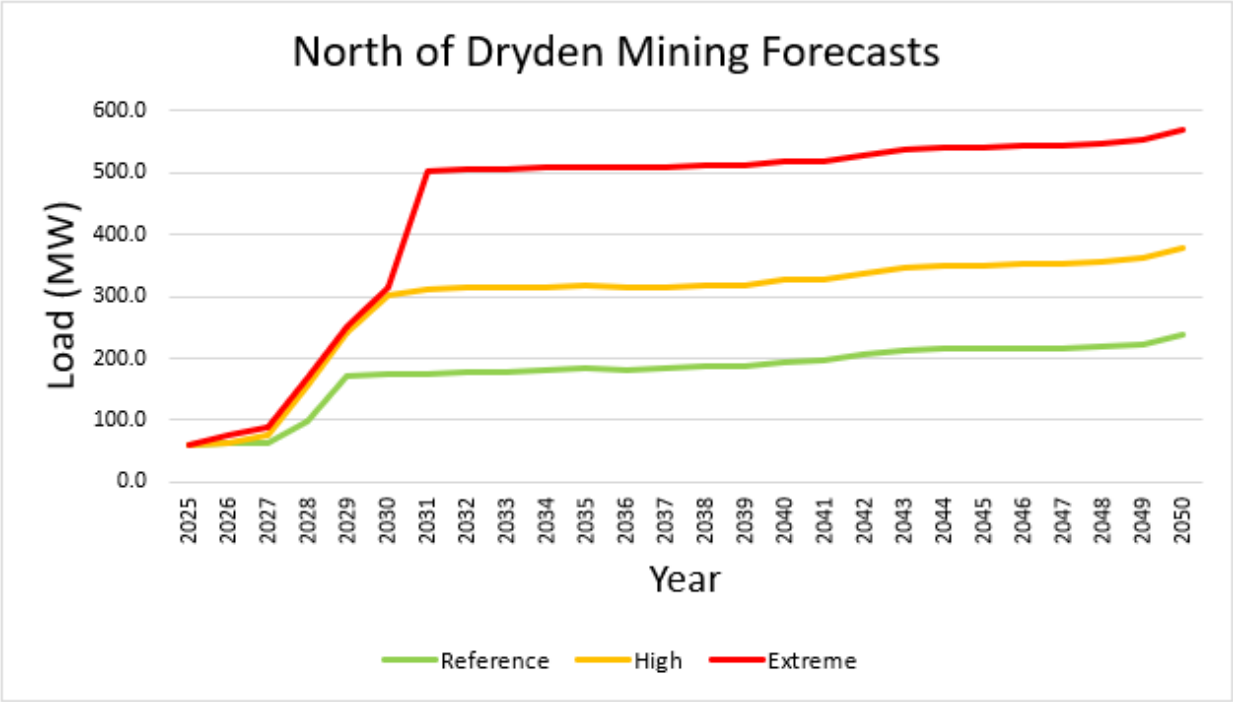
The mining forecast is presented across three scenarios, Reference, High, and Extreme to reflect varying levels of project certainty. The likelihood of a project materializing is informed by factors such as data reliability, project development stage, and expected in-service dates. The IESO also consulted with the Ministry of Energy and Mines and incorporated feedback from the Northwestern Ontario Municipal Association, which recommended removing likelihood-based discounting to better reflect worst-case planning scenarios. NOMA's mining forecast was also used to update the IESO's internal projections.

Table 5.1 | Mining Forecast Scenario Descriptions

Scenario	Description
Reference	• Includes all active mining projects, as well as those classified as committe and are most likely to connect • Established from mining forecasts and other commitment indicators/factc such as commodity outlook and prospective in-service dates of projects reported from System Impact Assessments (SIA) and Technical Feasibilit Studies (TFS) • Aligned with 2025 Annual Planning Outlook Reference scenario
High	Reference Scenario plus: • Mining projects that have more uncertainty in timing.
Extreme	High Scenario plus: • Mining projects that have the greatest uncertainty in timing.

Figure 5.4 illustrates the mining demand forecast under all three scenarios. The high and extreme cases show significantly higher MW values compared to the reference scenario. The figure includes demand from both new and existing mines but does not include distribution-connected demand.

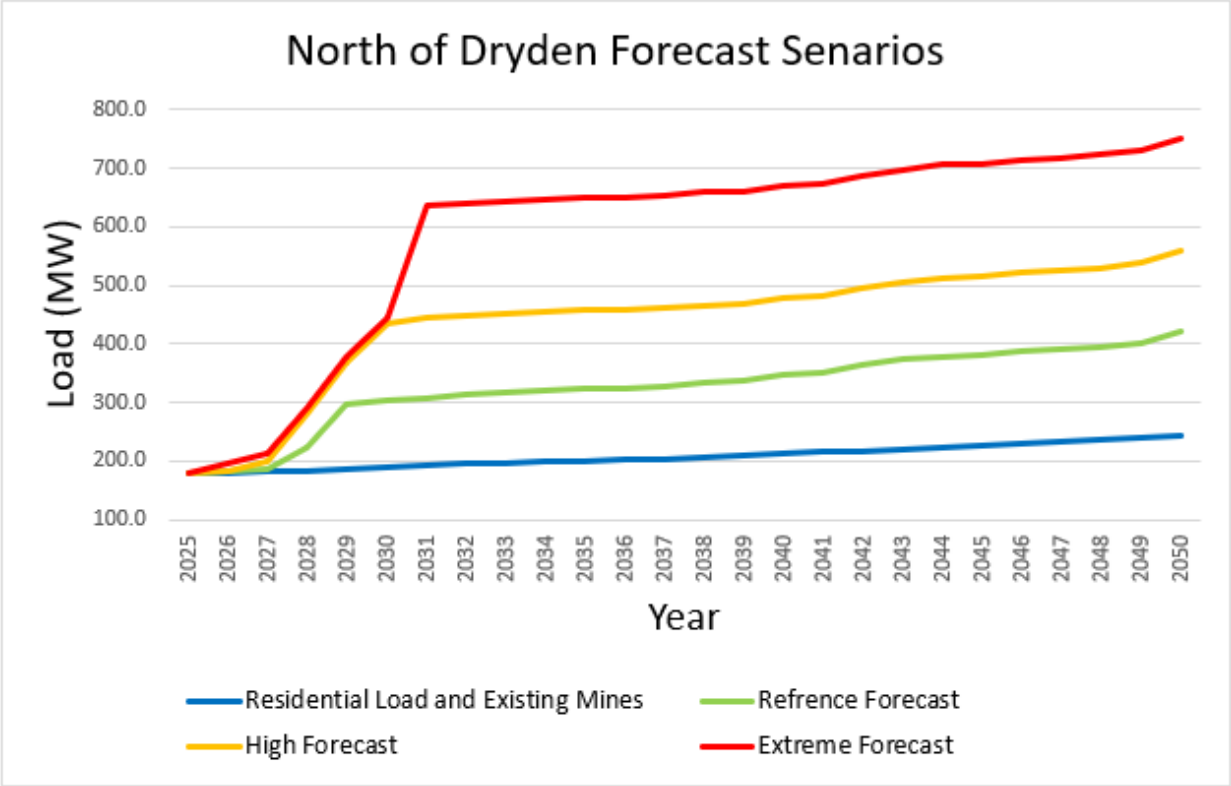
Figure 5.4 | Mining Demand Forecast



5.4 Total North of Dryden Demand Forecast Scenarios

Figure 5.5 presents the total non-coincident demand forecast for the North of Dryden sub-region. The forecast shows a marked increase in demand beginning in 2027, driven primarily by industrial and mining sector growth.

Figure 5.5 | Total North of Dryden Demand Forecast



5.5 Demand Profile – Red Lake, Pickle Lake, and Dryden

In addition to annual peak forecasts, hourly demand profiles were developed for the Red Lake, Pickle Lake, and Dryden areas, regions where non-wires alternatives (NWAs) were evaluated. These profiles span 8,760 hours per year and are used over the 25-year forecast horizon to characterize demand at one or more stations with identified needs.

Hourly profiles are developed using a multiple linear regression model based on historical data. The model is applied under various weather and calendar conditions to simulate a range of future hourly demand scenarios. These profiles are then ranked by median energy values, and the median profile is scaled to match the annual peak forecast for each year. This approach supports the evaluation of NWAs by estimating energy requirements and informing technology selection.

It is important to note that these profiles are not intended to deterministically define hourly energy needs for NWAs. Instead, they provide a reasonable approximation of energy requirements for planning purposes, including estimating operating costs and selecting appropriate technologies. As consumer behaviour evolves, new businesses emerge, and electrification trends accelerate, demand patterns may shift significantly. The Technical Working Group will continue to monitor these developments as part of the ongoing planning process.

Details on the demand profiling methodology can be found in Appendix D.1 of the 2023 NW IRRP.

6. Needs

This section outlines the transmission system needs identified for the North of Dryden sub-region. These needs focus on localized supply and reliability concerns in key areas, including Dryden, Red Lake, and Pickle Lake. While the IRRP is primarily concerned with regional infrastructure and reliability, it also considers committed transmission projects identified through bulk system planning such as the Waasigan Transmission Line Project where relevant. Although bulk system needs are outside the scope of the IRRP, this report highlights potential interactions between regional and bulk system developments.

This section is organized as follows:

- **Section 6.1** – Methodology for identifying system needs
- **Section 6.2** – Firm station capacity and local operational needs under the reference forecast
- **Section 6.3** – Potential needs under higher-than-forecast growth scenarios.

6.1 Needs Assessment Methodology

Based on the reference demand forecast (net demand under extreme weather conditions), system capability, transmitter-identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the Working Group identified electricity system needs in the following categories:

- **Station Capacity Needs**
  These arise when forecast demand exceeds the ability of regional step-down transformer stations to deliver power to the local distribution network during peak periods. A station's capacity rating is typically based on the 10-day Limited Time Rating (LTR) of its smallest transformer, assuming the largest transformer is out of service. Capacity may also be constrained by downstream or upstream equipment (e.g., breakers, disconnect switches, low-voltage bus, or transmission circuits) that are undersized relative to the transformer rating.
- **Supply Capacity Needs**
  These refer to the transmission system's ability to continuously supply electricity to a local area at peak demand. Supply capacity is determined by the Load Meeting Capability (LMC), which accounts for transmission element limitations under contingency conditions, as defined by ORTAC and NERC/NPCC standards. LMC studies are conducted using power system simulation tools.
- **End-of-life Asset Refurbishment Needs**
  These are identified by transmitters based on asset age, expected service life, condition, and risk of failure. Near-term and early mid-term replacement needs are typically condition-based, while medium- to long-term needs are often based on expected service life.

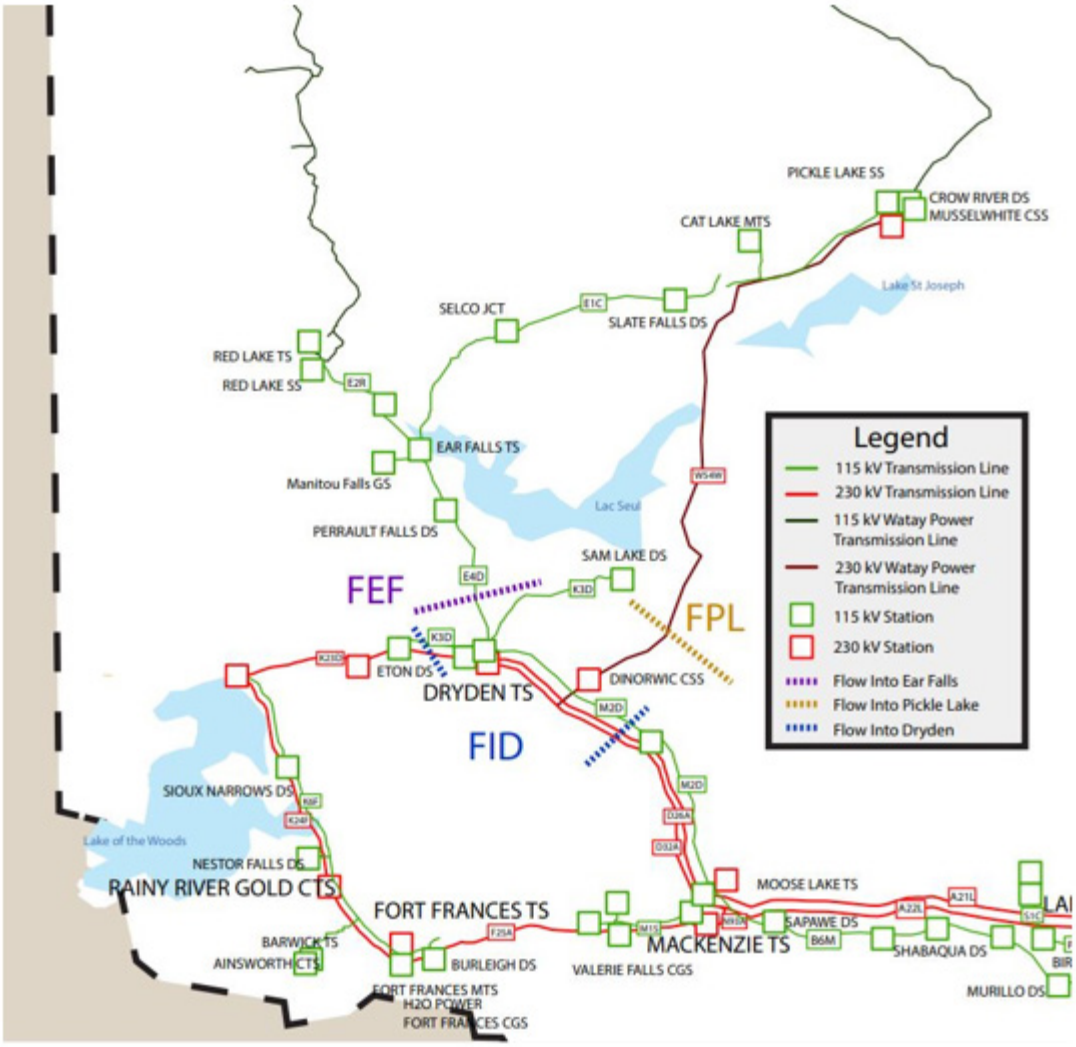
- **Load Security and Restoration Needs**
  These describe the system's ability to minimize the impact of major transmission outages and restore service within reasonable timeframes. Load security refers to the amount of supply interrupted during an outage (e.g., loss of both circuits on a double-circuit tower line), while load restoration refers to the system's ability to recover supply. Requirements are defined in Section 7 of ORTAC.

6.2 Needs Identified

To assess transmission reliability and identify emerging needs in the North of Dryden sub-region, the Study analyzed power flows across key interfaces that define how electricity is delivered into major areas. Specifically, the analysis focused on flows into the Ear Falls, Pickle Lake, and Dryden areas, each representing distinct supply paths. These interfaces form the basis for evaluating system capacity and determining when reinforcements may be required.

The geographic extent of each interface is illustrated in Figure 6.1.

Figure 6.1 | North of Dryden Interfaces



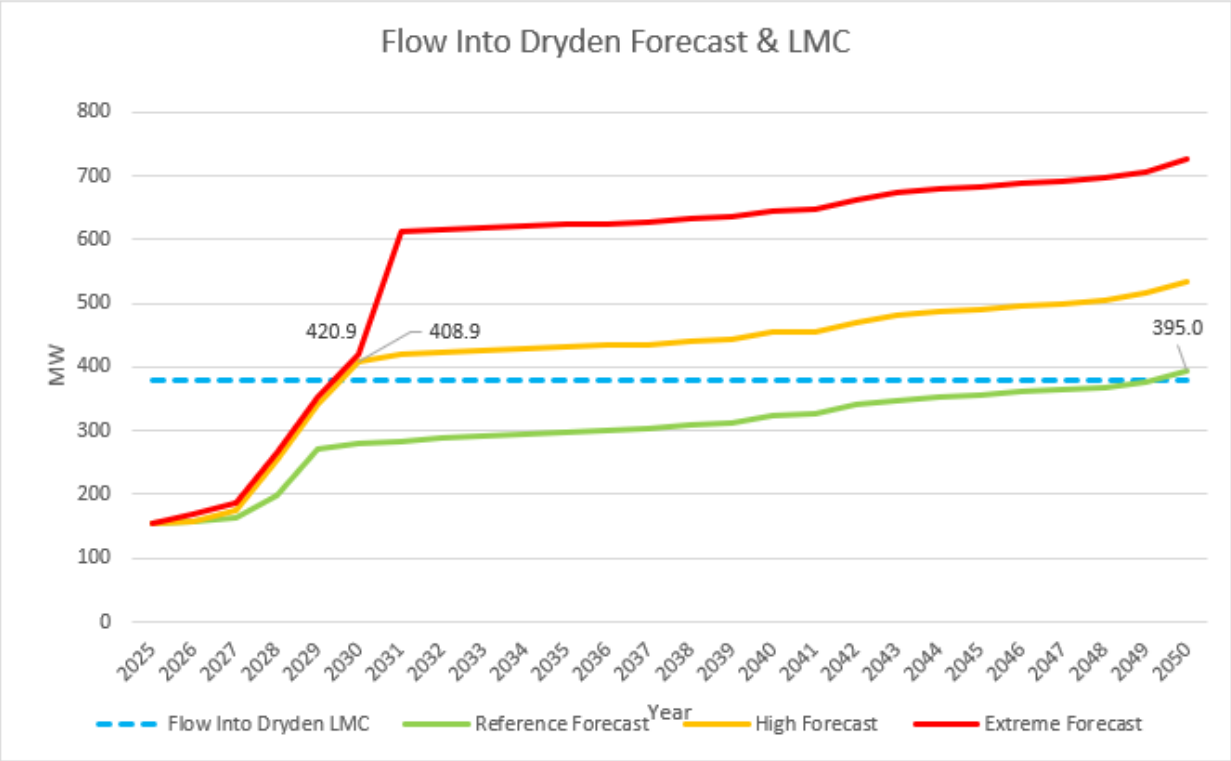
6.2.1 Flow into Dryden

The Flow into Dryden (FID) interface is defined by the transfer of electricity into the Dryden area via:

- 230 kV circuits D26A and D32A from Mackenzie (once Waasigan Phase 2 is in service)
- Circuits K23D and M2D from Kenora and Moose Lake

The LMC of this interface is 380 MW, limited by summer thermal constraints under single-element outage conditions. In the event of a contingency on D32A, the remaining D26A circuit reaches its thermal limit when demand north of Dryden exceeds 380 MW. Figure 6.2 shows forecast demand across the FID interface relative to its LMC. Under the Reference scenario, demand remains within limits until approximately 2049, after which exceedances begin to appear. However, under high and extreme growth scenarios, constraints could emerge earlier, highlighting the need for continued evaluation. Further analysis will be conducted in the next regional planning cycle for Northwestern Ontario, commencing in 2025.

Figure 6.2 | Flow into Dryden Load Meeting Capability and Forecast Scenarios



6.2.2 Flow into Pickle Lake

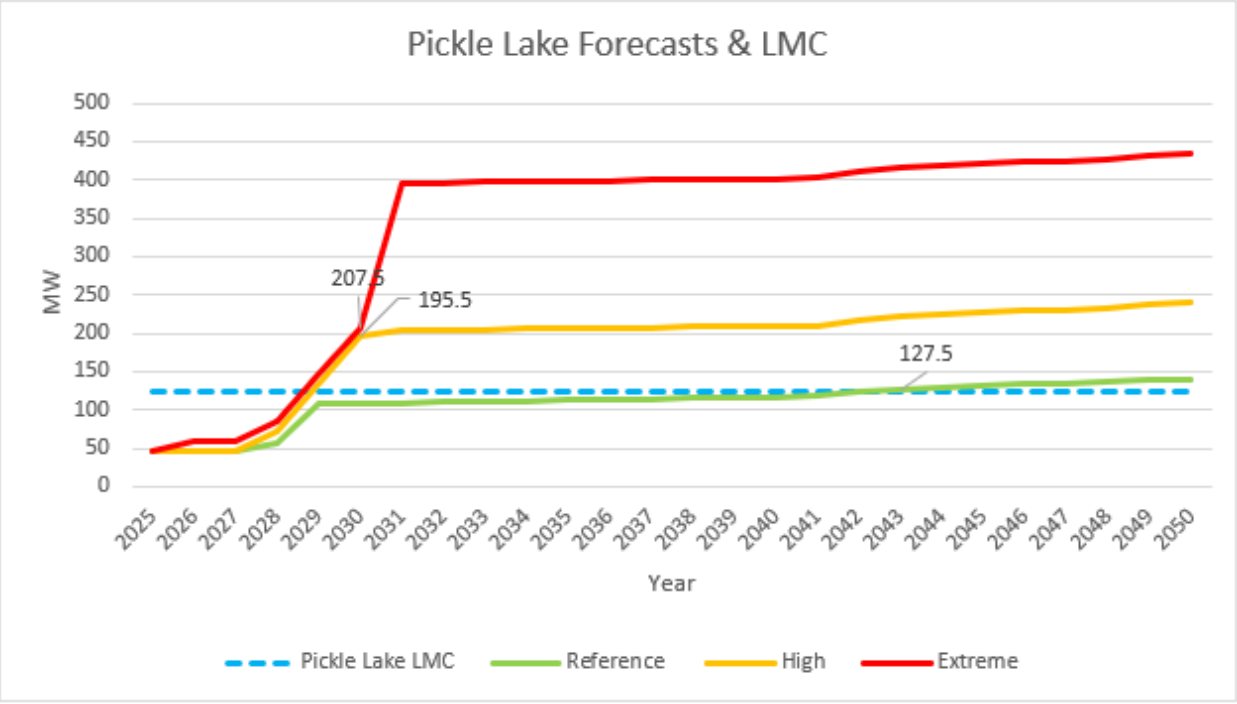
The Flow into Pickle Lake (FPL) interface is defined by the radial supply via circuit W45W, with circuit E1C providing a partial backup path through the Red Lake system. The current load meeting capability (LMC) of the Pickle Lake area is approximately 125 MW, constrained by pre-contingency voltage limits as defined by ORTAC. Voltage sensitivity analysis under the reference load growth scenario indicates that these criteria will be violated at Pickle Lake TS by 2043, limiting the area to supply further demand.

To address this, 40 MVar of capacitive compensation will be required to support future load connections. However, rather than waiting until 2043, the IRRP recommends advancing the installation of a 40 MVar capacitor bank at Pickle Lake TS. This proactive step will not only mitigate the anticipated voltage deficiencies but also deliver near-term benefits by improving operability during outages and supporting load restoration efforts. The region currently faces reliability challenges due to limited remote operational capability and the absence of backup supply, which increases restoration time and complexity. The capacitor bank will help alleviate these issues by enhancing voltage stability and reactive support under contingency conditions.

The capacitor bank addresses the voltage violations in the Pickle Lake area and enables the system to support load levels exceeding 300 MW. However, under N-1 conditions, ORTAC load security criteria limit interruptible load to 150 MW. While the reference scenario remains within this threshold, the high-growth scenario exceeds it by 2030. Load forecasts under reference, high-growth, and extreme-growth scenarios are shown in Figure 6.3. Recommendations in this section are based on the reference scenario.

Looking ahead, the plan recommends that the TWG continue to monitor demand growth and explore reinforcement options for the corridor between Pickle Lake and Red Lake. This would further improve backup supply capability and overall reliability in the region.

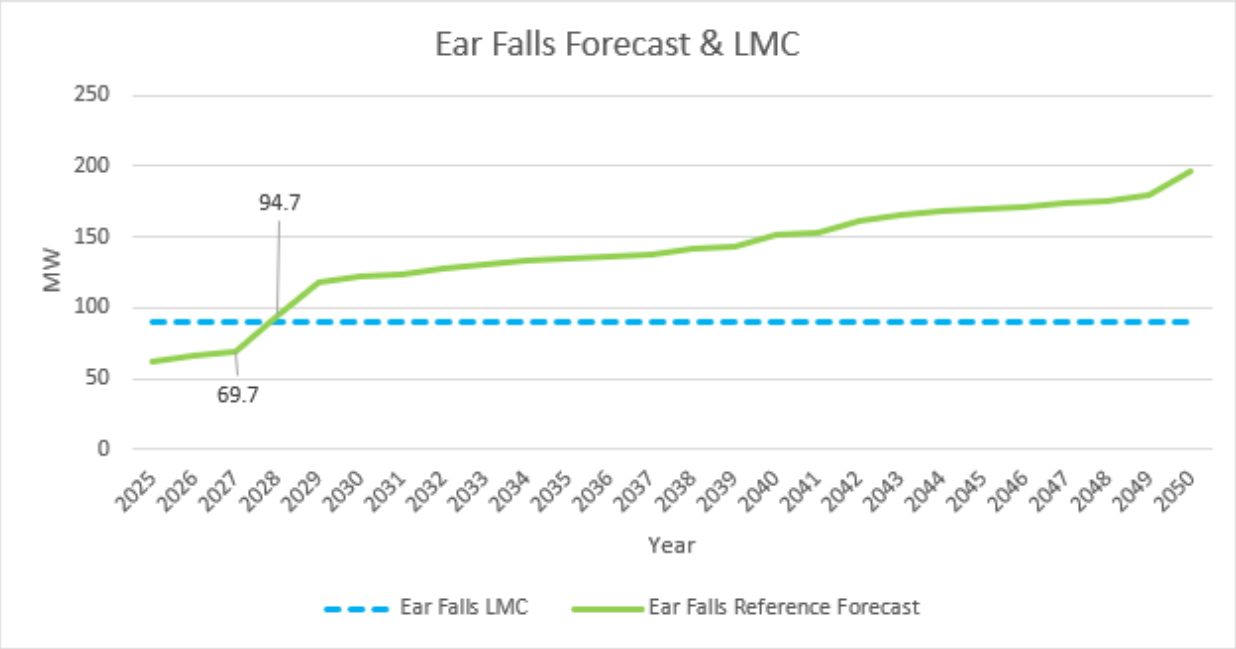
Figure 6.3 | Flow into Pickle Lake Load Meeting Capability and Forecast Scenarios



6.2.3 Flow into Ear Falls

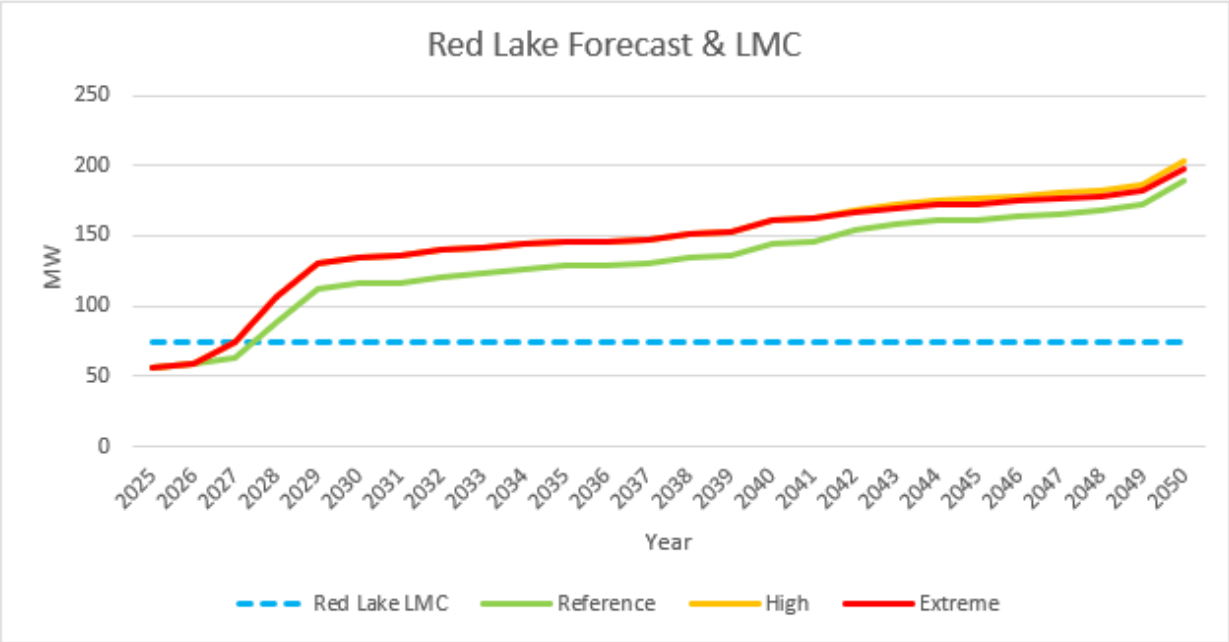
The Flow into Ear Falls (FEF) interface is defined by radial supply via circuit E4D, with circuit E1C offering potential backup. The current LMC for this interface is 90 MW, limited by the summer thermal rating of E4D. Figure 6.4 shows forecasted demand across the FEF interface relative to this threshold. Under the reference forecast, demand exceeds the LMC by 2028.

Figure 6.4 | Flow into Ear Falls Load Meeting Capability and Forecast Scenarios



Within the broader Ear Falls area, the Red Lake subsystem is of particular interest. It is radially supplied via circuit E2R, with a summer LMC of 74 MW based on E2R's continuous thermal rating. Figure 6.5 shows forecasted demand across E2R relative to its thermal capacity. The subsystem is nearing its capacity, with thermal limitations on both E2R and E4D constraining supply under pre-contingency summer conditions.

Figure 6.5 | Red Lake Load Meeting Capability and Forecast Scenarios



In winter, the LMC increases to approximately 93 MW, though it remains limited by both thermal and voltage constraints on E2R. According to System Impact Assessment (SIA) 2022–730, the connection of the 13 MW Great Bear Resources Mine would require additional reactive compensation and would nearly exhaust the available capacity of the Ear Falls–Red Lake corridor. Any further load additions in the Red Lake area would exceed the current system capability and require transmission reinforcements.

System operators have also raised concerns about the lack of operational flexibility between the Pickle Lake and Red Lake subsystems, particularly given rising demand and the diminishing effectiveness of the Patricia Islanding scheme. Hydro One is currently addressing this issue.

Given that the reference forecast exceeds the FEF and Red Lake LMCs by 2028, reinforcement is required not only at the Ear Falls interface but also within the Red Lake supply corridor. While the high and extreme scenarios do not present immediate thermal constraints, they will require additional reactive support to maintain voltage performance under higher loading conditions.

6.2.4 E1C Operation and End-of-Life

The most recent cycle of regional planning identified operational challenges associated with the 115 kV E1C transmission line, which plays a critical role in supporting the Pickle Lake and Interlake area system. Its operational configuration has a significant impact on overall system performance. Two key issues were noted: limited supply capacity when E1C operates in a normally closed state, and high voltage levels under light load conditions when operated in a normally open state.

To maintain system adequacy and meet forecasted demand in the Ear Falls, Red Lake, and Pickle Lake areas, it is necessary to introduce a normally open point at the Ear Falls TS end of E1C. This adjustment would relieve loading on E4D and shift demand in the Pickle Lake area to the newly commissioned 230 kV W54W transmission line. However, operating E1C in an open configuration introduces high voltage concerns during periods of low demand.

As outlined in the 2023 Northwest Regional Infrastructure Plan, the Technical Working Group (TWG) recommended opening E1C at the Ear Falls TS end and installing reactors at Pickle Lake SS to mitigate voltage issues.

Currently, E1C has approximately 30 MW of available supply capacity. However, with potential mining developments in the Interlakes area, this remaining capacity may be insufficient under higher growth scenarios. Additionally, Hydro One has identified E1C as reaching end-of-life, with approximately 70% of pole replacements already completed.

Table 6.1 summarizes the firm transmission needs identified in this Addendum.

Table 6.1 | Summary of Near-Term and Medium- Term Needs

Subsystem	Need	Timing
Red Lake	The Flow into Red Lake LMC is expected to reach capacity in 2028. Voltage deficiencies due to load growth are also expected to occur by 2028. Reliability in this area is low due to inadequate remote load restoration and backup supply.	2028
Pickle Lake	Voltage deficiencies due to load growth are expected to occur by 2043. Reliability in this area is low due to inadequate remote load restoration and backup supply	2043
Ear Falls	E1C is reaching end-of-life and the Hydro One sustainment program is underway to replace the conductor like-for-like	Ongoing

6.3 Long-Term Needs under High Growth Scenario

Electricity demand in the North of Dryden sub-region is primarily driven by the mining sector, which tends to introduce large, incremental blocks of load with short lead times. This can create constraints on the existing transmission system.

To ensure flexibility, high-growth scenarios were studied for the Dryden, Red Lake, and Pickle Lake areas. The goal was to test the robustness and scalability of the transmission solutions developed for the reference scenario. This was achieved by simulating new projects at proposed connection points or nearby transformer stations and applying planning criteria outlined in Section 2.

By quantifying system limitations under high-growth conditions, planners can more effectively monitor demand and initiate timely reinforcements if required. Sensitivity studies show that extensive transmission reinforcement and/or resource procurement will be needed to support forecasted load growth in each area.

Table 6.2 | Summary of Long-Term Needs

Subsystem	Need	Timing
Dryden	The Flow in Dryden LMC is expected to reach capacity in 2049. This need advances significantly under high and extreme growth scenarios and will trigger additional supply capacity needs on the FID interface and additional reactive compensation.	2049
Pickle Lake	The Flow in Pickle Lake LMC is expected to reach capacity in 2042. This need advances significantly under high and extreme growth scenarios and will trigger additional supply capacity needs on the FPL interface and additional reactive compensation.	2042

7. Options Analysis and Recommendations

This section summarizes the transmission and non-wires options evaluated to address electricity system needs in the North of Dryden sub-region. The analysis includes:

- Section 7.1 – Transmission and non-wires options considered for near- to medium-term needs
- Section 7.2 – Comparison of transmission options
- Section 7.3 – Non-wires alternatives analysis.
- Section 7.4 – Recommendation

7.1 Transmission Options

To address the identified electricity needs, three primary transmission options were evaluated, along with a fourth variation involving double-circuiting. These options were informed by Hydro One's technical assessments, IESO planning studies, and feedback from local communities.

7.1.1 Option 1

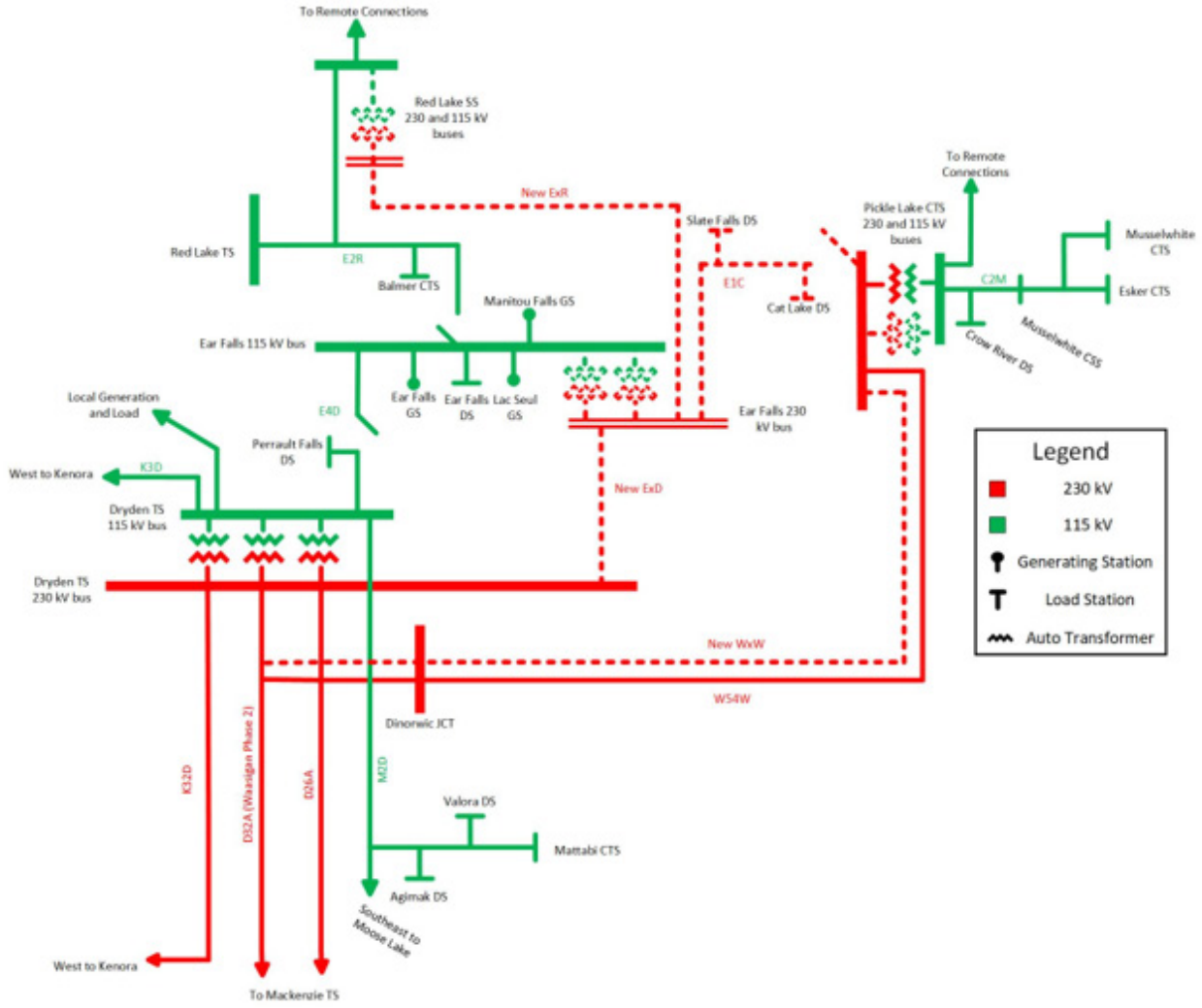
This option includes:

- A new 230 kV transmission line from Dryden to Ear Falls (100 km)
- A new 230 kV transmission line from Ear Falls to Red Lake (62 km)
- A new 230 kV transmission line from Ear Falls to Pickle Lake (260 km)
- A new 230 kV transmission line from Dinorwic Junction to Pickle Lake (302 km)

Supporting infrastructure includes:

- Two 230/115 kV autotransformers at Ear Falls TS
- One 230/115 kV autotransformer at Red Lake SS
- One 230/115 kV autotransformer at Pickle Lake CTS
- Replacement of step-down transformers at Perrault Falls, Slate Falls, and Cat Lake MTS with 230/12.5 or 25 kV units
- A new switching station with a 230 kV ring bus at Dinorwic TS
- Decommissioning of existing 115 kV E1C
- Reactive compensation for voltage support

Figure 7.1 | Transmission Option 1



7.1.2 Option 2

This option includes:

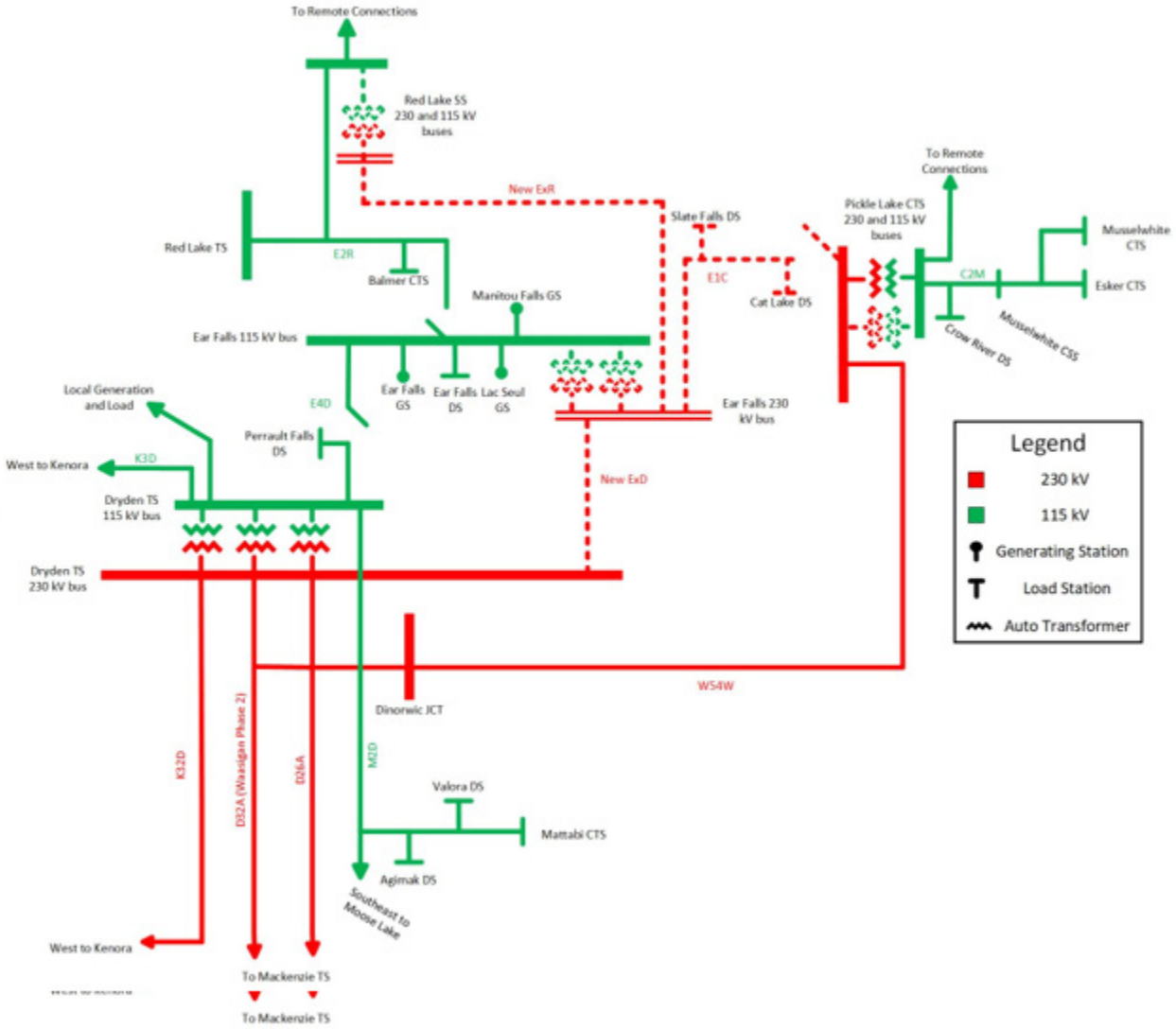
- A new 230 kV transmission line from Dryden to Ear Falls (100 km)
- A new 230 kV transmission line from Ear Falls to Red Lake parallel to E2R (62 km)
- A new 230 kV transmission line from Ear Falls to Pickle Lake (260 km)

Supporting infrastructure includes:

- Two 230/115 kV autotransformers at Ear Falls TS
- One 230/11 kV autotransformer at Red Lake SS
- One 230/115 kV autotransformer at Pickle Lake CTS

- Replacement of step-down transformers at Perrault Falls, Slate Falls, and Cat Lake MTS with 230/12.5 or 25 kV units
- Decommissioning of existing 115 kV E1C
- Reactive compensation for voltage support

Figure 7.2 | Transmission Option 2



7.1.3 Option 3

This option includes:

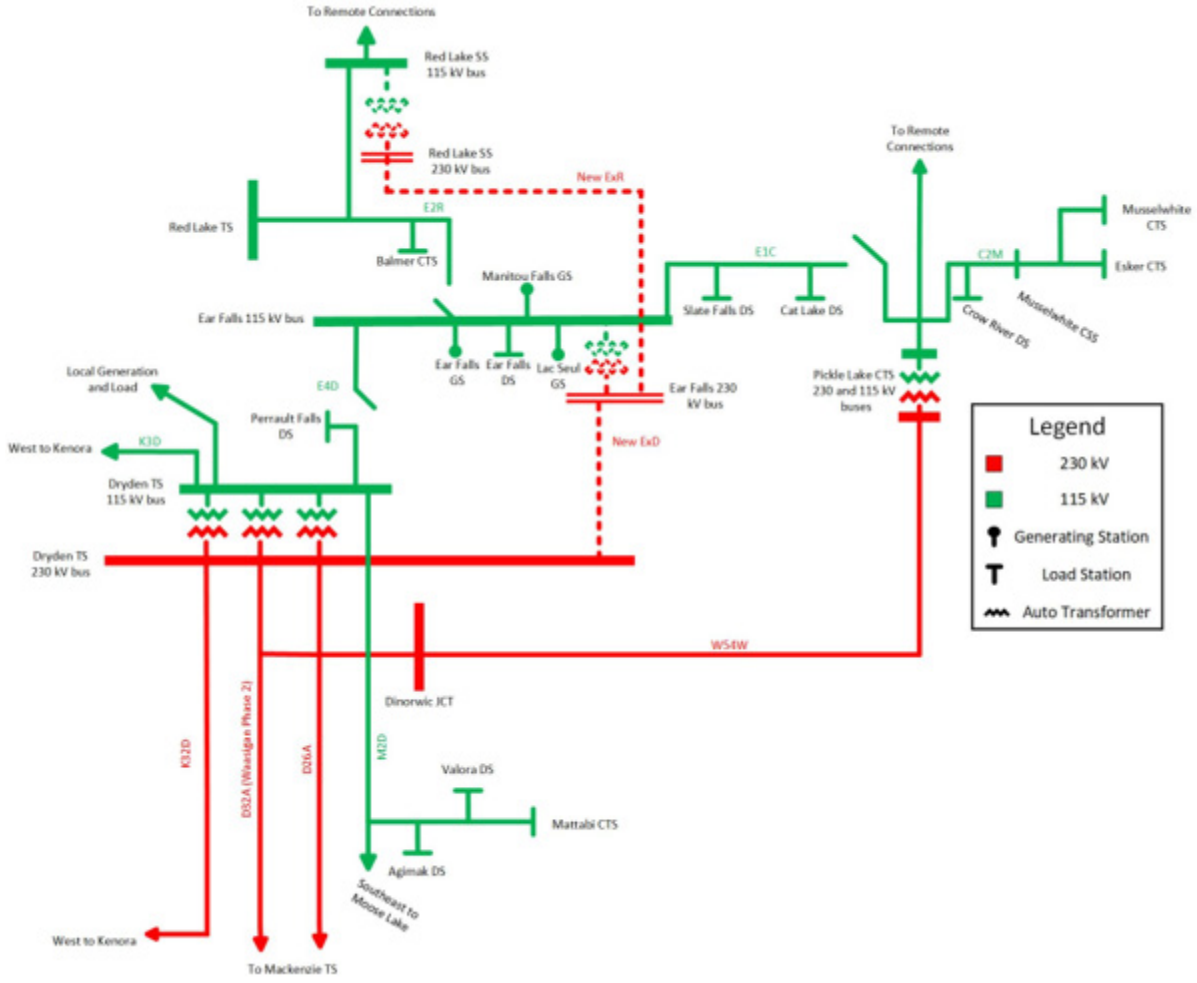
- A new 230 kV transmission line from Dryden to Ear Falls (100 km long)
- A new 230 kV transmission line from Ear Falls to Red Lake (62 km long)

Supporting infrastructure includes:

- One 230/115 kV auto-transformer at Ear Falls TS
- One 230/115 kV auto-transformer at Red Lake SS.
- Reconfiguration of existing 115 kV circuits E4D and E2R to operate normally open
- Reactive compensation for voltage support

A single line diagram of this transmission option can be found in Figure 7.3.

Figure 7.3 | Transmission Option 3



All three options involve a single-circuit supply to Red Lake and Pickle Lake. While the transmission lines can technically supply the demand forecast meeting thermal and voltage criteria, this configuration does not meet ORTAC load security criteria, which limits the amount of interrupted load following a contingency to 150 MW. Load growth beyond this threshold would require exemptions or additional infrastructure. Single-circuit supply also limits system reliability and resiliency, particularly during outages.

7.1.4 Option 3 – Double-circuit

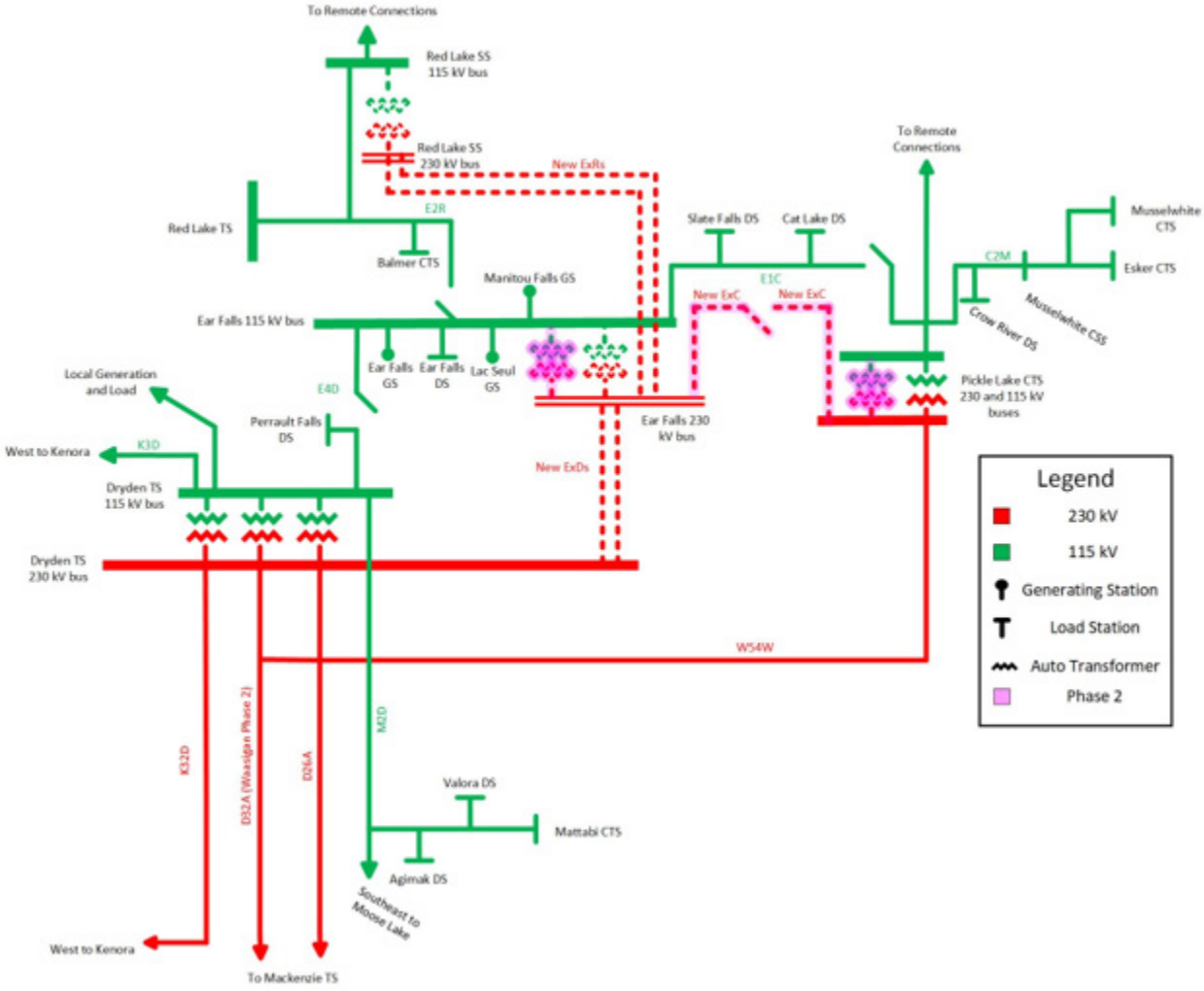
To enhance reliability and resiliency, a variation of Option 3 was studied that involved an upgraded double-circuit 230 kV line Dryden to Red Lake and reinforced supply to Pickle Lake. The following transmission upgrades summarize the scope of work needed for this option:

- A new 230 kV double-circuit transmission line from Dryden to Ear Falls (100 km long)
- A new 230 kV double-circuit transmission line from Ear Falls to Red Lake (62 km long)
- Reconfiguration of existing 115 kV circuits E4D and E2R to operate normally open

Supporting infrastructure includes:

- Two 230/115 kV auto-transformers at Ear Falls TS
- Two 230/115 kV auto-transformers at Red Lake SS
- Reactive compensation for voltage support

Figure 7.4 | Transmission Option 3 Double Circuit



7.2 Options Comparison

Each transmission option was assessed against the applicable planning criteria under all-in service, N-1, and N-1-1 configurations, as detailed in Section 2.

7.2.1 Options Load Meeting Capability Comparison

Table 7.1 | Option Load Meeting Capabilities

Transmission Option	LMC Flow into Dryden (MW)	LMC Flow into Pickle Lake (MW)	LMC Flow into Ear Falls (MW)
Option 1	381	404	150 or 355 (with criteria exemption)
Option 2	381	150 or 307 (with criteria exemption)	150 or 355 (with criteria exemption)
Option 3	381	150 or 307 (with criteria exemption)	150 or 355 (with criteria exemption)
Option 3 (double circuit)	381	150 or 307 (with criteria exemption)	437

Constructing a double-circuit transmission line upfront is generally more cost-effective than staging and building two separate single-circuit lines over time. In addition to the economic advantages, this approach also reduces the overall footprint of transmission infrastructure, minimizing environmental impact and land use. This principle informed the evaluation of Option 3 (Double-Circuit) as a more efficient and sustainable solution.

For Options 1 and 2, the LMCs for Dryden and Ear Falls are identical due to the shared 230 kV upgrade from Dryden to Red Lake. However, achieving these LMCs requires exemptions from ORTAC load security criteria, which limit the maximum amount of interruptible load to 150 MW for the loss of a single element. In contrast, Option 3 (Double Circuit) complies fully with ORTAC without requiring exemptions, offering a more resilient and standards-compliant solution.

The higher LMC for Pickle Lake in Option 1 is due to the inclusion of the new line parallel to the existing 230 kV transmission line W54W from Dinorwic JCT to Pickle Lake TS. This configuration meets all planning criteria without exemptions but comes at a significantly higher cost compared to Option 3 (Double Circuit) with a 230 kV E1C upgrade, as discussed in Section 7.2.2.

Additionally, the 115 kV circuits E4D and E2R (Dryden–Ear Falls and Ear Falls–Red Lake) are approaching end-of-life within the next 20 years. The IESO has studied these circuits as potential backup supply paths. Preliminary analysis suggests that uprating these circuits may be economically viable to enhance backup capability. The IESO will continue to monitor load growth in the Red Lake and Ear Falls areas to determine appropriate replacement strategies, which will be further explored in the next regional planning cycle beginning in Q3 2025.

7.2.2 Options Cost Comparison

Table 7.2 summarizes the cost of the three options, including the cost of double-circuit configuration for Option 3.

Table 7.2 | Option Cost Comparison

Transmission Option	Estimated Capital Cost ($M)	New Circuit kms	Meets Red Lake area Reference Load Need Until	Meets Red Lake area High Load Growth Need Until
Option 1	2,490	724	2040	2034
Option 2	1,560	422	2040	2034
Option 3	720	262	2040	2034
Option 3-dbl	830	424	2050 and beyond	2050 and beyond

7.2.3 E1C upgrade and new customer connection point

As discussed in Section 6.2.4, circuit E1C is undergoing end-of-life replacement. It is recommended that Hydro One replace the conductor with a 411 kcmil conductor or better, which has a continuous rating of100 MVA. This upgrade will increase supply capacity and enable a proposed industrial customer to connect to E1C instead of their previously proposed location. This connection would be approximately 90 km shorter, resulting in a $150–$200 million reduction in transmission costs for the project. To support this connection, an additional 55 MVar shunt capacitor will be required at the new E1C connection point.

Following the customer connection, E1C should be operated normally open at Pickle Lake, consistent with recommendations in the 2023 Northwest IRRP. The upgraded conductor will also enhance E1C's ability to back up at least 50 MW of additional load in both Pickle Lake and Red Lake during contingencies, which provides system benefit.

To further improve reliability in the Pickle Lake and Red Lake areas, especially under high-growth scenarios, it may be necessary to reinforce the connection between these areas via the existing E1C corridor or by constructing a new 230 kV line parallel to the Wataynikaneyap W54W line. If E1C is upgraded to 230 kV, it could serve as a parallel supply path to Pickle Lake, complementing the Option 3 (Double-Circuit) transmission line from Dryden to Red Lake.

This configuration would allow the entire Pickle Lake area load to be backed up during outages. Additional reactive support (capacitive compensation) will be required at Pickle Lake TS, Ear Falls TS, and downstream corridors to enable full backup capability.

7.2.4 Transmission Options Conclusion

For the remainder of the analysis, Options 1, 2, and 3 were no longer considered, as they do not meet the demand in the long term, making them less resilient and cost-effective compared to Option 3 (Double Circuit), which meets all criteria and supports long-term growth through 2050 and beyond.

7.3 Non-Wires Alternatives (NWA)

In addition to evaluating transmission solutions for the North of Dryden sub-region, non-wires alternatives (NWAs) were also considered. The assessment focused on three sub-systems: Red Lake, Pickle Lake, and Dryden.

In the Red Lake area, forecasted load growth is expected to exceed the region's Load Meeting Capability (LMC) of 74 MW, creating a significant supply gap. While new Electricity Demand Side Management (eDSM) measures have been considered, their impact is relatively modest and provides only 5 MW of capacity savings by 2050. This limited contribution highlights the challenge of addressing the area's growing energy needs through demand-side solutions alone. As a result, there remains a substantial net requirement of 127 MW (755,995 MWh) by 2050, much of which is driven by expanding mining activity. Mining loads typically have a flat demand profile, requiring consistent supply across all hours and seasons, with peak demand occurring during winter months.

Various resource options were considered to create a range of NWA costs for North of Dryden. The following NWA economic assessments were studied:

1. Natural gas
2. Biomass
3. Solar + Wind + BESS
4. Wind +BESS
5. Solar + BESS

Although the NWA options 4 and 5 were studied, not every load requirement of every hour (8760 hourly needs) would be served. As a result, these two options were ruled out from the NWA analysis.

Some assumptions were also made during the economic assessment which include:

- Various emitting and non-emitting resource options were considered creating a range of costs for Non-Wire Alternative's (NWA's).

- Emitting resources considered included Combine Cycle Gas Turbine (CCGT) and Biomass facilities, with overnight capital costs, fixed operating and maintenance (FOM), biomass fuel and variable operating and maintenance (VOM) sourced from 2024 Annual Technology Baseline (ATB) data by The National Renewable Energy Laboratory (NREL).
- Natural gas fuel costs and carbon costs assumptions from 2025 Annual Planning Outlook (APO).
- NWA emitting and non-emitting levelized costs are based on 2024 ATB data from NREL whereby the values are converted to Canadian (CAD) 2025$.
- System benefits based on the 2025 APO Capital Expansion (CapEx) portfolio https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/APO-2025-Marginal-Energy-Costs-and-Capacity-Costs.xlsx
- All dollar figures are $2025 Real, the inflation rate is assumed to be 2% per year, and the social discount rate is 4% Real.
- Net present value (NPV) is considered from 2026 to 2102, with the transmission option commencing in 2033 for 70 yrs and the NWA aligning with this transmission timeline. The transmission costs consist of the Red Lake portion of the transmission options.

Further details on assumptions made for NWA can be found in Appendix D.

Table 7.3 presents a comparative economic analysis of various supply options for meeting future electricity needs in the Red Lake area. It includes both transmission and non-wires alternatives (NWAs), evaluating each option across several key dimensions: total utility cost, system benefit, net impact to ratepayers, land requirements, and the percentage of need and load served.

A key metric in this analysis is System Benefit, which refers to the option's contribution to Ontario's overall resource adequacy and energy requirements. In other words, it reflects how much the resource helps meet provincial-level electricity demand not just local needs. This is particularly important when considering NWAs, as some options may offer broader system value beyond the immediate region.

Table 7.3 | Economic Assessment for Wires and Non-Wires Alternatives

Options	Total Cost (Utility)	System Benefits	Net Benefit/Cost to Ratepayer	Land Requirement	% of Need Served	% of Load Served
Transmission Option 3	$647 M	$0 M	-$647 M	~500–1000 hectares/5–10 km^2	100.0%	100.0%
Natural Gas	$1,378 M	$1,378 M	$0 M	~20–40 hectares/0.2 - 0.4 km^2	100.0%	100.0%
Biomass	$2,755 M	$1,585 M	-$1,170 M	~20–40 hectares/0.2 - 0.4 km^2	100.0%	100.0%
Solar + Wind + BESS	$3,295 M	$2,923 M	-$372 M	~6,572 hectares/65.7 km^2	99.2%	99.7%
Wind + BESS	$11,118 M	$10,092 M	-$1,026 M	~48,895 hectares/ 489 km^2	99.0%	99.6%
Solar + BESS	$6,035 M	$5,193 M	- $842 M	~4,344 hectares/ 43.4 km^2	97.6%	98.9%

Note: All values are Net Present Values (NPVs), from 2026 to 2102, at a 4% social discount rate, in $2025 CAD.

Based on Table 7.3, transmission option 3 (as a single circuit) has the least transmission cost to ratepayers ($647 M). However, natural gas net cost has the least cost option for the Red Lake area of $0 M based on the 2024 National Renewable Energy Laboratory's (NREL) cost for a Combine Cycle Gas Turbine (CCGT) facility. Due to the later introduction of Option 3 built as a double circuit, a full economic assessment was not completed. However, it would be expected to have higher costs (of approximately 25%) than the single circuit option with a similar distribution of costs to benefits (i.e., no system benefits). Natural gas overnight capital cost from NREL is likely understated as these costs do not capture incremental costs associated with locating in the northwest region of Ontario. In addition, the natural gas supply needs for a 127 MW gas plant may not be feasible, since Red Lake is supplied by a gas distribution lateral off the TransCanada Energy Mainline. Further analysis is required to assess the true feasibility of implementing this option. In contrast, the biomass option has the highest cost to ratepayers in comparison to all the listed options, with a net benefit of $1.2 B.

Within the non-emitting NWA options, Wind + Solar + BESS has the least net benefit cost of $372 M, which is a lower net cost relative to the transmission option 3 of $647 M. This option would require about 65.7km^2 of land, which would need to be discussed with the local area community to assess for siting feasibility and acceptance. The options Wind + BESS and Solar + BESS are also provided to illustrate the possible land requirement range. Nonetheless, these options will not be able to meet 100% of the hours of the sub-region, which is an important factor to consider.

Overall, when evaluating non-wires alternatives, a natural gas generator presents comparable initial utility costs to those of transmission option 3. While the generator may offer certain system benefits, it also raises several significant concerns that make the transmission alternative a more attractive and viable recommendation. Key issues include the challenges of load restoration during generator outages, unserved load risks, and the absence of interconnection for backup supply between the Pickle Lake and Red Lake area. Further uncertainty exists regarding the exact location of the proposed plant, construction risks, the alignment of pipeline infrastructure, and the level of community acceptance. Additionally, reliance on a gas plant would not resolve the broader transmission limitations, as it only addresses the needs of the Red Lake area under the reference scenario. In the high-demand scenario, a generator of the size considered in this study would be insufficient to meet the projected capacity requirements. Finally, reliance on natural gas generation to meet demand, on a continuous basis, would not be compliant with the Clean Electricity Regulations (CER) enacted under the Canadian Environmental Protection Act. These regulations establish a performance standard of 30 tonnes of CO2 emissions per gigawatt-hour (T/GWh). Should additional needs arise in both the Pickle Lake and Red Lake areas, further reinforcement, either through transmission expansion or an additional generation facility in the Pickle Lake area, would be necessary. Although both options have strong stakeholder support, the transmission alternative remains the more favourable option due to these unresolved concerns associated with the natural gas option.

7.4 Recommendation

The transmission options were evaluated based on several key metrics, including:

- Cost to ratepayers
- Ability to serve forecasted load
- Compatibility with existing infrastructure
- Potential for future expansion
- System reliability and resilience

Option 3, when built as a single-circuit transmission line, is capable of meeting the reference load forecast up to the medium term. However, under this configuration, nearly all load in the Red Lake and Ear Falls areas would be radially supplied via a single circuit. In the event of a contingency, this load would be interrupted, and while circuit E4D could provide backup, it is insufficient to restore full supply. Over the long-term, this configuration violates ORTAC load security criteria, which limits the amount of interrupted load following a contingency to 150 MW.

Recommended Solution: Option 3 – Double-Circuit

To address these concerns, the IRRP recommends Option 3 built to a double-circuit transmission line, consisting of the following elements:

- Construct a double-circuit 230 kV transmission line from Dryden TS to Ear Falls TS (100 km)
- Construct a double-circuit 230 kV transmission line from Ear Falls TS to Red Lake SS (62 km)
- Install two new 230/115 kV autotransformer at Ear Falls TS
- Install two new 230/115 kV autotransformer at Red Lake SS
- Reconfigure existing 115 kV circuits E4D and E2R to operate normally open
- Install 40 MVar shunt capacitors at:
- Red Lake SS
- Ear Falls TS
- 230 kV side of Pickle Lake TS

The proposed 230 kV transmission line does not align well with the Transmitter Selection Framework (TSF) due to the urgent need to increase supply capacity in the Red Lake area. The TSF best suits projects with longer lead times (≥ 6 years) to accommodate a competitive procurement process. Given the time-sensitive nature of this project, proceeding outside the TSF would better support timely delivery, system reliability and support economic development.

Benefits of the Recommended Option

This option:

- Meets regional electricity needs through 2050 and beyond, under reference, high, and extreme demand scenarios
- Improves reliability and reduces load interruptions in the North of Dryden sub-region
- Supports connection of new resources, including hydroelectric, biomass, and other generation, by reducing connection costs and enabling power transfer to the broader grid
- Enhances system robustness and resilience, while remaining compliant with planning criteria
- Reduces long-term costs, as the incremental cost of building a double-circuit line is significantly lower than constructing a parallel single-circuit line later
- Leverages existing rights-of-way, where feasible, to minimize environmental and land-use impacts.

Considering the construction challenges in Northern Ontario and the incremental cost advantages, the double-circuit configuration provides enhanced reliability for municipalities, remote communities, and industrial customers. It also prepares the transmission system for future expansion to accommodate high and extreme load growth in the Pickle Lake area.

8. Community and Stakeholder Engagement

Engagement is critical in the development of an Addendum. Providing opportunities for input in the regional planning process ensures that the views and perspectives of Indigenous communities, municipalities, stakeholders, communities, market participants, customers, and the general public, are considered in the development of the Plan, helping to lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the North of Dryden Addendum.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework and the Indigenous Engagement Framework are built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 8.1 | IESO'S Engagement Principles



The IESO's engagement principles[11] help to ensure that all interested parties are aware of and can contribute to the development of this Plan. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

8.2 Engagement Approach

To ensure that the Plan reflects the needs of Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, engagement involved:

- Leveraging the North of Dryden engagement webpage to post updated information, engagement opportunities, meeting materials, input received and the IESO responses to feedback,
- Holding targeted discussions with municipalities, associations and mining industry to help inform the engagement approach for this planning cycle and to understand feedback and perspectives at key milestones,
- Hosting a series of public webinars at major junctions in the Plan's development to share plan details, understand feedback and answer questions
- Carrying out communications and other engagement tactics to enable broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement for the North of Dryden Addendum included:

- A dedicated webpage[12] on the IESO website to post all webinar materials, feedback received and IESO responses to the feedback throughout the engagement process,
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin,
- Hosting public webinars at major milestones in the plan development to share plan details, understand feedback, and answer questions,
- Targeted one-on-one outreach with Indigenous communities, municipalities, and stakeholders to ensure that their identified needs are addressed.

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, leveraging existing relationships built through the previous planning cycle. This started with an email to impacted municipalities, Indigenous communities, industry stakeholders, and municipal associations to announce the commencement of the development of an Addendum to the 2023 Northwest Integrated Regional Resource Plan.

[11] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

[12] https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-North-of-Dryden-Sub-Region

An invitation was sent to targeted municipalities to discuss the draft demand forecast and electricity needs in the region. A virtual meeting was held early in the process and feedback was received, which centered on the need to ensure that municipal energy planning, economic development and industrial growth (mining) were included in the development of the Addendums demand forecast. In addition, reliability remained a paramount concern within this region. The IESO had further engagement with the Northwest Energy Task Force (NW-ETF) to help further inform the Addendum demand forecast.

A second in-person meeting was held with elected officials and municipal staff from impacted municipalities to provide an update on the progress of the Addendum. During the meeting, the IESO shared the demand forecast, electricity needs, and preliminary options screening results.

The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the Northwest planning region as well as all identified municipalities and Indigenous communities to ensure that all interested parties were made aware of this opportunity for input.

A third virtual meeting was held with elected officials and municipal staff from impacted municipalities, as well as the NW-ETF, to provide an update on the options evaluation and draft recommendations and seek feedback. Municipalities and the NW-ETF were supportive of the draft recommendations for the Addendum and what the Plan means for the growth in their communities and economic development. NW-ETF noted how pleased they were with how collaborative the regional plan was. The Municipality of Red Lake and the NW-ETF shared concerns that long lead times for transmission infrastructure may not align with the timing of planned industrial projects.

Two public webinars were held at key stages during the Plan's development to give interested parties an opportunity to hear about progress and provide feedback to each component of the Plan. The first public webinar was held on May 7, 2025 to share the draft demand forecasts, needs, and options screening. The webinar, attended by a cross-representation of community representatives, municipalities, associations, businesses, and other stakeholders, and written feedback was collected over an approximately two-week comment period after the webinar, also sought feedback from interested stakeholders and community representatives.

A second public webinar was held on July 30, 2025 to share the options analysis and draft recommendations, and sought feedback from interested stakeholders and community representatives. The webinar was attended by a cross-representation of community representatives, municipalities, associations, businesses, and other stakeholders, and written feedback was collected over an approximately two-week comment period after the webinar.

The public webinars invited input on:

1. The electricity demand forecasts, the electricity needs for the region and potential options to meet the identified needs.
2. The analysis of options and draft Addendum recommendations.

Comments received during this engagement focused on the following major themes:

- Cost allocation methodology for new transmission infrastructure.
- Consideration of local developments, growth plans and reliability concerns in demand forecasts particularly in communities with limited capacity.
- Consideration of non-wire alternatives to meet needs, as well as existing resources in the region where contracts are due to expire.
- Concern about long lead times for transmission infrastructure and the resulting impacts on planned industrial project timelines, along with feedback that the Addendum should address interim needs as new transmission is developed.
- General support for the draft Option 3 Double Circuit recommendation.
- Request that government declare Addendum recommendation a priority project to expediate the new transmission line.

Each engagement session received strong participation and interest with a cross-representation from stakeholders and community representatives. Feedback received as a result of each engagement meeting and webinar was considered throughout the development of each milestone of the Addendum.

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities, in addition to webpage updates. All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's North of Dryden Addendum engagement webpage.

Discussions during the Addendum engagement showed strong interest in further exploring the potential development of the mining sector, opportunities to unlock regional economic growth, and alternative energy solutions to meet local needs—particularly as communities and industries face capacity constraints or transition toward electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts, including an upcoming Northwest Integrated Regional Resource Plan.

8.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this Addendum. At major milestones in the Addendum process, meetings were held with targeted municipalities in the region to discuss key issues of concern, including forecasts, regional electricity needs, options for meeting the region's future needs, reliability concerns, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this Addendum process.

Throughout these discussions valuable feedback was received concerning anticipated growth in the mining industry and local communities, including:

- Municipality of Red Lake is preparing a Red Lake Gap Analysis Study that could be used as an input to better understand the residential and commercial growth expected in the next 3–5 years, due to enhanced transportation infrastructure that would connect neighboring communities.
- Northwest Energy Task Force shared their demand forecast for the region to be used as an input into the finalization of the Addendums demand forecast.
- Advocacy that more electricity infrastructure was needed in the Northwestern region to support current and future residential and industrial growth.

These insights have been invaluable to the IESO, as they support an understanding of local growth and accurate electricity demand forecast scenarios, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

8.5 Engaging with Indigenous Communities

The IESO remains committed to ongoing, effective dialogue with Indigenous communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities to provide input, the IESO invited Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use to participate in webinars that were held on:

- Addendum Letter of Commencement November 29, 2024
- May 7, 2025
- July 30, 2025

The following First Nations communities were invited to the webinars:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Asubpeeschoseewagong First Nation
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biigtigong Nishnaabeg
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort Severn
- Gakijiwanong Anishinaabe Nation
- Ginoogaming First Nation
- Gull Bay First Nation
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Koocheching First Nation
- Lac des Mille Lacs
- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Missanabie Cree
- Muskrat Dam Lake
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- Niisaachewan Anishinaabe Nation
- North Caribou Lake
- North Spirit Lake

- Northwest Angle No. 33
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Pays Plat
- Pikangikum
- Poplar Hill
- Rainy River
- Sachigo Lake
- Sandy Lake
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Weenusk
- Whitesand
- Whitewater Lake
- Wunnumin Lake

The following Tribal Councils and Provincial Territorial Organizations (PTOs) were invited to the webinars:

- Anishinabek Nation, Union of Ontario Indians
- Chiefs of Ontario
- Grand Council Treaty #3
- Independent First Nations Alliance (IFNA)
- Keewaytinook Okimakanak/Northern Chiefs Council
- Matawa First Nations Management
- Matawa First Nations Tribal Council
- Nishnawbe Aski Nation
- Shibogama First Nations Council
- Windigo First Nations Council

The following Métis communities were invited to the webinars:

- Métis Nation of Ontario
- Red Sky Independent Métis Nation

The IESO also had one-on-one meetings with Indigenous communities for opportunities to provide input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this Addendum.

Feedback on IESO engagement efforts from Indigenous communities included:

- Support for the construction of a new 230kV line from Dryden to Red Lake, as the recommended option due to risks that First Nation communities north and south of Red Lake will face development restrictions in a time when new housing, community infrastructure, and services are badly needed.
- Projects will require the consent and meaningful participation of First Nations to move forward with construction. Hydro One is best positioned to develop the Project and has committed to meaningful First Nations participation under its "First Nation Equity Partnership Model."
- Land rights and ownership need to be respected and Manito Aki Inaakonigewin (MAI), the "Great Earth Law," needs to be followed and adhered to for all proposed activities and projects occurring in Treaty #3. The options did not show the potential negative environmental footprint on the land itself. The environmental impacts need to be discussed and addressed prior to new transmission going ahead.

8.5.1 Information about Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective options after it has engaged with stakeholders and Indigenous communities and publishes recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement the recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report.

In instances where transmission is the recommended option, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then apply to the OEB for approval through a Leave to Construct hearing and, only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

9. Conclusion

The Northwest IRRP Addendum identifies electricity system needs in the North of Dryden sub-region over a 25-year planning horizon from 2025 to 2050. It examines near-, medium-, and long-term requirements.

Based on the analysis, the IESO recommends the development of Transmission Option 3, constructed to a double-circuit standard with appropriate reactive support. This solution balances cost-effectiveness with reliability and scalability, ensuring the system can adapt to future growth.

The Study also recommends that the Working Group continue to monitor demand growth, particularly in the Pickle Lake areas, and triggering planning for further reinforcements from Ear Falls towards Pickle Lake as load materializes under high-growth scenarios. Sensitivity analyses conducted in this Addendum have established load meeting capability thresholds that should be used to trigger future regional planning activities.

The IESO will continue to plan for high-growth scenarios in the next cycle of regional planning for Northwest Ontario, which commenced in Q3 2025. This upcoming cycle will explore transmission options aligned with ongoing bulk system studies and assess the feasibility of non-wires alternatives.

The Working Group will meet regularly to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, the plan may be revisited through an amendment or by initiating a new regional planning cycle ahead of the standard five-year schedule mandated by the Ontario Energy Board (OEB).

Appendix A – 2023 Northwest IRRP

This Addendum is built on the 2023 Northwest Integrated Regional Resource Plan ("2023 NW IRRP"). The 2023 NW IRRP, Appendices, and Data Tables can be found on IESO's Northwest regional planning engagement website.

Appendix B – Additional Figures

B.1 Single Line Diagrams

Figure B.1 | Option 1

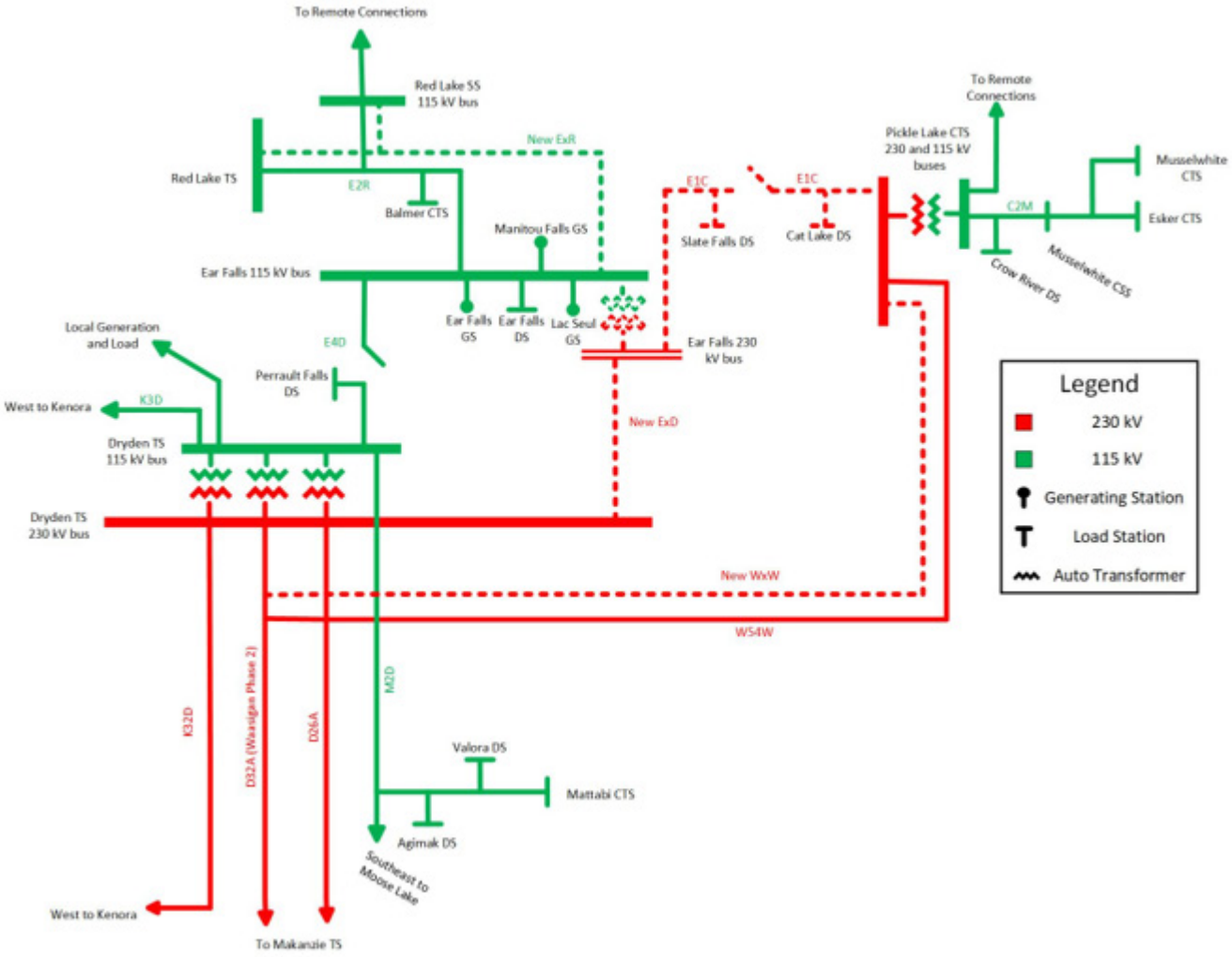


Figure B.2 | Option 2

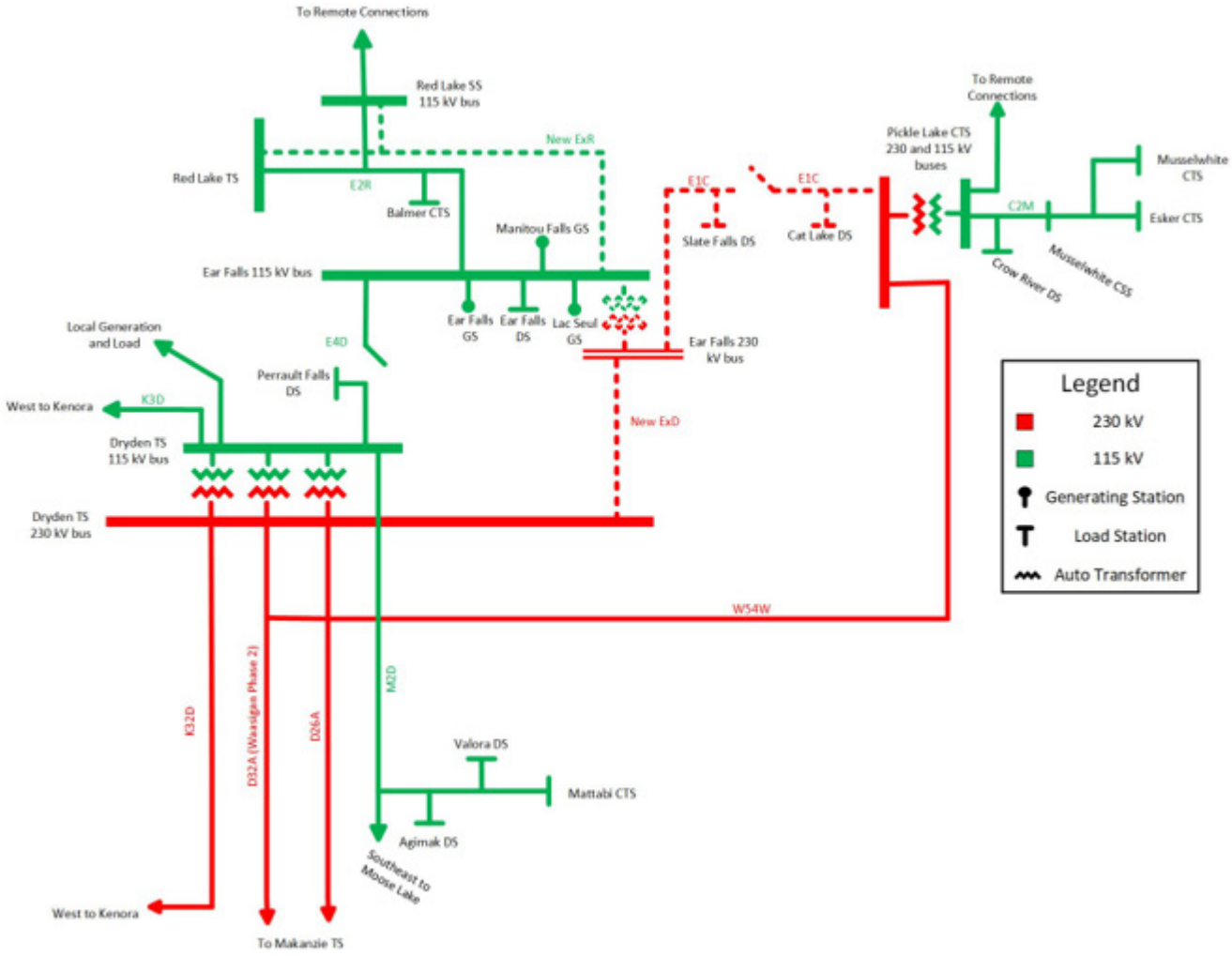
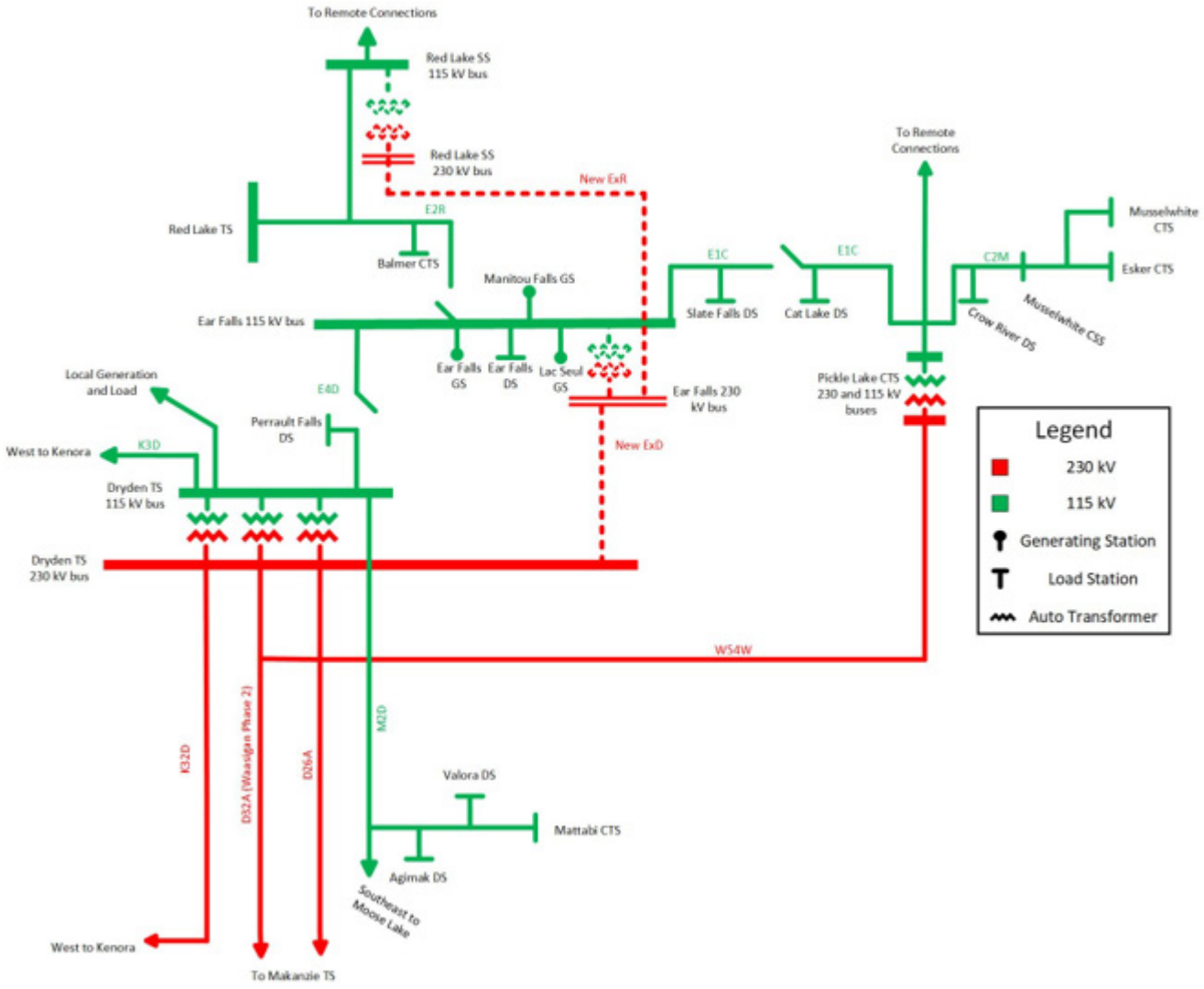


Figure B.3 | Option 3



Appendix C – Options Reactive Support Requirements

It should be noted that these reactive support requirements are in addition to reactive support recommended at the connection point of certain industrial customers. In particular the 60 MW customer that is connecting in the interlakes area will require 55 Mvar of reactive support, and the 23 MW customer connecting in the Watay Power operated Red Lake area will require 10 Mvar of reactive support. This support is needed to maintain transfer capability in these regions, as large industrial loads can negatively affect voltages, particularly in weaker parts of the system.

C.1 Option 1

The reactive support requirements for option 1 for the reference load case are as follows:

- 40 Mvar @ 220kV capacitor at Red Lake SS
- 40 Mvar @ 220kV capacitor at Ear Falls TS
- 40 Mvar @ 220kV capacitor at Pickle Lake TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar of support to respect voltage change criteria.

The reactive support requirements for option 1 for the high load case are as follows:

- 40 Mvar at Ear Falls TS
- 40 Mvar at Dinorwic CSS
- 100 Mvar at Pickle Lake TS 230 kV
- 200 Mvar at Wawa TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar and STATCOMS with over 100 Mvar of reactive support to respect voltage change criteria.

C.2 Option 2

The reactive support requirements for option 2 for the reference load case are as follows:

- 40 Mvar at Red Lake SS
- 40 Mvar at Ear Falls TS
- 40 Mvar at Pickle Lake TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar of support to respect voltage change criteria.

The reactive support requirements for option 2 for the high load case are as follows:

- 40 Mvar at Ear Falls TS
- 40 Mvar at Dinorwic CSS
- 100 Mvar at Pickle Lake TS 230 kV
- 200 Mvar at Wawa TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar and STATCOMS with over 100 Mvar of reactive support to respect voltage change criteria.

C.3 Option 3

The reactive support requirements for option 3 for the reference load case are as follows:

- 40 Mvar at Red Lake SS
- 40 Mvar at Ear Falls TS
- 40 Mvar at Pickle Lake TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar of support to respect voltage change criteria.

The reactive support requirements for option 3 for the high load case are as follows:

- 40 Mvar at Ear Falls TS
- 100 Mvar at Dinorwic CSS
- 100 Mvar at Pickle Lake TS 230 kV
- 200 Mvar at Wawa TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar and STATCOMS with over 100 Mvar of reactive support to respect voltage change criteria.

Appendix D – Non-Wires Alternatives Economic Assessment Assumptions

The following assumptions were made for the Non-Wires Alternatives Analysis:

- Various emitting and non-emitting resource options were considered creating a range of costs for Non-Wire Alternatives (NWAs)
- Emitting resources that were considered included: Combine Cycle Gas Turbine (CCGT) and Biomass facilities, overnight capital costs, fixed operating and maintenance (FOM), biomass fuel and variable operating and maintenance (VOM) sourced from 2024 Annual Technology Baseline (ATB) data by the National Renewable Energy Laboratory (NREL).
- Natural gas fuel costs and carbon costs assumptions from 2025 Annual Planning Outlook (APO)
- NWA emitting and non-emitting levelized costs are based on 2024 ATB data from NREL whereby the values are converted to Canadian (CAD) 2025$
- System benefits are based on the 2025 APO Capital Expansion (CapEx) portfolio
- All dollar figures are $2025 CAD Real, the inflation rate is assumed to be 2% per year, and the social discount rate is 4% Real
- Net present value (NPV) is considered from 2026 to 2102, with the Transmission (Tx) option commencing in 2033 for 70 yrs and the NWA aligning with this Tx timeline
- Land Requirements Supplemental Information:
    - Land area of Red Lake is 600 km^2
    - 1 Hectares = 0.01 km^2
    - Wind Land Requirement = 34 Hectares/MW[13]
    - Solar Land Requirement = 3.04 Hectares/MW[14]
    - Battery Land Requirements = 0.65 Hectares/200MWh (or 0.003 Hectares/MWh)[15]
    - Natural Gas Requirements = According to Natural Gas Association, the average natural gas plant requires between 20 and 40 acres of land
    - Biomass facility land requirement is assumed to equal the natural gas land requirement provided above

[13] Source: Land-Use Requirements of Modern Wind Power Plants in the United States (nrel.gov)
[14] Source: https://www.nrel.gov/docs/fy13osti/56290.pdf
[15] Source: Goreway - Battery Energy Storage System - Capital Power



NEEDS ASSESSMENT REPORT

Northwest Region

September 3rd, 2025

Northwest Region

Technical Working Group Members

Atikokan Hydro Inc.

Fort Frances Power Corporation

Hydro One

IESO – Connecting Today. Powering Tomorrow.

NextEra Energy Canada

Sioux Lookout Hydro

Synergy North – The Power of the North

Wataynikaneyap Power

Disclaimer

This Needs Assessment ("NA") Report was prepared for the purpose of identifying potential needs in the Northwest and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group ("TWG") for this region at the time. Updates may be made based on the best available information throughout the planning process.

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

Summary

This is the 3rd cycle of Regional Planning for the Northwest Region. The previous Regional Planning cycle was completed in August 2023 with the publication of the Regional Infrastructure Plan ("RIP") report. The Technical Working Group ("TWG") consists of Atikokan Hydro Inc., Fort Frances Power Corp., Hydro One Transmission & Distribution, Independent Electricity System Operator, NextEra Energy Canada, Sioux Lookout Hydro, Synergy North, and Wataynikaneyap Power.

Based on load forecasts provided by Local Distribution Companies ("LDC"), existing directly connected customers, recent customer connection applications, information provided by regional municipalities, proactive groups, and existing government initiatives and strategies, the TWG recommends a comprehensive electrical plan for the region. In recognition of the distinctive, urgent and ever evolving demands of customers in the Northwest region – such as mining operation, data centers, forestry companies and large industrial manufacturers, and in accordance with the Transmission System Code ("TSC"), the TWG has agreed to begin the Scoping Assessment ("SA") phase promptly, which will then lead into development of the Integrated Regional Resource Plan ("IRRP") and finally completing the regional planning cycle with a RIP. To support this, the LDCs have already provided their respective 20-year forecast.

Broadly speaking, the needs are capacity and reliability in nature for all Northwest sub-regions. The IRRP will review the results of Waasigan Phase 1 & 2 against future system needs and will decide if further bulk studies are needed. The IRRP will also analyze wires and non-wires alternatives such as transmission, distribution, traditional generation, new energy resource technologies including Battery Energy Storage System ("BESS"), and demand side management strategies to meet the capacity and reliability needs in the region.

In summary, by starting the Scoping Assessment and advancing toward the IRRP, the TWG is taking critical, coordinated steps to ensure that the Northwest region's growing and evolving energy needs are met with reliable, sustainable, and forward-looking solutions.

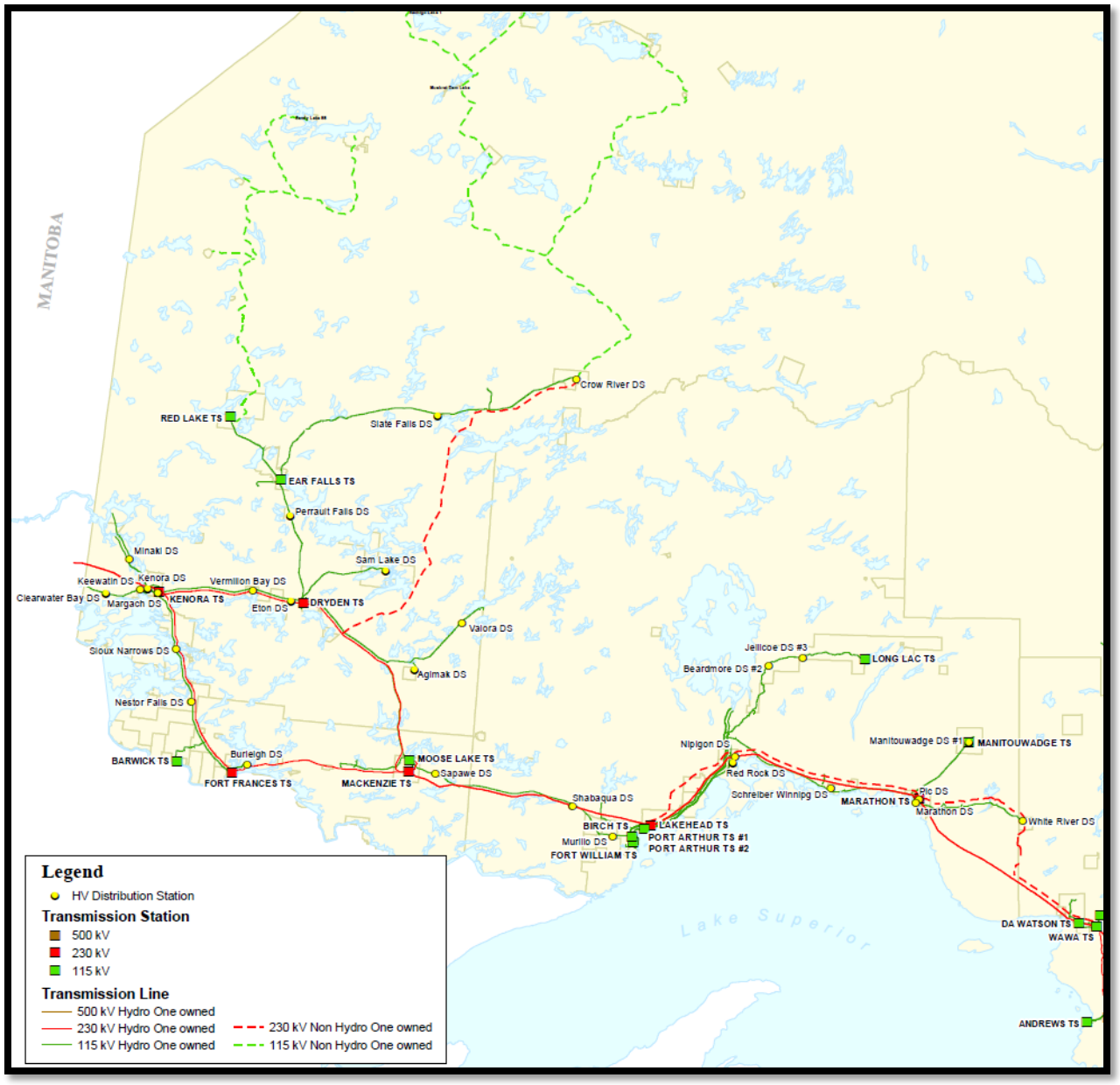


Fig. 1 – Overview of Northwest Region

Windsor-Essex Integrated Regional Resource Plan

April 3, 2025

Filed: 2026-10-07
EB-2026-0164
Exhibit B-1-1
Section 1.2
Attachment 24
Page 1 of 81

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Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this document are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this document, as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed herein. The IESO undertakes no obligation to revise or update any information contained in this document as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

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Appendix G. Windsor-Essex IRRP Technical Study

List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CHP	Combined Heat and Power
CTS	Customer Transformer Station
DESN	Dual-Element Spot Network
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
eDSM	electricity Demand Side Management
FIT	Feed-in-Tariff
GHG	Greenhouse Gas
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
km	kilometre
kV	kilovolt
LDC	Local Distribution Company
LED	Light Emitting Diode
LMC	Load Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere

Acronym	Definition
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-Wires Alternative
OGVG	Ontario Greenhouse Vegetable Growers
ORTAC	Ontario Resource and Transmission Assessment Criteria
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SS	Switching Station
TS	Transformer Station
UVLS	Under Voltage Load Shedding

Executive Summary

The Windsor-Essex Integrated Regional Resource Plan (IRRP) addresses electricity needs in the region over the twenty-year period from 2024 to 2043. The Windsor-Essex region is located in southwest Ontario, east of the Chatham-Kent/Lambton/Sarnia region. It includes the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, Township of Pelee Island, and the western portion of the Municipality of Chatham-Kent.

Due to the rapidly growing agricultural sector and more recent economic developments, regional electricity planning in southwestern Ontario has been occurring on a continuum since 2019 rather than the typical five-year cycle, with no signs of slowing down. From 2018 to 2022, winter net electricity demand in the region has increased by approximately 370 megawatts (MW) and the region is projected to be winter peaking going forward. Successful electricity resources implemented in the region include 857 MW of generation procurements since 2020, the construction of a new double-circuit transmission line into the region, the completion of Lakeshore Transmission Station (TS), and the completion of South Middle Road Dual-Element Spot Network (DESN) #1, with construction of South Middle Road DESN #2 underway to be completed in 2025. In 2023 there were 3 MW of verified electricity Demand-Side Management (eDSM) savings in the region. This IRRP builds upon those previous regional and bulk plans to continue to ensure reliable electricity supply across the region.

The IESO conducted extensive engagement and outreach throughout the planning process through targeted discussions, webinars and communications to seek input and ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. In response to sustained growth driven by municipal and housing developments, greenhouse development, industrial development, and electrification initiatives in the West Essex and Windsor sub-system as well as Lakeshore/Tilbury sub-system, the Technical Working Group recommends:

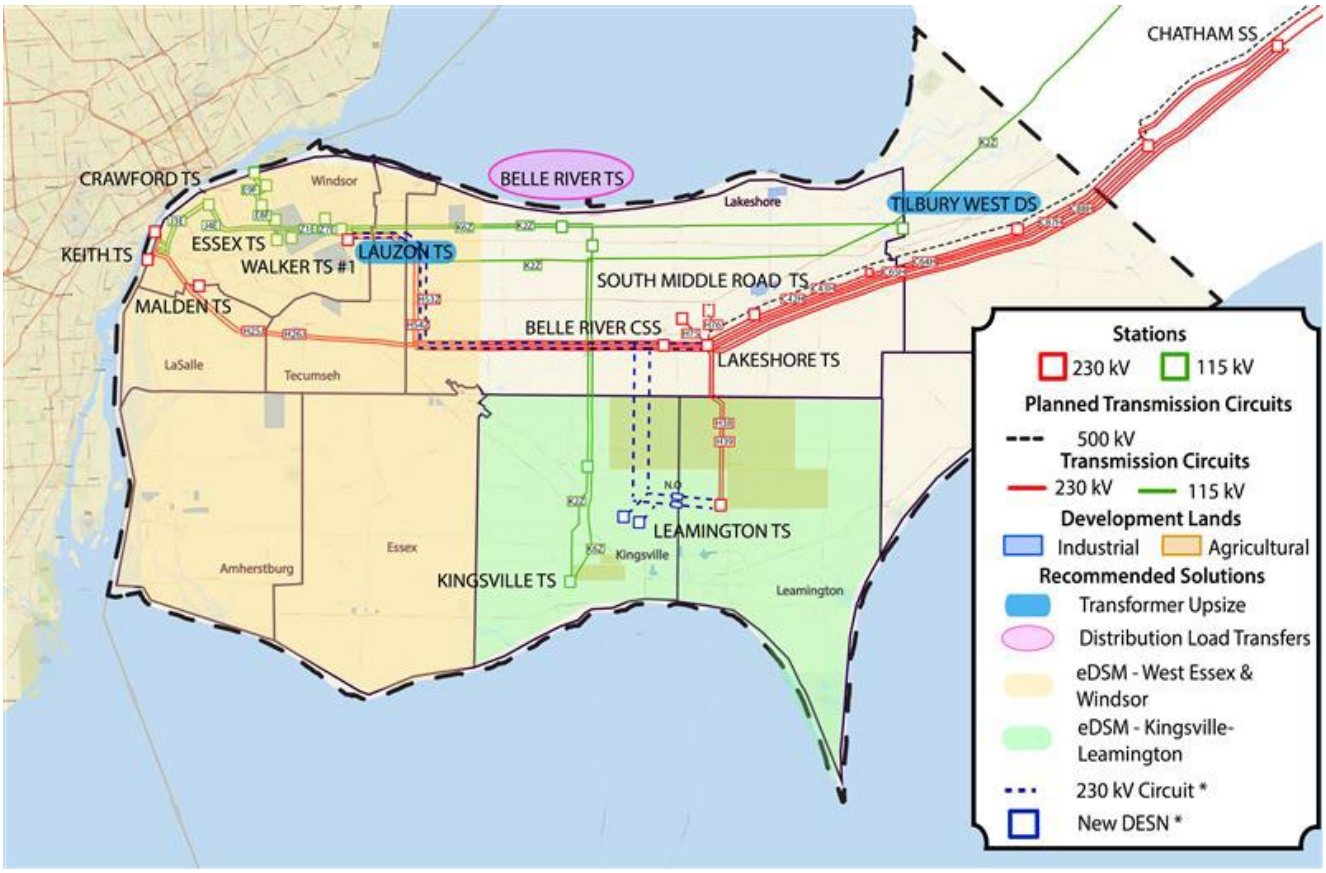
- Considering potential targeted eDSM programs for the West Essex and Windsor sub-system;
- Constructing a new double-circuit 230 kV transmission line from Lakeshore TS to Lauzon TS, to increase the supply capacity into the area, as well as enable potential electricity supply resource connections;
- Exploring the potential scope and value of a corridor study to identify future transmission paths into the West Essex and Windsor sub-system;
- Upsizing the transformers at Lauzon TS DESN 2, to address multiple station capacity needs and enable the forecast load growth at Lauzon TS and load from Belle River TS, after load transfers; and
- Upsizing the transformers at Tilbury West DS, to address the local station capacity need.

To address continued growth in the agriculture sector, the Technical Working Group reinforces the recommendations from the 2022 Windsor-Essex Addendum for:

- Continuing targeted eDSM programs for the Kingsville-Leamington sub-system (e.g., continuing the targeted greenhouse sector incentives supporting Light Emitting Diode – or LED – conversions and advanced lighting controls).
- Constructing two new DESNs with a connecting double-circuit 230 kV transmission line from Lakeshore TS, to increase the station and supply capacity in Kingsville-Leamington; and
- Constructing a double-circuit 230 kV transmission line connecting the new lines to H38/H39 with normally open breakers to provide load restoration capability.

Figure 1 visually depicts the IRRP recommendations across the Windsor-Essex region.

Figure 1 | Overview of Recommended Solutions for Windsor-Essex IRRP



The Technical Working Group will continue to monitor growth across the region to determine if or when further reinforcements will be needed. This includes monitoring any future community energy plans, electrification trends, customer connection queues, and changes to local generation. In the interim, operational measures can be used to support growth in the region through use of operating ratings and improving the redundancy of the Lakeshore Remedial Action Scheme (RAS).[1]

[1] A Remedial Action Scheme – or RAS – is a set of pre-planned operating actions that are initiated under select contingencies to ensure the reliability and stability of the electricity grid. In particular, the Lakeshore RAS monitors the 230 kV circuits in the region and may reject load or generation depending on the contingency observed.

Engagement is critical in the development of an IRRP. It provides opportunities for input in the regional planning process enables the views and perspectives of the public, Indigenous communities, market participants, municipalities, stakeholders, communities, and customers to be considered in the development of the plan. Furthermore, engagement helps lay the foundation for successful implementation of the IRRP.

The Technical Working Group will continue to meet to develop the Regional Infrastructure Plan (RIP) and annually thereafter to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

1. Introduction

This IRRP addresses the electricity needs of the Windsor-Essex region over the 20-year period from 2024 to 2043. The Windsor-Essex region is located in southwest Ontario, east of the Chatham-Kent/Lambton/Sarnia region. It includes the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, Township of Pelee Island, and the western portion of the Municipality of Chatham-Kent.

Several Indigenous communities are located in or near the region, including: Aamjiwnaang First Nation, Caldwell First Nation, Chippewas of Kettle and Stony Point First Nation, Chippewas of the Thames First Nation, Eelŭnaapéewi Lahkéewiit Delaware Nation, Munsee-Delaware Nation, Oneida Nation of the Thames, and Walpole Island First Nation.

The region's electricity is delivered by five Local Distribution Companies (LDCs): ENWIN Utilities Ltd. ("ENWIN"), Essex Powerlines Corporation ("Essex Powerlines"), E.L.K Energy Inc. ("E.L.K."), Entegrus Powerlines Inc. ("Entegrus"), and Hydro One Networks Inc. ("Hydro One Distribution"). Hydro One Networks Inc. ("Hydro One Transmission") is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of the LDCs, Hydro One Transmission, and the IESO.

Figure 2 depicts the electrical transmission infrastructure for the Windsor-Essex region. Power is transmitted into the region via 230 kV transmission lines from Chatham Switching Station (SS) east of the region to Lakeshore TS, which supplies Leamington TS and South Middle Rd TS. The 230 kV corridor continues west with two circuits toward Lauzon TS and two circuits toward Keith TS via Malden TS. Keith TS provides an interconnection with the Michigan system via 230 kV circuit J5D.

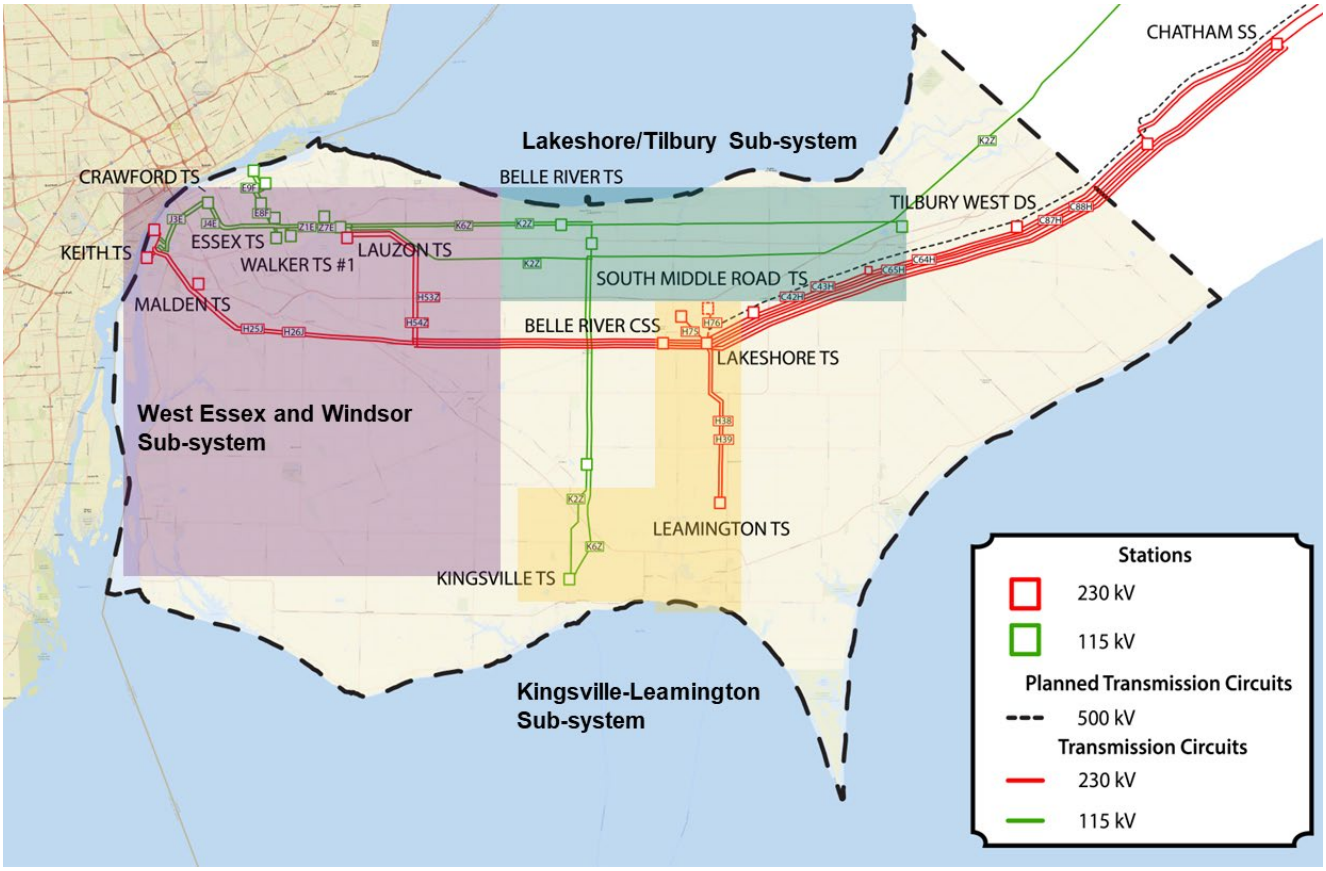
Historically, the region was supplied by four 230 kV circuits along with local generation resources; however, as of December 2024, two additional 230 kV circuits from Chatham SS to Lakeshore TS were completed.

For the purposes of regional planning, the Windsor-Essex region has been divided into three sub-systems, as shown in Figure 2:

- The **West Essex and Windsor sub-system** in the west of the region, electrically defined by the load and generation connected to and downstream of the H53Z, H54Z, H25J, and H26J 230 kV circuits west of Lakeshore TS. In Windsor, Keith TS and Lauzon TS connect the region's 115 kV network to the 230 kV transmission system via two autotransformers at each station. These supply the 115 kV transmission lines that connect to Belle River TS, Crawford TS, Essex TS, Kingsville TS, Lauzon TS, Tilbury West DS, Walker Municipal Transformer Station (MTS) #2, and Walker TS #1. Keith TS has one DESN and Lauzon TS has two DESNs (in addition to the autotransformers). Malden TS and NextStar TS are also connected to the 230 kV lines in this sub-system.
- The **Kingsville-Leamington sub-system** in the south-east of the region, electrically defined by the load and generation connected to Kingsville TS, the H38 and H39 230 kV radial circuits south of Lakeshore TS, and the H75 and H76 radial circuits north of Lakeshore TS.

- The **Lakeshore/Tilbury sub-system** in the north-east of the region, electrically defined by the load and generation connected to the K2Z and K6Z 115 kV circuits downstream of Lauzon TS, inclusive of Belle River TS and Tilbury West DS but excluding Kingsville TS.

Figure 2 | Map of the Windsor-Essex Region and Defined Sub-systems



There are seven transmission-connected customers in the region served by Customer Transformer Stations (CTSs). There are also several transmission-connected generation resources in the region, primarily gas and wind generation, some solar generation, as well as some battery storage facilities under development. The distribution-connected resources or distributed generation (DG) in the region includes natural gas combined heat and power (CHP), solar and wind resources, and a small amount of biogas.

This report describes the culmination of the Windsor-Essex IRRP, which was initiated in May 2023 following the publication of the Needs Assessment Report in February 2023 by Hydro One and the Scoping Assessment Outcome Report in May 2023 by the IESO. The Scoping Assessment identified needs requiring further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, eDSM contributions, and DG assumptions are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Windsor-Essex region over the twenty-year period from 2024 to 2043. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs, considering reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Windsor-Essex electricity demand forecast, provided by the LDCs, anticipates sustained growth driven by municipal and housing developments, industrial development, expansion of the agriculture industry, and electrification initiatives. The decreased reliance on emitting generation and resources coming off contract in the region are also major drivers of the electricity supply needs into and within the region.

The IRRP recommendations below are organized under near-term, medium-term, and other ongoing or long-term initiatives to address needs in the three sub-systems identified: West Essex and Windsor, Kingsville-Leamington, and Lakeshore/Tilbury. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term as electrification, energy efficiency, and development plans evolve.

2.1. Status of Ongoing Work

Following the previous cycle of region planning and various bulk plans, several projects were recommended which have now been completed or are presently underway. The plans implemented a multi-pronged approach of both wires and non-wires solutions to address electricity needs across the region. The status of these projects is summarized in Table 1.

Table 1 | Summary of Ongoing and Recently Completed Projects

Project	Expected In-Service Date
Conduct IESO Grid Innovation Fund targeted call for indoor agriculture projects	Complete
Upsize Keith TS end-of-life 230/115 kV autotransformers T11/T12	Complete
Decommission Keith TS end-of-life T1 (115 kV/27.6 kV) transformer	Complete

Project	Expected In-Service Date
Build a new switching station at the Leamington Junction[2]	Complete
Acquire 550 MW of new or existing local resources[3]	Complete
Begin bilateral negotiations for Brighton Beach Generating Station	Complete[4]
Build a new supply station, South Middle Road DESN 1	Complete
Build a new 230 kV double-circuit transmission line from Chatham SS to Lakeshore TS	Complete
Carry out Greenhouse-specific Light Emitting Diode (LED) Incentive, Save On Energy incentives in the Southwest zone, and Advanced Lighting Controls	Ongoing
Build a second new supply station, South Middle Road DESN 2	2025
Upsize Lauzon TS DESN 1 end-of-life step-down transformers	2026
Replace the phase-shifting transformer at Keith TS ("PSR5")[5]	2028
Build a new 230 kV double-circuit transmission line from Lambton TS southwards to Chatham SS (the "St. Clair line")	2028
Build a single-circuit 500 kV transmission line from Longwood TS to Lakeshore TS	2030
Build two new 230 kV DESNs and double-circuit connection lines from Lakeshore TS, including the option for a new 230 kV line between Leamington TS and the new DESNs, and transfer Kingsville TS load to the new DESNs	On hold – recommended again in this IRRP

[2] This was ultimately put into service as Lakeshore TS.
[3] Approximately 857 MW of generation was procured in Windsor-Essex since 2020.
[4] The negotiations for Brighton Beach Generating Station are also complete, with a contract term from July 16, 2024 to July 15, 2034.
[5] This recommendation is a result of a joint intertie study completed by the IESO and the Midcontinent Independent System Operator, rather than a regional planning or bulk planning initiative. The purpose of this project is to address end-of-life concerns and increase the capability of the device to improve control of scheduled intertie flows between the two jurisdictions.

2.2. Near- to Medium-Term Plan

The Technical Working Group recommends the near- to medium-term plans, including several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. The following subsections discuss these near- to medium-term plans.

2.2.1. Targeted Electricity Demand Side Management

The Kingsville-Leamington and West Essex and Windsor areas are experiencing sustained growth, driven by greenhouse lighting, industrial development, municipal and housing growth, and electrification initiatives. For this reason, a combination of non-wires alternatives (NWAs) and wires options is required to address the needs in these two sub-systems. The Technical Working Group recommends the continuation of energy efficiency programs targeted to the greenhouse sector, as well as exploring opportunities to leverage provincial eDSM programs for the local area.

2.2.2. Supply Stations and Connection Lines in Kingsville-Leamington

An integrated solution is recommended to address the capacity needs and load restoration needs in Kingsville-Leamington. The Technical Working Group recommends two new 230 kV load supply stations in the Kingsville-Leamington area to address the forecast capacity requirements starting in 2027. The new supply stations also have the potential to offload a portion of Kingsville TS. These stations are to be supplied via a new 230 kV double-circuit line from Lakeshore TS. A new 230 kV double-circuit line between the new supply stations and Leamington TS should also be built to address the sub-system's load restoration needs. The new DESNs and supply lines will enable the connection of both new load and generation resources, and the load restoration lines will improve reliability in the area.

Depending on the subsequent design and environmental assessment phases, there may be an opportunity to integrate the recommended double-circuit 230 kV transmission line from Lakeshore TS to the new Kingsville-Leamington supply stations with the transmission pathway for the new double-circuit 230 kV transmission line recommended from Lakeshore TS to Lauzon TS (see Section 2.2.5). There could be a portion of transmission line shared between these two recommendations west of Lakeshore TS, which would split into two separate paths– one toward Kingsville-Leamington and one toward Lauzon TS. The combined solution would optimize the use of the transmission infrastructure and provide further integration in the Windsor-Essex region.

2.2.3. Load Transfer from Belle River TS

Belle River TS is forecast to immediately exceed its station capacity by 1 MW, with the need increasing slowly over the 20-year study period to 17 MW in 2043. Given the magnitude of this need and the available capacity on the nearby Lauzon TS once DESN 1 and DESN 2 are both upsized in 2025 and 2029 respectively, the Technical Working Group recommends load transfers from Belle River TS to Lauzon TS DESNs 1 and 2 (see Section 2.2.4). In the interim, operational measures, such as using operational ratings, can be used to manage this need until the wires solution is in place.

2.2.4. Upsize Lauzon TS DESN 2

Lauzon TS DESN 2 has an asset replacement need in 2029, as well as a station capacity need starting in 2032. The Technical Working Group recommends upsizing the transformers at Lauzon TS DESN 2 to address these two needs, and to help address the Belle River TS capacity need.

2.2.5. New Transmission into West Essex and Windsor

To ensure continued supply to the West Essex and Windsor sub-system, the Technical Working Group recommends a new 230 kV double-circuit line from Lakeshore TS to Lauzon TS to meet the supply capacity need in 2032. This will increase the transfer capability into the sub-system, allow for additional connections, and improve the resource deliverability along this transmission path. As noted in Section 2.2.2, there is potential for this solution to integrate with the recommendation for Kingsville-Leamington capacity need.

2.2.6. Summary of Near- to Medium-Term Plans

Table 2 summarizes these near- to medium-term plans for Windsor-Essex.

Table 2 | Summary of the Near- to Medium-Term Plans for the Windsor-Essex IRRP

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
West Essex and Windsor supply capacity need	Leverage targeted eDSM programs to support growth in West Essex and Windsor[6]	IESO	N/A
Kingsville-Leamington load security and operational concerns	Explore options to make the design of the Lakeshore Remedial Action Scheme (RAS)[7] redundant	Hydro One Transmission	N/A
Kingsville-Leamington station and supply capacity needs	Continue existing eDSM programs to manage demand across and the sub-system[6]	IESO	N/A

[6] Whereas eDSM programs are recommended in the near-term, they are also expected to contribute to the long-term growth and reliable electricity supply in the region.

[7] A Remedial Action Scheme – or RAS – is a set of pre-planned operating actions that are initiated under select contingencies to ensure the reliability and stability of the electricity grid. In particular, the Lakeshore RAS monitors the 230 kV circuits in the region and may reject load or generation depending on the contingency observed.

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
Kingsville-Leamington station capacity, supply capacity, and load restoration needs	Construct two new supply stations in the Kingsville-Leamington area with two 230 kV circuits from Lakeshore TS Connect the two new 230 kV circuits to Leamington TS via two additional 230 kV circuits	Hydro One Transmission	2027–2029
Belle River TS station capacity need	Transfer load from Belle River TS to the upsized Lauzon TS DESN 1 and 2	Hydro One Distribution	2026–2031
Lauzon TS DESN2 station capacity need	Upsize transformers	Hydro One Transmission	2029
West Essex and Windsor supply capacity need	Build a new 230 kV double-circuit line from Lakeshore TS to Lauzon TS	Hydro One Transmission	2032

2.3. Long-Term Plan and Ongoing Initiatives

In the long term, the Windsor-Essex region's electricity demand is projected to continue to grow. This IRRP sets out recommended actions required to ensure that options remain available to address future needs in the most efficient and cost-effective way, if and when they ultimately arise.

2.3.1. Upsize Tilbury West DS

Tilbury West DS is forecast to exceed its peak station capacity in 2036. The recommendation to upsize the transformers at Tilbury West DS can be implemented in three to five years. Given the timing of this need, the Technical Working Group recommends monitoring growth and triggering the upsizing of transformers at Tilbury West DS as needed, or revisiting this need in the next cycle of regional planning.

2.3.2. West Essex and Windsor Corridor Study

The High Forecast for West Essex and Windsor indicates the need for further supply in this sub-system; however, there are land restrictions due to conservation areas, an airport, and flooding risks. Thus, the Technical Working Group recommends the scope and value of a corridor study be explored to identify additional paths for transmission supply into West Essex and Windsor, to prepare for a quicker response when higher growth materializes.

2.3.3. Monitor Load Growth

Load in this region is projected to increase and is expected to advance under the High Forecast. Given the uncertainty of the High Forecast, a firm recommendation addressing this level of growth is not required at this time. The Technical Working Group will continue to monitor load growth across the region – in particular, the agricultural sector in Kingsville-Leamington and industrial sector in West Essex and Windsor – and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also monitor and participate in any future community energy plans developed by municipalities in the Windsor-Essex region, as well as the status of bulk system transmission and resource developments.

2.3.4. Summary of Long-Term Plan

Table 3 summarizes the long-term recommendations beyond the ten-year horizon and ongoing initiatives.

Table 3 | Summary of Long-Term Plan for the Windsor-Essex IRRP

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
Tilbury West DS station capacity	Upsize transformers	Hydro One Distribution	2036
West Essex and Windsor High Forecast supply capacity	Conduct a corridor study to identify additional paths for transmission supply west of Lakeshore TS	IESO	N/A
Windsor-Essex region growth	Monitor load growth across the region, transmission projects, and changes in generation across the region	IESO	N/A

3. Development of the Plan

3.1. The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report, is posted on the IESO's website.

3.2. Windsor-Essex and IRRP Development

The process to develop the Windsor-Essex IRRP was initiated in May 2023, following the publication of the Needs Assessment report in February 2023 by Hydro One and the Scoping Assessment Outcome Report in May 2023 by the IESO. The Scoping Assessment recommended that the needs identified for the Windsor-Essex region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

This is the third cycle of regional planning for the Windsor-Essex region. Electricity planning in Ontario typically occurs on a cyclical basis. However, due to the rapidly growing agricultural sector and more recent economic developments, planning in southwestern Ontario has been occurring on a continuum over the last five years, with no signs of slowing down. The 2019 Windsor-Essex bulk study occurred in parallel with the 2019 Windsor-Essex IRRP, followed by the 2020 Windsor-Essex Regional Infrastructure Plan and the 2021 West of London bulk plan that considered a broader area that encompassed this region[8]. In tandem, the 2022 Windsor-Essex Addendum was undertaken to address remaining local needs in Kingsville and Leamington.

The previous regional and bulk recommendations and subsequent plans are summarized in the sections below.

4.1. Previous Regional Planning Cycle

The previous cycle of regional planning for the Windsor-Essex region was completed in 2019, which implemented a multi-pronged approach of both wires and non-wires solutions to address electricity needs across the region. Subsequently, an Addendum was completed in 2021 to assess remaining local reliability issues in the Kingsville and Leamington areas: capacity needs to enable new distribution-level customers to connect, as well as load restoration needs. Recommendations from this planning cycle are summarized below.

2019 Windsor-Essex IRRP

- IESO Grid Innovation Fund targeted call for indoor agriculture projects – two projects contracted within Kingsville-Leamington, with support provided between 2020 and 2023.
- Greenhouse-specific LED Incentive, Save On Energy incentives in the Southwest zone, and Advanced Lighting Controls – implemented under the 2021–2024 Conservation and Demand Management Framework and continuing under the 2025–2036 eDSM Framework. In 2023, there were 3 MW of verified eDSM savings in the region.
- Upsize Keith TS end-of-life 230/115 kV autotransformers T11/T12 from 125 MVA to 250 MVA– completed in 2023.
- Upsize Lauzon TS DESN 1 end-of-life step-down transformers T5/T6 – expected to be in-service by 2026.
- Decommission Keith TS end-of-life T1 (115 kV/27.6 kV) transformer – completed.

[8] The West of London bulk plan considered the area from outside the western edge of the City of London, to the City of Sarnia in the northwest, and to the City of Windsor in the west.

2020 Windsor-Essex Regional Infrastructure Plan

- Build a new supply station, South Middle Road DESN 1, connected to Lakeshore TS – completed in 2022.
- Build a second new supply station, South Middle Road DESN 2, connected to Lakeshore TS – work underway, expected to be in-service in 2025.

2022 Windsor-Essex Addendum

- Build two new 230 kV DESNs and double-circuit connection lines from Lakeshore TS, including a new 230 kV line between Leamington TS and the new DESNs – on hold pending customer commitment and is being recommended again in this IRRP.
- Transfer load in excess of the Kingsville TS station load meeting capability to the new DESNs once in-service – on hold until DESNs proceed and is being recommended again in this IRRP.
- Initiate engagement with customers to determine cost-justified measures to mitigate the load restoration need – on hold until DESNs proceed.

4.2. Bulk Planning and Other Developments

In addition to historical regional planning activities, the Windsor-Essex region has been the subject of bulk planning initiatives and other developments. The 2019 Windsor-Essex bulk plan focused on increasing the overall transfer capability of the bulk transmission system west of Chatham to reliably supply the forecast load growth in the Kingsville-Leamington area and Windsor-Essex region. The 2021 West of London bulk plan. This plan looked to address remaining bulk transmission system constraints east of Chatham and ensure adequate supply to the West of London area. In addition, given the expiry of generation contracts in the area, it intended to identify any transmission constraints limiting the ability of supply resources and imports within West of London to meet provincial needs.

2019 Windsor-Essex Bulk Plan

- Build a new switching station at the Leamington Junction (Lakeshore TS) – completed in 2022.
- Build a new 230 kV double-circuit transmission line from the existing Chatham SS to the new switching station at the Leamington Junction (Lakeshore TS) – completed in 2024 (one year earlier than planned).

2021 West of London Bulk Plan

- Build a new 230 kV double-circuit transmission line from Lambton TS southward to Chatham SS (the "St. Clair line") and associated station facility expansions or upgrades required at the terminal stations – development underway and regulatory approval received, expected to be in-service in 2028.

- Begin bilateral negotiations for Brighton Beach Generating Station, to support the area's needs in the near-term until the Lambton-to-Chatham transmission line is in-service – completed.[9]
- Build a single-circuit 500 kV transmission line from Longwood TS to Lakeshore TS – development underway, expected to be in-service in 2030.
- Acquire 550 MW of new or existing local resources – secured through completed procurements, expected to be in-service earlier than the 2030 to 2035 need.

2024 Central-West Bulk Plan

- Reconstruct the M31W circuit between Buchanan TS and the tap line for the planned Centennial TS with higher capacity double-circuit towers, strung with one circuit but capable of accommodating a second circuit in the future – development underway, expected to be in-service in 2027.
- Monitor load growth across the Central-West area and be prepared to implement dynamic voltage devices as demand grows, including Ingersoll TS.

Ongoing South and Central Bulk Planning

A new South and Central Bulk Plan is underway to address known bottlenecks in the transmission system, including between northern and southern Ontario, within the Greater Toronto Area, and along the Windsor-to-Hamilton corridor. The objectives of the study are to unlock opportunities for generation connections, enable phase-out of emitting resources, and support future growth and economic development. The study will determine the transmission reinforcements and/or network expansion required to enable reliable:

- Reliable supply under scenarios for decommissioning greenhouse gas (GHG) emitting resources; and
- Long-term, high-growth scenarios within key areas of the South-Central system, such as the Windsor-to-Hamilton corridor.

Other Developments

In 2022, a governmental directive declared that three of the transmission lines recommended in the regional and bulk plans above are priority projects, specifically:

- The Chatham-to-Lakeshore double-circuit 230 kV line (completed in 2024);
- The double-circuit 230 kV St. Clair line; and
- One single-circuit 500 kV line from Longwood TS to Lakeshore TS.

This would streamline the Ontario Energy Board's regulatory approval process and designate Hydro One Transmission as the transmitter for the priority projects. In the Order in Council the government also asked Hydro One Transmission to undertake development work and seek approvals for two future projects:

[9] The negotiations for Brighton Beach Generating Station are also complete, with a contract term from July 16, 2024 to July 15, 2034.

This had the effect of streamlining the Ontario Energy Board's leave to construct process for these projects. Further, in 2020 and 2022, the Minister of Energy issued Directives requiring Hydro One Transmission to develop these projects, including their associated station facility upgrades, along with two new projects:

- A new 230 kV line that would run from Lakeshore TS to the Windsor area; and
- A second 500 kV transmission line from Longwood TS to Lakeshore TS

4.3. Current Cycle of Regional Planning

The current cycle of regional planning began in 2023, with the publication of the Needs Assessment, in which several needs requiring further regional coordination were identified. The 2023 Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan over a 20-year period from 2024 to 2043.

This IRRP develops and recommends options to meet the electricity needs of the Windsor-Essex region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, eDSM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

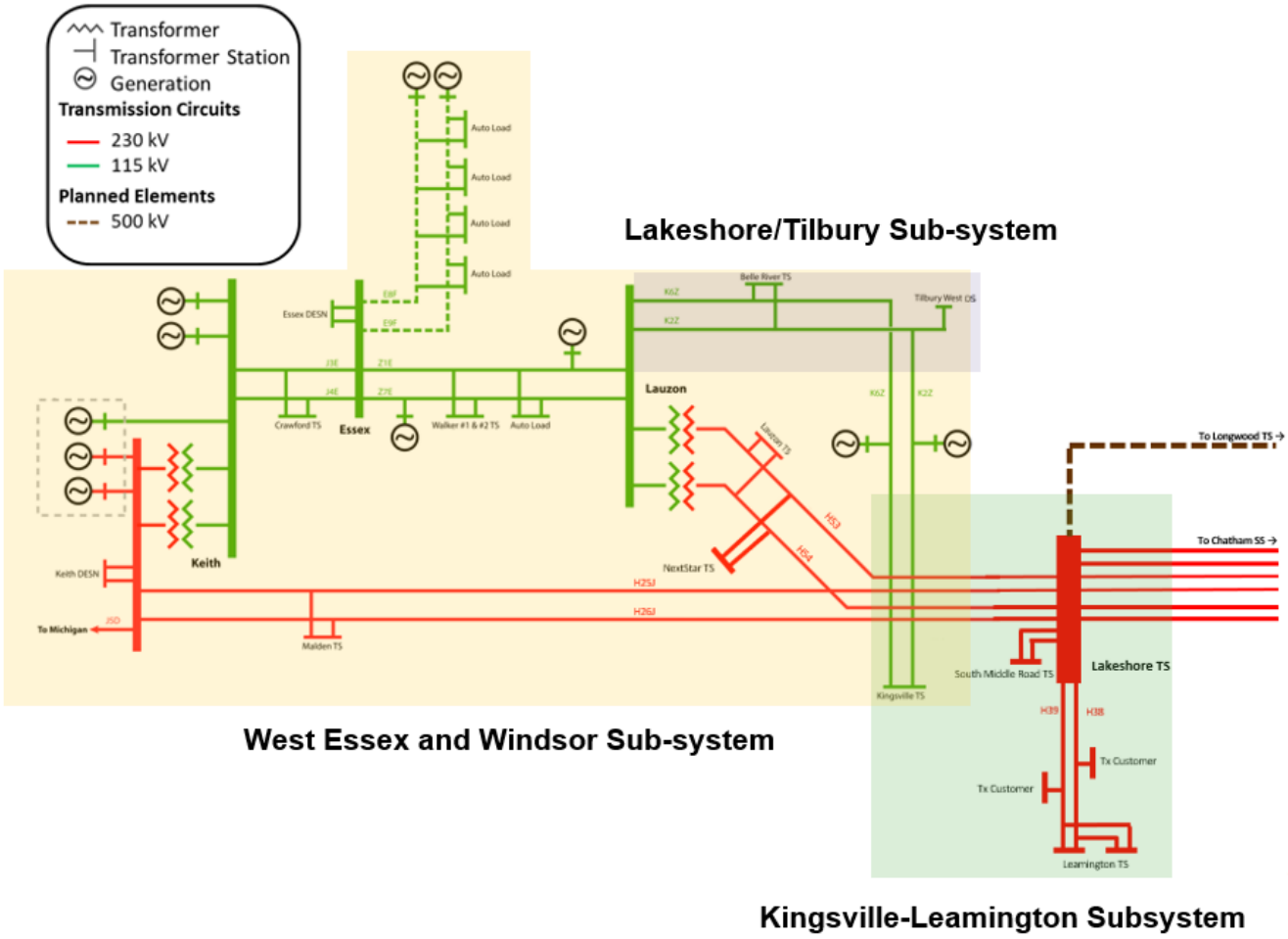
The following transmission facilities were included in the scope of this study:

- Transformer stations: Belle River TS, Crawford TS, Essex TS, Keith TS, Kingsville TS, Lauzon TS, Leamington TS, Malden TS, South Middle Road TS, Tilbury West DS, Walker MTS #2, Walker TS #1, and eight CTS.
- 115 kV transmission circuits: J3E, J4E, E8F, E9F, Z1E, Z7E, K6Z, and K2Z.
- 230 kV transmission circuits: H25J, H26J, H53Z, H54Z, H38, H39, H75, and H76.

The single line diagram of the Windsor-Essex region is shown in Figure 3. Note that the bulk system transfer capabilities into the region[10] are not within the scope of the IRRP, but are encompassed in the ongoing South and Central Bulk study. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[10] Includes flow into Lakeshore from the six 230 kV circuits from Chatham SS and the recommended 500 kV circuit from Longwood TS under development.

Figure 3 | Single Line Diagram of the Windsor-Essex Region



The Windsor-Essex IRRP was developed by completing the following steps:

- Establishing alternatives to address system needs, including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives, including eDSM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near- and long-term needs.
- Considering the impact of the High Forecast as a sensitivity of the flexibility and optionality of the potential alternatives.
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Windsor-Essex region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of eDSM and DG, and the development of a High Forecast scenario. The "Planning Scenario" was derived based on firm loads (current and planned), organic growth, residential, electrification, community energy plans, greenhouse growth, and industrial growth as described in more detail in Appendix B. The "Planning Forecast" is the result of "Planning Forecast" presented net of existing DG and eDSM, and corrected for extreme weather. The Planning Forecast is used in assessing the electricity needs of the area over the planning horizon.

The "High Scenario" incorporates potential demand growth that is less certain, in terms of timelines, magnitude and location, into the Planning Scenario. The "High Forecast" is also the result of the High Scenario adjusted to be net of existing DG and eDSM, and corrected for extreme weather. The High Forecast used as the basis for a sensitivity analysis as described further in Section 5.7.2.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. In the past, the Windsor-Essex region peak loading has historically occurred in the summer. However, with the recent and projected growth of the greenhouse sector, the region is now winter peaking.

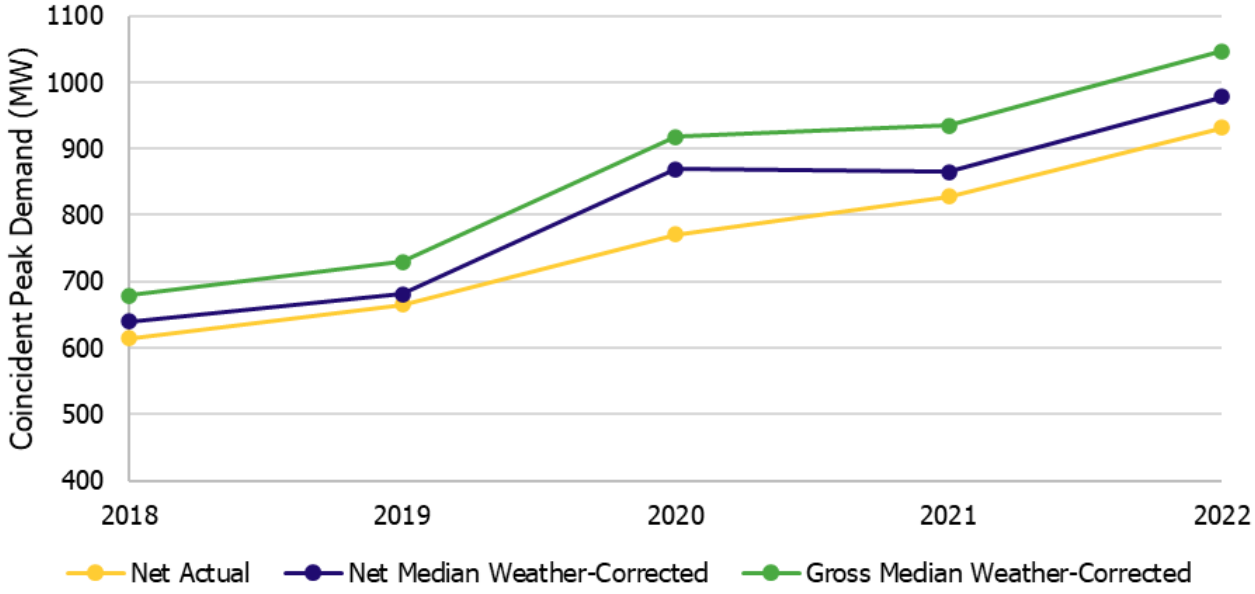
5.1. Historical Demand

The Windsor-Essex region is winter peaking mainly due to increased greenhouse load for lighting during winter months. From 2018 to 2022, electrical demand[11] grew by nearly 370 MW, peaking between approximately 9 AM to 6 PM. Figure 4 shows the historical winter peak demand as measured three different ways:

1. Coincident net actual, as observed at the metering point;
2. Net median weather-corrected (adjusted to reflect median weather conditions); and
3. Gross median weather-corrected historical demand with contributions of DG removed.

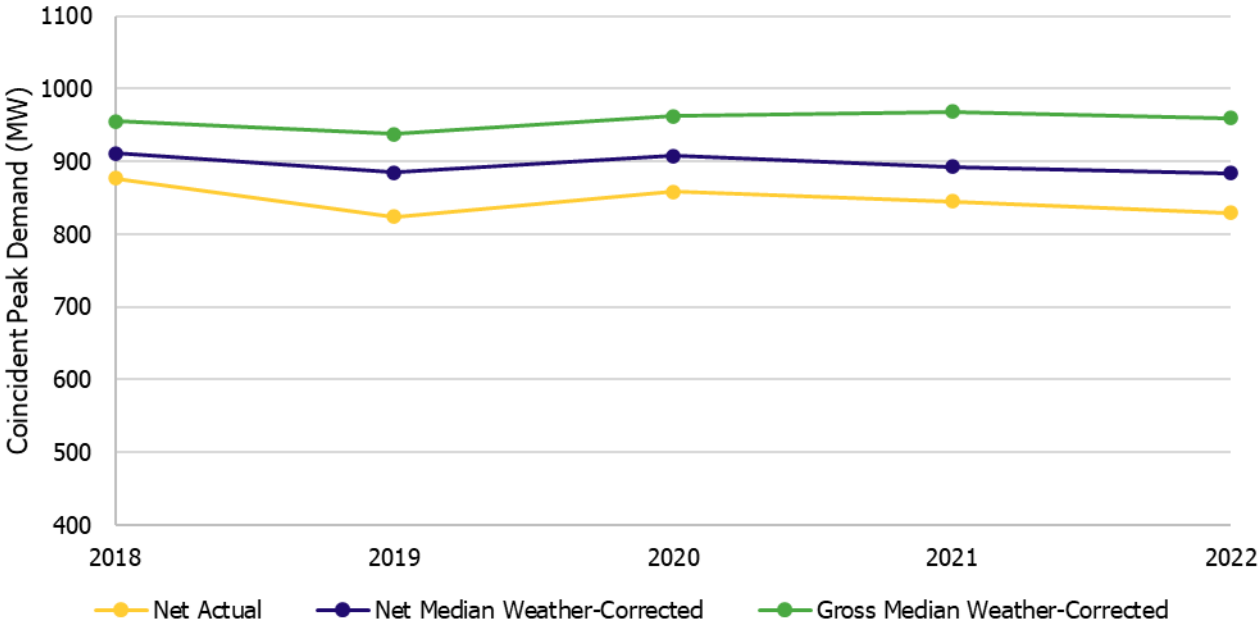
[11] Gross median weather-corrected demand.

Figure 4 | Historical Winter Peak Demand in the Windsor-Essex Region



Summer peak electricity demand within the Windsor-Essex region has remained stable in the five years prior to this planning cycle. Figure 5 shows the summer coincident net actual, net median weather-corrected, and gross median weather-corrected historical demand. The summer gross median weather-corrected demand has averaged 960 MW over the past five years, with the peak demand hour for each year occurring between approximately 2 PM to 5 PM.

Figure 5 | Historical Summer Peak Demand in the Windsor-Essex Region



Since the forecast was developed in 2023, the 2022 summer and winter gross median weather-corrected peaks at each station in the Windsor-Essex region were used as the starting points for the forecast.

5.2. Current Drivers of Load Growth

Electricity demand in the Windsor-Essex region is growing at a rapid pace due to residential and commercial growth, continued expansion of the agricultural and industrial sectors, and electrification. Agriculture has been driving electricity demand growth and needs in the region over the last several years, especially in winter, and continues to be an important driver going forward. Broader economic development across the region, electrification, and local climate action plans are also expected to be key factors for future electricity needs. These factors identified as drivers of growth are used to inform the forecasts developed for the region and are discussed in more detail in the following subsections.

5.2.1. Community Load Growth

The population of the Windsor-Essex region is approximately 420,000 people, with close to 10,000 new residents welcomed between 2021 and 2022, according to the latest census. The Provincial Housing Commitment is anticipated to result in the development of 13,000 new homes over the next ten years in the Windsor-Essex region. This residential development will be accompanied by population growth, and Windsor expects a need will arise to expand its infrastructure to support this growth. The region also anticipates that new residences will employ electric heating and that existing residences will convert to electric heating, with the lowest expected conversion rate being 60 per cent. In addition to electric heating, electric vehicle uptake is expected to increase in the area, in accordance with forward looking projections from Statistics Canada and the regulated targets for zero-emission vehicles within the Electric Vehicle Availability Standard implemented by the Government of Canada in 2023. Electric vehicle uptake is expected by both municipal fleets and more broadly by community members.

Further, the region anticipates climate change and resulting extreme weather will have an impact on electricity demand. Windsor-Essex experiences hotter summers than other areas of Ontario because of its southern geography, which results in more days requiring electric cooling. The City of Windsor and County of Essex are surrounded on three of four sides by large bodies of water, and there are a number of shoreline and low-lying areas in the region that are vulnerable to flooding.[12]

The communities of the Windsor-Essex region anticipate steady population growth accompanied by necessary residential development. The City of Windsor, Municipality of Leamington, Town of LaSalle, Town of Tecumseh, and Municipality of Chatham-Kent each expect a population increase near to or greater than 6,000 individuals over a ten-year period, as informed by their Development Charges Background Studies.

Communities have identified large development projects that will increase electricity demand; these include the Howard-Bouffard Secondary Plan in the Town of LaSalle, the Tecumseh Hamlet Secondary Plan, Oldcastle Hamlet Development plan and Manning Road Secondary Plan in Tecumseh, the Settlements Areas for Employment Lands plan in the Town of Essex, and the Sewage Treatment Facility expansion in the Town of Kingsville. Moreover, some communities have identified objectives for reducing electricity demand through Energy Management plans like the City of Windsor and the Town of Lakeshore.

[12] Based on the City of Windsor East Riverside Flood Risk Assessment and Essex Region Conservation Authority website.

5.2.2. Agricultural Sector

The Kingsville-Leamington area within the Windsor-Essex region is home to North America's largest concentration of greenhouse vegetable production. Growth in the agricultural sector has been driven by strong indoor agricultural growth, mainly vegetable greenhouses, as well as, in part, cannabis, specifically through existing greenhouses switching to lit indoor facilities, expansion of greenhouse facilities, and supplemental load to support the sector. There are also early indications of expansion to include berries and propagation.

Indoor agriculture loads are significantly different from other industrial, commercial, and residential loads in the province. The concentration of indoor agriculture in Windsor-Essex owes much to the region's natural advantages. Its proximity to the Windsor-Detroit border crossing is ideal for supplying both the Canadian and U.S. markets, and its southern latitude and climate provide optimal conditions for agricultural activities. Windsor-Essex also hosts an established ecosystem of support industries and partners, including agriculture research and greenhouse fabrication facilities, which further encourage greenhouse growth in the area.

Since the last cycle of regional planning, the greenhouse sector continues to grow. Both transmission-connected greenhouse loads, and the recommended supply stations (South Middle Rd DESNs 1 and 2) have connected or are under development. In the future, agricultural growth may concentrate in the southern portion of Chatham-Kent, between Wheatly and Port Alma.

5.2.3. Industrial Sector

Windsor-Essex remains the country's manufacturing and automotive powerhouse, with significant recent investments in electric vehicle battery manufacturing. Windsor-Essex is home to more than 1,000 manufacturers, with more than 90 parts manufacturers, including two original equipment manufacturers, over 250 machine, tool, die and mould manufacturers, and more than 500 automation-related firms.[13]

In April 2024, the Ontario government announced that it will offer support to four companies in the automotive and food processing industries (DS Actimo Canada, Kautex Textron, Integrity Tool & Mold Inc. and Highbury Canco Corp.) to expand their manufacturing capacity in the area. The government anticipates that these companies will invest around $215 million, and create around 153 new local jobs.[14] In October 2024, NextStar Energy (a joint venture between Stellantis and LG Energy Solution) started production in their new electric vehicle battery plant in Windsor. At full production, the plant is expected to employ 2,500 workers and produce enough battery cells to power 450,000 vehicles annually. In addition, the Ontario government announced that it would invest over $9 million to train approximately 2,300 manufacturing and construction sector workers in Windsor.[15]

5.3. Demand Forecast Methodology

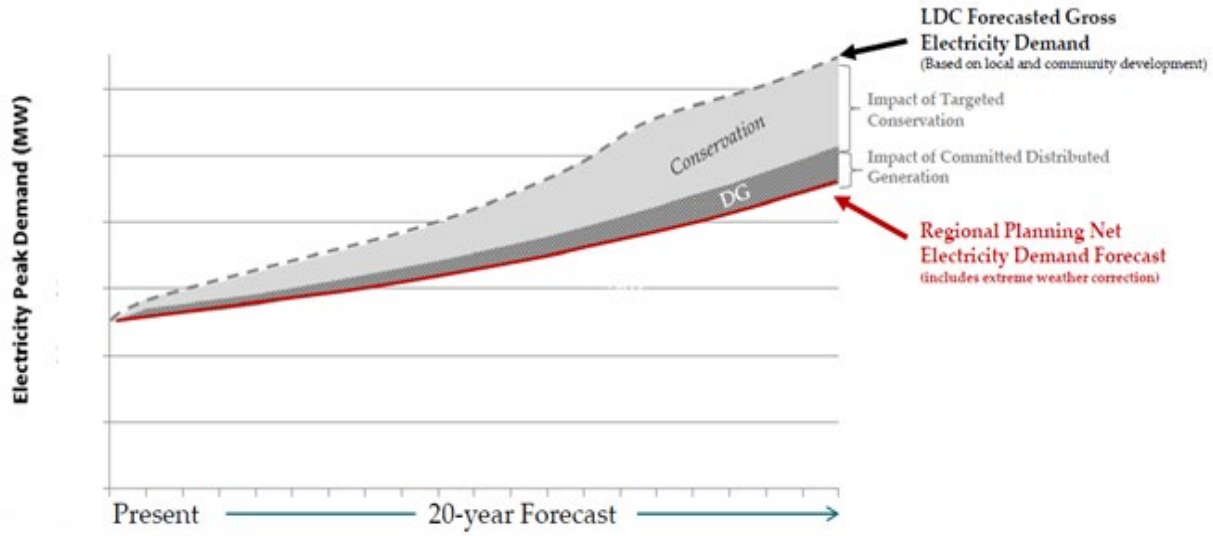
The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 6. Gross demand forecasts, which assume the weather conditions of an average year based on historical

[13] https://www.investwindsoressex.com/industries/advanced-manufacturing/#:~:text=Industry%20profile,Automate%20Canada
[14] https://news.ontario.ca/en/release/1004431/ontario-welcomes-125-million-manufacturing-boost-in-southwestern-ontario
[15] https://news.ontario.ca/en/release/1005049/ontario-investing-over-9-million-to-train-2300-workers-in-windsor

weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT, and adjusted to reflect extreme weather conditions in order to produce a Planning Forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The Ontario Energy Board has also published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 6 | Illustrative Development of Demand Forecast



5.4. Gross LDC Forecasts

Each participating LDC in the Windsor-Essex region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and in response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.5). The gross LDC forecasts assume median on-peak weather conditions and loading that is coincident to each station.

Figure 7 and Figure 8 show the gross non-coincident demand forecasts provided by the LDCs for the Windsor-Essex region under the Planning Scenario and High Scenario for summer and winter peak demand.

Figure 7 | Total Summer Gross Non-Coincident Demand Forecasts Provided by LDCs (Median Weather)[16]

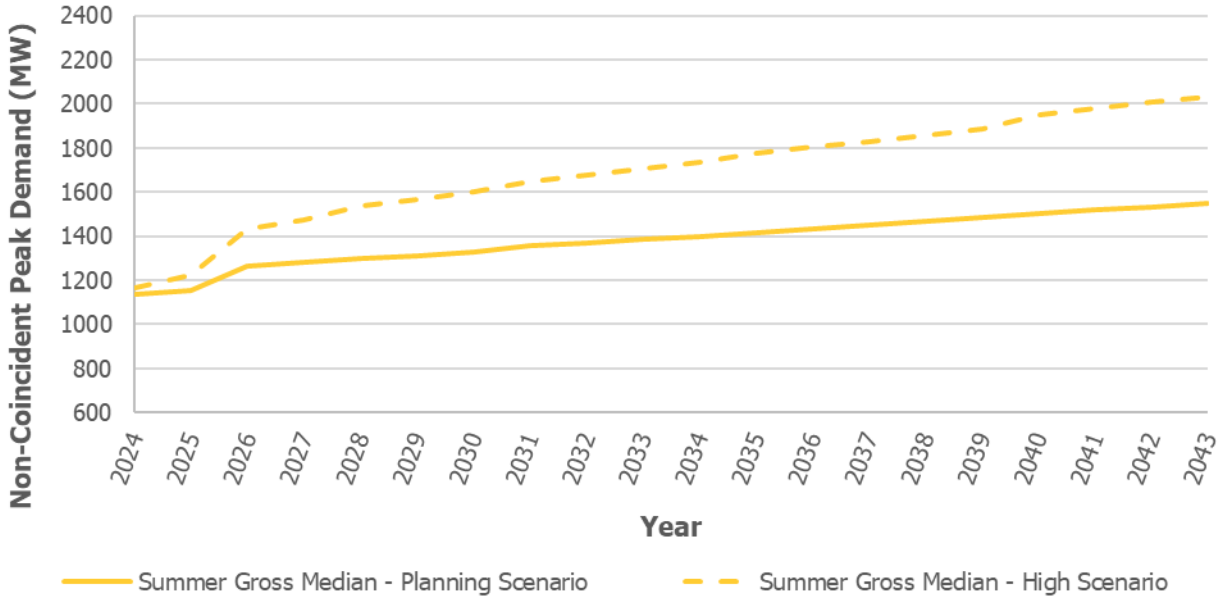


Figure 8 | Total Winter Gross Non-Coincident Demand Forecasts Provided by LDCs (Median Weather)[17]



[16] Excludes existing transmission-connected industrial customers in the Windsor-Essex region (historically contributing an average of 75 MW to the summer non-coincident peak demand), as well as forecasted greenhouse and industrial sector growth not assigned to specific LDCs.

[17] Excludes existing transmission-connected industrial customers in the Windsor-Essex region (historically contributing an average of 63 MW to the winter non-coincident peak demand), as well as forecasted greenhouse and industrial sector growth not assigned to specific LDCs.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities and communities that they serve. The IESO typically carries out demand forecasting at the provincial level. More details on LDC load forecast assumptions can be found in Appendix B.2 to B.6.

5.5. Contribution of Energy Efficiency to the Forecast

Energy efficiency is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. Energy efficiency is achieved through a mix of codes and standards amendments, as well as eDSM program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to eDSM program-related activities account for the 2021–2024 Conservation and Demand Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. Under the 2021–2024 Conservation and Demand Management Framework, the IESO centrally delivered programs on a province-wide basis to serve business and residential customers, as well as Indigenous communities.

The demand forecast was finalized before approval of the new 2025–2036 eDSM framework and its savings targets, and assumes that programs continue at 2021–2024 Conservation and Demand Framework levels, with adjustments for gross demand growth. The increased targets under the new framework may impact the exact scale and timing of needs.

Figure 9 and Figure 10 show the estimated total yearly reduction to the demand forecast due to energy efficiency (from codes, standards, and eDSM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.8 and Appendix E.

Figure 9 | Total Summer Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)

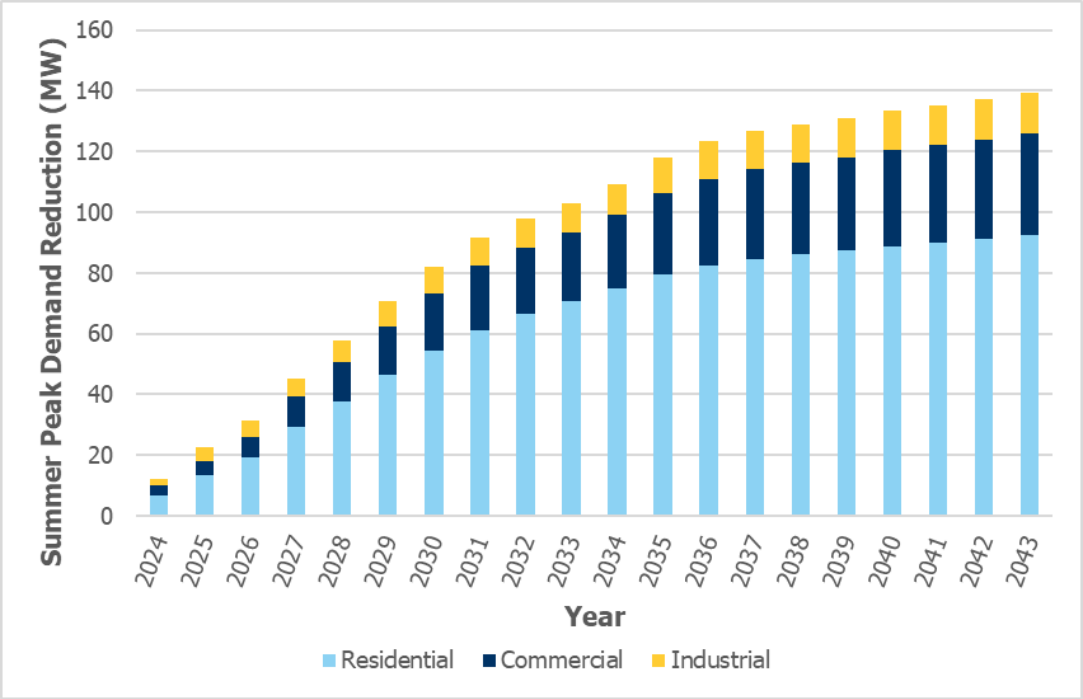
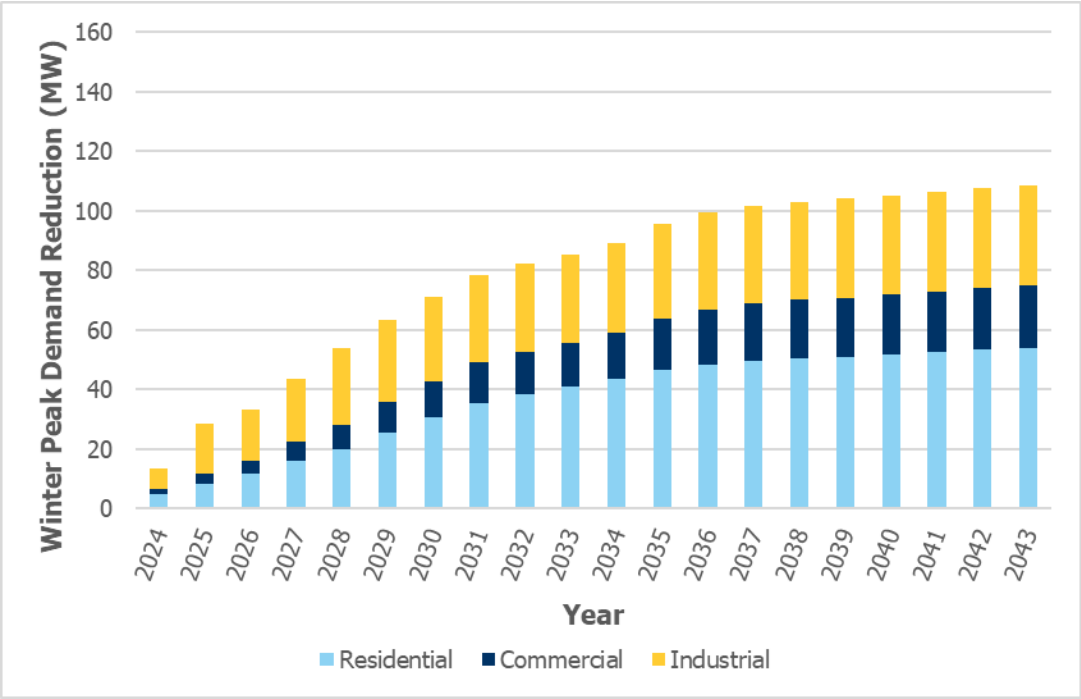


Figure 10 | Total Winter Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)

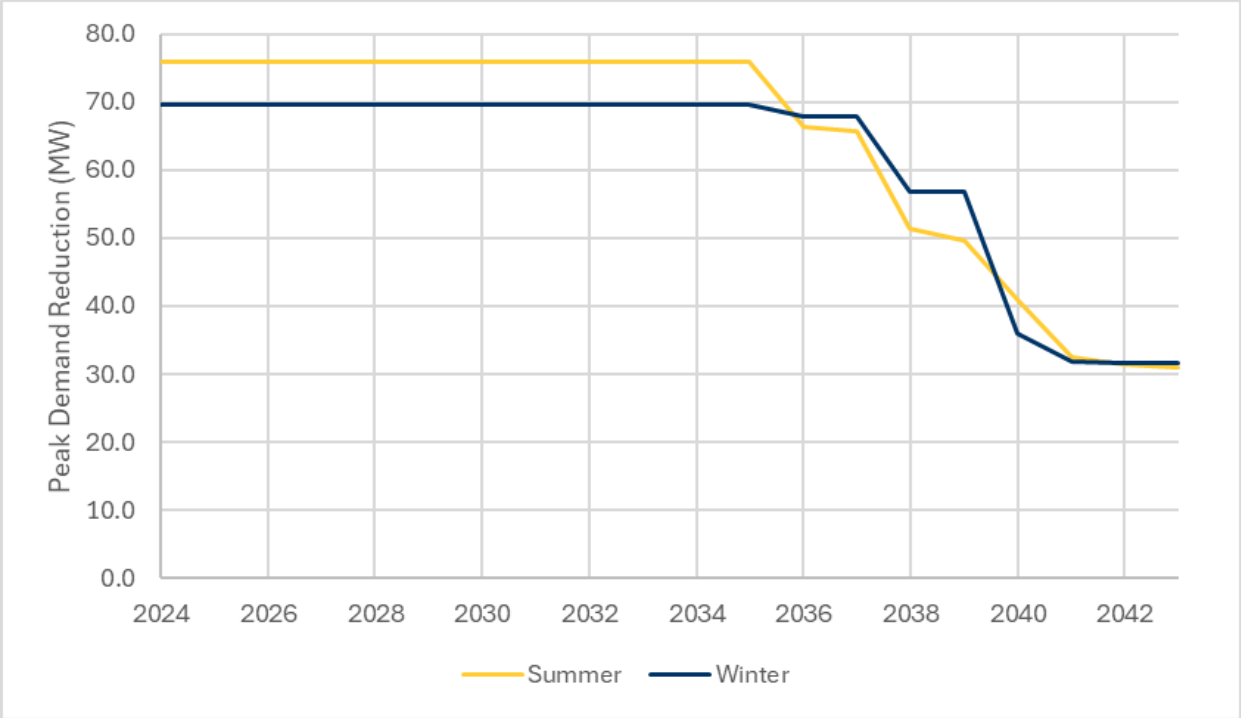


5.6. Contribution of Distributed Generation to the Forecast

In addition to energy efficiency, DG in the Windsor-Essex region is also forecast to offset peak demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Tables 3 and 4 of the accompanying IRRP data tables (provided as a separate Excel file). Most of the total installed DG capacity in the Windsor-Essex region is wind and solar, with the remainder being natural gas (CHP) and biogas facilities.

After reducing the demand forecast due to energy efficiency (as described in Section 5.5) the forecast is further reduced by the expected contribution from contracted DG. Figure 11 shows the impact of DG on reducing the Windsor-Essex region demand forecasts. Note that facilities without a contract with the IESO were not included in the DG peak demand reduction forecast, except for DG facility information provided directly by the LDCs.

Figure 11 | Peak Demand Reduction Due to DG



A decision was made within the Technical Working Group to consider the expected lifespan of each DG facility based on resource type, rather than assuming that facilities will not be re-contracted past their current contract end date. In alignment with the IESO 2024 Annual Planning Outlook, the assumption for resource expected lifespans was 25 years for solar, and 30 years for wind, natural gas and biogas. A total of 76 MW of summer peak contribution is identified for the Windsor-Essex region in 2024, reducing to 30 MW by 2044. This reduction is reflected in the planning forecasts as discussed in the next section.

5.7. Planning Forecasts

After taking into consideration the combined impacts of energy efficiency and DG, a 20-year net demand forecast was produced for the Windsor-Essex region considering the Planning Scenario and High Scenario. The following subsections describe the implementation of weather correction to create the Planning Forecast and High Forecast, the total demand outlook for the region, and the specific demand outlooks for the agricultural and industrial forecasts (which represent significant and unique portions of the overall load growth).

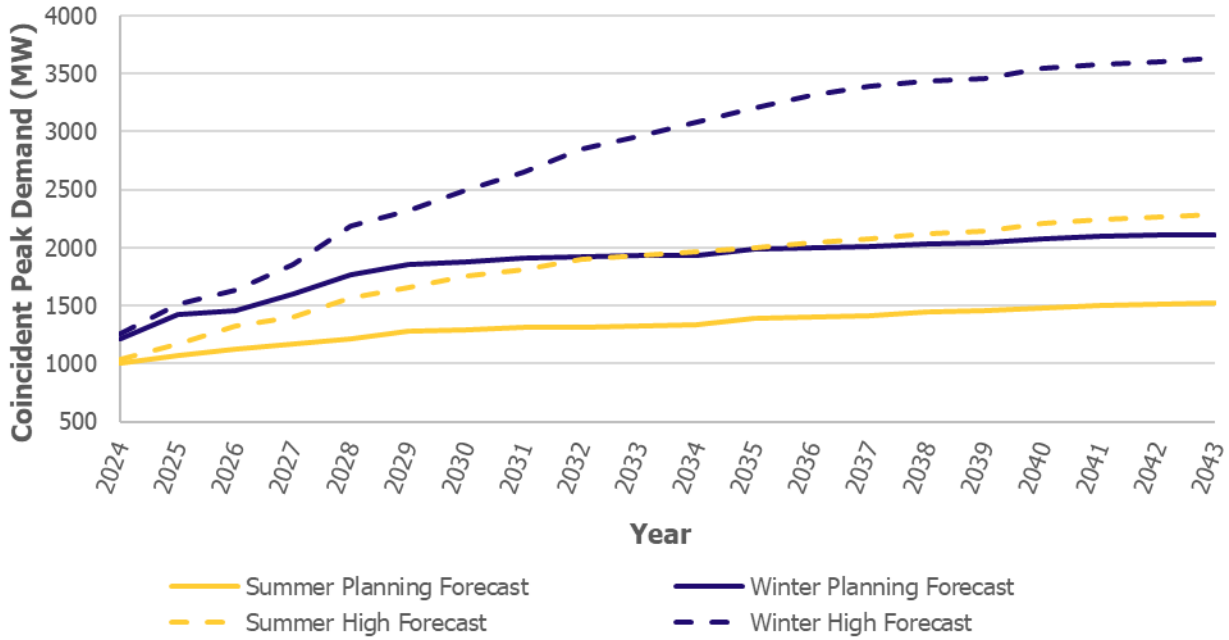
5.7.1. Net Extreme Weather Planning Forecast

The net extreme weather forecast is created by adjusting the net median weather forecast (the gross demand forecast including the forecast DG and eDSM impacts) for extreme weather conditions. The weather correction methodology is described in Appendix B.1. The Planning Forecast results from the net extreme-weather forecast applied to the Planning Scenario.

Note that this Planning Forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past five years.

The coincident net extreme weather forecast for the Windsor-Essex region is shown in Figure 12 Figure 12: both the Planning Forecast and High Forecast representing peak summer and winter demand.

Figure 12 | Net Extreme Weather Planning Forecast and High Forecast for the Windsor-Essex Region



5.7.2. High Forecast Scenario

The Technical Working Group developed a High Forecast sensitivity scenario for the Windsor-Essex region, which is also shown in Figure 12. The High Forecast is meant to quantify prospective development in the Windsor-Essex region that is not yet committed. This higher demand scenario is driven by significant growth potential in the agricultural and industrial sectors, as described in detail in Sections 5.7.3 and 5.7.4.

The High Forecast can be used as a proxy for a variety of factors that could drive demand higher over the next 20 years, including, but not limited to:

- Electric vehicle charging;
- Electrified space and water heating;
- A faster pace of residential development;
- Unanticipated new industrial customers of growth among existing industrial customers; and
- Higher growth in the agricultural sector.

The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future electricity concerns may be and when they could materialize. This information can also be useful for communities conducting community energy plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders to consider when planning various projects in the region. Moreover, while developing this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.7.3. Agricultural Forecast

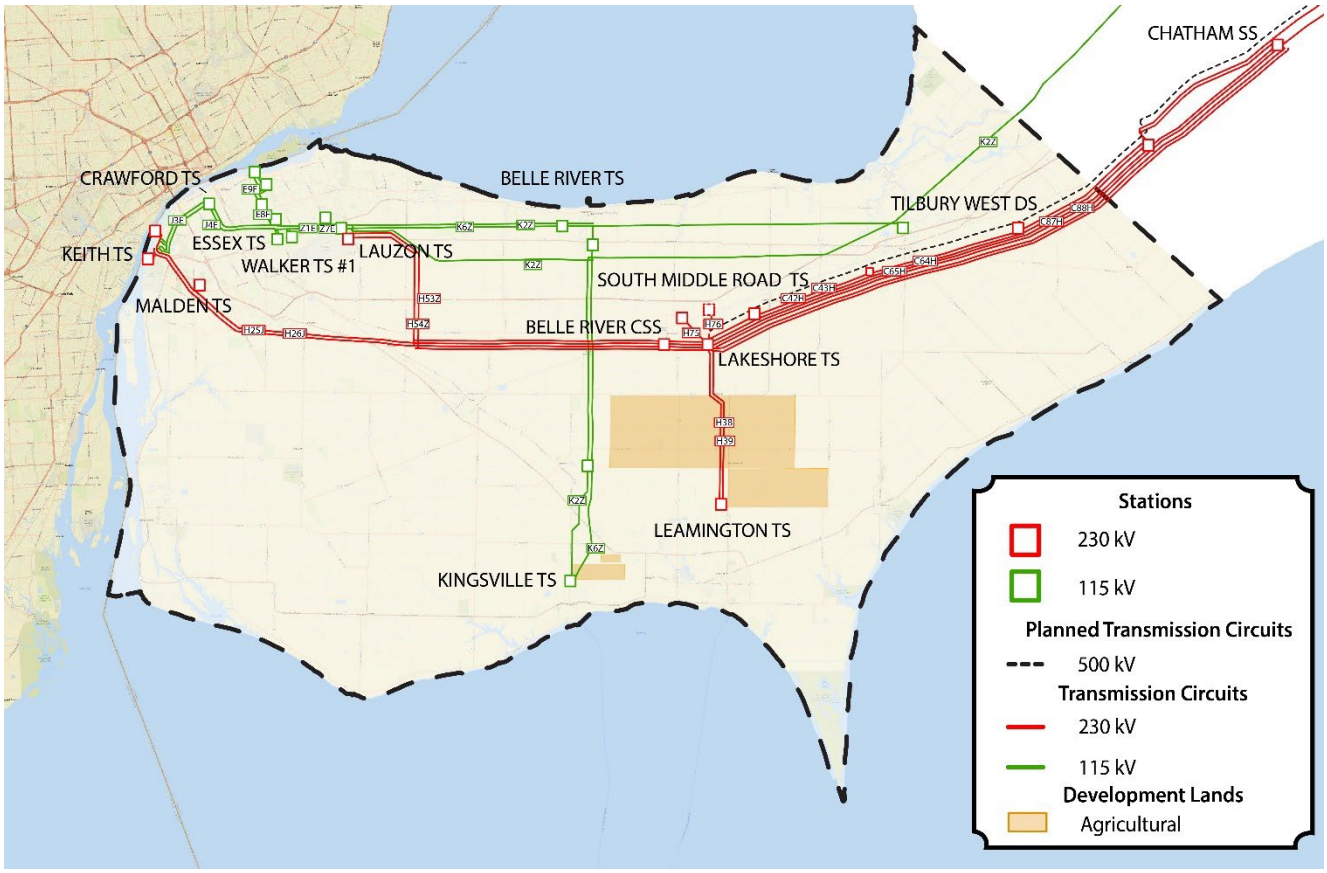
The agricultural forecast was developed to capture the future growth of the agricultural sector, including greenhouses, in both the Planning Forecast and High Forecast scenarios. The forecast incorporates the anticipated greenhouse developments that were known at the time it was produced. The greenhouse sector continues to expand – the previous IRRP projected a five per cent annual growth rate, which has been realized in the near term. Future growth in the Planning Forecast is expected to be four per cent for the sector, with High Forecast growth of seven per cent. Increasing construction and operational costs contribute to growth levels projected to be slower than the 2019 IRRP forecast.

The Ontario agricultural market is increasingly looking for local greenhouse food as a reliable and secure alternative to importing from traditional suppliers. As a result, Ontario greenhouse growers are expanding their operations, changing their propagation practices, and modifying the items they grow. The sector is shifting from propagating plants in fields to propagation within the greenhouse, to reduce insect contamination and other impurities. Vegetable growers are also starting to expand into berry production, which requires chilled warehouses and more packing space.

To develop the agricultural forecast, engagement was conducted with Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public. Public webinars allowed stakeholders to provide their inputs into the planning process and issue public comments on the load forecast, needs, and recommendations. In particular, information on the geographic locations of agricultural growth in Windsor-Essex was provided by municipalities in

the region and Ontario Greenhouse Vegetable Growers (OGVG). Greenhouse development remains concentrated in the Leamington and Kingsville areas of Windsor-Essex. This geographic information was used as an approximation to map the agricultural forecast load for the purpose of conducting the needs and options studies, as shown in Figure 13.

Figure 13 | Geographic Locations of Agricultural Growth in the Windsor-Essex Region



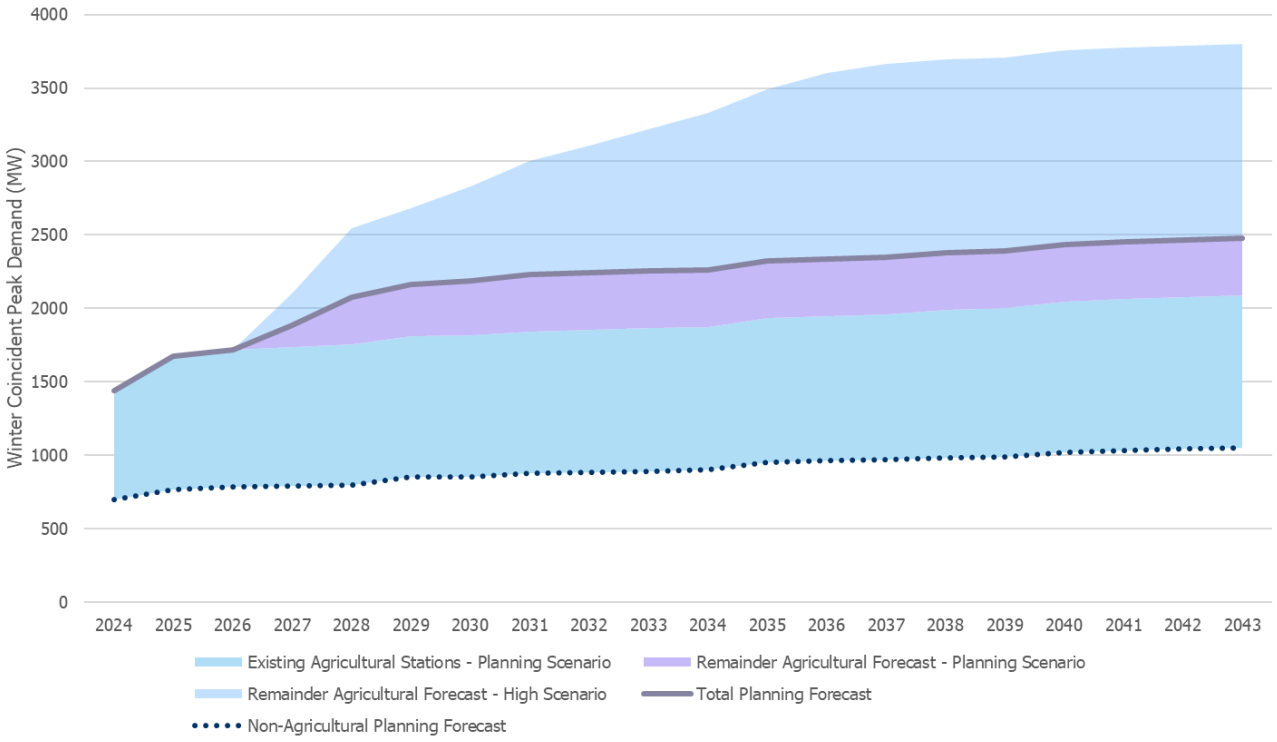
After the forecast was finalized, there were early indications of greenhouse load potential in the area between Wheatly toward Chatham-Kent, along Lake Erie. This pocket of growth is likely to be located in the Chatham-Kent/Lambton/Sarnia planning region outside of the geographic/electrical boundaries shown in Figure 13. It is not expected that this growth will detract from the forecast growth in Windsor-Essex.

Greenhouse developments are subject to a variety of factors, including land availability, municipal support, and water supply. The availability of water supply is a key constraint, with some growers digging their own wells and capturing rainwater to be processed and used to overcome the limitations of municipal/county water supplies.

Peak demand for the agricultural forecast is seen in the winter when greenhouses use grow lights to support their crop production. As greenhouses shift to LED lights (including under an IESO-administered eDSM program), peak demand per acre drops, allowing greenhouses to produce more for the same electricity usage. Grow lights tend to be used between October to April, but growers consider September, October, March, and April to be shoulder months. Electricity demand for greenhouses persists year-round as production continues; however, grow lights are not typically

required during summer months. Figure 14 depicts the winter agricultural peak demand forecasts for the Planning and High scenarios.

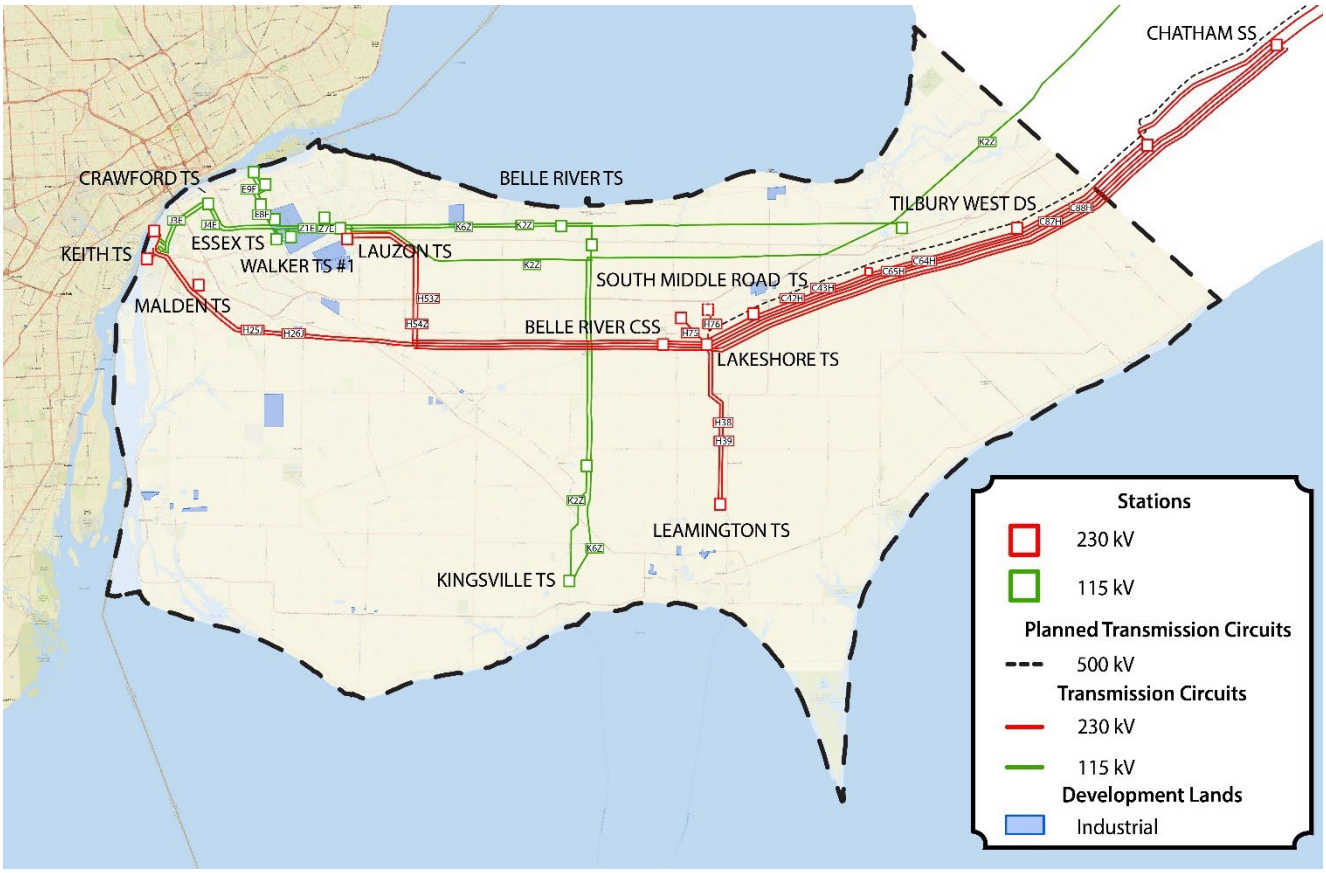
Figure 14 | Agricultural Winter Forecast



5.7.4. Industrial Forecast

Information on potential industrial development lands in the Windsor-Essex region was provided from the County of Essex and Invest WindsorEssex – the not-for-profit organization supported by the City of Windsor and County of Essex responsible for advancing economic development in the region. As shown in Figure 15, industrial development lands are primarily concentrated in the West Essex and Windsor area. The municipalities supplied information on potential industrial land developments, and in some cases, industrial expansion forecasts used in the Planning Scenario and High Scenario. Across the Windsor-Essex region, approximately 800 new acres have been allocated for industrial development, with construction started in 2024.

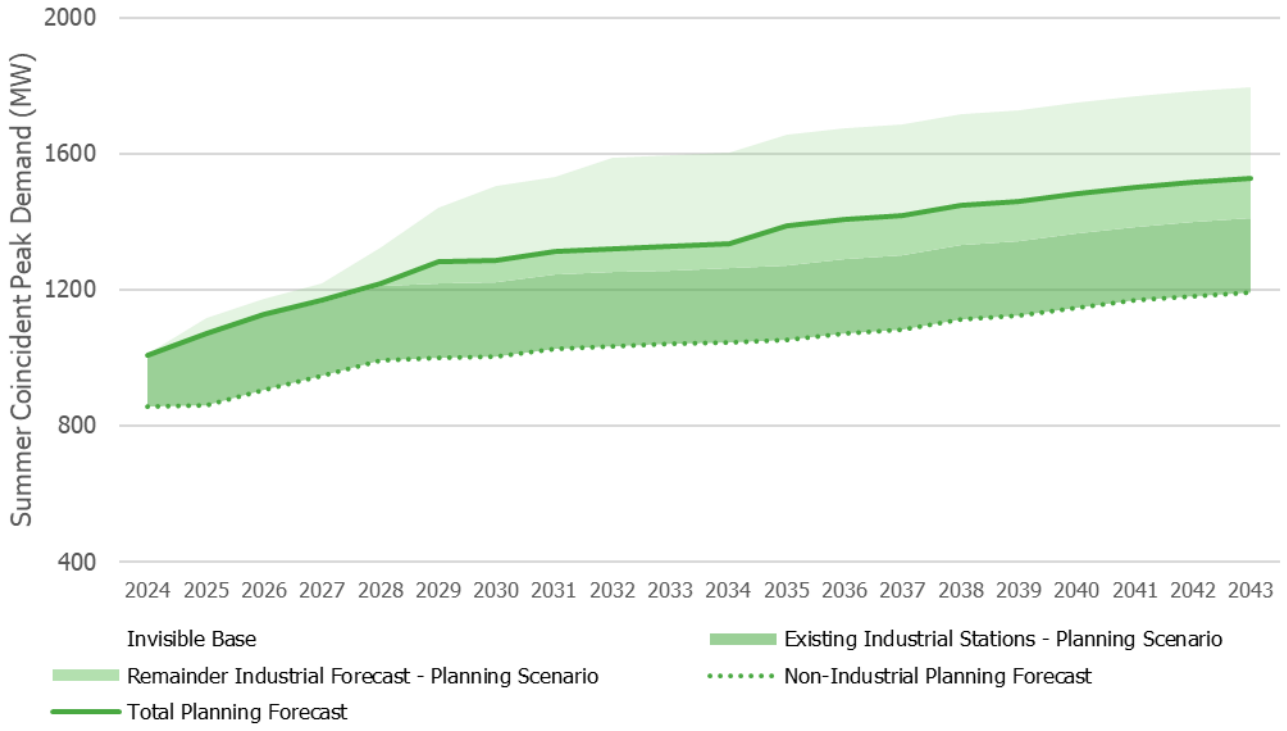
Figure 15 | Geographic Locations of Industrial Growth in the Windsor-Essex Region



The information provided by Invest WindsorEssex identifies approximately 20 new projects in the area requiring significant electrical supply. In addition, anticipated development in the Town of LaSalle could require approximately three gigawatts of power to service business parks and natural environment developments.

The Planning Forecast considered firm and reasonably expected industrial loads, while the High Forecast also incorporated less certain industrial load potential based on municipal and stakeholder input. Figure 16 shows the contributions of the industrial loads to the forecast under the Planning and High Forecasts, relative to the loads at existing stations, and particularly the existing industrial loads in the region. The demand captured in the industrial forecast is relatively constant throughout the year, as industrial loads generally have no relationship with weather conditions.

Figure 16 | Industrial Contribution to Summer Forecast



5.8. Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for station(s) included in identified needs were developed to characterize the needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand, such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak Planning Forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details, including hourly heat maps for needs where non-wires alternatives other than eDSM were assessed, can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors, like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of the implementation of the plan.

6. Needs

6.1. Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-5.1, and Northeast Power Coordinating Council (NPCC) Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment (i.e., breakers, disconnect switches, low-voltage bus, or high voltage circuits) or by voltage drop limitations, which are independent of thermal ratings.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is referred to as the load meeting capability (LMC) of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-5.1, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter by an asset condition assessment, which is based on a range of considerations, such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early medium-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage

within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the Windsor-Essex IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 to 6.7.1 for the most limiting season for each of the three sub-systems.

6.2. West Essex and Windsor Sub-system Needs

There is an asset replacement need at Lauzon TS DESN 2 that, when combined with the station capacity need under the Planning Forecast, was assessed for the opportunity to consider an integrated solution. There is also a supply capacity need on transmission path into the West Essex and Windsor sub-system, which consists of the four 230 kV supply circuits going west from Lakeshore TS: two circuits to Lauzon TS (H53Z and H54Z) and two circuits to Keith TS (H25J and H26J). Table 4 summarizes the needs for the West Essex and Windsor sub-system under the Planning Forecast.

Table 4 | Summary of West Essex and Windsor Sub-system Planning Needs

Need	Need Date	Need by 2043 (MW)
Lauzon DESN 2 (T7/T8) end-of-life	2029	n/a
Lauzon DESN 2 (T7/T8) station capacity	2032	37
West Essex and Windsor supply capacity	2032	230

6.2.1. Asset Replacement Needs

The asset replacement need for Lauzon TS DESN 2 was included within the scope of the Windsor-Essex IRRP for its potential integration with the station's capacity need.

6.2.1.1. Lauzon DESN 2 End-of-Life Needs

Lauzon TS DESN 2 transformers were identified as requiring replacement based on asset condition and were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere (MVA) units by 2032. The IRRP 20-year demand forecast identified station capacity needs at Lauzon TS DESN 2, necessitating the need to reconsider the like-for-like replacement plan.

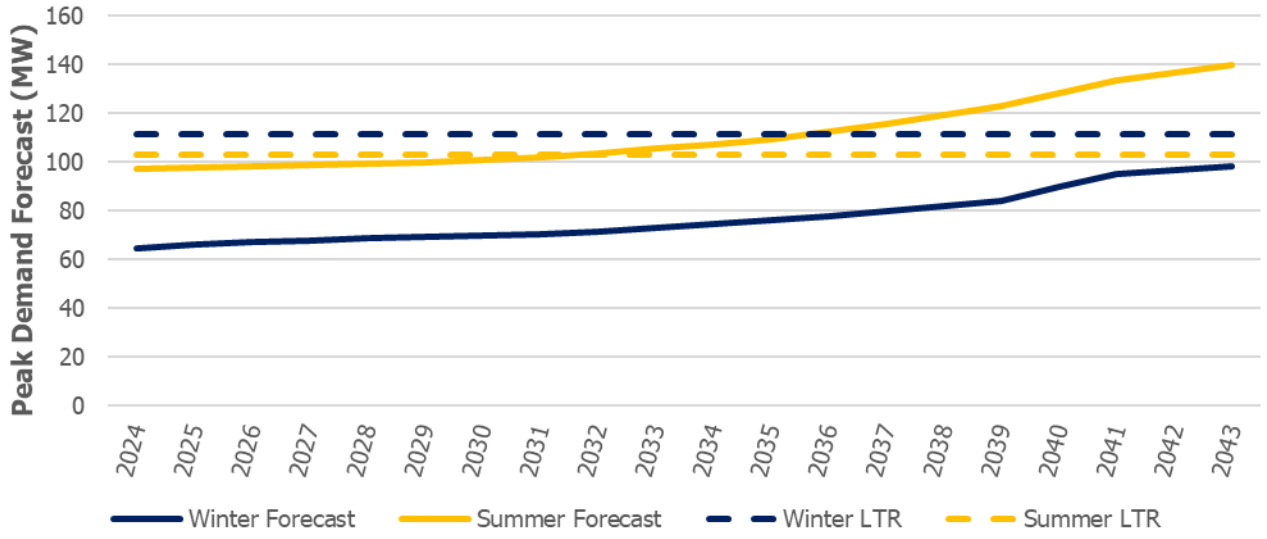
6.2.2. Station and Supply Capacity Needs

The station capacity needs are driven by industrial loads that cannot be accommodated at the existing supply stations due to the magnitude and uncertainty of their location, as well as load growth at Lauzon TS.

6.2.2.1. Lauzon DESN 2 Station Capacity Needs

Supplying customers in West Essex and Windsor, Lauzon TS DESN 2 is forecast to reach its summer station capacity limit in 2032 and grow to a 37 MW need by 2043. The station consists of two 115 kV/27.6 kV transformers with an LTR of 103 MW.

Figure 17 | Lauzon TS DESN 2 Station Capacity Need



6.2.3. West Essex and Windsor Supply Capacity Need

The load in the West Essex and Windsor sub-system is supplied through 230 kV transmission lines from Lakeshore TS (near Comber) to Lauzon TS and to Keith TS (both in Windsor). The 230/115 kV autotransformers at Lauzon TS and Keith TS supply the 115 kV network in West Essex and Windsor. The area is also served by local generation in the Windsor area. The LMC of the sub-system is limited to 840 MW based on the thermal capability of the circuits going to Lauzon TS under the various planning scenarios and applicable contingencies to the circuits along the Lakeshore to Lauzon TS/Keith TS corridor. Considering the forecast growth in the sub-system – including the industrial forecast presented in Section 5.7.4 – this sub-system has a supply capacity need starting in 2032 with 65 MW, which increases to 230 MW in 2043.

6.2.4. High Forecast Needs

Considering the High Forecast, the West Essex and Windsor supply capacity need increases to 840 MW and is advanced by seven years – to 2025 from 2032 under the Planning Forecast. This illustrates the potential impact on the need year, if a portion of the High Forecast materializes. Considering station capacity needs, the Lauzon TS DESN 2 need is advanced to the near-term and two new station capacity needs are identified at Malden TS and Keith TS, as summarized in Table 5.

Table 5 | Summary of New/Updated West Essex and Windsor Sub-system High Forecast Needs

Need	Need Date[18]	2043 Need (MW)
Lauzon DESN 2 (T7/T8) station capacity	2025	120
West Essex and Windsor supply capacity	2025	790
Keith TS station capacity	2033	42
Malden TS station capacity	2040	45

6.3. Kingsville-Leamington Sub-system Needs

The Kingsville-Leamington sub-system continues to experience rapid electricity demand growth from greenhouse loads. Due to the nature of the load growth, the sub-system is expected to be winter peaking and has a unique load profile relative to the rest of the region. Thus, all loading and capacity values in this section refer to the non-coincident winter peak. There are restoration needs, as well as station and supply capacity needs that have been identified, which will be discussed in the following subsections. Table 6 summarizes the Kingsville-Leamington sub-system needs.

Table 6 | Summary of Kingsville-Leamington Sub-system Needs

Need	Need Date[19]	2043 Need (MW)
Leamington TS load restoration	Immediate	320
Kingsville-Leamington Greenhouse station and supply capacity	2027	390

6.3.1. Planning Load Security and Restoration Needs

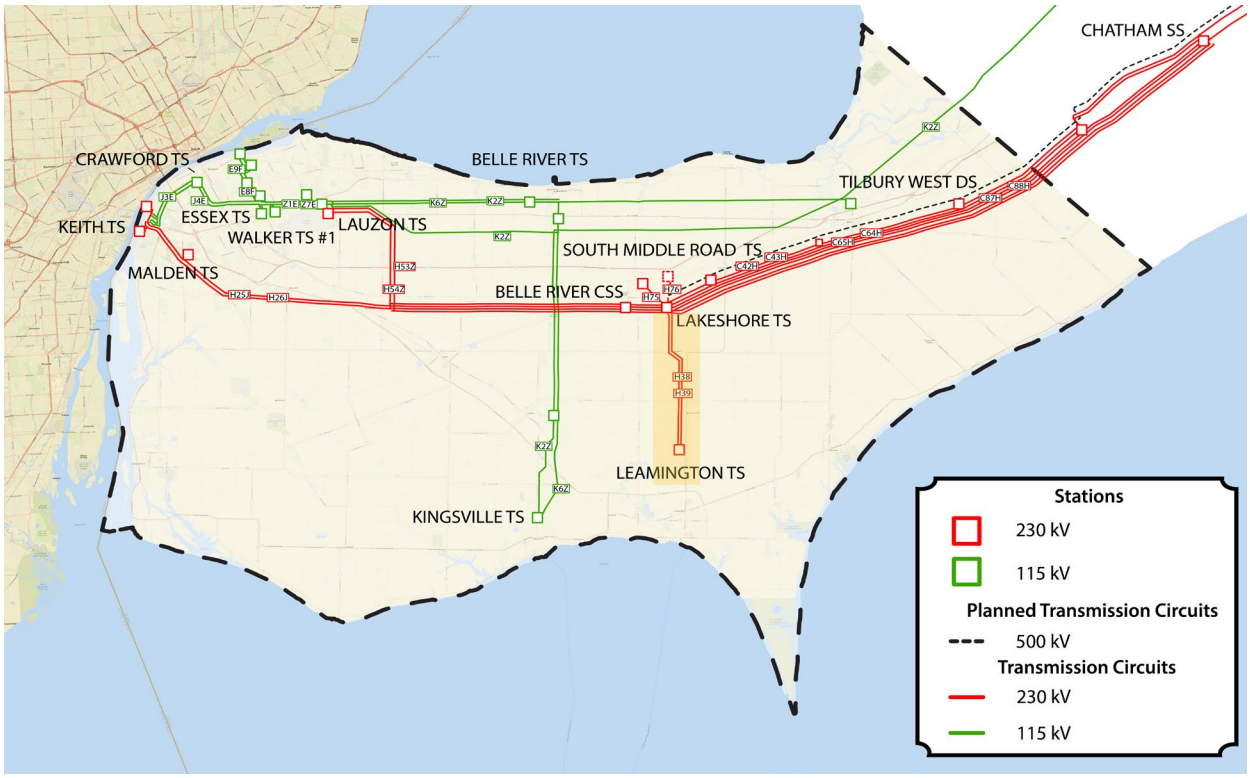
6.3.1.1. Leamington TS Supply (H38/H39 circuits)

The load restoration need on the twelve kilometre, 230 kV double-circuit line from Lakeshore TS to Leamington TS was identified in the 2022 Windsor-Essex Addendum. Leamington TS DESN 1 and DESN 2, as well as two transmission-connected customers south of Lakeshore TS, are supplied radially through these circuits. Figure 18 depicts this portion of the transmission system in the Windsor-Essex region.

[18] Based on non-coincident station forecasts for station capacity needs and coincident station forecasts for supply capacity needs, as explained in Section 0.

[19] Based on non-coincident station forecasts.

Figure 18 | Map of Leamington TS Transmission (Highlighted Yellow)



As per ORTAC Section 7.1, no more than 150 MW is allowed to be interrupted by configuration following a single-element contingency, and a total of 600 MW (by configuration, load curtailment or load rejection) following a two-element contingency. The current system has a RAS, whereby up to 170 MW would be lost following the loss of either radial supply circuit. With all recommended bulk reinforcements in-service, it is expected that the RAS will no longer be needed, such that the load security need is addressed.

By the end of the study period, approximately 490 MW would be interrupted following an outage to both circuits, H38 and H39, by configuration. Of this 490 MW, Hydro One Transmission has indicated that only 30 MW of the load could be restored within four hours through a load transfer to Kingsville TS. Thus, the restoration targets of load in excess of 250 MW cannot be restored within 30 minutes, nor can load in excess of 150 MW be restored within four hours. This is in violation of load restoration planning requirements (ORTAC Section 7.2), and is summarized in Table 7.

Table 7 | Load Restoration Planning Requirements on the Leamington Supply Lines

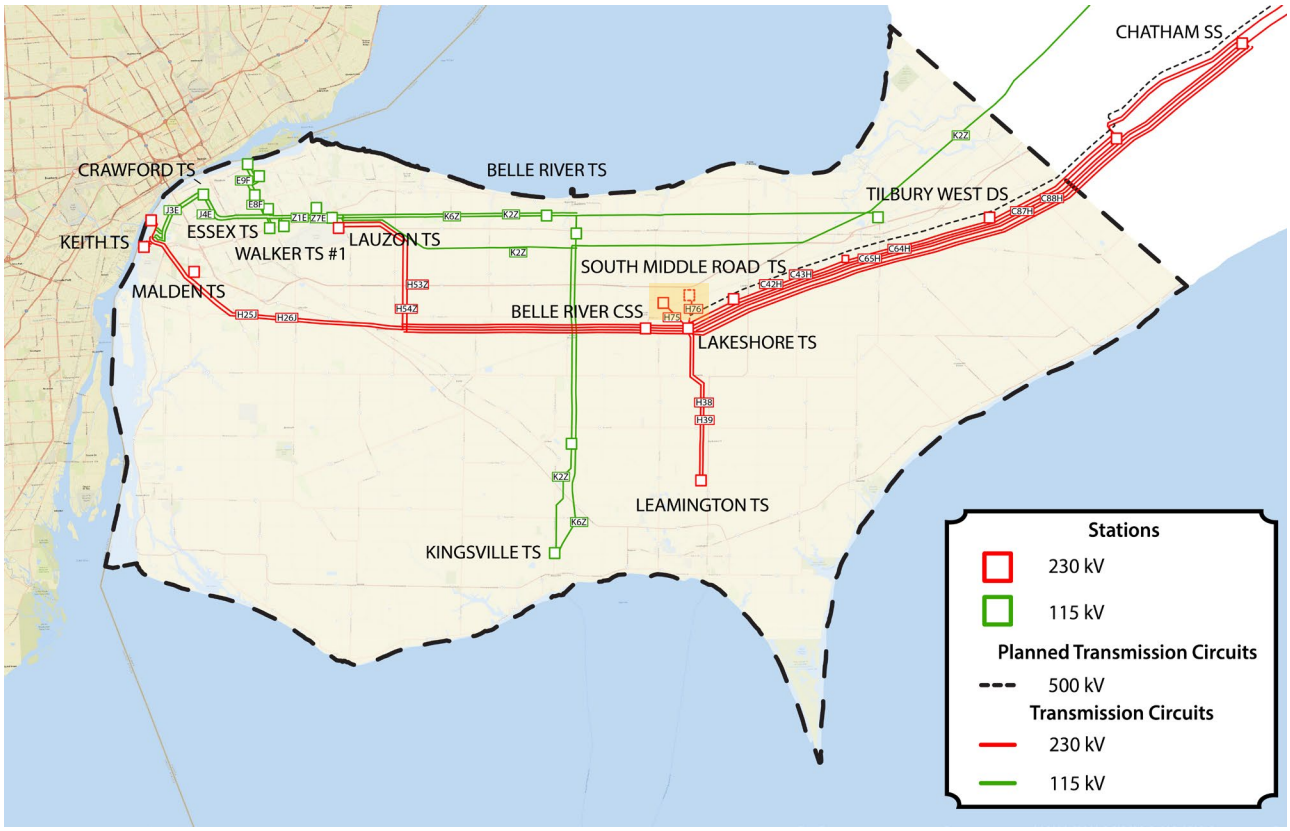
Time Post-Contingency	ORTAC Requirement: Restoration Target	Peak Load to be Restored	Achievable Based on the Current and Planned Transmission System?
Within 30 minutes	Load in excess of 250 MW	240 MW	No
Within four hours	Load in excess of 150 MW	340 MW	No, 30 MW is achievable
Within eight hours	All load	490 MW	Yes – the circuits are assumed to be restored by the transmitter within eight hours

6.3.1.2. South Middle Rd Supply (H75/H76)

A load restoration need on the one kilometre, 230 kV double-circuit line from Lakeshore TS to South Middle Rd TS (H75 and H76) was identified in the Needs Assessment. South Middle Rd TS DESN 1 and DESN 2 are supplied radially through these circuits. Figure 19 provides an overview of this portion of the transmission system in the Windsor-Essex region. Since these circuits are one kilometre or less in length, the loss of H75 and H76 is not a respected double contingency per planning criteria. Thus, there are no load restoration violations identified.

As per ORTAC criteria, no more than 150 MW is allowed to be interrupted by configuration following a single contingency. Under the current configuration and RAS, 120 MW of load would be lost following the loss of H75 or H76, which falls within the load security criteria. Thus, no load security concerns have been identified.

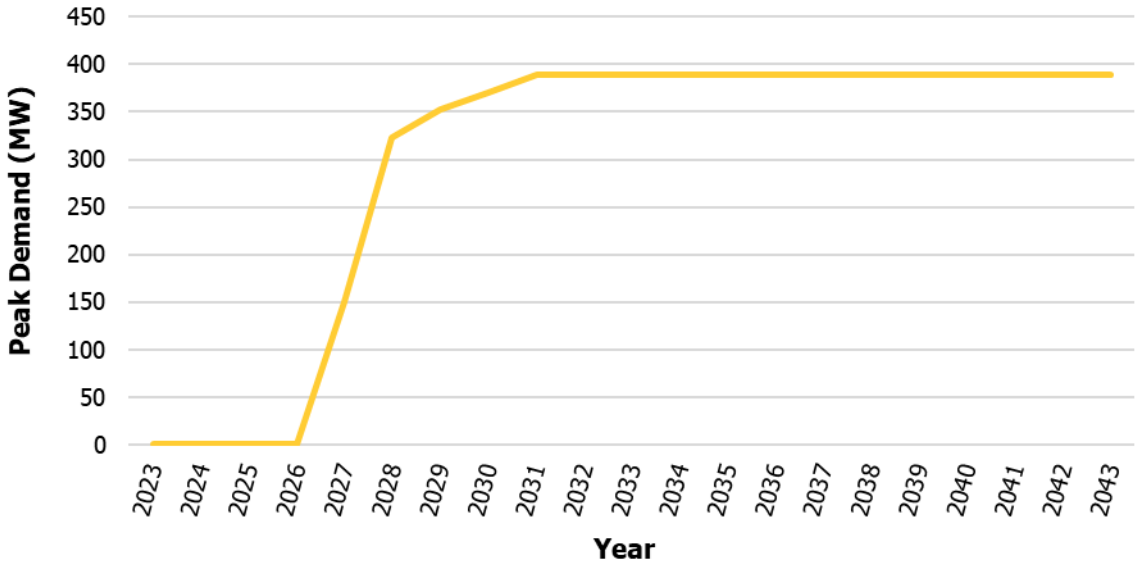
Figure 19 | Map of South Middle Rd Transmission Supply (Highlighted Yellow)



6.3.2. Station and Supply Capacity Needs

The Kingsville-Leamington capacity need is driven by load growth and new greenhouse developments that cannot be accommodated at the existing supply stations. The capacity need starts at 150 MW in 2027 and quickly reaches 390 MW by 2031.

Figure 20 | Kingsville-Leamington Greenhouse Developments Capacity Need



The supply capacity in the Leamington area is measured by the LMC on the Leamington tap – the 230 kV circuits identified as H38 and H39. The current system is limited to 380 MW due to the maximum allowable voltage drop.[20] There is sufficient capacity to supply the existing loads on these circuits, but it is unable to accommodate the 390 MW in additional greenhouse demand.

The supply capacity in the South Middle Rd area, measured by the LMC on the South Middle Rd tap, is limited to 455 MW, also based on maximum allowable voltage drop, assuming the voltage dependent load model. This is limited to 417 MW, based on the station capacity. This is sufficient to supply the two DESN stations at South Middle Rd TS, approximately 410 MW combined for the 2043 winter peak.

6.3.3. High Forecast Needs

Under the High Forecast, the magnitude of the load increases significantly among the total loads in the Kingsville-Leamington area – consisting of Kingsville TS, Leamington TS, South Middle Rd TS, and the new greenhouse developments. Considering the non-coincident peaks of theses loads, the electricity demand forecast increases from 1,400 MW in the Planning Forecast to 2,400 MW.

6.4. Lakeshore/Tilbury Sub-system Needs

There are immediate summer station capacity needs at Belle River TS. In the longer term, there are station capacity needs at Tilbury West DS, which emerge in 2036 due to a summer need, but the magnitude of need in 2043 is driven by a winter need. Table 8 summarizes needs for the Lakeshore/Tilbury sub-system.

Table 8 | Summary of Lakeshore/Tilbury Sub-system Needs

Need	Need Date	2043 Need (MW)
Belle River TS station capacity	Immediate	16
Tilbury West DS station capacity[21]	2036	13

6.4.1. Station Capacity Needs

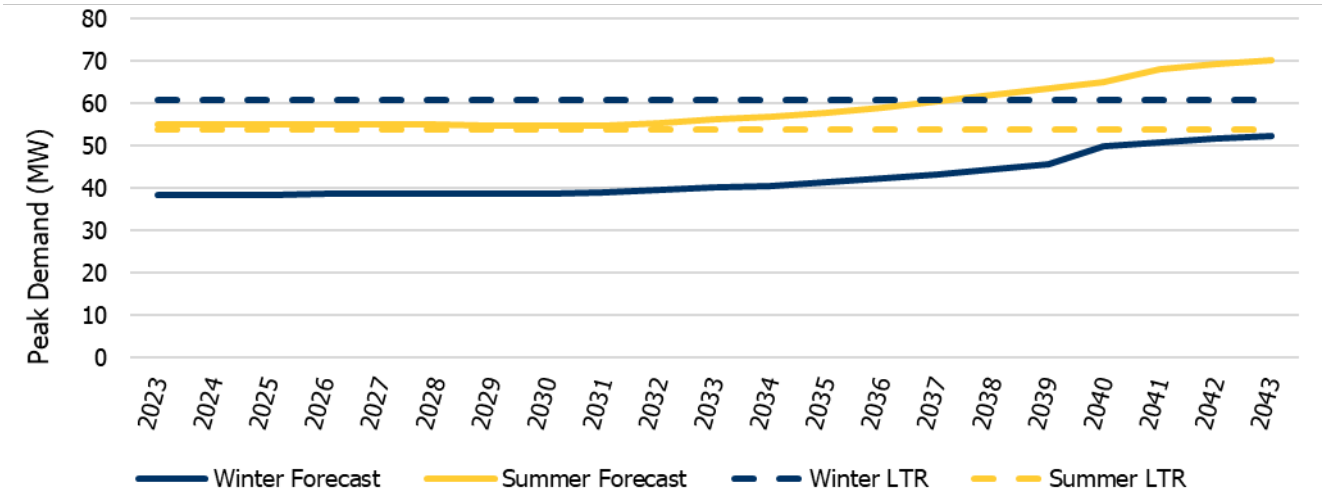
6.4.1.1. Belle River TS Station Capacity Needs

Belle River TS has an immediate summer station capacity need of one megawatt in 2024. Over the forecast period, the summer need increases to 16 MW by 2043. There is no winter need over the forecast period. Figure 21 shows the peak demand forecast relative to the summer and winter LTR values for Belle River TS.

[20] With all elements in service, ORTAC Section 4.3 limits the percentage voltage drop change following a contingency on the transmission system to 10 per cent before tap changer action and 10 per cent after tap changer action.

[21] Need date is driven by summer need but size of need is driven by winter need.

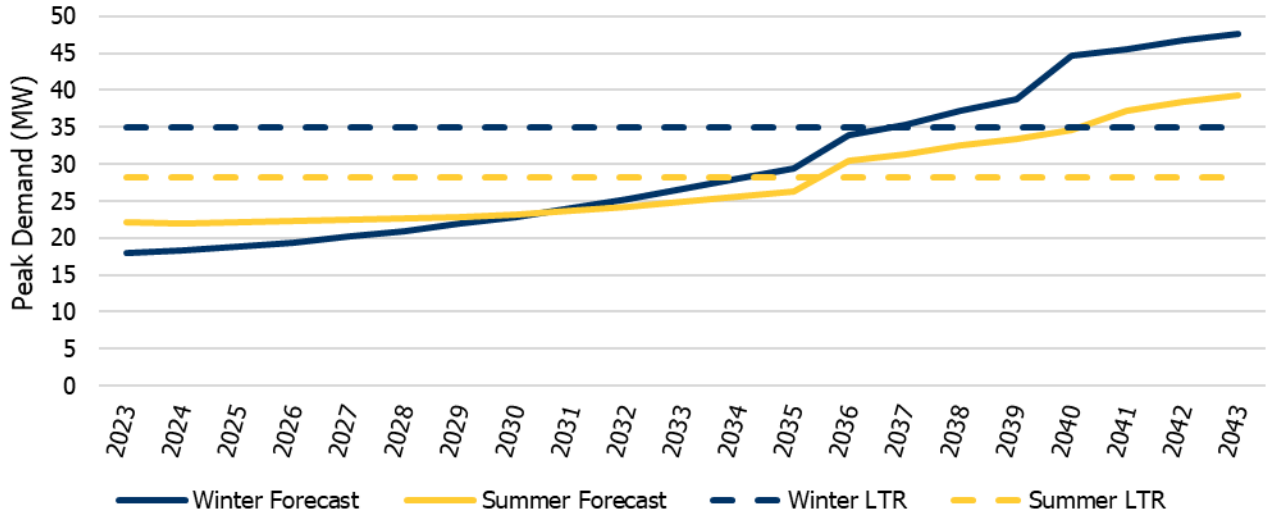
Figure 21 | Belle River TS Station Capacity Need



6.4.1.2. Tilbury West DS Station Capacity Needs

Tilbury West DS has a station capacity need of three megawatts in summer 2036, which increases to 13 MW by winter 2043. Figure 22 shows the Tilbury West DS demand forecast in relation to the summer and winter LTR values.

Figure 22 | Tilbury West DS Demand Forecast



6.5. Operational Issues

Operational issues are not defined as planning needs; however, they affect the reliability and operability of the region. As a result, the Technical Working Group investigates the potential for addressing operational issues using solutions already being considered to meet planning needs, where opportunity for overlap exists. The following operational issues were identified by the Technical Working Group:

- **Kingsville-Leamington Sub-system Load Security:** There is a temporary RAS in place for the Kingsville-Leamington sub-system, known as the Lakeshore RAS. This scheme allows for load connections in advance of the recommended transmission reinforcements coming into service, to continue to enable growth in the interim. However, the RAS impacts reliability in the Kingsville-Leamington sub-system. It is also operationally complex, due to the lack of redundancy and interaction with the Windsor RAS.
- **Lakeshore TS Station Configuration:** There is an operational concern at Lakeshore TS, where a contingency can that introduce low voltage concerns on the downstream circuits. in
- **Lauzon TS Station Configuration:** There is an operational concern at Lauzon TS., where a contingency can result in low voltage concerns, in the area.
- **Lakeshore/Tilbury sub-system Load Security:** There is an under voltage load shedding (UVLS) scheme in place for the Lakeshore/Tilbury sub-system. This sub-system is radially supplied from Lauzon TS, resulting in post-contingency voltage concerns., which is mitigated through the UVLS. As load increases in this sub-system, the reliance on this scheme may increase.

6.6. Supply into Windsor-Essex

The focus of regional planning is to ensure reliable supply within a region. While supply into the region is out of scope of this IRRP, the High Forecast indicates a potential need for additional transmission reinforcement into the Windsor-Essex region in the mid-2030s. The ongoing South and Central Bulk Plan will assess this potential need, while considering the transmission reinforcements and/or network expansion required to support economic development, reduce reliance on emitting resources and enable reliable long-term supply.

6.7. Summary of Identified Needs

6.7.1. Planning Needs

Table 9 provides an overview of all the Planning needs identified in this IRRP.

Table 9 | Summary of Planning Needs in the Windsor-Essex Region

Sub-System	Need	Need Date	2043 Need (MW)
West Essex and Windsor	Lauzon DESN 2 end-of-life	2029	n/a
West Essex and Windsor	Lauzon DESN 2 (T7/T8) station capacity	2032	37
West Essex and Windsor	West Essex and Windsor supply capacity	2032	230
Kingsville-Leamington	Leamington TS load restoration	Immediate	320
Kingsville-Leamington	Kingsville-Leamington Greenhouse Development station and supply capacity	2027	390
Lakeshore/Tilbury	Belle River TS station capacity	Immediate	16
Lakeshore/Tilbury	Tilbury West DS station capacity	2036	13

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Windsor-Essex region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, federal regulations, technical feasibility, cost effectiveness, lead time, local preferences, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs:

- Build new transmission or distribution infrastructure. These are commonly referred to as "wire" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing capability. These are commonly referred to as "Non-Wire" Alternatives (NWAs) and can include things like local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or eDSM.

Section 7.1 provides a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1. Non-Wires Analysis Process in IRRPs

Wires options are always considered in regional planning, and while they are always viable options for regional needs, NWAs may be more suitable for specific need types and characteristics. To select and appropriately size non-wire options like generation or battery storage, additional work is required – including the creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile, which is the hourly demand above the existing station or system capability The profile indicates the duration, frequency, magnitude, and total energy associated with each need. More details on the NWA process and analysis are provided in Appendix C.

7.1.1. Needs Screening

While traditional wires infrastructure is always a viable option for regional needs, NWAs are suitable for specific types of needs, as described in the Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives. An initial screening step is performed to identify which NWAs may be suitable for the type of need addressed.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. Similarly, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. The complete list of assumptions used in the needs screening and options analysis is provided in Appendix F.

New eDSM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021–2024 Conservation and Demand Management Framework and Save on Energy brand are already included in the load forecast, as discussed in Section 5.5. As part of this framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional eDSM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors to leverage distribution rates to help address distribution and transmission system needs using NWAs. Generally, incremental eDSM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few per cent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

Where NWAs are screened in and determined to be feasible, the upfront capital and operating costs for both wire options and NWAs are compiled to generate levelized annual capacity costs (measured in dollars per kW per year). In this scenario, the cash flow of the levelized costs for the options are compared over the lifespan of the wire option and the net present value of these levelized costs is the primary basis through which feasible options are compared. Where NWAs are screened out or determined to be infeasible for meeting the need, overnight capital costs for wire options are used instead.

NWAs are subject to uncertainties in the procurement in terms of both the resource costs bid my proponents and the overall success of the procurement. Pilot or demonstration projects can be explored in cases where other barriers (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options following the completion of the IRRP.

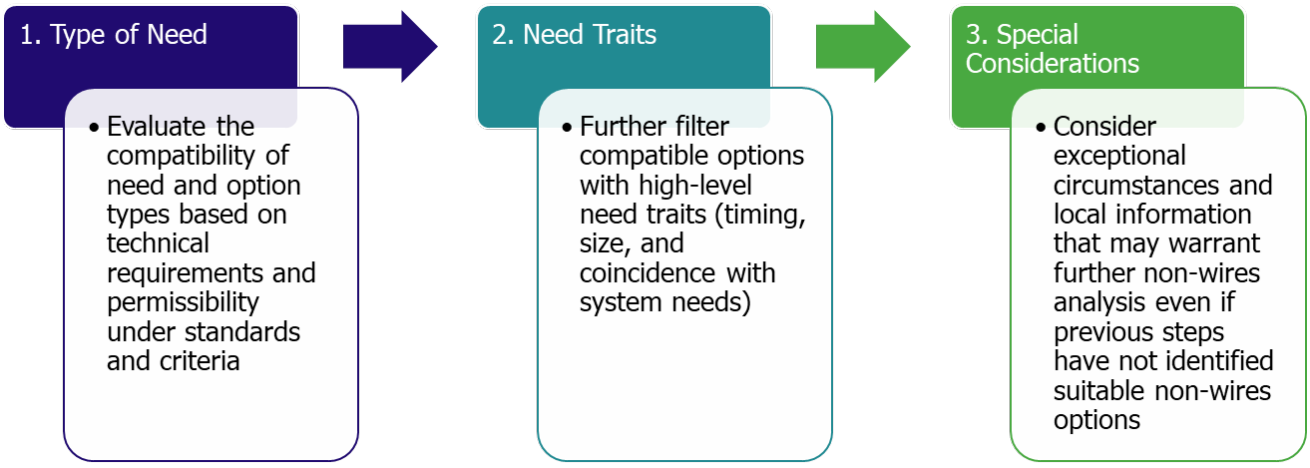
It is important to recognize that there is a significant error margin around cost estimates at the planning stage (from minus 50 per cent on the low side to plus 100 per cent on the high side), as they are only intended to enable comparison between options during the IRRP. The transmitter-led RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if cost estimates differ significantly.

7.2. NWA Screening Results

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically feasible solution that aligns with stakeholder needs and preferences.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) toward the most promising options. The three-step, high-level approach is shown in Figure 23.

Figure 23 | IRRP Screening Mechanism



The results of the application of the screening mechanism to the Windsor-Essex IRRP needs are summarized in Table 10 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C. The list of assumptions made in the needs screening and option analysis can be found in Appendix F.

Table 10 | Results of the Windsor-Essex IRRP Screening

Sub-system	Need	Options Screened In	Options Screened Out[22]
West Essex and Windsor	Lauzon TS DESN 2 end-of-life and station capacity	Wires options	All NWA options
West Essex and Windsor	West Essex and Windsor supply capacity	Wires options Energy efficiency Transmission-connected generation	Distributed generation Demand response

[22] Since the IESO is mandated to centrally deliver provincial eDSM programs, the incremental eDSM potential is estimated for each need regardless of its ability to meet the need.

Sub-system	Need	Options Screened In	Options Screened Out[22]
Kingsville-Leamington	Kingsville-Leamington Greenhouse Developments station and supply capacity	Wires options Demand response Energy efficiency	Distributed generation Transmission-connected generation
Kingsville-Leamington	Kingsville-Leamington load restoration	Wires options	All NWA Options
Lakeshore/ Tilbury	Belle River TS station capacity	Wires options Energy efficiency Distributed generation	Transmission-connected generation Demand response
Lakeshore/ Tilbury	Tilbury West DS station capacity	Wires options Energy efficiency Distributed generation	Transmission-connected generation Demand response

7.3. West Essex and Windsor Sub-system Evaluation

This section evaluates options to address the asset replacement need and station capacity need at Lauzon DESN 2, and the supply capacity need into the sub-system.

7.3.1. Lauzon TS Asset Replacement and Supply Capacity Needs

As described in Section 6.2, an asset replacement and station capacity need were identified at Lauzon TS DESN 2. These needs at Lauzon TS are evaluated together in this section to consider integrated solutions.

Wires Options

The wires options assessed were:

1. Upsizing the existing transformers at Lauzon TS DESN 2; and
2. Constructing a new DESN at Lauzon TS or connected to the circuits between Lauzon TS and Lakeshore TS.

Out of the two wires options, only option one – upsizing the existing transformers at Lauzon TS DESN 2 – addresses both the asset replacement and station capacity needs at Lauzon TS. In addition, upsizing the DESN from its current LTR of 100 MW to 180 MW would supply the need at Lauzon TS DESN 2 while also facilitating up to 15 MW of load transfers from Belle River TS (see Section 7.5.1). The remainder of the incremental capacity could be used to supply a portion of additional West Essex and Windsor load, depending on where the future loads materialize. The incremental cost of upsizing the transformers at Lauzon DESN 2, relative to a like-for-like replacement, is estimated to be between $15–30M.

Option two could address the Lauzon TS DESN 2 station capacity need by providing 180 MW of additional capacity but would not address the asset replacement need. The estimated cost of option

two is $60M, which is substantially higher than option one, since it does not take advantage of the end-of-life sustainment.

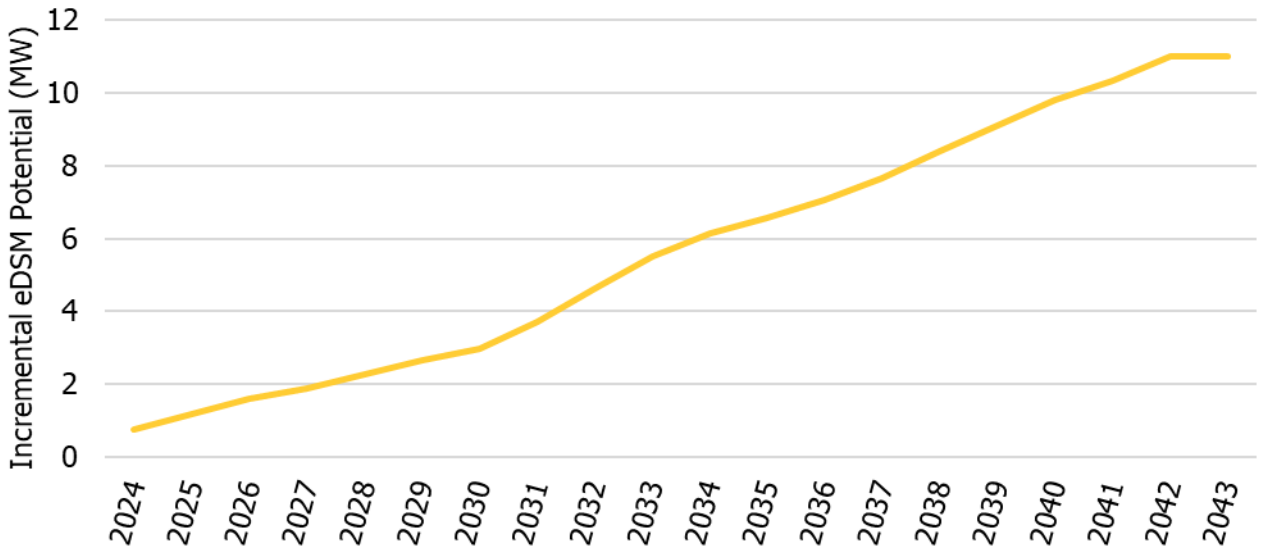
Non-wires Options

Since a cost-effective, integrated solution to address both needs is possible, all NWAs were screened out. However, since energy efficiency is important in managing demand in Ontario, the incremental eDSM potential for Lauzon TS DESN 2 was estimated. EDSM plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. The IESO is mandated to centrally deliver province-wide eDSM programs for Ontario that target businesses, residential customers, and First Nations communities. The IESO offers incentives and rebates to electricity customers through a suite of Save On Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs.

While eDSM does not address the asset replacement need, it could be used to meet approximately 11 MW of the 40 MW need at Lauzon TS, as shown in Figure 24. The eDSM can be targeted to Lauzon TS DESN 2 customers using regional adders to encourage uptake in areas where transmission constraints exist, as well as targeted local programming, both of which are delivered by the IESO through the Save On Energy brand. The cost of eDSM is estimated to be $50M; however, this was assumed to be cost-effective to the system, meaning that there is a net benefit when comparing the program investment (cost) against the provincial average avoided costs of providing electricity (benefit).

There are other potential benefits to NWAs, such as customer cost savings, maximizing the utilization of the existing electricity system, and reducing GHG emissions. As some of these other objectives may align with municipal energy plans in the region, this may be useful input for identifying the potential for projects and strategies at the local level, while identifying where electrical system benefits and infrastructure deferral value may also exist.

Figure 24 | Estimated Incremental eDSM Potential for Lauzon TS DESN 2



Long-term Considerations

Going forward, the need for additional transformation at Lauzon TS should be monitored. Under the High Forecast, other stations in the West Essex and Windsor sub-system – namely Keith TS and Malden TS – are forecast to develop station capacity needs. Monitoring load growth and implementing eDSM programs across the West Essex and Windsor sub-system will help to ensure that the electricity system is able to reliably meet future needs.

Recommendations

Based on the Technical Working Group's analysis of the options to address the Planning Forecast, it is recommended to upsize the transformers at Lauzon TS DESN 2 to 180 MW LTR to meet both the asset replacement need and station capacity need at Lauzon TS.

This solution also facilitates load transfers from Belle River TS and can be used to serve new industrial developments in the area. The Technical Working Group should also monitor load growth across other stations in the sub-system.

7.3.2. West Essex and Windsor Supply Capacity Need

As presented in Section 6.2, there is a supply capacity need to the West Essex and Windsor sub-system.

Wires Options

To address the supply capacity needs of the West Essex and Windsor sub-system, transmission expansion options were evaluated. Two electrical pathways for additional transmission into the sub-system were considered: Lakeshore TS to Lauzon TS and Lakeshore TS to Keith TS. Transmission options focused on the path from Lakeshore TS to Lauzon TS, based on the location of the thermal limitation identified. The length of this transmission path is 32 km. This path is also identified in the non-wires options analysis as limiting the ability to connect large amounts of generation. Thus, options to reinforce this path would address the supply capacity need and improve deliverability at the same time. The option of reinforcing the existing transmission line to Lauzon TS, instead of constructing a new line, was also considered, but this option was ultimately rejected, since it would not provide sufficient capacity to meet the need.

The following wires options were evaluated:

1. A single-circuit 230 kV line from Lakeshore TS to Lauzon TS;
2. A double-circuit 230 kV line from Lakeshore TS to Lauzon TS; and
3. A single-circuit 500 kV line from Lakeshore TS to Lauzon TS.

For option one, the single-circuit 230 kV transmission line would increase the transfer capability by 360 MW, which can address the Planning Forecast need and account for changes in generation supply. Based on preliminary estimates, this option is expected to cost $120M. This option falls within the scope of the Minister of Energy's existing direction that Hydro One Transmission (Order in Council 875/2022) develop and seek approvals for "a new 230 kV transmission line that connects the

Windsor area to the Lakeshore Transformer Station, including associated station facility expansions or upgrades required at the terminal stations.". In addition, it can facilitate more connections at Lauzon TS and along the entire transmission corridor from Lakeshore TS.

For option two, the double-circuit 230 kV line increases the transfer capability by 510 MW, which addresses the Planning Forecast need and would help to serve additional loads beyond the Planning Forecast (e.g., if the High Forecast were to materialize). This option would also fall under the scope of existing direction to Hydro One Transmission (Order in Council 875/2022). This option is expected to cost between $235M but has additional benefits on top of the higher supply capability. The double-circuit option has the added benefit of providing improved redundancy and reliability, by allowing for outages to occur while still having one of the two circuits in-service to maintain supply. In addition, the connection of a double-circuit line at Lauzon TS would provide the opportunity to strategically locate the two termination points at the station to address some of the existing operational concerns at Lauzon TS identified in Section 6.5.

For option three, the 500 kV transmission line provides a comparable amount of transfer capability as option two, but is more expensive – estimated to cost between $350M. This is driven by the cost of higher voltage equipment, as well as the need to build a new 500 kV station with new autotransformers. Option three also limits new load connections to Lauzon TS instead of facilitating the growth along the entire corridor. Since the 500 kV transmission network is the backbone of the electricity system, the ability to connect directly to it is restricted. In addition, this option would essentially lock-in further load growth as needing to connect to Lauzon TS, limiting the location of economic development across the West Essex and Windsor sub-system. This option would also be beyond the scope of Order in Council 875/2022, potentially compounding the longer lead times assumed for a 500 kV transmission project.

Non-wires Options

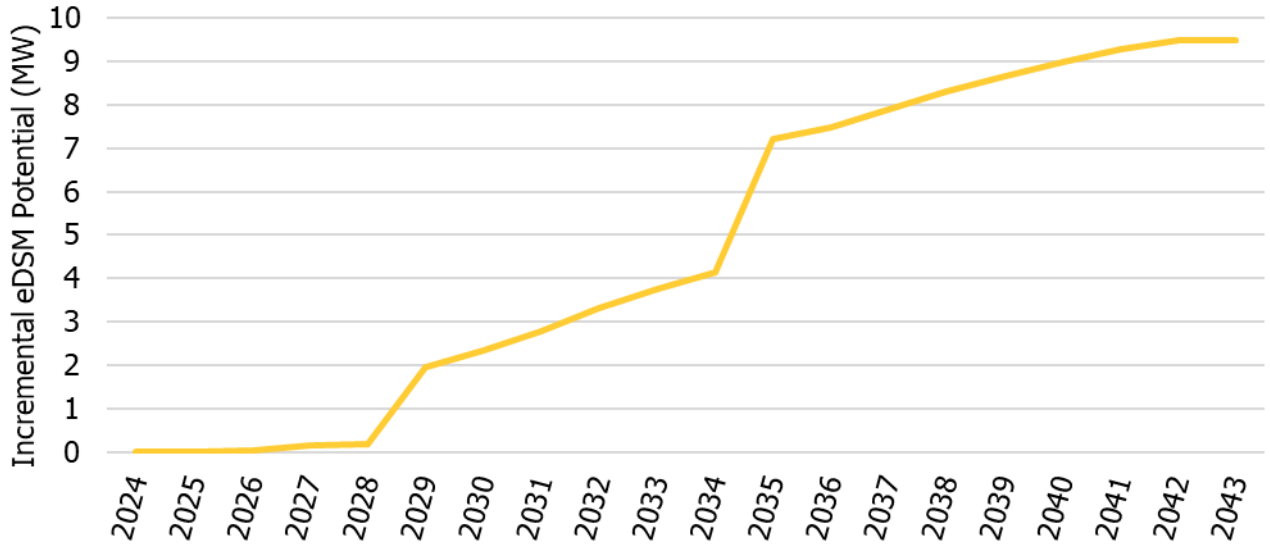
Due to the large magnitude of the West Essex and Windsor supply capacity, eDSM, demand response, and DG were not found to be adequate to resolve the needs. However, eDSM was considered as a cost-effective way to address near-term load growth. Thus, for the West Essex and Windsor supply capacity need, the following non-wires options were assessed:

1. eDSM; and
2. Transmission-connected generation at Lauzon TS.

As shown in Figure 25, eDSM can only provide 9 MW of the 230 MW need but can be used to support growth across the West Essex and Windsor sub-system at a cost of $35M, which is cost effective relative to system benefits. The IESO recently received an increased level of funding to support industrial energy efficiency.[23] The eDSM can be targeted to West Essex and Windsor customers using regional adders to encourage uptake in areas where transmission constraints exist, as well as targeted local programming delivered by the IESO through the Save On Energy brand.

[23] IESO Receives Natural Resources Canada Funding for Industrial Energy Efficiency

Figure 25 | Estimated Incremental eDSM Potential for West Essex and Windsor Industrial Developments



Transmission-connected generation options were sized to meet the need profile of 230 MW peak demand, 20 hours of maximum continuous energy, and 100,000 megawatt-hours (MWh) of maximum continuous energy. The following generation options were identified as meeting the need profile:

- 1,000 MW of wind with 270 MW / 2,700 MWh of Battery Energy Storage System (BESS); and
- 400 MW of solar with 220 MW / 1200 MWh of BESS.

A solar-only option was considered but did not meet the adequacy criteria to be able to meet the duration of the need from 2040 onwards. A wind-only solution was screened out due to the size of the summer need, a BESS-only solution was screened out due to the duration of the need, and implementation of a small modular reactor was screened out based on the size of the need and load characteristics. The combination of wind, solar, and BESS was considered, but this combination did not require any wind generation to meet the need.

Given the size of the resources needed to meet the need profile, all three transmission-connected generation options exceeded the connection capacity of the H53Z and H54Z circuits, and were, therefore, technically infeasible. They also require significant land-use in an urban area (ranging from 1,400 to 34,000 hectares), which would also limit space for economic development.

Long-term Considerations

The High Forecast indicates the need for additional supply into the West Essex and Windsor sub-region. If additional transmission is required, the termination of the transmission supply would depend on the location of economic development in the area. Options include expanding to existing stations in the area (Lauzon TS or Keith TS), or building a new station optimally located to supply multiple pockets of growth.

Options were considered to adapt the 230 kV wires options (options one or two), so that additional supply capacity could be available along the same infrastructure. One way would be to construct the

option with 500 kV towers, so that the circuit(s) could be converted to the higher voltage in future, by replacing the conductors and insulators. However, this would restrict where load growth in West Essex and Windsor could occur, by concentrating supply transfer at Lauzon TS. Another possibility would be to construct half of the 230 kV wires option with 500 kV equipment, but operate it at the lower voltage until the optimal termination of the 500 kV circuit within West Essex and Windsor could be determined. However, these variations are cost prohibitive. In addition, it will be difficult to convert the line from 230 kV to 500 kV after it is in-service. The conversion would take an extended period of time, which would interrupt supply to a significant portion of existing loads in West Essex and Windsor for an unacceptable amount of time. This introduces the risk of increasing the upfront cost, overbuilding, and stranding assets in the future.

Future growth in the area beyond the Planning Forecast could be supported by additional transmission supply, but would need to consider any potential land limitations. The West Essex and Windsor sub-system – and the City of Windsor in particular – is prone to flooding and severe weather events. Surrounded by three bodies of water – Lake Erie, Lake St. Clair, and the Detroit River – the City of Windsor is known as one of Ontario's most flood-prone areas. Over the past decade, the city's low flood plain, along with an increase in the frequency of severe weather events, has contributed to a spike in major water damage for the region. These issues are expected to exacerbate further due to climate change. There is value in conducting a corridor study to consider diversification of supply, enable load and generation resources in the region, and provide redundancy between transmission pathways and station locations.

Recommendations

To meet the supply capacity need and support future growth in the area, it is recommended to build a new double-circuit 230 kV line from Lakeshore TS to Lauzon TS. Depending on the design and environmental assessment process, there may be an opportunity to integrate this solution with the recommendation for the Kingsville-Leamington sub-system. Furthermore, additional eDSM programs targeting the West Essex and Windsor sub-system are recommended.

According to the High Forecast, further transmission line reinforcements or local generation in West Essex and Windsor may be needed to enable additional industrial load growth. Due to land restrictions and uncertainty of load growth locations, a corridor study could help identify potential paths for transmission supply into the West Essex and Windsor area that best supply growth across the sub-system.

The Technical Working Group also recommends that a corridor study should be conducted to identify potential transmission paths into the sub-system to position the system to more quickly respond when higher growth materializes.

7.4. Kingsville-Leamington Sub-system Evaluation

This section evaluates options to address the station capacity, supply capacity and load restoration needs in the sub-system.

7.4.1. Kingsville-Leamington Greenhouse Development Station and Supply Capacity Needs

As described in Section 6.3, station and supply capacity needs were identified for the Kingsville-Leamington greenhouse loads. Options to address these needs are evaluated together in this section.

Interim Solution – Operational Measures

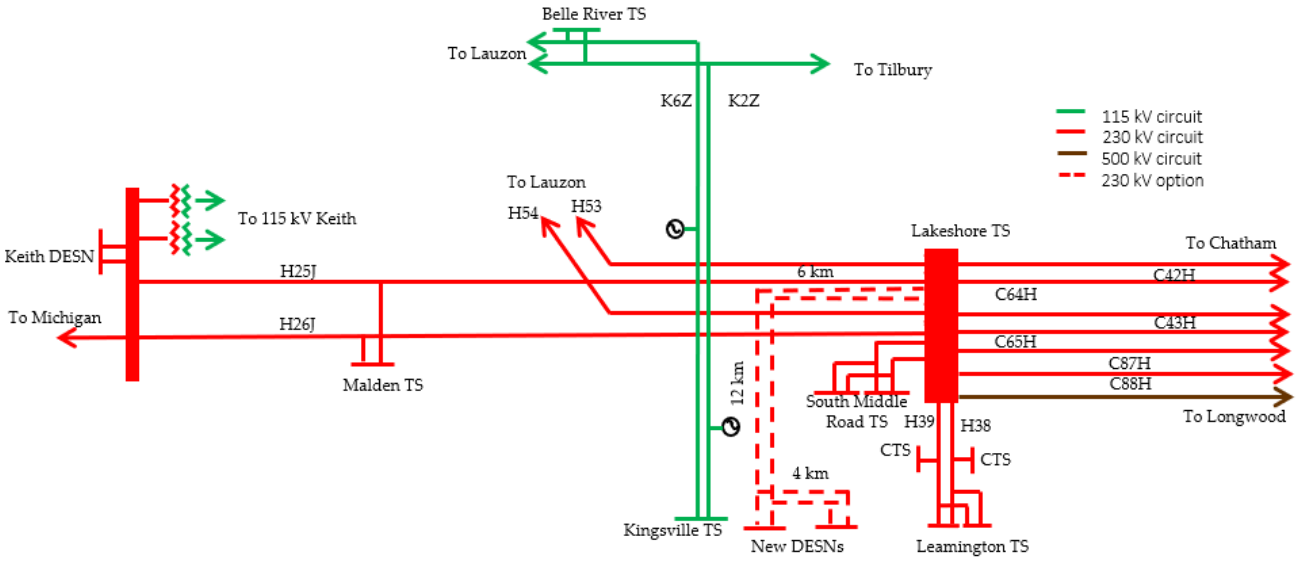
As discussed in Section 6.3.1.1, capacity needs are being addressed using the Lakeshore RAS in the interim, until the previously recommended bulk transmission reinforcements come in-service. Once the transmission reinforcements come into service over the 2028 to 2030 period, the Lakeshore RAS will no longer be needed to address the load security needs. By making the Lakeshore RAS redundant in the interim, the magnitude of loads potentially subject to the lower level of reliability is reduced.

As an interim solution, it is recommended that Hydro One Transmission explore options to modify the design of the Lakeshore RAS to make this operational measure more redundant and improve the near-term reliability in the Kingsville-Leamington sub-system.

Wires Options

The Technical Working Group evaluated the transmission wire option, which was previously recommended in the 2022 Windsor-Essex Addendum – to construct a new radial double-circuit 230 kV line from Lakeshore TS, connecting to two new DESNs. The locations of the DESNs have been estimated based on best available information from Hydro One Distribution, which may be updated during the RIP or subsequent design and environmental assessment work. Thus, the assumed length of the radial line is 22 km, comprising 18 km to the first DESN and 4 km to the second DESN. Figure 26 depicts the single line diagram of this option.

Figure 26 | Configuration of Option for New 230 kV TS and Connection Lines



This option fully addresses the sub-system's station capacity and supply capacity needs. It is expected to cost $210M, with an estimated implementation time between four and five years. This option facilitates both load and generation connections in the Kingsville-Leamington sub-system and allows offloading of the existing Kingsville TS.

This option also provides integration with other needs across the region. It will allow for Kingsville TS to be offloaded via distribution transfers, relieving the 115 kV network limitation discussed in Section 7.5. It provides additional connection capacity for greenhouse load, broader growth in the area and DG, which is otherwise limited in the sub-system. The wires option also enables the load restoration solution, as described in Section 7.4.2. Finally, it is possible that a portion of the transmission pathway for this option can be integrated with the recommended solution for addressing the West Essex and Windsor supply capacity (see Section 7.3.2). Depending on the subsequent design and environmental assessment process, there could be a portion of transmission line shared between these two recommendations west of Lakeshore TS, which would split into two separate paths– one toward Kingsville-Leamington and one toward Lauzon TS. The combined solution would optimize the use of the transmission infrastructure and provide further integration in the Windsor-Essex region.

The Technical Working Group also evaluated the possibility of using the existing radial supply lines to serve the load. However, the remaining capacity on these circuits is insufficient to meet the Planning Forecast. This approach would also exacerbate the existing load restoration concerns and would be limited by the length of the H75/H76 tap, as well as the physical constraints for expansion on the H38/H39 tap.

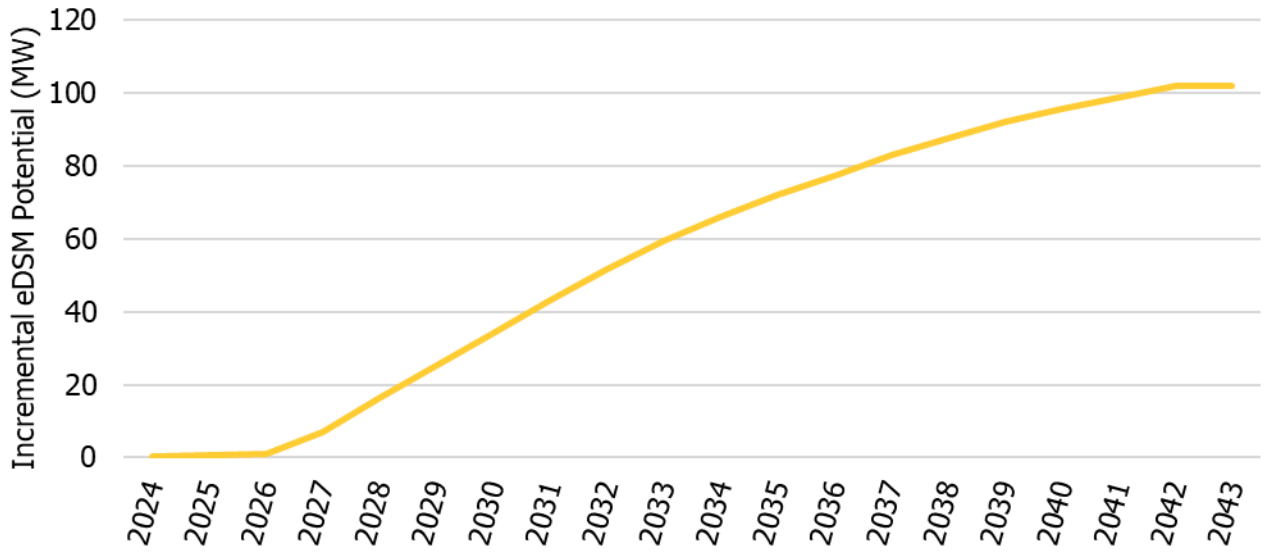
Non-wires Options

As presented in Section 7.2, the following non-wires options were screened in:

1. Energy efficiency (eDSM); and
2. Demand response.

Under the existing eDSM framework and programs primarily targeting greenhouses, up to 100 MW of the total 390 MW winter need can be addressed. The expected cost of achieving the full 100 MW of peak demand savings is $330M. As covered in Section 7.3, eDSM is important for managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. In the Kingsville-Leamington area, eDSM savings are primarily achieved through programs targeting greenhouse grow lights and greenhouse envelope improvements, which have a substantial impact in winter months (see Appendix E for more details).

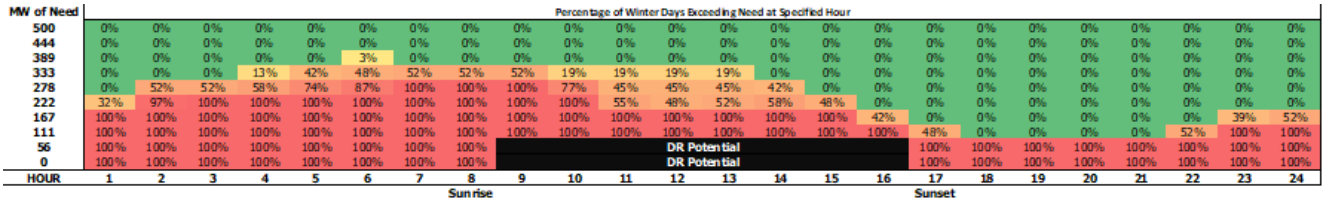
Figure 27 | Estimated Incremental eDSM Potential of Kingsville-Leamington Greenhouse Loads



Demand response is an option to address the Kingsville-Leamington station capacity and supply capacity needs. However, a new local program would be required, since the local need profile is not aligned with the design of the provincial procurement. This would require its own procurement process and a unique, local activation system. It is expected that such a program would take two to three years to implement. While there are no cost benchmarks for this type of solution, it is expected that a demand response solution would be more expensive than leveraging the existing eDSM framework and programs in the area.

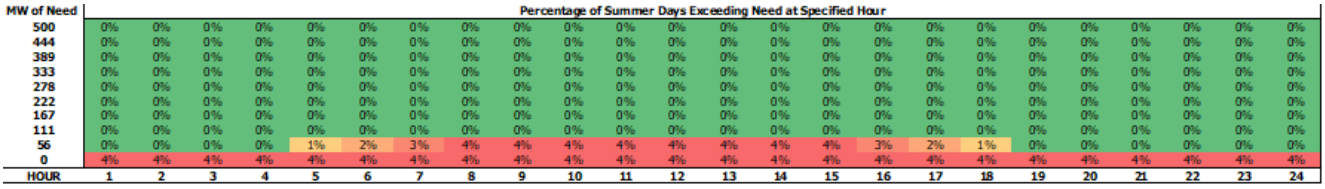
Demand response among the greenhouse loads in the Kingsville-Leamington sub-system would be feasible through use of a third-party aggregator to allow participation of all the loads in the area. Greenhouses could participate in demand response by reducing the use of grow lights during the daytime in winter months. Based on information provided by OGVG, the potential greenhouse peak demand reduction is in the order of tens of megawatts during winter daytime periods. Figure 28 shows the heat map of the hourly winter need for December 2043, overlaid with the expected magnitude and timing of demand response ("DR Potential"). Figure 29 shows the 2043 hourly summer need, represented by July. No greenhouse demand response was indicated to be possible in the summer.

Figure 28 | Heat Map of Kingsville-Leamington Need in December 2043



MW of Need	Percentage of Winter Days Exceeding Need at Specified Hour																							
500	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
444	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
389	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
333	0%	0%	0%	13%	42%	48%	52%	52%	52%	19%	19%	19%	19%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
278	0%	52%	52%	58%	74%	87%	100%	100%	100%	77%	45%	45%	45%	42%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
222	32%	97%	100%	100%	100%	100%	100%	100%	100%	100%	55%	48%	52%	58%	48%	0%	0%	0%	0%	0%	0%	0%	0%	0%
167	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	42%	0%	0%	0%	0%	0%	39%	52%	
111	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	48%	0%	0%	0%	0%	52%	100%	100%
56	100%	100%	100%	100%	100%	100%	100%	100%	DR Potential								100%	100%	100%	100%	100%	100%	100%	100%
0	100%	100%	100%	100%	100%	100%	100%	100%	DR Potential								100%	100%	100%	100%	100%	100%	100%	100%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
								Sunrise									Sunset							

Figure 29 | Heat Map of Kingsville-Leamington Need in July 2043



MW of Need	Percentage of Summer Days Exceeding Need at Specified Hour																							
500	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
444	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
389	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
333	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
278	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
222	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
167	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
111	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
56	0%	0%	0%	0%	1%	2%	3%	4%	4%	4%	4%	4%	4%	4%	4%	3%	2%	1%	0%	0%	0%	0%	0%	0%
0	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

As shown in these heat maps, the winter need peaks between 5 AM and 6 AM, whereas the demand response potential is available between 8 AM and 4 PM. Furthermore, the winter need persists 24 hours per day, which does not align with a demand response program's ability to deliver short-term capacity relief. Finally, while the magnitude of need in the Kingsville-Leamington sub-system is greatest in winter, a summer need persists which would not be addressed by the demand response option.

Long-term Considerations

The High Forecast indicates additional station capacity needs in the Kingsville-Leamington sub-system, if agricultural load growth in the region accelerates. Up to six additional supply stations would be required to meet the 930 MW of additional greenhouse growth in the High Forecast. The placement of these supply stations would be sited depending on the location of the growth. It is also possible that some of the growth materializes within southwestern Ontario but would be situated outside of the Windsor-Essex region. Should higher growth occur within the Windsor-Essex region, supply connection lines to the upstream 230 kV corridor, as well as connections between the existing supply stations, will be required to enable this capacity. The Technical Working Group will continue to monitor growth to enable the required supply stations and connections as required.

Recommendations

The recommended option to address the station capacity, supply capacity, and load restoration is the integrated wires option of a 22 km double-circuit 230 kV transmission line from Lakeshore TS serving two new transformer stations in the Kingsville-Leamington area.

This solution is depicted in Figure 26. Depending on the design and environmental assessment process, there may be an opportunity to integrate this solution with the recommendation for the West Essex and Windsor sub-system.

It is recommended to continue the existing eDSM programs in the Kingsville-Leamington area to increase capacity in the sub-system and provide broader system benefits.

Considering the uncertainty among the forecast drivers in the region and the potential for increased eDSM targets under the new 2025-2036 eDSM Framework, the Technical Working Group will continue to monitor growth in the region to determine whether sector trends and connection requests indicate a need for development beyond the Planning Forecast.

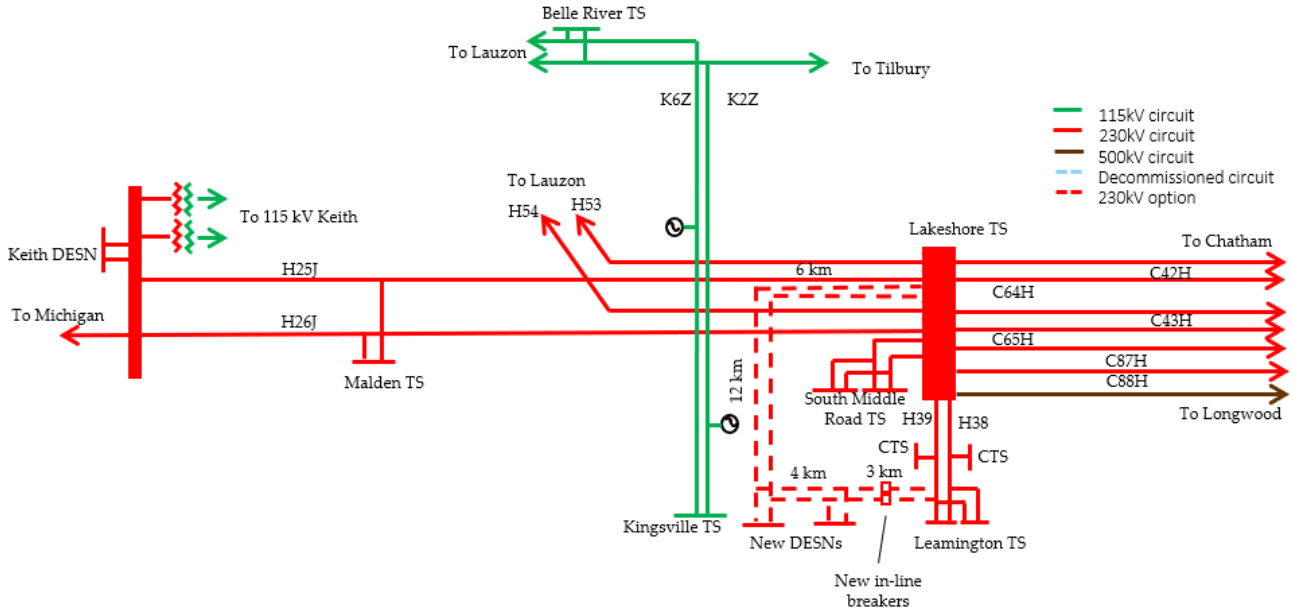
7.4.2. Leamington TS Load Restoration and Security Needs

The load restoration need for the supply circuits toward Leamington TS is evaluated in this section. As discussed in Section 6.3.1.1, load security will be addressed by ongoing transmission reinforcements in the area; thus, no load security needs are identified in this sub-system.

Wires Options

Figure 30 shows the integrated wires option to address the load restoration need – a double-circuit 230 kV transmission line connecting the existing H39/H39 circuits with the wires solution to address the station capacity and supply capacity needs in the sub-system. Under the Planning Forecast scenario, in-line breakers would be required in a normally open position to operate the load restoration lines. This provides a benefit to the broader Kingsville-Leamington sub-system, since the solution provides improved flexibility to restore supply to loads under a variety of outages and contingencies. However, under specific outage scenarios (e.g., peak winter load), not all customers will be restored. Since the specific loads that can be restored cannot be guaranteed, there is a broader benefit to this option for all load in the sub-system.

Figure 30 | Integrated Solution to Address Kingsville-Leamington Station Capacity, Supply Capacity, and Load Restoration Needs



The pathway and length of the load restoration lines are subject to future design work and the environmental assessment process. Based on best available information from Hydro One Distribution regarding the expected location of new DESNs, the load restoration lines are estimated to be three kilometres long. The portion of the integrated solution addressing the load restoration needs in the Kingsville-Leamington sub-system is expected to cost $30M.

Non-wires Options

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as eDSM, demand response, and DG cannot be applied to load restoration needs because they do not restore the connection of loads to the bulk transmission system. Thus, non-wires options are infeasible for load restoration needs. However, as noted in the 2022 Windsor-Essex IRRP Addendum study, there may be value in pilot projects or other demonstration projects to help meet the sub-systems load restoration needs using NWAs – in addition to constructing the load restoration line.

Long-term Considerations

The projected load flows under the Planning Forecast require that the load restoration lines are operated with normally open in-line breakers. However, the High Forecast indicates the potential need for additional supply stations and lines in the Kingsville-Leamington sub-system. In this scenario, the optimal configuration would be to convert the radial supply lines into a transmission loop. This would require unique connections to the upstream transmission system on either end of the supply lines (i.e., at Lakeshore TS and another supply station west or east of Lakeshore TS, depending on the location of additional growth in this area). This would support new supply stations, allow for redundant supply, and address the load restoration needs. There may be opportunities to integrate this with the High Forecast transmission options for the West Essex and Windsor sub-system, if both paths are aligned.

Recommendations

The recommended option to address the load restoration need is the integrated wires option: the 3 km double-circuit 230 kV transmission line connecting the existing H39/H39 circuits to the new supply stations and connection lines recommended in the previous section, as shown in Figure 30.

7.5. Lakeshore/Tilbury Sub-system Evaluation

The station capacity needs at Belle River TS and Tilbury West DS are evaluated in this section.

7.5.1. Belle River TS Station Capacity Need

As described in Section 6.4.1, a station capacity need was identified at Belle River TS. This section evaluates the wires and non-wires options to address that need.

Wires Options

For the Belle River TS station capacity need, the following wires options were evaluated:

1. Load transfers on the distribution system;
2. Upsize transformers at Belle River TS; and
3. New DESN at Belle River TS.

Option one is to leverage capacity on the existing transmission system to transfer load from Belle River TS to nearby stations, namely Lauzon TS DESN 1 and DESN 2. The planned upsizing of Lauzon TS DESN 1 from 100 MW to 180 MW LTR in 2025 will enable load transfers on the distribution system from Belle River TS to Lauzon DESN 1 to meet some of the station capacity need. Similarly, the recommended solution to address the end-of-life and station capacity need of Lauzon TS DESN 2 will also result in upsized transformers, which will enable additional load transfers on the distribution system to fully meet the Belle River TS station capacity need. This solution is expected to cost between $10M and $15M to implement. The load transfers are expected to take place between 2026 and 2031, considering the timing of upsizing Lauzon DESN 1 in 2025 and Lauzon DESN 2 in 2029.

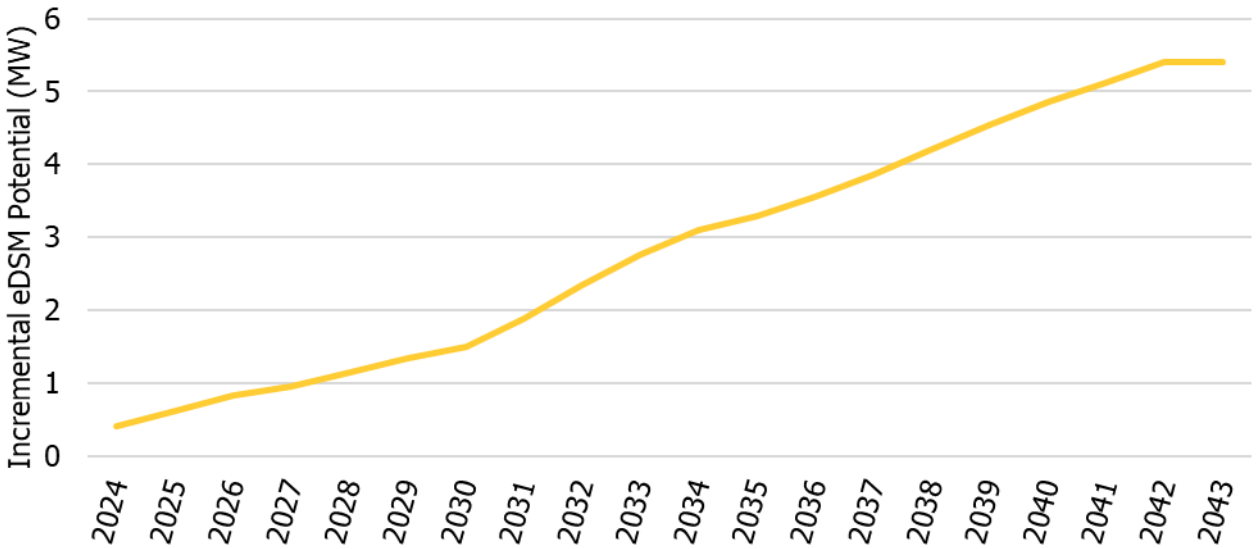
Option two is to upsize the DESN at Belle River TS from 53 MW LTR to 100 MW LTR, which is estimated to cost between $15M and $30M. Option three is to construct a new 100 MW LTR DESN at Belle River TS, which is estimated to cost $60M. Both options two and three are expected to take between three and five years. These options also provide additional capacity beyond the Belle River TS need; however, this capacity cannot be utilized due to upstream capacity limitations.

Non-wires Options

New eDSM programs in the area could meet 5 MW of the 17 MW need over the 20-year period, as illustrated in Figure 31. The estimated cost of achieving these eDSM savings is $18M, which is considered cost effective to the system. However, previous eDSM programs targeting loads at Belle River TS have had less than expected impact, reflecting challenges targeting programs to relatively

small areas and predominantly residential load composition. Consequently, there is a higher level of uncertainty with this option.

Figure 31 | Estimated Incremental eDSM Potential for Belle River TS



Long-term Considerations

Load growth beyond the Planning Forecast may require additional supply to the Lakeshore/Tilbury 115 kV sub-system. Options for increasing future supply in the region include new 115 kV circuits, a 230 kV conversion, or new 230 kV supply, depending on the level of growth anticipated and the cost effectiveness of these solutions to meet the projected need. Long-term considerations in the Lakeshore/Tilbury sub-system are also interrelated with options to supply the Kingsville-Leamington sub-system, since options to offload Kingsville TS loads onto the 230 kV system could alleviate supply concerns on the 115 kV system.

Recommendations

In the interim, operational measures, such as loading the transformer beyond its LTR, can be used to manage this need until the wires solution is in place.

In the near term, the recommendation to address the Belle River TS station capacity need is to transfer load through the distribution system to the upsized Lauzon TS DESN1 and DESN2 by 2031. This work may commence after Lauzon TS DESN1 has been upsized in 2025, but is expected to take an additional one to two years to complete after Lauzon TS DESN2 has been upsized in 2029.

7.5.2. Tilbury West DS Station Capacity Need

As described in Section 6.4.1, a station capacity need was identified at Tilbury West DS. This section evaluates the wires and non-wires options to address that need.

Wires Options

To meet the Tilbury West DS station capacity need, load transfers are not feasible since load could only be transferred to Belle River TS, which already has a capacity need. The remaining wires options assessed are:

1. Upsize transformers at Tilbury West DS; and
2. New DESN at Tilbury West DS.

For option one, upsizing the transformers at Tilbury West DS would increase the summer LTR from 28 MW to 53 MW. This is estimated to cost between $15M and $30M and take three to five years to implement. This option also improves reliability and resiliency in the area by increasing the capability to transfer load on the distribution system in the event of an outage.

Option two is a new 100 MW LTR DESN. This is more expensive than option one. It is estimated to cost $60M and would take the same amount of time as option one to implement. This option was determined to be infeasible, since upstream limitations would mean that this capacity cannot be fully utilized and would be a stranded asset.

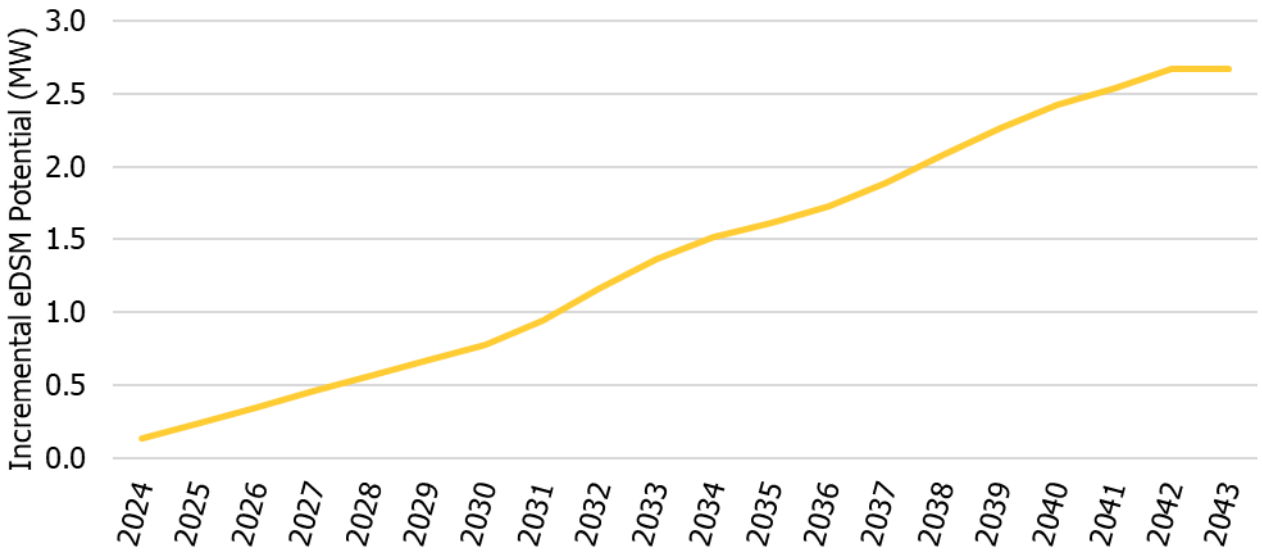
Non-wires Options

For Tilbury West DS, the following non-wires options were assessed:

1. eDSM; and
2. DG.

eDSM programs targeting load supplied by Tilbury West DS could meet 3 MW of the 13 MW need over the 20-year period, as illustrated in Figure 32. The eDSM can be targeted to Tilbury West DS customers using regional adders to encourage uptake in areas where transmission constraints exist, as well as targeted local programming delivered by the IESO through the Save On Energy brand. The estimated cost of achieving these eDSM savings is $8M, which is considered cost effective to the system.

Figure 32 | Estimated Incremental eDSM Potential for Tilbury West DS



By 2043, the need profile for Tilbury West DS peaks at 13 MW, requires 91 hours of maximum continuous demand, and approximately 600 MWh of maximum continuous energy supplied. Based on the characterization of the need, the following DG solutions were screened in:

- Combined wind and BESS solution;
- Combined solar and BESS solution; and
- Combined solar, wind, and BESS solution.

Wind as a standalone option was screened out due to the land requirements combined with the maximum continuous hours of need. Solar as a standalone option was screened out since it could not meet the winter and overnight needs. BESS as a standalone solution was screened out based on the continuous hours of the need and magnitude of energy for these hours. Small modular reactors were screened out, since the need size does not warrant this type of technology.

Among the screened-in generation options, the following solutions were sized to meet the need:

- 22 MW of wind and 26 MW / 250 MWh of BESS;
- 60 MW of solar and 26 MW / 250 MWh of BESS; and
- 20 MW of wind, 8 MW of solar, and 24 MW / 230 MWh of BESS.

All three DG options exceed the DG connection capacity at Tilbury West DS, which currently has a thermal capacity limit of 19 MW. Furthermore, there are connection restrictions downstream of the 115 kV K2Z circuit due to inverter-based resource limitations, as well as the fact that this circuit has a limited ability to deliver resources to the rest of the province. In particular, Tilbury West DS has a low short-circuit ratio, which limits its capability to connect new inverter-based resources. In addition, these options have a large land requirement of between 200 and 770 hectares. If these solutions were feasible, they would be expected to take between four to six years to implement.

Long-term Considerations

Long-term considerations for this need are discussed in Section 7.5.1.

Recommendations

The recommendation to address the Tilbury West DS station capacity need is to upsize transformers at Tilbury West DS to 25/41.7 MVA (rated for 53 MW LTR) to meet the need by 2036.

Given that this option would take three to five years to implement, while the need emerges in 2036, the Technical Working Group recommends load monitoring. This way, upsizing the transformer can be triggered when needed, or revisited in the next cycle of regional planning.

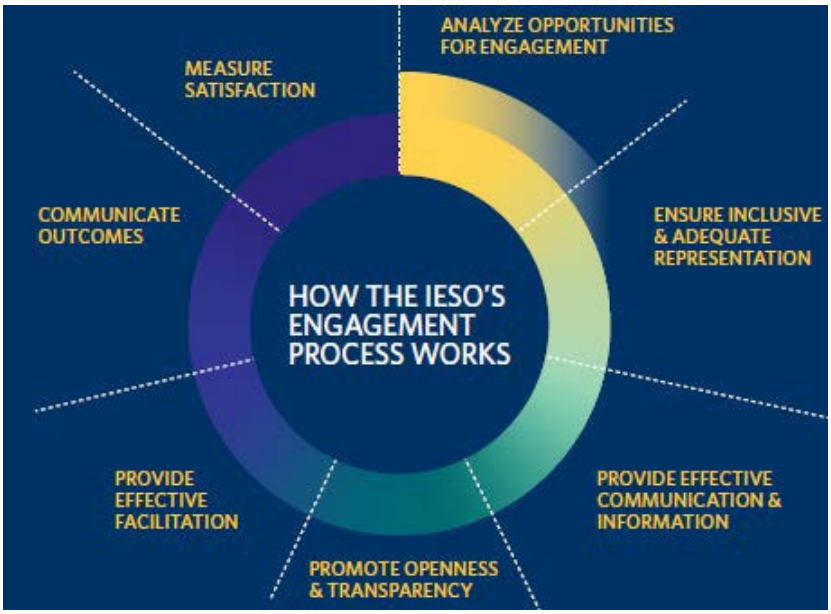
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Windsor-Essex IRRP.

8.1. Engagement Principles

The IESO's External Relations Engagement Framework and the Indigenous Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 33 | The IESO's Engagement Principles





8.2. Engagement Approach

To ensure that the Plan reflects the needs of Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, engagement involved:

- Leveraging the Windsor-Essex engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback,
- Targeted discussions with municipalities and associations to help inform the engagement approach for this planning cycle and to understand feedback and perspectives at key milestones,
- Hosted a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process,
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin,
- Public webinars, and

- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3. Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, and to continue to build relationships and dialogue in this region from past engagements. This started with the Scoping Assessment Outcome Report for the Windsor-Essex region. An invitation was sent to targeted Indigenous communities, municipalities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Windsor-Essex region Scoping Assessment Report finalization. A public webinar was held in April 2023 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in May 2023, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, several targeted outreach meetings began with municipalities and associations in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement and to ensure growth, electrification, and development plans have been accurately captured in the Technical Working Group's draft demand forecast scenarios. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Windsor-Essex region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, municipalities, associations, businesses, and other stakeholders, and written feedback was collected over an approximately three-week comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, and electricity demand forecast scenarios – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Windsor-Essex region (including lands designated for industrial developments and planned agricultural developments) have been considered and accounted for in the IRRP work;
- Ensuring infrastructure development matches future potential growth; and
- Keeping lines of communication following the plan completion to share information and updates.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Windsor-Essex region subscribers, municipalities, and Indigenous communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP, and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g., future urban expansion and employment areas as outlined in the updated Windsor-Essex region Official Plan). This insight has been valuable to the IESO – it supported an understanding of local growth and accurate electricity demand forecast scenarios, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Windsor-Essex IRRP engagement webpage.

8.4. Bringing Municipalities and Associations to the Table

The IESO held meetings with municipalities and association to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities, and associations in the region to discuss key issues of concern, including ensuring infrastructure development matches growth, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the development of the forecast scenarios, municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions, valuable feedback was received around strong anticipated growth in major growth centres in the region, including, but not limited to the following feedback:

- Strong population growth across the Windsor-Essex region based on 2051 growth projections and in some areas above and beyond the regional forecast.
- The County of Essex zoning plans for residential and employment lands.
- Residential growth in the Town of LaSalle due to new residential development.
- The City of Windsor plans for residential development, energy conservation, and industrial expansion.
- The Municipality of Leamington's expected residential growth and indications of greenhouse developments in the region.
- The Town of Amherstburg's residential growth forecasts and industrial development lands.

- The Town of Essex's residential growth forecast and employment lands for industrial development.
- The Town of Kingsville's planning applications for residential units, municipal infrastructure plans, greenhouse development expectations, and expected trend for electricity demand.
- The Town of Lakeshore's residential growth forecast, industrial developments, and agricultural development lands.
- The Town of Tecumseh's residential development plans.
- New development and growth projects identified by Invest WindsorEssex.
- Expected growth rate in the greenhouse sector based on Ontario Greenhouse Vegetable Growers.

8.5. Engaging with Indigenous Communities

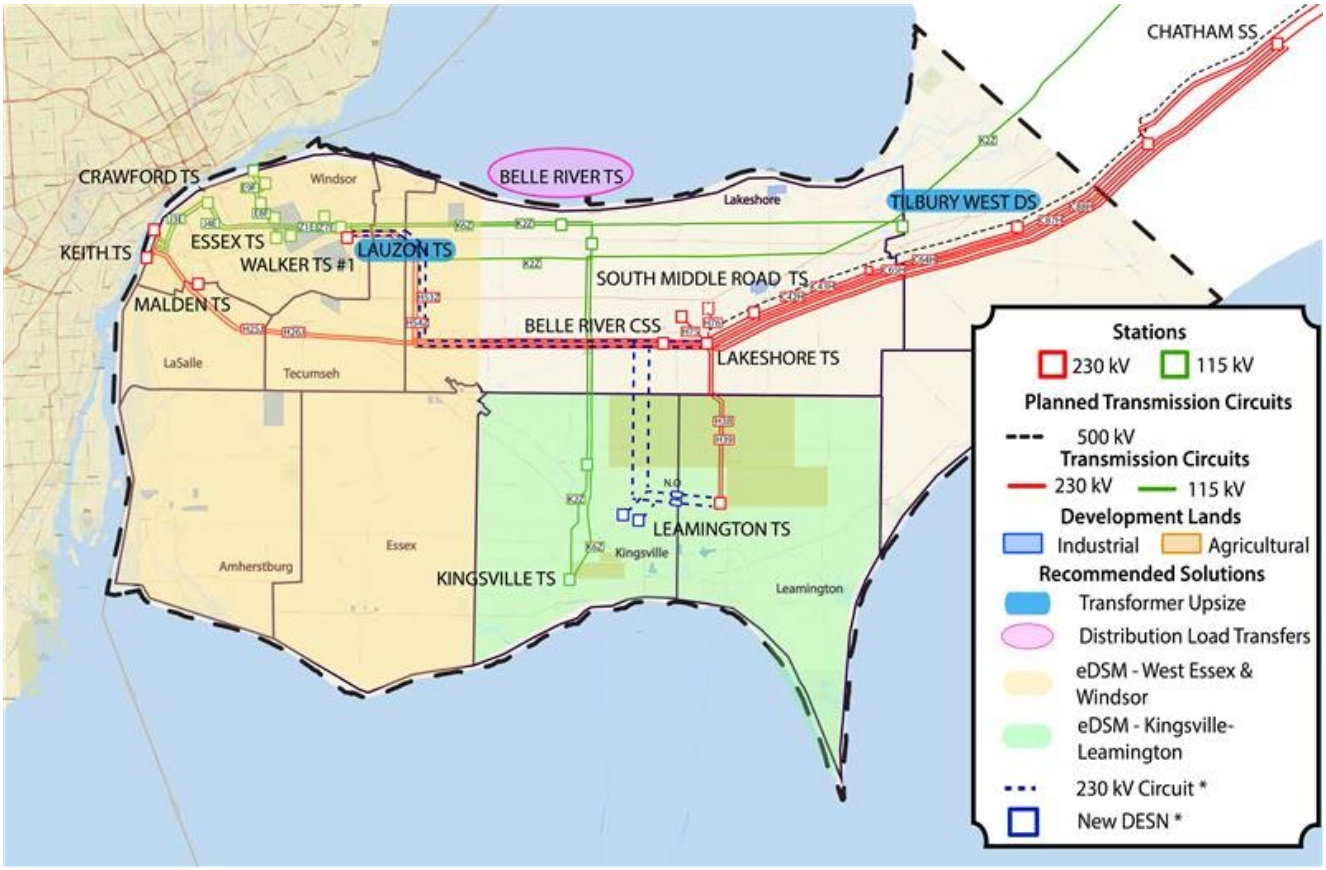
To raise awareness and share information about the regional planning activities underway and invite participation in the engagement process, regular outreach including extending the opportunity to meet one-on-one was made to Indigenous communities within the Windsor-Essex region throughout the development of the plan. This includes the communities of the Aamjiwnaang First Nation, Caldwell First Nation, Chippewas of Kettle and Stony Point First Nation, Chippewas of the Thames First Nation, Eelŭnaapéewi Lahkéewiit Delaware Nation, Munsee-Delaware Nation, Oneida Nation of the Thames, Walpole Island First Nation.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

The Windsor-Essex IRRP identifies electricity needs in the region over the 20-year period from 2024 to 2043, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. Figure 34 visually depicts these recommendations across the region.

Figure 34 | Overview of Recommended Solutions for the Windsor-Essex IRRP



In the interim, operational measures can be used to support growth in the region through the use of operating ratings and improving the redundancy of the Lakeshore RAS. The Technical Working Group also recommends targeting eDSM programs in the Kingsville-Leamington and West Essex and Windsor sub-systems to support both near-term and long-term growth.

In the near term, the Technical Working Group recommends upsizing the transformers at Lauzon TS DESN 2 and transferring loads on the distribution system from Belle River TS to Lauzon TS. The Technical Working Group also recommends constructing two new transformer stations in the Kingsville-Leamington sub-system with a double-circuit 230 kV transmission line connection from Lakeshore TS, along with a double-circuit 230 kV transmission line linking the new connection lines to H38/H39 with normally open breakers for load restoration.

In the medium-term, a new double-circuit 230 kV transmission line from Lakeshore TS to Lauzon TS is recommended to support growth in the West Essex and Windsor sub-system. Depending on the

subsequent design and environmental assessment process, there may be an opportunity to integrate this recommendation with the 230 kV double-circuit line into Kingsville-Leamington recommended in the near term.

In the long term, the Technical Working Group recommends upsizing the transformers at Tilbury West DS. Finally, the Technical Working Group recommends exploring the scope and value of a corridor study to identify future transmission paths into the West Essex and Windsor sub-system.

The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach. The Technical Working Group will continue to monitor growth across the region to determine if or when further reinforcements will be needed. This includes any future community energy plans, electrification trends, customer connection queues, changes to local generation, and changes to eDSM programs. The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.



REGIONAL INFRASTRUCTURE PLAN REPORT

WINDSOR-ESSEX

Regional Infrastructure Plan Report

Windsor-Essex

October 20, 2025

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Windsor-Essex Technical Working Group

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Disclaimer

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

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

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

Executive Summary

REGION	**Windsor-Essex** (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: April 24, 2025	**END DATE:** October 20, 2025

1. INTRODUCTION

Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes discussion of all the options, recommended plans, and preferred wire infrastructure investments identified in the phases to address the needs over the study period.

2. OBJECTIVES AND SCOPE

Objectives:

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

Scope:

- A consolidated report of the needs and relevant wires plans to address near- and medium-term (2024-2033) needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2024-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term (2034-2043) needs identified in the Windsor-Essex IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the geographical boundaries, circuit connections and stations located in the Windsor-Essex region through a regional planning area map and a single line diagram.

The Windsor-Essex region consists of the City of Windsor, the Municipality of Leamington, the Towns of Amherstburg, Essex, Kingsville, Lakeshore, LaSalle, Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent. The region also includes a number of Indigenous communities including Aamjiwnaang First Nation, Caldwell First Nation, Chippewas of the Thames, Haudenosaunee Confederacy Chiefs Council (HCCC)/Haudenosaunee Development Institute (HDI), Oneida Nation of the Thames, Six Nations of the Grand River and Walpole Island First Nation (Bkejwanong Territory).

The Windsor-Essex region is divided into three sub-systems, each with some transmission facility, for regional planning purposes: the West Essex and Windsor sub-system in the west of the region; the Kingsville-Leamington sub-system in the south-east of the region; and the Lakeshore/Tilbury sub-system in the north-east of the region.

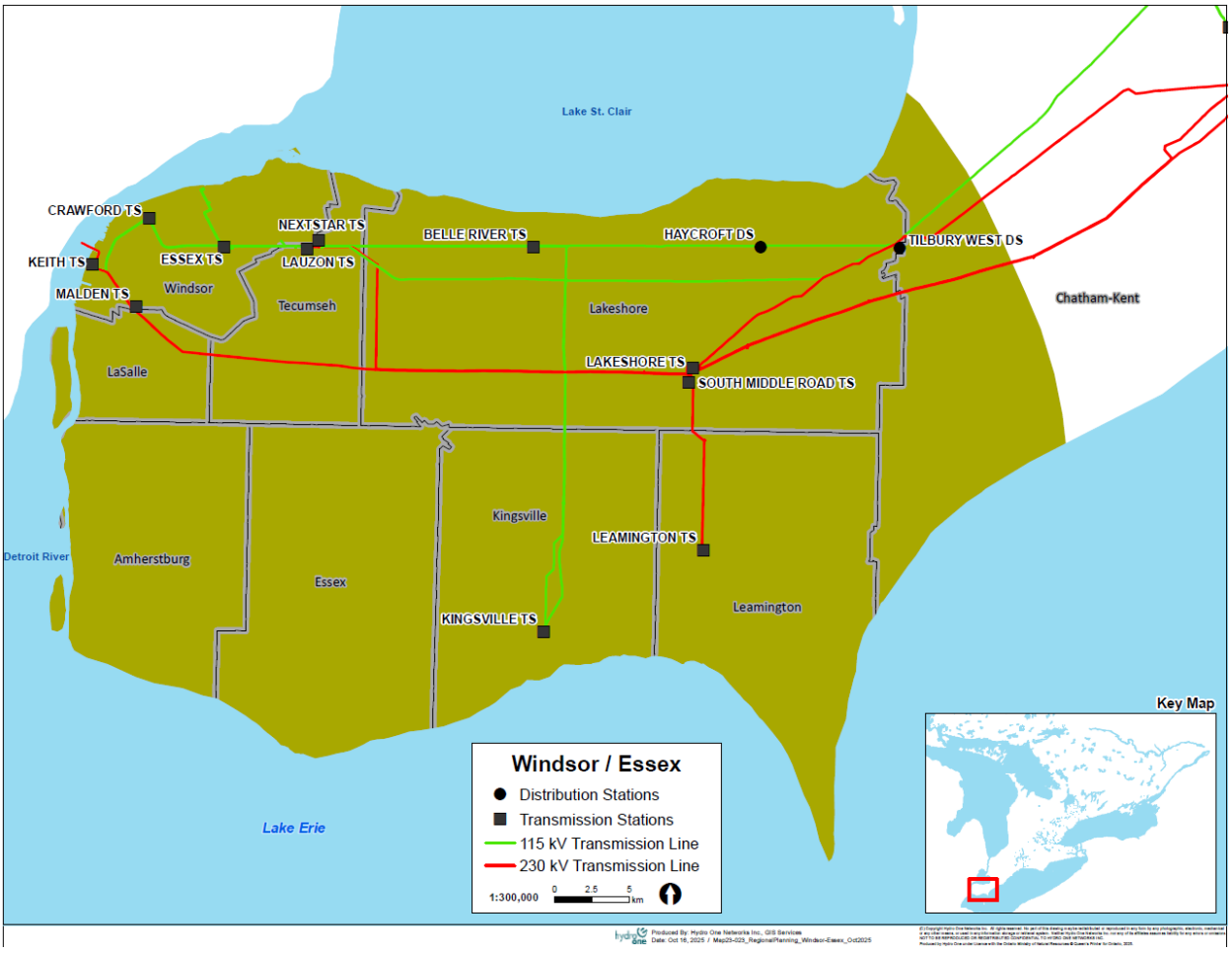


Figure 1-1: Windsor-Essex Region Map

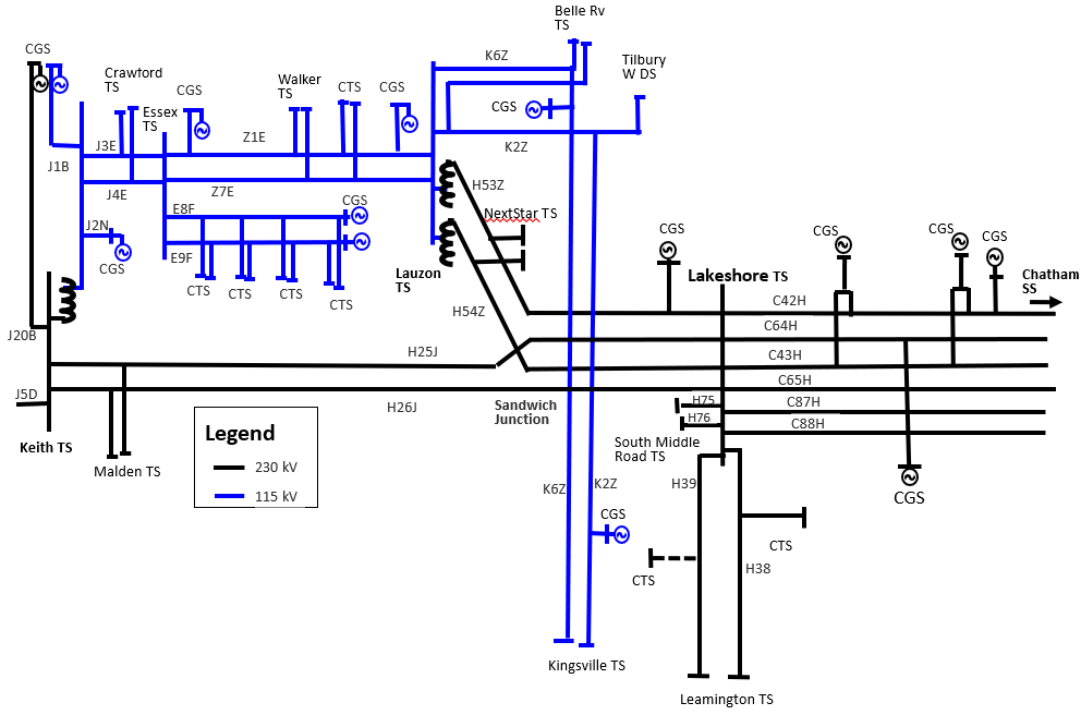


Figure 1-2: Single Line Diagram Windsor-Essex Region's Existing Transmission System

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

This section provides a summary and brief description of all the projects completed in the past ten years or are currently underway.

I. Following Major projects were completed in the region during the last ten years:

1. Keith TS breakers replacement: the following breakers were replaced SC11K, SC11SC, SC1B, T11P, T12P, and SC2Y (I/S 2015); HT11K, HT12K, L1P and T1L3 renamed L3K (I/S 2024); L2P and L3P (I/S 2025).
2. Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017).
3. Malden TS breakers replacement: two 27.6 kV feeder breakers were replaced (I/S 2018).
4. Supply to Essex County Transmission Reinforcement: A new 13 km double-circuit 230 kV transmission line to Leamington area tapped to previous C21J/C22J (Chatham SS x Keith TS) circuits, and new 75/100/125 MVA Leamington TS DESN1 (I/S 2018).
5. Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to accommodate the construction of Gordie Howe International Bridge (I/S 2018).
6. Leamington TS expansion: Installation of 75/100/125 MVA Leamington TS DESN2 (I/S 2019).
7. Kingsville TS 25/42 MVA transformers (T1, T2, T3, T4) replacement with 50/83 MVA units T5, T6 (I/S 2022).
8. Keith TS 115 MVA autotransformers replacement with 150/200/250 MVA units (I/S 2023).

9. Tilbury TS decommissioned (2019).
10. Keith TS transformer T1 decommissioned (2021).
11. Built new switching station (Lakeshore TS) at Leamington Junction (I/S 2022).
12. Built new 75/100/125 MVA South Middle Road TS DESN1 (I/S 2022).
13. Build Chatham SS x Lakeshore TS 2-cct 230 kV line (I/S 2024).
14. Built new 75/100/125 MVA South Middle Road TS DESN2 (I/S 2025).

II. Following Major projects are underway in the region:

1. Keith TS 300/500 MVA phase angle regulator PSR5 replacement (expected I/S 2028).
2. Lauzon DESN1 50/83 MVA transformers T5 and T6 asset renewal with 75/125 MVA units (expected I/S 2026).
3. Development of Chatham SS x Lambton TS 2-cct 230 kV line* (expected I/S 2028).
4. Development of Longwood TS x Lakeshore TS 1-cct 500 kV line (expected I/S 2030).

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

* The Chatham SS x Lambton line is outside the Windsor-Essex region but will improve power transfer into the region.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the Windsor-Essex region is expected to grow at a compound annual rate of approximately 2% in winter and 1.3% in the summer from 2024 to 2043. (Based on the high load forecast, the rates would be 6.7% in winter and 3.6% in the summer.) The Region has become winter peaking, hence this assessment considers both summer and winter peak loads.

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2024-2043.
- LDCs reconfirmed load forecasts up to 2043 in the area are the same as the IRRP, except for the addition of new load in the Coatsworth area for the greenhouse sector and the modification of the eDSM to be in line with the IESO 2025 Annual Planning Outlook.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is based on both winter and summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature for summer peaking stations, and winter 10-day Limited Time Rating (LTR) based on 10°C ambient temperature for winter peaking stations.

- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Windsor-Essex region to meet the needs in the region and lists the facilities that require reinforcement over the study period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment

- Lauzon TS DESN2 transformers T7 and T8

b. Station Capacity

- Lauzon TS DESN2 transformers T7 and T8
- Tilbury West DS
- Belle River TS
- Keith TS and Malden TS
- Kingsville-Leamington Greenhouse Supply Stations
- New Coatsworth Area Greenhouse Supply Stations

c. Transmission Supply Capacity

- West Essex and Windsor Sub-system Supply Capacity
- Kingsville-Leamington Sub-system Supply Capacity
- Coatsworth Area Supply Capacity

d. System Reliability, Operation and Load Restoration

- Kingsville-Leamington Sub-system Load Restoration

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the preferred wires solutions for the Windsor-Essex Region. The needs include those previously identified in the NA and IRRP for the Windsor-Essex Region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the Windsor-Essex region, in the near and medium terms, are given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Lauzon TS DESN2 transformers (T7/ T8)	Replace 50/83 MVA units with 75/125 MVA units	Hydro One Transmission	2032	$76M
Station Capacity Needs				
Lauzon TS DESN2 transformers (T7/ T8)	Replace 50/83 MVA units with 75/125 MVA units.	Hydro One Transmission	2032	$76M
Belle River TS	Load transfer to Lauzon TS DESN1/2	Hydro One Distribution	2026	$15M
Kingsville-Leamington Greenhouse supply stations	Leamington DESN5/6 (230/27.6 kV 75/125 MVA)	Hydro One Transmission	2029	$120M
Coatsworth Greenhouse supply station	Coatsworth DESN1 (230/27.6 kV 75/125 MVA)	Hydro One Transmission	2029	$60M
Transmission Line Capacity Needs				
230 kV supply line to West Essex and Windsor sub-system*	Establish: (a) a new double-circuit 230 kV Lakeshore TS x Lauzon line; (b) Lauzon 230 kV switchyard.	Hydro One Transmission	2032	$300M
230 kV supply line to Kingsville-Leamington sub-system	Establish a new double-circuit 230 kV from Lakeshore TS into the Leamington/Kingsville area	Hydro One Transmission	2029	$176M
230 kV supply line to Coatsworth area	Establish a new 230 kV line tap from Chatham SS x Lakeshore TS line to Coatsworth DESN1	Hydro One Transmission	2029	$96M
System Reliability, Operation and Load restoration Needs				

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Operational complexity of Lakeshore RAS	Installation of dual batteries at Leamington TS and South Middle Road TS	Hydro One Transmission	2027	$9M
Low voltage concern about loss of Lauzon TS HV capacitor bank with autotransformer	Development of 230 kV switching at Lauzon TS will mitigate this risk.	Hydro One Transmission	2032	Nil**
Restoration in Kingsville-Leamington sub-system	Establish a new double-circuit 230 kV from Leamington DESN5/6 to H38/H39 for restoration of loads connected to these lines.	Hydro One Transmission	2030	$60M

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required).
c) * Development work for the recommended Lakeshore TS x Lauzon line has commenced.
d) ** The mitigation of low voltage concern is an incidental benefit of the Lauzon 230 kV switching facility development for the 230 kV supply line to West Essex and Windsor sub-system
e) Switchyard reconfiguration is not planned for Lakeshore TS hence an opportunity does not exist to alleviate the operational low voltage concern due to the loss of a high voltage capacitor bank.

The long-term needs which have been identified are to be monitored to enable timely commencement of appropriate work.

Tilbury West DS: capacity need identified in 2037.

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process. Hydro One as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The third cycle of the Regional Planning process for the Windsor-Essex region was initiated with the publication of Needs Assessment (NA) and the report was published in February 2023 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in May 2023 and in April 2025 respectively, by the Independent Electricity System Operator (IESO).

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by the Windsor-Essex TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC"), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1.

Table 1: Windsor-Essex region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission)
2	Independent Electricity System Operator (IESO)
3	Enwin Utilities Ltd (Enwin)
4	Hydro One Networks Inc. (Distribution)
5	Essex Powerlines Corporation (Essex Powerlines)
6	E.L.K Energy Inc. (E.L.K. Energy)
7	Entegrus Powerlines Inc. (Entegrus)

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Windsor-Essex region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the Windsor-Essex region.

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

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and electricity Demand Side Management ("eDSM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2024-2033 identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2024-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Windsor-Essex IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near to medium term (1 – 10 years), whereas long-term (10 – 20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., electricity Demand Side Management (eDSM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

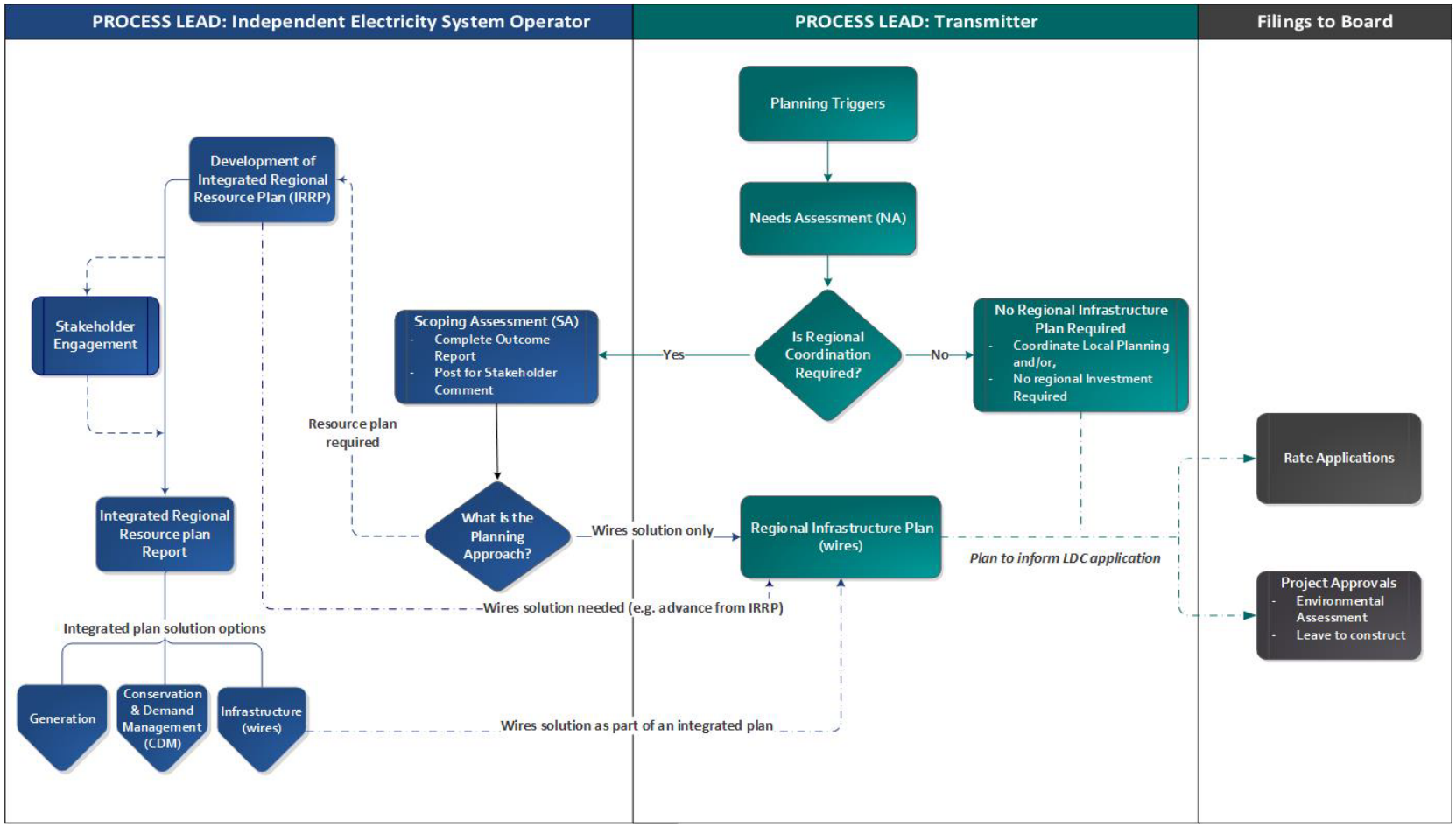
The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, IESO's foreast eDSM contributions as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

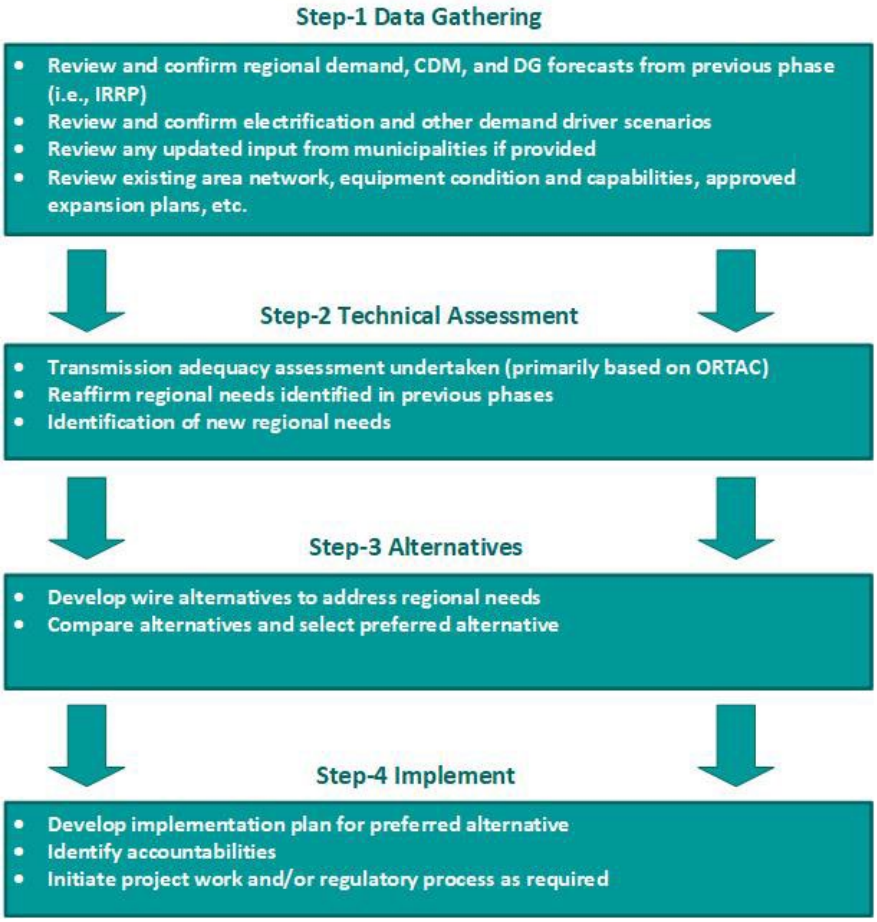
The various phases of Regional Planning Process (NA, SA, IRRP and RIP) and their respective phase trigger, lead, and outcome are shown below in figure-1.

Figure-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and electricity demand management programs. The load forecast from the IRRP was used for this RIP, except for the addition of new load in the Coatsworth area for the greenhouse sector and the modification of the eDSM to be in line with the IESO 2025 Annual Planning Outlook.

- Review and confirm electrification and other growth scenarios which affects the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

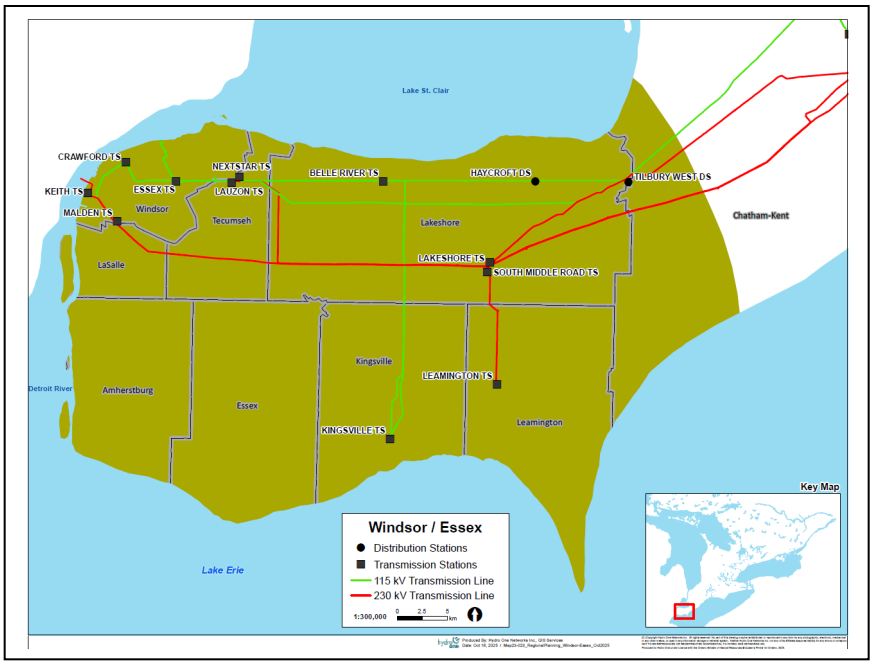
The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Windsor-Essex region consists of the City of Windsor, the Municipality of Leamington, the Towns of Amherstburg, Essex, Kingsville, Lakeshore, LaSalle, Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent. The region also includes several Indigenous communities including Aamjiwnaang First Nation, Caldwell First Nation, Chippewas of the Thames First Nation, Chippewas of Kettle and Stony Point First Nation, Oneida Nation of the Thames, and Walpole Island First Nation. For electricity planning purposes, the region is defined by electricity infrastructure boundaries, not municipal boundaries. It is one of seven planning regions in Southwest Ontario, adjacent to the Chatham-Kent/Lambton/Sarnia region to the east.

The geographical boundaries of the Windsor-Essex region are shown in Figure 3 below.

Figure 3: Map of Windsor-Essex Regional Planning Area



The region's 230 kV transmission include: Chatham SS x Lakeshore TS circuits (C42H, C43H, C64H, C65H, C87H, C88H), Lakeshore TS x Keith TS circuits (H25J, H26J), Lakeshore TS x Lauzon TS circuits (H53Z, H54Z), Lakeshore TS x Leamington TS circuits (H38, H39), Lakeshore TS x South Middle Road TS circuits (H75, H76), Brighton Beach CGS x Keith TS circuit (J20B) and the Keith TS x Michigan interconnection J5D. The regions 115 kV transmission include: Keith TS x Essex TS circuits (J3E, J4E), Essex TS x Lauzon TS circuits (Z1E, Z7E), Essex TS x E. Windsor CGS circuits (E8F, E9F), Brighton Beach CGS x Keith TS circuit (J1B) and W. Windsor Power CGS x Keith TS circuit (J2N). The 115 kV network connects to the 230 kV system via auto transformers at Keith TS and Lauzon TS. The major transmission stations in the region are Lakeshore TS, Keith TS and Lauzon TS.

The region has remedial action schemes (RAS) for managing risks of thermal overloads and voltage decline: the Lakeshore RAS and the Windsor Area RAS.

This region is served by five LDCs: Enwin, Essex Powerlines, E.L.K. Energy, Entegrus, and Hydro One Distribution. Enwin and Hydro One Distribution are directly connected to the transmission system, while the three other LDCs have connections to Hydro One distribution feeders. The region is now winter peaking with some stations peaking in the winter and others in the summer.

Electricity demand in the region is growing at a rapid pace due to residential and commercial development, and continued expansion of the agricultural and industrial sectors. Agriculture has been driving electricity demand growth and needs in the region over the last several years, especially in winter, and continues to be an important driver going forward. Broader economic development across the region,

electrification, and local climate action plans are also expected to be key factors for future electricity needs. These factors identified as drivers of growth are used to inform the forecasts developed for the region.

The circuits and stations of the area are summarized in Table 2 below:

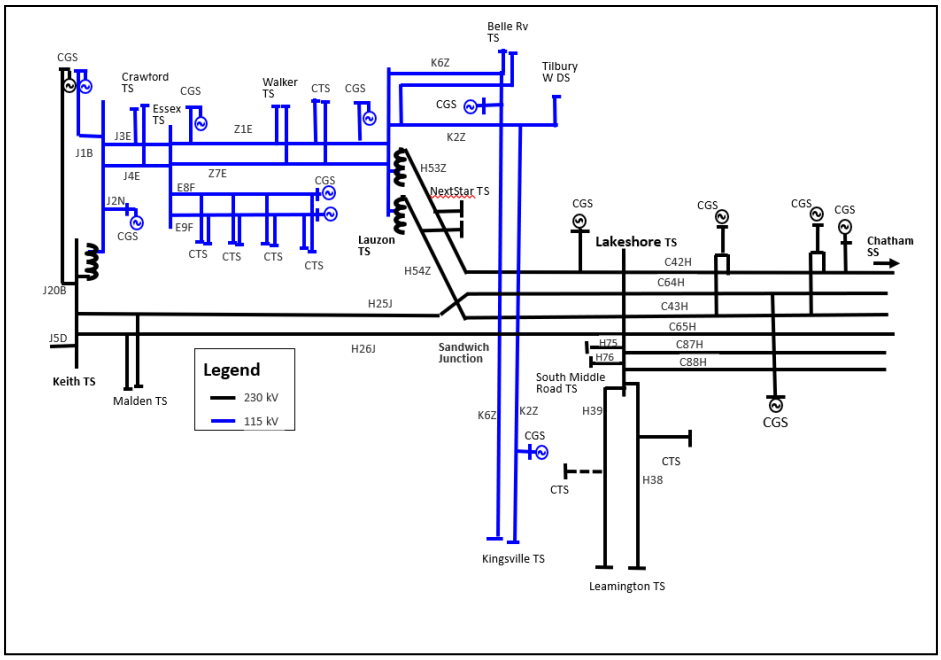
Table 2: Transmission Station and Circuits in the Windsor-Essex region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
J3E, J4E, Z1E, Z7E, E8F, E9F, J1B, J2N, K2Z, K6Z, N5K	C42H, C43H, C64H, C65H, C87H, C88H, H25J, H26J, H53Z, H54Z, H38, H39, H75, H76, J20B, J5D	Lakeshore TS, Keith TS*, Lauzon TS*, Malden TS, NextStar TS, Leamington TS, South Middle Road TS, Kingsville TS, Belle River TS, Crawford TS, Essex TS, Walker TS #1, Tilbury West DS, Walker MTS#2, CTS1, CTS2, CTS3, CTS4, CTS5, CTS6, CTS7	Total 13 CGS, 1723 MW Total 1 BESS, 87 MW

*Stations with autotransformers installed

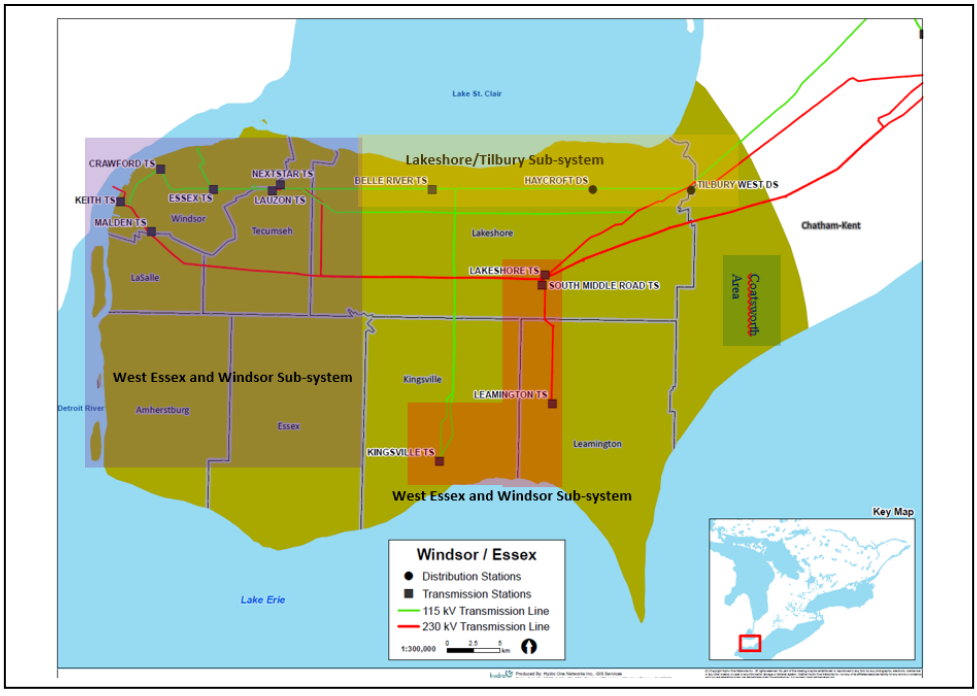
The single line diagram of the Transmission Network of Windsor-Essex region is shown in Figure 4 below.

Figure 4: Windsor-Essex Transmission Single Line Diagram



The region is divided into three sub-systems, each with some transmission facility, for regional planning purposes (Figure 5):

Figure 5: Sub-systems in Windsor-Essex Region



- The **West Essex and Windsor sub-system** in the west of the region, electrically defined by the load and generation connected to and downstream of the H53Z, H54Z, H25J, and H26J 230 kV circuits west of Lakeshore TS. In Windsor, Keith TS and Lauzon TS connect the region's 115 kV network to the 230 kV transmission system via two autotransformers at each station. These supply the 115 kV transmission lines that connect to Belle River TS, Crawford TS, Essex TS, Kingsville TS, Lauzon TS, Tilbury West DS, Walker MTS #2, and Walker TS #1.
- The **Kingsville-Leamington sub-system** in the south-east of the region, electrically defined by the load and generation connected to Kingsville TS, the H38 and H39 230 kV radial circuits south of Lakeshore TS, and the H75 and H76 radial circuits north of Lakeshore TS. The stations in this sub-region are winter peaking on account of the greenhouse sector and their large uptake of artificial crop lighting.
- The **Lakeshore/Tilbury sub-system** in the north-east of the region, electrically defined by the load and generation connected to the K2Z and K6Z 115 kV circuits downstream of Lauzon TS, inclusive of Belle River TS and Tilbury West DS but excluding Kingsville TS.

The **Coatsworth area**, located in the south-east of the region, where there is expectation of significant greenhouse development is outside of the three subsystems because there is currently no transmission facility in the area.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the **Windsor-Essex region** to improve the supply capability and reliability.

Hydro One, being the Transmission Asset Owner (TAO) in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. The following Major projects were completed during the last ten years:

1. Keith TS breakers replacement: the following breakers were replaced SC11K, SC11SC, SC1B, T11P, T12P, and SC2Y (I/S 2015); HT11K, HT12K, L1P, T1L3, renamed L3K (I/S 2024); L2P and L3P (I/S 2025).
2. Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017).
3. Malden TS breakers replacement: two 27.6 kV feeder breakers were replaced (I/S 2018).

4. Supply to Essex County Transmission Reinforcement: A new 13 km double-circuit 230 kV transmission line to Leamington area tapped to the previous C21J/C22J (Chatham SS x Keith TS) circuits, and new 75/100/125 MVA Leamington TS DESN1 (I/S 2018).
5. Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to accommodate the construction of Gordie Howe International Bridge (I/S 2018).
6. Leamington TS expansion: Installation of 75/100/125 MVA Leamington TS DESN2 (I/S 2019).
7. Kingsville TS 25/42 MVA transformers (T1, T2, T3, T4) replacement with 50/83 MVA units T5, T6 (I/S 2022).
8. Keith TS 115 MVA autotransformers replacement with 150/200/250 MVA units (I/S 2023).
9. Tilbury TS decommissioned (2019).
10. Keith TS transformer T1 decommissioned (2021).
11. Built new switching station (Lakeshore TS) at Leamington Junction (I/S 2022).
12. Built new 75/100/125 MVA South Middle Road TS DESN1 (I/S 2022).
13. Build Chatham SS x Lakeshore TS 2-cct 230 kV line (I/S 2024).
14. Built new 75/100/125 MVA South Middle Road TS DESN2 (I/S 2025).

II. Following Major projects are underway:

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

1. Keith TS 300/500 MVA phase angle regulator PSR5 replacement (expected I/S 2026).
2. Lauzon TS 50/83 MVA transformers T5 and T6 replacement with 75/125 MVA units (expected I/S 2026).
3. Development of Chatham SS x Lambton TS 2-cct 230 kV line (expected I/S 2028). This project, while outside the Windsor-Essex region, will improve transfers into the region.
4. Development of Longwood TS x Lakeshore TS 1-cct 500 kV line (expected I/S 2030).

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

After verification from the TWG participants, the following two updates were provided and the W-E IRRP Load Forecasts were modified accordingly for the development of this Report:

(a) the addition of new load in the Coatsworth area due to expected significant development of the greenhouse sector in the area (as provided by Hydro One Distribution), and

(b) eDSM update based on the IESO 2025 Annual Planning Outlook (as provided by the IESO).

TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast. The municipalities were contacted as part of IRRP stakeholder

engagement process to get their insight on the future load growth and was considered during IRRP load forecast development.
The study considers a reference planning forecast and a high forecast, both based on extreme weather. The reference planning forecast is based on relatively firm assumptions: firm loads, organic growth, electrification, community energy plans, residential growth, greenhouse growth, and industrial growth. The high forecast is a proxy for a variety of factors which could result in higher demand over the next 20 years, such as electrification, higher growth in the agricultural sector and development that is not yet committed. The reference forecast is used to recommend near- to medium-term plans and action plans to monitor long-term needs, while the high forecast is used to identify where future needs may arise and recommend actions to ensure options would be available to address these needs if they arise.

During the study period (2024 to 2043), the load in the Windsor-Essex region is expected to grow at a compound annual rate of approximately 2% in winter and 1.3% in the summer. Based on the high load forecast, the rates would be 6.7% in winter and 3.6% in the summer. The Region is now winter peaking.

Figures 5 & 6 show the Windsor-Essex region extreme summer and winter weather net coincident and non-coincident load forecasts from 2024 to 2043. The regional coincident forecast is the demand observed at each station for the hour of the year in which the overall demand in the region is maximum. The regional non-coincident forecast represents the peak demand at each station in the region regardless of the time of occurrence in the season. Non-coincident and coincident forecast for the individual stations in the region is available in Appendix A. The non-coincident forecast is used to determine the need for station capacity relief at each station, while the coincident forecast is used to determine the need for supply capacity in an area.

Figure 6: Windsor-Essex region summer/winter coincident Net Peak Reference Load Forecasts

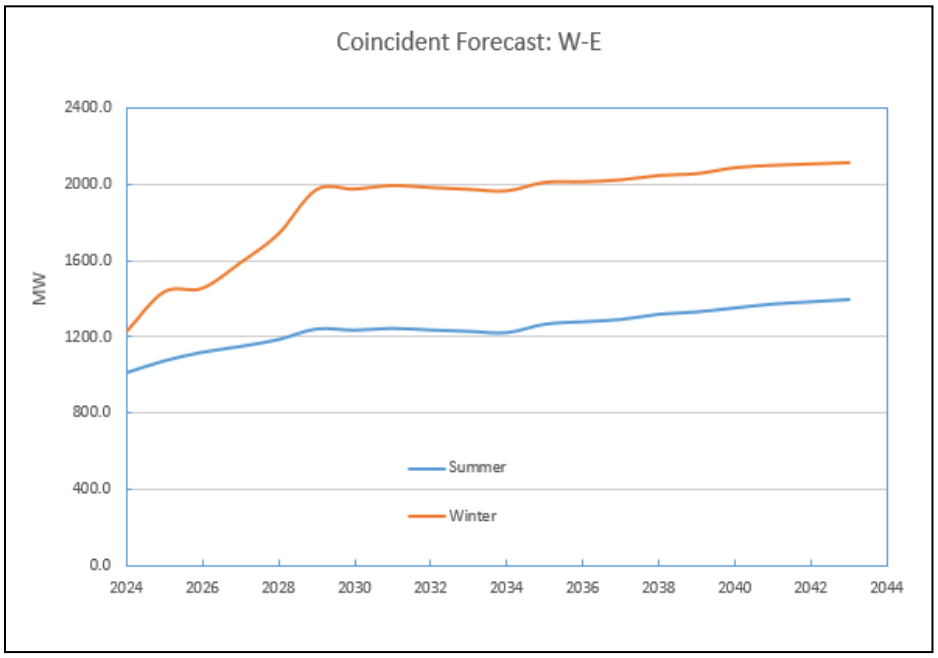


Figure 7: Windsor-Essex region summer/winter Non-coincident Net Peak Reference Load Forecasts

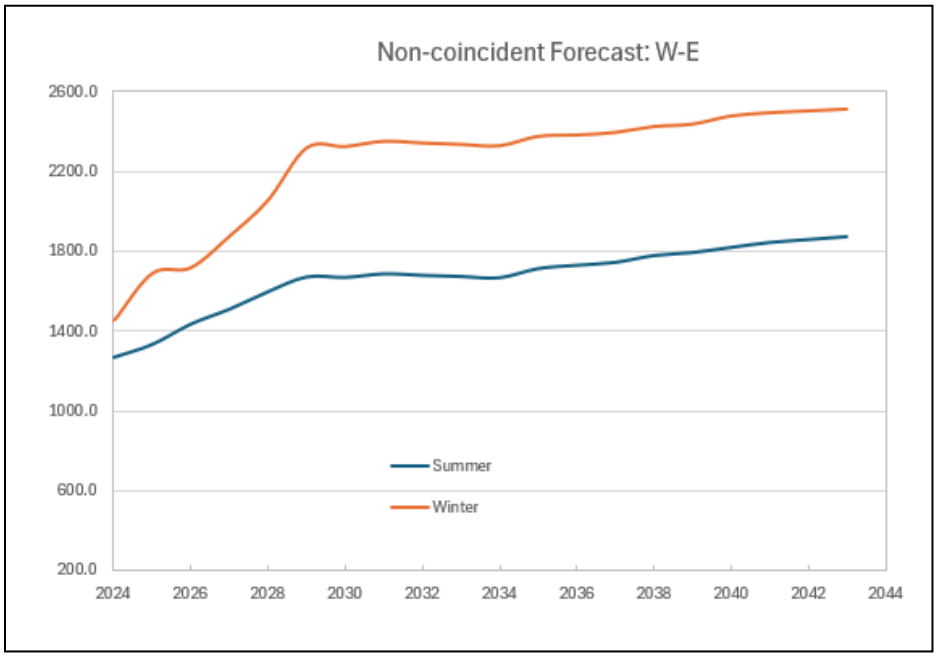


Figure 8: Windsor-Essex region summer/winter coincident Net Peak High Load Forecasts

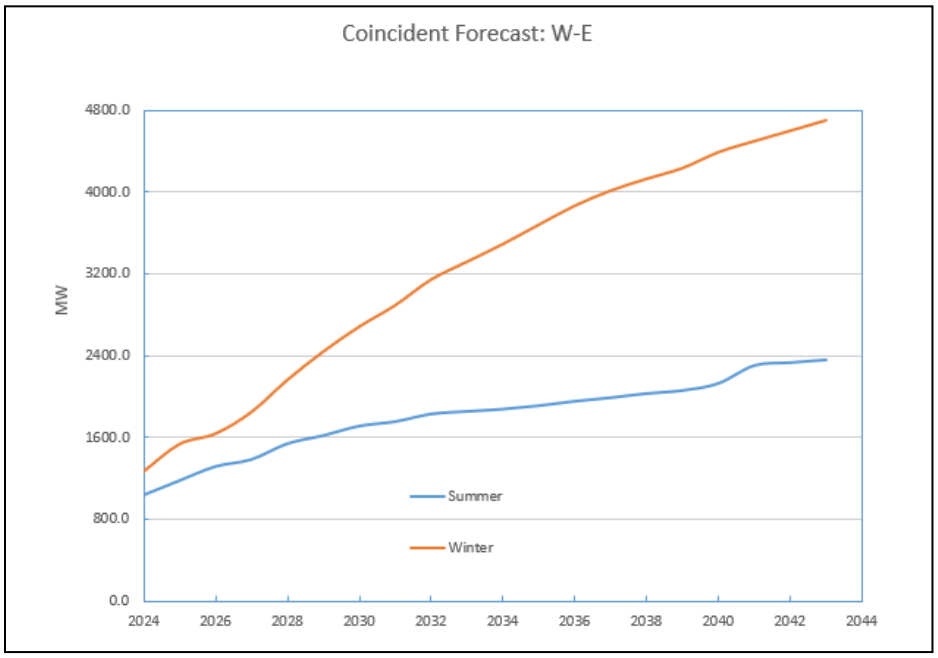
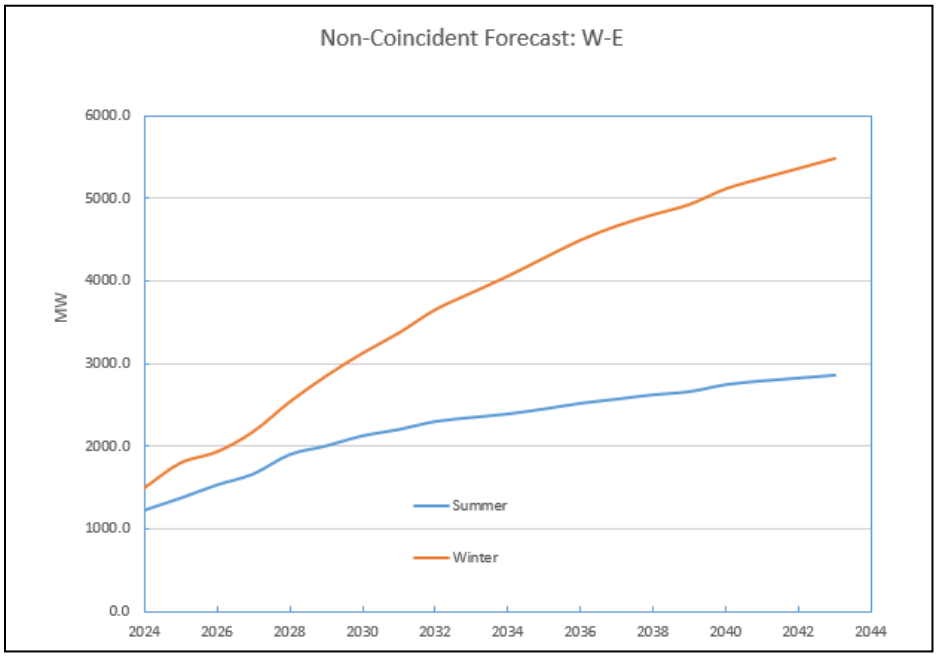


Figure 9: Windsor-Essex region summer/winter Non-coincident Net Peak High Load Forecasts



6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2024 – 2043, the same as the IRRP.
- All planned facilities for each project which has been initiated and listed in section 4 are assumed to be in-service as of the planned project in-service year.
- The Region is winter peaking, so this assessment considers both summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Windsor-Essex region and lists the facilities requiring reinforcement over the near- and mid-term periods. The adequacy assessment assumes that all the projects that are listed in **"Section 5"** are completed.

In the current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Windsor-Essex region Second cycle Needs Assessment Report, Completed in February 2023 by Hydro One.
- Windsor-Essex region Second cycle Scoping Assessment Report, Completed in May 2023 by the IESO.
- Windsor-Essex region Second cycle Integrated Regional Resource Plan Report, Completed in April 2025 by the IESO.

The Technical Working Group identified several regional needs based on the load demand forecast over the study period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the 2024 -2033 period in the Windsor-Essex region. The complete list of major HV transmission equipment requiring replacement in the Windsor-Essex region is provided in table 3 in this sub-section. Hydro One and Enwin are the only Transmission Asset Owners (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Table 3: Major HV Transmission Asset assessed for Replacement in the region planned in next 10 years

Station/Circuit	Need Description	Planned ISD
Lauzon TS DESN2 transformers (T7/T8)	Units built in 1972 and due for replacement in 2029. (Station capacity exceedance: 0.6 MW in summer 2035.)	2032
Lauzon TS DESN2 transformers (T5/T6)	50/83 MVA transformers T5 and T6 replacement with 75/125 MVA units	2026
Keith TS Phase shifters	300/500 MVA phase angle regulator PSR5 replacement	2026

Note: The planned in-service year above is tentative and is subject to change.

7.2. Station Capacity Needs

Over the study period 2024-2043 RIP reviewed the capacity of all the 230kV and 115kV transformer stations within the Windsor-Essex region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and identifies the need for station capacity to support new load in the Coatsworth area due to greenhouse development in the area. The stations which require capacity relief during the study period are shown in Table 4 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 4: Windsor-Essex region Station Capacity Needs in the study period

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2023 Loading (MW) (Summer/Winter)	Need Date
1	Lauzon TS DESN2 (T7/T8)	103.2/111.5	96.9/63.5	2035 (2025)[1]
2	Belle River TS	53.7/60.8	55.1/38.4	Immediate
3	Tilbury W DS	22.5/22.5	22.1/17.9	2037 (2036)[1]
4	Keith TS	104.8/112.0	65.3/62.7	(2034)[1]
5	Malden TS	183.4/194.8	102.2/80.5	(2040)[1]
6	Leamington DESN5/6*	183.4/194.8	-/-	2027
7	Coatsworth DESN1*	183.4/194.8	-/-	2029

[1] Need year in brackets based on high load forecast.

* Station to be developed as per need date, the listed LTR is expected.

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period 2024-2043 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Windsor-Essex region. The IRRP indicated the need to increase transmission supply capacity into the West Essex and Windsor sub-system due to new load, and further showed that a supply circuit (H54Z) to the sub-system would require capacity relief with all elements in service within the study period; and the need for transmission supply capacity for the Kingsville-Leamington sub-system to support new load stations (Leamington DESN5/6). The RIP has confirmed these needs based on the load forecast and identifies the need for transmission supply capacity to support a new load station in the Coatsworth area. The transmission line capacity needs are summarized in Table 5 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 5: Windsor-Essex region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Maximum Capacity (LTE)	2024 Loading	Need Date
1	H54Z	Lakeshore TS x Sandwich Jct	1047 A	463 A	2032 (2025)[1]
2	New 230 kV supply line to Kingsville x Leamington sub-system	Lakeshore TS x Leamington DESN5/6	-	-	2027 (2027)[1]
3	New 230 kV supply line to Coatsworth area	Chatham SS x Lakeshore x Coatsworth	-	-	2029 (2029)[1]

[1] Need year in brackets based on high load forecast.

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operation and Load Restoration Needs

The following operational issues were identified:

- Operational complexity of the Lakeshore RAS due to its lack of redundancy.
- Operational low voltage concerns at Lakeshore TS which may result from the loss of a high voltage capacitor bank and a supply circuit due to station configuration.
- Operational low voltage concerns and at Lauzon TS which may result from the loss of a high voltage capacitor bank and a 230/115 kV autotransformer due to the station configuration.

Load security and load restoration needs were reviewed as part of the current study. ORTAC Section 2.4.10 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The IRRP identified restoration needs in the Leamington-Kingsville sub-system and the RIP further confirms this.

The above 30-minute and 4-hour restoration requirements cannot be met for loads supplied by the radial two-circuit line H38/H39 (Leamington DESN1/DESN2, and two customer transformer stations). However, all loads can be restored within 8 hours, and 30 MW of Leamington TS DESN1/DESN2 load can be restored by transfer to Kingsville TS.

For loads at Leamington DESN1/DESN2 and two customer transformer stations which are supplied by the radial two-circuit line H38/H39 from Lakeshore TS, all can be restored within 8 hours while 30 MW of Leamington DESN load can be restored by transfer to Kingsville TS within 4 hours. Hence, the above 30-minute and 4-hour restoration requirements cannot be met. For the new Leamington DESN5 and DESN6 which are needed for the Kingsville-Leamington Greenhouse Development, all loads can be restored within 8 hours, but the 30-minute and 4-hour restoration requirements cannot be met. There is need for a solution to address these restoration requirements.

Restoration Need Table

Circuits Supplying Load	30-minute restoration (need date)	4-hour restoration (need date)
H38/H39	192 MW (immediate) 210 MW (2043)	262 MW (immediate) 280 MW (2043)
Kingsville-Leamington Greenhouse line	66 MW (2028) 105 MW (2043)	166 MW (2028) 205 MW (2043)

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Windsor-Essex Region. These needs include those previously identified in the NA and IRRP for the Windsor-Essex Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning estimates and are used for comparative purposes only and may vary. The needs in the region are summarized in Table 6 below:

Table 6: Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
Lauzon DESN 2 T7/T8 transformers	Replacement based on asset condition assessment	2032	8.1.1

Station Capacity Needs			
Lauzon DESN 2	Existing station capacity exceeded	2035 (2025)[1]	8.2.1
Belle River TS	Existing station capacity exceeded	2024	8.2.2
Tilbury West DS	Existing station capacity exceeded	2037 (2036)[1]	8.2.3
Kingsville-Leamington Greenhouse Supply Stations	New DESNs are needed for new load due to greenhouse development	2027	8.2.4
Coatsworth Area Greenhouse Supply Stations	New DESN is needed for new load due to greenhouse development	2029	8.2.5
Keith TS DESN	Station capacity exceedance based on high load forecast	(2034)[1]	8.2.6
Malden TS	Station capacity exceedance based on high load forecast	(2040)[1]	8.2.6
Transmission Line Capacity Needs			
230 kV Supply line to West Essex and Windsor sub-system	New supply line to West Essex and Windsor sub-system due to significant increase in demand from municipal growth, industrial development and electrification initiatives.	2032 (2025)[1]	8.3.1
230 kV Supply line to Kingsville-Leamington sub-system	New double-circuit 230 kV line needed to supply new DESN stations	2027 (2027)[1]	8.3.2
230 kV Supply line to Coatsworth Area	New double-circuit 230 kV line needed to supply a new DESN station	2029 (2029)[1]	8.3.3
System Reliability, Operation and Load restoration Needs			
Operational Issue	Operational complexity of the Lakeshore RAS due to lack of redundancy.	2024	8.4.1
Operational Issue	Low voltage may result from the loss of a high-voltage capacitor bank and another element at Lakeshore TS and Lauzon TS.	2024	8.4.1
Restoration line in Kingsville-Leamington sub-system	A 230 kV line is needed to meet the 30-minute and 4-hour ORTAC restoration requirements.	2024	8.4.2

[1] Need year in brackets based on high load forecast.

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for “right sizing” the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

8.1.1 Lauzon TS – DESN2 T7/T8 Transformers

T7/T8 50/83 MVA 230/27.6 kV power transformers were built in 1972 and based on asset condition assessment, are identified for replacement in 2032. A like-for-like replacement of these units would be adequate in meeting the load up to 2035. However, as discussed in Sect 8.2, there are station capacity needs in the medium term which require upsizing the transformers.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2043 for the 230kV and 115kV Transforming stations in the Windsor-Essex region using either the summer or winter peak load forecasts. Based on the results, the following station capacity needs have been identified over the study period:

8.2.1 Lauzon TS DESN2 (T7/T8 50/83 MVA 230/27.6 kV)

Lauzon TS is located in the eastern part of the City of Windsor, and includes 230/115 kV autotransformers (T1, T2), as well as two 230/27.6 kV DESNs (T5/T6 and T7/T8). Lauzon TS is connected to the 230 kV circuits H53Z/H54Z, and to 115 kV circuits Z1E/Z7E and K2Z/K6Z. Lauzon DESN 1 T5/T6 units are in the process of being replaced with larger units.

Lauzon TS DESN 2 is summer peaking. Based on the reference forecast, the capacity of the DESN is expected to be reached by 2035 due to municipal growth, industrial development and electrification initiatives in the West-Essex and Windsor sub-system. It would exceed this capacity by 37 MW in 2043. Considering a high load forecast scenario, the DESN capacity would be reached by 2025, and by 2043 would be exceeded by 120 MW.

Alternatives and Recommended Plan

The following alternatives were considered to accommodate excess load at the station.

- Alternative 1: Electricity demand side management program
  Electricity demand side management (eDSM) targeted at the station customers may be used to achieve about 11 MW of load reduction by about 2043, at a cost of $50M. This option does not fully address the need.

- Alternative 2: Construct a new DESN in the vicinity of Lauzon TS
  Constructing a new 50/83 MVA 230/27.6 kV DESN at Lauzon TS would be at an estimated cost of $60M.

- Alternative 3: Upsize existing units
  Replacing the existing 50/83 MVA power transformers with 75/125 MVA units at an estimated incremental cost, relative to like-for-like replacement, of $15 - $30M.

Replacing T7 and T8 transformers with the larger 75/125 MVA units in 2032 is the preferred wires option being the least cost option. This upsizing would also provide for the transfer of load from Belle River TS which is forecast to be marginally over its station capacity in the near term (2 MW in 2025), increasing slowly over the 20-year study period to 13 MW in 2043.

8.2.2 Belle River TS (T1/T2 25/42 MVA 115/27.6 kV)

Belle River TS is located the Municipality of Lakeshore, and connected to 115 kV circuits K2Z and K6Z. This is a summer peaking station, and its capacity is currently exceeded, and by 2043 the exceedance would be 17 MW. The transformers were built in 2005 and are not due for replacement until 2065. The following alternatives were considered to accommodate the excess load at the station.

- Alternative 1: Electricity demand side management program
  New eDSM programs targeted at the station customers may be used to achieve about 5 MW of the need by 2043 at a cost of $18M. This alternative would not fully meet the need.

- Alternative 2: Construct a new DESN at Belle River TS
  Constructing a new 50/83 MVA 115/27.6 kV DESN at Belle River TS would be at an estimated cost of $60M. This option would provide additional capacity beyond the need of the station. However, this additional capacity would not be realisable because of limitations in the 115 kV network.

- Alternative 3: Advance and upsize the replacement of T1/T2
  Advancing the replacement of the existing units with upsized units would be at an estimated incremental cost of $15 - $30M relative to like-for-like replacement, plus advancement cost. This option would provide additional capacity beyond the need of the station. However, this additional capacity would not be realisable because of limitations in the 115 kV network.

- Alternative 4: Load transfer
  The excess load from Belle River TS could be transferred to the upsized Lauzon DESN1/2 via the distribution system at an estimated cost of $15M.

Transferring load from Belle River TS to Lauzon DESN1/2 is the preferred wires option.

8.2.3 Tilbury West DS (T1/T2 15/25 MVA 115/27.6 kV)

Tilbury West DS is located in the Municipality of Lakeshore, and it is supplied from 115 kV circuit K2Z. This is currently a summer peaking station, and based on the reference forecast it is expected to become winter peaking by 2031, and by 2025 on the based on the high forecast. The station summer capacity would be marginally exceeded in 2037 and by 8 MW in 2043; the winter capacity would be marginally exceeded in 2039 and by 9 MW in 2043. Considering a high load forecast scenario, the DESN capacity would be marginally exceeded by 2036, and by 15 MW in 2043. The transformers were built in 1988 and are not due for replacement until 2048. The following alternatives were considered to accommodate the excess load at the station.

- Alternative 1: Electricity demand side management program
  New eDSM programs may be used to achieve about 3 MW of the need by 2043 at a cost of $8M.

- Alternative 2: Construct a new DESN at Tilbury West
  Constructing a new 50/83.3 MVA 115/27.6 kV station at Tilbury West DS would be at an estimated cost of $60M. This option would provide station summer capacity of 92 MW. However, the additional capacity beyond the need of the station would not be realisable because of limitations in the 115 kV network.

- Alternative 3: Advance and upsize the replacement
  Advancing the replacement of the existing units with upsized 25/42 MVA units would be at an estimated incremental cost of $15 - $30M relative to like-for-like replacement, plus advancement cost. This option would provide additional capacity beyond the need of the station.

Advancing the replacement of existing units with upsized 25/42 MVA units is the preferred wires option.

8.2.4 Kingsville-Leamington Greenhouse Supply Stations

New greenhouse development is expected to continue in the Kingsville-Leamington sub-system resulting in rapid load growth in the area. By 2027 there would be need for 150 MW of station capacity and this need would grow to 390 MW by 2031 under the reference forecast. Under the high forecast the need would be 930 MW by 2043. As the station capacity need cannot be met by existing stations, the following alternatives were considered to meet this need.

- Alternative 1: Electricity demand side management program
  The potential peak demand reduction through the reduction of grow lights in the winter daytime periods is expected to be in the order of tens of MWs in the winter and nothing in the summer. eDSM targeting greenhouses is expected to achieve about 20 MW by 2028 and about 100 MW by 2043 at a cost of about $330M. Hence these non-wires options cannot meet the need.

- Alternative 2: Construct new DESN stations
  The wires option to meet the need of the reference forecast is the establishment of two new 75/125 MVA 230/27.6 -27.6 kV DESN stations (Leamington DESN 5 and 6). (The high forecast need of 930 MW by 2043 would require six similarly sized DESNs.) The location(s) of the stations would depend on customer input. Given the four to five-year timeline to establish a new facility, the earliest in-service date for these stations is 2028. The cost estimate for the two DESN stations is about $120M. The DESNs would need to be supplied by a new 22 km double-circuit 230 kV line from Lakeshore TS.

  The recommended option is the construction of new DESNs. The location of the stations would depend on customer input. The existing need to transfer some load off Kingsville TS for the relief of the 115 kV network, can be met with the transfer of some Kingsville TS load to the new DESNs following their establishment.

8.2.5 Coatsworth Area Greenhouse Supply Station

The Coatsworth area is located in the south-west of the Municipality of Chatham-Kent. There are indications of very significant new greenhouse development in this area which would result in 190 MW of new load in 2029 and remaining flat under the reference forecast. Under the high load forecast the need would steadily increase to 1400 MW by 2043, requiring seven new DESN stations. The nearest transmission supply station to the area is Leamington TS about 20 km to the west. As the station capacity need cannot be met by existing stations, the following alternatives were considered to meet this need.

- Alternative 1: Electricity demand side management program
  The application of eDSM targeting greenhouses is not a viable alternative without transmission connection of the greenhouses.

- Alternative 2: Construct new DESN station
  The wires option to meet the need of the reference forecast is the establishment of a new 75/125 MVA 230/27.6 -27.6 kV DESN station (Coatsworth DESN 1). The high forecast need of 1440 MW by 2043 would require seven similarly sized DESNs. The location(s) of the stations would depend on customer input. The cost estimate for the new DESN station is about $60M. The DESN would need to be supplied by a new double-circuit 230 kV line.

The recommended option is the construction of a new DESN.

8.2.6 Keith TS and Malden TS

There is no station capacity need at Keith TS and Malden TS over the study period based on the reference forecast. However, the high load forecast indicates station capacity need in 2043 of 37 MW at Keith TS and of 39 MW at Malden TS.

Given that these needs are based on the high forecast and arise in the long term, targeting eDSM programs at the stations' customers while monitoring load growth is recommended to ensure that the electricity system can reliably meet future needs.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. In the process of regional planning, Transmission Lines Capacity Assessment was performed over the study period 2024-2043 for the 230kV and 115kV Transmission line circuits in the Windsor-Essex region by assessing thermal limits of the circuit and the voltage range as per ORTAC. Based on the results, the following line capacity needs have been identified in region:

8.3.1 230 kV Supply Line to West Essex and Windsor sub-system

The Lakeshore TS x Lauzon TS (34 km) double-circuit 230 kV line comprise circuits H53Z and H54Z. H54Z is strung with 795 kcmil ACSR (26/7) conductor over the Lakeshore TS x Sandwich Jct section, but with 1192.5 kcmil ACSR (54/19) conductor over the balance of the circuit. The companion circuit, H53Z, is strung with 1192.5 kcmil ACSR (54/19) conductor the entire length. Based on the reference summer forecast, H54Z would be thermally overloaded in year 2032 following the loss of double-circuit H53Z/H25J. By 2036 the loss of H53Z + H25J or H54Z + H26J would result in voltage collapse of Lauzon 230 kV. Under the high forecast scenario, the thermal overload would occur in 2024. The thermal overload of H54Z and the voltage collapse of Lauzon 230 kV have both resulted in the need to increase the supply capacity into the West Essex and Windsor sub-system. Under the reference summer forecast, the need would be 65 MW in 2032 increasing to 230 MW in 2043. Under the high load forecast, the need would arise in 2025 and increase to 840 MW in 2043. The following alternatives were considered to meet the need under the reference forecast.

Alternative1: New Lakeshore TS x Lauzon 1-cct 230 kV line

- Lakeshore TS x Lauzon 1-circuit 230 kV line which would provide 360 MW of additional transfer capability to meet the 2043 capacity need at a cost of $250M. This option would require the development of 230 kV switching facilities at Lauzon TS.

Alternative 2: New Lakeshore TS x Lauzon 2-cct 230 kV line

- Lakeshore TS x Lauzon double-circuit 230 kV line which would provide 510 MW of additional transfer capability at a cost of $300M. This option would require the development of 230 kV switching facilities at Lauzon TS.

Alternative 3: New Lakeshore TS x Lauzon 1-cct 500 kV line

- Lakeshore TS x Lauzon 1-circuit 500 kV line which would provide about 500 MW of additional transfer capability at a cost of $350M. This option would require the development of 500 kV and 230 kV switching facilities at Lauzon TS.

The recommended alternative is the development of the Lakeshore TS x Lauzon new double-circuit 230 kV 34 km line. This option is within the scope of the Order in Council Directive 875/2022 requiring Hydro One Networks to expand the transmission system. This would require a new right-of-way between Lakeshore TS and Sandwich Junction. The existing right-of-way between Lauzon TS and Sandwich Junction in which the existing double-circuit H53Z/H54Z line is located can accommodate two additional circuits, however final transmission line routing will be established through the Environmental Assessment process. A new 230 kV switchyard will be required for appropriate termination and switching for the new and existing 230 kV elements. This will partially address operational voltage concern at the station resulting from the coincident loss of the station 115 kV capacitor bank, a 230/115 kV autotransformer and 230 kV circuit H54Z due to the station configuration. It is to be noted that development for this recommended alternative has commenced.

8.3.2 230 kV Supply Line to Kingsville-Leamington Sub-system

Leamington DESN5/6 cannot be supported by the existing transmission hence there is need, in 2027, to increase the transmission supply capacity into the sub-region. The viable wires option to meet this need is the construction of a double-circuit 230 kV line from Lakeshore TS into the sub-region to connect the two DESNs. The new line would require a new right-of-way. The locations of the stations would inform the length of the new line. Currently, it is assumed that a 22 km line would be needed for the two DESNs. This would require four to five years to develop at an estimated cost of $176M.

The recommended wires option is to build the double-circuit 230 kV line to supply the DESNs. There is an opportunity to coordinate the development of this line with the recommended Lakeshore TS x Lauzon TS double-circuit line to leverage benefits. By having the supply line to Kingsville-Leamington tap off the Lakeshore TS x Lauzon TS line, its length would be reduced to about 16 km for a cost saving of about $48M.

8.3.3 230 kV Supply Line to Coatsworth Area

There is currently no transmission line facility in the Coatsworth area. The viable wires option to meet the need to supply Coatsworth DESN1 is the construction of a double-circuit 12 km 230 kV line. The line would be tapped off the Chatham SS x Lakeshore 230 kV line at about 18 km from Lakeshore TS and would require a new right-of-way. The length of the line and the location of the tap to the Chatham SS x

Lakeshore line would depend on the location of the DESN. This would require four to five years to develop at an estimated cost of $96M.

The recommended wires option is to build the double-circuit 230 kV line to supply the DESN.

8.4 System Reliability, Operation and Restoration Needs

Issues which relate to system operability, system general reliability and restoration were considered by the Woking Group, and the feasibility of leveraging solutions developed to address regional needs to also address operational needs was considered.

8.4.1 Operational Issues

The following issues were identified: operational complexity of the Lakeshore RAS due to its lack of redundancy; operational low voltage concerns at Lakeshore TS which may result from the loss of a high voltage capacitor bank and a supply circuit; and at Lauzon TS from the loss of high voltage capacitor bank and a 230/115 kV autotransformer due to the station configuration.

- It is recommended to mitigate the operational complexity of the Lakeshore RAS by installing dual batteries at Leamington TS and at South Middle Road TS. This will take about two years to develop at an estimated cost of about $9M.
- The development of a new Lakeshore TS x Lauzon TS line would provide the opportunity to reconfigure Lauzon TS to alleviate the voltage concern at the station resulting from the coincident loss of the station 115 kV capacitor bank and a 230/115 kV autotransformer due to the station configuration (Sect 8.3.1).
- Switchyard reconfiguration is not planned for Lakeshore TS hence an opportunity does not exist to alleviate the operational low voltage concern associated with the simultaneous loss of a high voltage capacitor bank and a supply circuit.

8.4.2 Restoration Needs in Kingsville-Leamington Sub-system

All loads supplied by the radial two-circuit line H38/H39 (Leamington DESN1/DESN2, and two customer transformer stations) can be restored within 8 hours following a permanent fault on the line; similarly for all loads to be supplied by the new 230 kV line to the Kingsville-Leamington Sub-system (Leamington DESN5 and DESN6) following a permanent fault.

However, the 30-minute and 4-hour restoration requirements cannot be met for loads supplied by these lines, as only 30 MW of Leamington DESN load can be restored by transfer to Kingsville TS within 4 hours. The restoration needs are summarized below.

Circuits Supplying Load	30-minute restoration need (date)	4-hour restoration need (date)
H38/H39	192 MW (immediate) 210 MW (2043)	262 MW (immediate) 280MW (2043)
Kingsville-Leamington Greenhouse line	66 MW (2028) 105 MW (2043)	166 MW (2028) 205 MW (2043)

The load restoration requirement can be achieved by developing a new double-circuit 230 kV 3 km restoration line to link the new supply line to the Kingsville-Leamington sub-system (Sect 8.3.2) to circuits H38/H39 with normally open breakers at Leamington TS. The breakers would be closed for load restoration, as needed. A normally closed 230 kV disconnect switch would be installed on each circuit immediately north of the first supply station from Lakeshore TS. The switches are intended to be used for isolating the permanently faulted section to enable restoration to proceed. This will take about two years to develop at an estimated cost of $60M. The extent to which need is met would depend on the location of the outage and the loading conditions.

It is recommended to construct the 3 km double-circuit 230 kV restoration line for restoration of loads supplied from circuits H38/H39 and the proposed supply line to the Kingsville-Leamington sub-system.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure plan Report for Windsor-Essex region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2024-2033 are provided in Table 7 below, along with their planned in-service dates (ISD) and planning cost estimates.

The Windsor-Essex RIP identifies electricity needs in the region over the 20-year period from 2024 to 2043, recommends a plan to address near- and mid-term reference needs, and lays out actions to monitor long-term reference needs.

Table 7: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Lauzon DESN2 (T7/T8)	Existing T7/T8 50/83 MVA transformers to be replaced with 75/125 MVA units plus associated station upgrade	Hydro One Transmission	2032	$76M

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station Capacity Needs				
Lauzon DESN2 (T7/T8)	Transformer replacement with upsized units plus associated station upgrade	Hydro One Transmission	2032	$76M
Belle River TS	Load transfer to Lauzon DESN1/2 following upsizing of transformers. Operational measures would be used to manage capacity overload until the transfer.	Hydro One Distribution	2025	$15M
Kingsville-Leamington Greenhouse Supply Stations	Develop two new 75/125 MVA 230/27.6 -27.6 kV DESN stations (Leamington DESN 5 and 6).	Hydro One Transmission	2027	$120M
Coatsworth Area Greenhouse Supply Station	Develop Coatsworth Area 75/125 MVA 230/27.6 -27.6 kV DESN1	Hydro One Transmission	2029	$60M
Transmission Line Capacity Needs				
230 kV supply line to West Essex and Windsor sub-system*	[1]Develop a new 34 km double-circuit 230 kV Lakeshore TS x Lauzon TS line plus associated Lauzon 230 kV switching facility.	Hydro One Transmission	2032	$300M
230 kV supply line to Kingsville-Leamington sub-system	[1]Develop a new 22 km double-circuit 230 kV from Lakeshore TS to supply the new Leamington DESN 5 and 6.	Hydro One Transmission	2029	$176M
230 kV supply line to Coatsworth Area	Develop a new 12 km double-circuit 230 kV from Chatham SS x Lakeshore TS corridor to supply the new Coatsworth Area DESN1	Hydro One Transmission	2029	$96M
System Reliability, Operation and Load restoration Needs				
Operational complexity of the Lakeshore RAS	Installation of dual batteries at Leamington TS and South Middle Road TS.	Hydro One Transmission	2027	$9M
Low voltage concern about loss of Lauzon TS HV capacitor bank with autotransformer	Development of an appropriate 230 kV switching at Lauzon TS will mitigate this concern.	Hydro One Transmission	2032	Nil**

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Restoration in Kingsville-Leamington Sub-system	Development of 2-circuit230 kV line linking the new Kingsville-Leamington supply line to Leamington TS.	Hydro One Transmission	2030	$60M

Notes:

a) The planned in-service dates are tentative and subject to change

b) Costs are based on planning estimates and excludes the cost for distribution infrastructure (if required)

c) * Development work for the recommended Lakeshore TS x Lauzon line has commenced.

d) ** The mitigation of low voltage concern is an incidental benefit of the Lauzon 230 kV switching facility development for the 230 kV supply line to West Essex and Windsor sub-system.

e) [1] Coordinated development of these two projects is recommended. This will enable the Kingsville-Leamington supply line to tap off the supply line to West Essex and Windsor sub-system for a cost saving of about $48M.

f) Switchyard reconfiguration is not planned for Lakeshore TS hence an opportunity does not exist to mitigate the risk of operational low voltage associated with the loss of a high voltage capacitor bank.

The following need, which has been identified to arise beyond 10 years, is to be monitored to enable timely commencement of the alternative identified in Section 8.

- **Tilbury West DS: capacity need identified in 2037**. The station summer capacity would be marginally exceeded in 2037 and by 8 MW in 2043; the winter capacity would be marginally exceeded in 2039 and by 9 MW in 2043. The transformers were built in 1988 and are not due for replacement until 2048. The preferred plan is replacement of the existing units with upsized 25/42 MVA units.

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 6.0 September 10, 2025)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Windsor-Essex region – Summer Coincident - Reference Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	49.8	49.9	50.0	49.7	49.3	49.1	48.8	48.5	48.3	48.4	48.6	48.8	49.6	50.5	51.7	53.0	54.3	55.7	58.5	59.4	60.2
Crawford TS	63.9	63.6	63.4	62.5	61.6	60.8	60.1	59.4	58.7	58.1	57.5	56.9	56.7	56.5	56.7	56.8	57.0	57.2	57.4	57.6	57.8
Essex TS	68.4	68.1	67.8	66.9	65.8	64.9	64.1	63.3	62.5	61.8	61.2	60.5	60.2	60.0	60.1	60.2	60.3	60.5	60.6	60.8	61.0
Keith TS	55.7	56.3	57.0	57.1	56.6	56.3	56.0	55.9	55.7	55.7	55.7	55.7	56.3	61.9	63.1	66.3	67.7	69.2	70.9	72.6	74.5
Kingsville TS	61.1	61.7	62.4	62.4	62.3	62.4	62.3	62.4	61.5	60.8	60.1	59.4	59.3	59.3	60.0	71.1	71.9	75.5	77.7	78.5	79.1
Lauzon DESN1	102.3	101.9	101.7	100.4	99.0	97.9	96.7	95.7	110.9	110.1	109.4	101.1	101.4	101.7	102.7	103.7	104.8	105.9	106.9	107.7	108.5
Lauzon DESN2	89.5	90.1	90.7	90.6	90.5	90.7	90.8	91.0	91.2	91.9	92.8	93.6	95.5	97.7	100.6	104.1	107.4	112.2	116.6	119.4	122.4
Leamington DESN1	50.1	50.8	51.1	50.6	49.9	49.3	48.7	48.2	47.7	47.5	47.6	47.5	48.3	49.3	50.9	52.5	54.2	55.8	57.3	58.5	59.8
Leamington DESN2	46.2	45.9	45.2	43.8	42.2	40.9	39.6	38.4	37.2	36.0	35.0	34.0	33.4	33.0	32.9	32.9	32.9	32.9	32.9	32.8	32.8
Malden TS	88.2	89.9	91.9	92.9	91.9	91.4	90.8	90.4	90.0	89.9	89.9	90.0	90.9	94.1	95.9	99.6	100.3	105.5	109.0	111.1	113.2
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	37.5	49.6	51.4	49.9	48.3	46.9	45.6	44.3	43.1	41.9	40.9	39.8	39.3	38.9	39.0	39.1	39.2	39.2	39.3	39.4	39.4
South Middle Road DESN2	0.0	0.0	0.0	46.3	47.2	48.1	46.7	45.4	44.2	43.0	41.9	40.8	40.3	39.9	40.0	40.1	40.2	40.2	40.3	40.4	40.4
Tilbury West DS	17.8	17.8	17.8	17.7	17.5	17.5	17.5	17.5	17.6	17.7	18.0	18.2	18.6	21.8	22.4	23.3	23.9	24.8	26.8	27.7	28.3
Walker MTS #2	44.1	48.1	48.1	47.5	47.1	46.9	46.6	46.5	46.3	46.1	45.9	45.7	45.9	45.9	46.5	46.9	47.3	47.7	48.1	48.4	48.5
Walker TS #1	48.1	47.9	47.9	43.3	42.6	42.1	41.7	41.2	40.8	40.4	40.0	47.3	47.1	46.9	47.0	47.2	47.5	47.7	47.8	47.9	48.0
CTS1	23.7	23.8	23.8	23.8	23.8	23.9	23.9	23.9	23.9	24.0	24.0	24.0	24.0	24.1	24.1	24.1	24.1	24.2	24.2	24.2	24.2
CTS2	8.5	8.5	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.7
CTS3	9.3	9.3	9.3	9.3	9.3	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5
CTS4	1.1	1.1	1.1	10.8	10.8	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
CTS5	14.3	14.2	14.1	14.0	13.8	13.7	13.6	13.4	13.4	13.3	13.3	13.3	13.2	13.2	13.2	13.2	13.2	13.2	13.3	13.3	13.3
CTS6	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
CTS7	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	37.2	77.5	82.2	83.7	85.4	82.9	80.6	78.4	77.2	76.2	76.1	76.1	76.1	76.1	76.0	75.9	75.9
West Essex and Windsor Industrial Developments	0.0	3.0	4.4	4.4	7.6	7.5	60.0	60.4	60.9	61.3	61.8	62.3	104.1	103.5	103.5	103.5	103.5	103.4	103.4	103.4	103.3
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	8.2	7.9	7.7	7.4	7.2	7.0	6.9	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8

Table A.2: Windsor-Essex region – Winter Coincident - Reference Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	33.4	33.6	33.7	33.7	33.6	33.6	33.5	33.5	33.4	33.6	33.9	34.1	34.8	35.5	36.4	37.3	38.3	42.0	42.8	43.3	43.9
Crawford TS	45.6	45.6	45.8	45.4	45.1	44.9	44.6	44.3	44.1	43.9	43.6	43.4	43.5	43.4	43.6	43.8	44.0	44.1	44.3	44.4	44.6
Essex TS	42.5	42.5	42.6	42.3	42.0	41.8	41.5	41.3	41.1	40.9	40.6	40.4	40.4	40.4	40.5	40.7	40.8	40.9	41.1	41.2	41.3
Keith TS	48.1	49.5	51.0	52.1	51.8	51.7	51.5	51.3	51.2	51.1	51.0	50.9	51.2	51.4	52.0	52.5	53.1	53.6	54.1	54.7	55.2
Kingsville TS	75.7	76.8	77.9	78.3	78.6	79.2	79.6	80.0	79.0	78.1	77.4	76.7	76.5	76.3	76.7	87.5	87.9	93.3	95.2	95.5	95.9
Lauzon DESN1	68.6	68.8	69.3	68.9	68.5	68.3	67.9	67.6	83.0	82.9	82.9	75.2	75.9	76.4	77.3	78.3	79.3	80.2	81.1	81.8	82.5
Lauzon DESN2	52.0	53.1	54.3	55.1	55.2	55.5	55.7	55.9	56.1	56.6	57.2	57.8	59.0	60.2	61.9	63.6	65.3	69.7	74.0	75.3	76.6
Leamington DESN1	109.0	110.4	111.7	112.2	111.9	112.0	111.8	111.6	111.4	112.0	113.0	113.8	116.3	118.8	122.2	125.7	129.2	132.7	135.5	137.7	139.8
Leamington DESN2	172.5	171.4	170.4	168.2	165.8	163.9	161.8	159.8	157.8	155.9	154.2	152.5	151.6	150.9	150.8	150.8	150.8	150.7	150.6	150.5	150.4
Malden TS	61.1	63.1	65.4	66.6	66.1	65.9	65.5	65.2	64.9	64.8	64.7	64.7	65.2	65.8	66.8	69.4	69.0	78.1	79.1	79.9	80.7
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	142.3	167.9	175.5	173.1	170.5	168.3	165.9	163.7	161.5	159.3	157.4	155.6	154.6	153.7	153.6	153.6	153.6	153.6	153.5	153.3	153.2
South Middle Road DESN2	0.0	0.0	137.6	152.7	158.8	165.2	162.9	160.8	158.7	156.7	155.0	153.2	152.3	151.5	151.4	151.4	151.4	151.3	151.2	151.1	151.0
Tilbury West DS	11.5	11.8	12.1	12.3	12.6	13.0	13.4	13.8	14.3	14.8	15.4	15.9	16.7	19.3	20.1	21.2	22.1	25.6	26.1	26.7	27.2
Walker MTS #2	41.3	45.7	45.9	45.7	45.8	46.0	46.1	46.3	46.4	46.5	46.6	46.7	47.1	47.3	47.8	48.3	48.6	48.8	49.1	49.3	49.4
Walker TS #1	37.3	37.3	37.5	33.3	33.1	33.0	32.9	32.8	32.7	32.6	32.5	40.4	40.4	40.4	40.5	40.7	40.8	41.0	41.1	41.2	41.4
CTS1	18.9	18.9	18.9	18.9	19.0	19.0	19.0	19.0	19.0	19.1	19.1	19.1	19.1	19.1	19.2	19.2	19.2	19.2	19.2	19.3	19.3
CTS2	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
CTS3	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
CTS4	1.5	1.5	1.5	11.0	11.0	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
CTS5	5.7	5.7	5.7	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.8
CTS6	26.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
CTS7	30.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	130.7	277.3	299.6	310.8	323.0	319.1	315.6	312.2	310.4	308.8	308.6	308.6	308.6	308.5	308.3	308.0	307.9
West Essex and Windsor Industrial Developments	0.0	3.0	4.5	4.4	7.7	7.7	61.2	61.9	62.5	63.2	63.9	64.6	108.1	107.6	107.5	107.5	107.5	107.5	107.4	107.3	107.3
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	164.9	162.8	160.8	158.9	157.1	155.4	154.5	153.7	153.6	153.6	153.6	153.5	153.5	153.3	153.2

Table A.3: Windsor-Essex region – Summer non-Coincident – Reference Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	55.1	55.2	55.3	55.1	54.6	54.4	54.1	53.9	53.6	53.8	54.1	54.3	55.2	56.2	57.6	59.1	60.5	62.0	65.1	66.1	67.0
Crawford TS	74.0	73.6	73.4	72.5	71.4	70.6	69.8	69.0	68.3	67.7	67.1	66.5	66.3	66.1	66.2	66.4	66.6	66.9	67.1	67.3	67.5
Essex TS	77.7	77.3	77.0	76.0	74.8	73.9	72.9	72.1	71.3	70.6	69.9	69.2	68.9	68.6	68.7	68.8	69.0	69.2	69.3	69.5	69.7
Keith TS	65.3	65.9	66.8	67.0	66.5	66.2	65.9	65.8	65.7	65.7	65.9	66.0	66.7	73.4	74.7	78.5	80.2	82.0	84.0	86.0	88.3
Kingsville TS	77.1	77.9	78.7	79.0	79.1	79.4	79.6	79.9	79.1	78.4	77.8	77.2	77.2	77.3	78.1	92.3	93.3	97.9	100.8	101.7	102.5
Lauzon DESN1	121.3	120.8	120.6	119.2	117.6	116.4	115.1	114.0	132.3	131.6	131.0	121.2	121.6	122.1	123.2	124.4	125.7	127.0	128.1	129.1	130.1
Lauzon DESN2	96.9	97.5	98.1	98.2	98.1	98.3	98.4	98.7	99.0	99.8	100.8	101.8	103.8	106.3	109.4	113.2	116.8	122.0	126.8	129.9	133.1
Leamington DESN1	79.2	80.2	80.5	80.5	80.0	79.8	79.4	79.2	79.0	79.5	80.2	80.8	82.6	84.5	87.2	89.9	92.7	95.5	97.9	100.0	102.2
Leamington DESN2	95.5	95.1	93.7	92.3	90.7	89.3	88.0	86.7	85.5	84.3	83.3	82.3	81.7	81.2	81.2	81.2	81.2	81.1	81.1	81.1	81.1
Malden TS	102.2	104.1	106.4	107.7	106.6	106.1	105.5	105.1	104.7	104.8	105.0	105.2	106.4	110.0	112.1	116.5	117.3	123.3	127.4	129.9	132.3
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	77.5	102.7	106.6	105.0	103.0	101.5	99.8	98.4	97.0	95.8	94.8	93.7	93.2	92.8	92.9	93.1	93.3	93.5	93.7	93.9	94.1
South Middle Road DESN2	0.0	0.0	0.0	97.4	100.6	104.1	102.4	100.9	99.5	98.3	97.2	96.1	95.6	95.2	95.3	95.5	95.7	95.9	96.1	96.3	96.5
Tilbury West DS	22.1	22.1	22.1	22.0	21.8	21.8	21.9	22.0	22.1	22.4	22.7	23.1	23.6	27.6	28.4	29.5	30.3	31.4	34.0	35.1	35.8
Walker MTS #2	52.5	57.3	57.2	56.6	56.2	56.0	55.7	55.6	55.4	55.3	55.2	55.0	55.2	55.3	56.0	56.5	57.0	57.4	57.9	58.2	58.3
Walker TS #1	57.4	57.1	57.0	51.6	50.9	50.4	49.8	49.4	48.9	48.5	48.1	56.9	56.7	56.5	56.6	56.9	57.2	57.4	57.6	57.7	57.9
CTS1	25.4	25.4	25.4	25.4	25.5	25.5	25.5	25.5	25.6	25.6	25.6	25.6	25.7	25.7	25.7	25.8	25.8	25.8	25.8	25.9	25.9
CTS2	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	10.0	10.0
CTS3	11.0	11.0	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.3
CTS4	1.7	1.7	1.7	16.7	16.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.8	19.8	19.8	19.8	19.8	19.8
CTS5	19.4	19.3	19.2	19.0	18.8	18.6	18.5	18.3	18.2	18.2	18.1	18.1	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.1	18.1
CTS6	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
CTS7	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	79.5	167.5	180.1	185.8	192.4	189.6	187.0	184.5	182.9	181.7	181.5	181.5	181.4	181.4	181.3	181.2	181.1
West Essex and Windsor Industrial Developments	0.0	3.0	4.4	4.4	7.6	7.5	60.0	60.4	60.9	61.3	61.8	62.3	104.1	103.5	103.5	103.5	103.5	103.4	103.4	103.4	103.3
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	18.5	18.3	18.0	17.8	17.5	17.3	17.2	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1

Table A.4: Windsor-Essex region – Winter non-Coincident – Reference Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	38.4	38.5	38.7	38.7	38.6	38.7	38.6	38.5	38.5	38.7	39.1	39.4	40.1	41.0	42.0	43.1	44.2	48.5	49.4	50.1	50.7
Crawford TS	55.0	55.0	55.2	54.8	54.4	54.2	53.9	53.7	53.4	53.2	53.0	52.8	52.8	52.8	53.0	53.2	53.4	53.7	53.8	54.0	54.2
Essex TS	49.3	49.2	49.4	49.0	48.7	48.5	48.2	48.0	47.7	47.5	47.3	47.1	47.1	47.1	47.2	47.4	47.5	47.7	47.8	48.0	48.1
Keith TS	62.7	64.4	66.4	67.9	67.6	67.6	67.3	67.2	67.1	67.1	67.1	67.1	67.5	67.9	68.5	69.3	70.0	70.7	71.4	72.1	72.9
Kingsville TS	95.8	97.0	98.2	99.0	99.7	100.7	101.4	102.2	101.2	100.4	99.7	99.0	98.9	98.8	99.2	113.0	113.6	120.4	122.8	123.3	123.8
Lauzon DESN1	85.8	85.9	86.5	86.2	85.8	85.6	85.2	84.9	104.4	104.4	104.5	95.0	95.9	96.6	97.7	99.0	100.2	101.4	102.5	103.3	104.3
Lauzon DESN2	63.5	64.8	66.2	67.2	67.5	67.9	68.2	68.5	68.9	69.6	70.4	71.2	72.7	74.3	76.3	78.3	80.4	85.9	91.1	92.8	94.4
Leamington DESN1	135.0	136.5	138.0	138.9	139.0	139.4	139.4	139.5	139.6	140.8	142.3	143.7	146.9	150.4	154.6	159.0	163.5	167.8	171.4	174.2	176.9
Leamington DESN2	196.2	194.8	193.5	191.3	188.9	187.0	184.8	182.8	180.8	178.9	177.2	175.5	174.6	173.8	173.8	173.8	173.8	173.7	173.6	173.5	173.4
Malden TS	80.5	83.0	85.9	87.6	87.2	87.0	86.6	86.2	86.0	86.1	86.3	86.4	87.2	88.0	89.3	92.7	92.2	104.3	105.6	106.7	107.8
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	175.6	206.8	216.0	213.6	210.9	208.8	206.3	204.1	201.8	199.7	197.8	195.9	194.9	194.0	193.9	193.9	193.9	193.9	193.8	193.6	193.5
South Middle Road DESN2	0.0	0.0	162.5	180.7	188.4	196.3	194.0	191.9	189.8	187.8	186.0	184.2	183.3	182.5	182.4	182.4	182.4	182.3	182.2	182.1	182.0
Tilbury West DS	17.9	18.3	18.8	19.3	19.8	20.5	21.2	22.0	22.8	23.8	24.9	25.9	27.1	31.4	32.8	34.5	35.9	41.5	42.3	43.4	44.2
Walker MTS #2	47.3	52.3	52.6	52.3	52.5	52.8	52.9	53.1	53.3	53.5	53.7	53.8	54.2	54.5	55.0	55.6	55.9	56.3	56.6	56.8	57.0
Walker TS #1	44.4	44.5	44.7	39.7	39.5	39.5	39.3	39.2	39.1	39.1	39.0	48.5	48.5	48.5	48.6	48.8	49.0	49.2	49.4	49.5	49.7
CTS1	20.8	20.8	20.9	20.9	24.7	29.1	30.1	30.8	31.5	31.6	31.6	31.8	31.9	32.0	32.1	32.1	32.1	32.1	32.2	32.2	32.2
CTS2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
CTS3	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1
CTS4	2.4	2.4	2.4	17.4	17.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
CTS5	10.3	10.2	10.2	10.2	10.2	10.2	10.2	10.1	10.1	10.1	10.2	10.2	10.2	10.2	10.2	10.2	10.3	10.3	10.3	10.4	10.4
CTS6	26.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
CTS7	30.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	148.9	316.3	342.3	355.5	370.1	366.2	362.7	359.3	357.5	355.8	355.7	355.7	355.7	355.5	355.4	355.1	354.9
West Essex and Windsor Industrial Developments	0.0	3.0	4.5	4.4	7.7	7.7	61.2	61.9	62.5	63.2	63.9	64.6	108.1	107.6	107.5	107.5	107.5	107.5	107.4	107.3	107.3
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	189.0	187.0	185.0	183.0	181.3	179.6	178.7	177.9	177.8	177.8	177.8	177.7	177.6	177.5	177.4

Table A.5: Windsor-Essex region – Summer Coincident – High Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	49.8	49.9	50.0	54.8	59.6	64.5	69.3	74.2	73.9	74.0	74.2	74.4	75.2	76.1	77.3	78.7	79.9	81.3	90.2	91.2	92.0
Crawford TS	64.1	64.1	64.2	63.6	63.1	63.2	63.2	63.4	63.5	63.7	64.0	64.2	64.8	65.3	66.2	67.0	67.9	68.8	76.3	77.1	78.0
Essex TS	68.7	68.5	68.5	67.7	67.0	66.6	66.3	66.0	65.7	65.6	65.5	65.2	65.5	65.6	66.1	66.6	67.1	67.6	74.8	75.4	75.9
Keith TS	55.4	56.9	58.5	78.1	79.0	80.4	81.8	83.2	84.8	86.4	88.1	89.8	91.9	99.1	101.7	106.4	109.2	112.0	124.0	127.0	129.9
Kingsville TS	61.1	61.7	62.4	62.4	62.3	74.2	74.2	74.2	73.4	72.6	72.0	71.3	71.2	71.2	71.9	83.0	83.8	87.4	108.9	109.8	110.5
Lauzon DESN1	102.5	122.8	150.7	209.8	215.0	224.8	225.3	226.0	242.9	243.8	245.0	238.2	240.2	242.1	244.6	247.1	249.7	252.3	269.5	272.0	274.3
Lauzon DESN2	88.9	93.0	97.1	100.5	104.0	109.2	114.3	119.5	124.7	130.4	136.3	139.8	148.4	153.3	158.8	164.9	170.7	178.0	197.9	203.3	208.5
Leamington DESN1	49.8	50.4	51.0	50.9	50.6	50.5	50.3	50.3	50.2	50.5	51.0	51.4	52.8	54.3	56.4	58.5	60.7	62.9	90.4	92.7	94.9
Leamington DESN2	46.2	45.9	45.2	43.8	42.2	40.9	39.6	38.4	37.2	36.0	35.0	34.0	36.8	36.4	36.3	36.3	36.3	36.3	60.8	60.8	60.8
Malden TS	87.7	90.5	93.6	95.8	96.8	98.8	100.7	102.8	105.0	107.5	110.2	112.7	116.3	122.0	126.2	130.4	135.5	175.9	195.2	199.7	204.1
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	37.5	49.6	51.4	49.9	48.3	46.9	45.6	44.3	43.1	41.9	40.9	39.8	39.3	38.9	39.0	39.1	39.2	39.2	39.3	39.4	39.4
South Middle Road DESN2	0.0	0.0	0.0	46.8	47.7	48.7	47.1	45.7	44.3	43.0	41.8	40.6	39.9	39.3	39.3	39.2	39.2	39.1	39.1	39.0	38.9
Tilbury West DS	18.1	18.5	18.8	19.1	19.4	19.9	20.5	21.1	21.9	22.8	23.9	25.0	26.3	30.3	31.8	33.5	35.0	36.8	39.7	41.6	43.1
Walker MTS #2	44.4	48.8	49.1	48.7	48.6	49.0	49.2	49.6	49.9	50.3	50.7	50.9	51.6	52.1	53.0	53.7	54.5	55.2	55.9	56.6	57.0
Walker TS #1	48.4	48.5	48.6	44.2	43.9	44.0	44.0	44.1	44.2	44.4	44.6	52.3	52.6	52.9	53.4	54.0	54.7	55.2	55.8	56.3	56.8
CTS1	23.7	23.8	23.8	23.8	23.8	23.9	23.9	23.9	23.9	24.0	24.0	24.0	24.0	24.1	24.1	24.1	24.1	24.2	24.2	24.2	24.2
CTS2	8.5	8.5	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.7
CTS3	9.3	9.3	9.3	9.3	9.3	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5
CTS4	1.1	1.1	1.1	10.8	10.8	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
CTS5	14.3	14.2	14.2	14.1	14.0	14.0	13.9	13.9	13.9	13.9	14.0	14.0	14.0	14.1	14.1	14.2	14.2	14.3	14.4	14.4	14.5
CTS6	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
CTS7	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	54.1	116.6	125.1	143.2	161.8	173.8	186.0	198.3	211.6	225.1	232.3	232.3	232.3	232.4	232.5	232.5	232.6
West Essex and Windsor Industrial Developments	0.0	3.0	46.4	46.4	49.6	104.5	157.1	215.7	214.7	264.3	263.4	262.4	255.2	254.6	254.5	254.5	254.5	254.5	254.5	254.4	254.4
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	8.2	12.1	16.0	20.0	24.0	27.9	32.0	36.1	40.3	44.5	48.7	52.9	57.0	61.2	65.4

Table A.6: Windsor-Essex region – Winter Coincident – High Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	33.4	33.6	33.7	38.6	43.5	48.4	53.3	58.2	58.1	58.3	58.6	58.8	59.5	60.2	61.1	62.1	63.0	66.7	67.5	68.1	68.6
Crawford TS	45.6	45.4	45.5	45.5	46.1	47.3	48.8	50.5	52.1	53.8	55.5	57.3	59.4	61.2	63.1	65.0	66.9	68.9	70.8	72.7	74.6
Essex TS	42.5	42.4	42.4	42.3	42.8	43.7	44.8	46.2	47.4	48.8	50.1	51.5	53.2	54.6	56.2	57.7	59.2	60.8	62.3	63.8	65.3
Keith TS	48.1	49.4	50.8	68.8	69.7	71.2	72.8	74.5	76.2	77.9	79.8	81.7	84.0	86.2	88.6	91.2	93.8	96.4	99.0	101.6	104.3
Kingsville TS	75.7	76.8	77.9	78.3	78.6	91.1	91.4	91.8	90.9	90.0	89.2	88.5	88.3	88.2	88.5	99.4	99.8	105.1	107.0	107.3	107.7
Lauzon DESN1	68.6	87.8	114.4	171.3	177.8	188.8	191.4	194.4	212.9	216.0	219.2	214.9	218.9	222.5	226.5	230.4	234.4	238.4	242.3	246.0	249.8
Lauzon DESN2	52.0	55.8	59.6	63.1	65.9	70.1	74.1	78.3	82.4	86.7	91.2	93.7	100.3	103.5	107.0	110.5	114.1	120.5	126.6	129.8	133.0
Leamington DESN1	109.0	110.3	111.7	112.1	112.2	112.8	113.0	113.3	113.6	114.7	116.3	117.6	120.6	123.8	127.8	131.8	136.0	140.1	143.5	146.4	149.2
Leamington DESN2	172.5	171.4	170.4	168.2	165.8	163.9	161.8	159.8	157.8	155.9	154.2	152.5	157.8	157.0	156.9	156.9	156.9	156.9	156.8	156.6	156.6
Malden TS	61.1	63.0	65.1	66.9	68.0	70.0	72.1	74.5	76.8	79.3	82.0	84.7	88.1	91.4	95.1	98.6	102.7	143.6	147.3	150.9	154.6
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	142.3	167.9	175.5	173.1	170.5	168.3	165.9	163.7	161.5	159.3	157.4	155.6	154.6	153.7	153.6	153.6	153.6	153.6	153.5	153.3	153.2
South Middle Road DESN2	0.0	0.0	139.0	154.3	160.5	166.9	164.7	162.6	160.5	158.5	156.7	154.9	154.0	153.2	153.1	153.1	153.1	153.0	153.0	152.8	152.7
Tilbury West DS	11.2	11.7	12.2	12.6	13.1	13.8	14.6	15.4	16.3	17.4	18.5	19.7	21.1	24.4	26.0	27.8	29.5	34.0	35.4	36.9	38.2
Walker MTS #2	41.3	45.5	45.6	45.7	47.1	49.1	51.5	54.1	56.7	59.3	61.9	64.6	67.6	70.2	72.9	75.7	78.0	80.3	82.7	84.8	86.9
Walker TS #1	37.3	37.2	37.3	33.3	34.0	35.1	36.6	38.2	39.8	41.4	43.1	52.7	54.6	56.2	57.9	59.7	61.4	63.1	64.8	66.5	68.1
CTS1	18.9	18.9	18.9	18.9	19.0	19.0	19.0	19.0	19.0	19.1	19.1	19.1	19.1	19.1	19.2	19.2	19.2	19.2	19.2	19.3	19.3
CTS2	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
CTS3	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
CTS4	1.5	1.5	1.5	11.0	11.0	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
CTS5	5.7	5.7	5.6	5.7	5.8	5.9	6.1	6.3	6.5	6.7	6.9	7.1	7.4	7.6	7.8	8.0	8.2	8.4	8.6	8.8	9.0
CTS6	26.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
CTS7	30.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	186.4	406.5	441.5	547.7	655.6	739.6	824.0	908.5	994.7	1081.0	1124.8	1124.8	1124.8	1125.5	1126.2	1126.8	1127.5
West Essex and Windsor Industrial Developments	0.0	18.0	46.5	46.4	49.7	96.7	158.4	203.2	202.4	281.6	280.9	280.2	274.6	274.1	274.1	274.1	274.1	274.0	274.0	273.9	273.8
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	164.9	239.0	313.2	387.4	461.9	536.4	611.7	687.1	763.2	839.4	915.6	991.7	1067.8	1143.9	1220.0

Table A.7: Windsor-Essex region – Summer Non-Coincident – High Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	55.1	55.2	55.3	60.7	66.0	71.4	76.8	82.2	82.0	82.2	82.5	82.7	83.6	84.6	86.0	87.4	88.9	90.3	93.4	94.5	95.4
Crawford TS	74.3	74.2	74.3	73.7	73.2	73.4	73.5	73.7	73.9	74.2	74.7	74.9	75.6	76.3	77.2	78.2	79.2	80.2	81.3	82.2	83.3
Essex TS	78.0	77.8	77.8	77.0	76.2	75.8	75.4	75.2	74.9	74.8	74.7	74.5	74.8	75.0	75.6	76.1	76.7	77.3	77.9	78.5	79.1
Keith TS	65.0	66.7	68.5	91.7	92.7	94.4	96.1	97.9	99.8	101.8	103.9	106.0	108.5	117.0	120.1	125.6	128.9	132.1	135.4	138.6	141.8
Kingsville TS	77.1	77.9	78.7	79.0	79.1	94.4	94.6	94.9	94.1	93.4	92.8	92.2	92.2	92.3	93.1	107.3	108.3	112.9	115.8	116.7	117.5
Lauzon DESN1	121.6	145.6	178.7	249.0	255.2	266.9	267.7	268.6	288.8	290.2	291.8	283.8	286.2	288.6	291.5	294.5	297.6	300.6	303.6	306.4	309.1
Lauzon DESN2	96.3	100.6	105.1	108.9	112.7	118.3	123.9	129.5	135.2	141.5	147.9	151.8	161.1	166.5	172.5	179.1	185.4	193.2	200.6	206.0	211.5
Leamington DESN1	78.8	79.6	80.5	81.0	81.1	81.6	81.9	82.4	83.0	84.2	85.7	87.1	89.6	92.4	95.8	99.4	103.0	106.7	109.9	112.8	115.8
Leamington DESN2	95.5	95.1	93.7	92.3	90.7	89.3	88.0	86.7	85.5	84.3	83.3	82.3	88.7	88.2	88.2	88.2	88.2	88.1	88.1	88.1	88.1
Malden TS	101.6	104.8	108.4	111.1	112.3	114.7	117.0	119.5	122.1	125.2	128.5	131.6	135.7	142.4	147.3	152.2	158.1	205.0	211.7	216.7	221.5
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	37.5	49.6	51.4	49.9	48.3	46.9	45.6	44.3	43.1	41.9	40.9	39.8	39.3	38.9	39.0	39.1	39.2	39.2	39.3	39.4	39.4
South Middle Road DESN2	0.0	0.0	0.0	46.8	47.7	48.7	47.1	45.7	44.3	43.0	41.8	40.6	39.9	39.3	39.3	39.2	39.2	39.1	39.1	39.0	38.9
Tilbury West DS	18.1	18.5	18.8	19.1	19.4	19.9	20.5	21.1	21.9	22.8	23.9	25.0	26.3	30.3	31.8	33.5	35.0	36.8	39.7	41.6	43.1
Walker MTS #2	44.4	48.8	49.1	48.7	48.6	49.0	49.2	49.6	49.9	50.3	50.7	50.9	51.6	52.1	53.0	53.7	54.5	55.2	55.9	56.6	57.0
Walker TS #1	48.4	48.5	48.6	44.2	43.9	44.0	44.0	44.1	44.2	44.4	44.6	52.3	52.6	52.9	53.4	54.0	54.7	55.2	55.8	56.3	56.8
CTS1	25.4	25.4	25.4	25.4	25.5	25.5	25.5	25.5	25.6	25.6	25.6	25.6	25.7	25.7	25.7	25.8	25.8	25.8	25.8	25.9	25.9
CTS2	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	10.0	10.0
CTS3	11.0	11.0	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.3
CTS4	1.7	1.7	1.7	16.7	16.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.8	19.8	19.8	19.8	19.8	19.8
CTS5	19.5	19.4	19.3	19.3	19.1	19.0	19.0	18.9	18.9	18.9	19.0	19.1	19.1	19.1	19.2	19.3	19.4	19.5	19.6	19.6	19.7
CTS6	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
CTS7	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	114.3	248.3	268.8	309.0	350.5	377.7	405.1	432.6	461.0	489.8	504.6	504.6	504.5	504.7	505.0	505.2	505.4
West Essex and Windsor Industrial Developments	0.0	3.0	46.4	46.4	49.6	104.5	157.1	215.7	214.7	264.3	263.4	262.4	255.2	254.6	254.5	254.5	254.5	254.5	254.5	254.4	254.4
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	18.5	26.9	35.3	43.8	52.2	60.7	69.2	77.8	86.4	95.1	103.8	112.4	121.1	129.8	138.4

Table A.8: Windsor-Essex region – Winter Non-Coincident – High Load Forecast

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Belle River TS	38.4	38.5	38.7	44.4	50.0	55.7	61.3	66.9	66.9	67.1	67.5	67.8	68.6	69.4	70.4	71.5	72.6	76.9	77.8	78.5	79.1
Crawford TS	55.0	54.8	54.9	54.9	55.7	57.2	59.0	61.1	63.1	65.2	67.4	69.5	72.0	74.2	76.5	78.9	81.2	83.5	85.8	88.1	90.4
Essex TS	49.3	49.1	49.1	49.1	49.6	50.7	52.0	53.6	55.1	56.7	58.3	60.0	61.9	63.6	65.3	67.1	68.9	70.7	72.5	74.2	76.0
Keith TS	62.7	64.2	66.1	89.6	90.9	92.9	95.0	97.3	99.6	102.1	104.6	107.2	110.2	113.1	116.3	119.7	123.0	126.4	129.9	133.3	136.8
Kingsville TS	95.8	97.0	98.2	99.0	99.7	115.7	116.4	117.2	116.2	115.4	114.7	114.0	113.9	113.8	114.2	128.0	128.6	135.4	137.8	138.3	138.8
Lauzon DESN1	85.8	109.7	142.9	214.3	222.5	236.4	239.7	243.4	266.9	270.9	275.1	269.8	274.8	279.4	284.3	289.3	294.3	299.3	304.1	308.8	313.5
Lauzon DESN2	63.5	68.0	72.7	77.0	80.5	85.7	90.7	95.8	100.9	106.3	112.0	115.0	123.2	127.0	131.3	135.7	140.1	147.9	155.4	159.3	163.2
Leamington DESN1	135.0	136.5	138.0	138.9	139.4	140.3	140.9	141.6	142.3	144.1	146.4	148.4	152.3	156.5	161.5	166.6	171.8	177.0	181.4	185.0	188.6
Leamington DESN2	196.2	194.8	193.5	191.3	188.9	187.0	184.8	182.8	180.8	178.9	177.2	175.5	181.6	180.8	180.8	180.8	180.8	180.7	180.6	180.5	180.4
Malden TS	80.5	82.8	85.6	88.1	89.6	92.4	95.3	98.4	101.7	105.2	109.0	112.7	117.2	121.6	126.5	131.2	136.5	190.6	195.5	200.3	205.2
NextStar TS	0.0	93.5	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
South Middle Road DESN1	175.6	206.8	216.0	213.6	210.9	208.8	206.3	204.1	201.8	199.7	197.8	195.9	194.9	194.0	193.9	193.9	193.9	193.9	193.8	193.6	193.5
South Middle Road DESN2	0.0	0.0	164.1	182.6	190.3	198.4	196.0	193.9	191.8	189.8	188.0	186.3	185.4	184.5	184.4	184.4	184.4	184.4	184.3	184.1	184.0
Tilbury West DS	17.5	18.1	19.0	19.7	20.6	21.8	23.0	24.4	26.0	27.8	29.7	31.8	34.0	39.4	41.9	44.8	47.4	54.6	56.9	59.2	61.2
Walker MTS #2	47.3	52.1	52.2	52.4	54.1	56.4	59.1	62.1	65.1	68.1	71.2	74.3	77.8	80.8	83.9	87.0	89.7	92.4	95.0	97.5	99.9
Walker TS #1	44.4	44.3	44.4	39.7	40.6	41.9	43.6	45.6	47.6	49.5	51.5	63.2	65.5	67.4	69.4	71.4	73.5	75.5	77.6	79.6	81.6
CTS1	20.8	20.8	20.9	20.9	20.9	20.9	20.9	21.0	21.0	21.0	21.0	21.0	21.1	21.1	21.1	21.1	21.2	21.2	21.2	21.2	21.2
CTS2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
CTS3	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1
CTS4	2.4	2.4	2.4	17.4	17.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
CTS5	10.3	10.2	10.2	10.2	10.4	10.7	10.9	11.3	11.7	12.1	12.5	12.9	13.3	13.7	14.0	14.4	14.8	15.2	15.6	15.9	16.3
CTS6	26.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
CTS7	30.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Kingsville-Leamington Greenhouse Developments	0.0	0.0	0.0	0.0	212.3	463.2	503.7	625.0	748.4	844.5	941.0	1037.6	1135.8	1234.2	1284.0	1284.0	1284.0	1284.8	1285.7	1286.4	1287.2
West Essex and Windsor Industrial Developments	0.0	18.0	46.5	46.4	49.7	96.7	158.4	203.2	202.4	281.6	280.9	280.2	274.6	274.1	274.1	274.1	274.1	274.0	274.0	273.9	273.8
Future Coatsworth Area	0.0	0.0	0.0	0.0	0.0	0.0	189.0	273.7	358.3	443.0	528.0	612.9	698.7	784.6	871.2	957.8	1044.5	1131.1	1217.7	1304.2	1390.8

Appendix B: List of Hydro One Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Keith TS	230/115	H25J, H26J, J5D, J20B, J1B, J2N, J3E, J4E
2	Lauzon TS	230/115	H53Z, H54Z, Z1E, Z7E
3	Malden TS	230/27.6	H25J, H26J
4	NextStar TS	230/27.6	H53Z, H54Z
5	Leamington TS	230/27.6	H38, H39
6	South Middle Road TS	230/27.6	H75, H76
7	Kingsville TS	115/27.6	K2Z, K6Z
8	Belle River TS	115/27.6	K2Z, K6Z
9	Crawford TS	115/27.6	J3E, J4E
10	Essex TS	115/27.6	J3E, J4E, Z1E, Z7E
11	Walker TS#1	115/27.6	Z1E, Z7E
12	Tilbury West DS	115/27.6	K2Z

Appendix C: List of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Chatham SS x Lakeshore TS	C42H	230
2	Chatham SS x Lakeshore TS	C43H	230
3	Chatham SS x Lakeshore TS	C64H	230

4	Chatham SS x Lakeshore TS	C65H	230
5	Chatham SS x Lakeshore TS	C87H	230
6	Chatham SS x Lakeshore TS	C88H	230
7	Lakeshore TS x Lauzon TS	H53Z	230
8	Lakeshore TS x Lauzon TS	H54Z	230
9	Lakeshore TS x Keith TS	H25J	230
10	Lakeshore TS x Keith TS	H26J	230
11	Keith TS x CTS	J5D	230
12	Keith TS x Brighton Beach CGS	J20B	230
13	Keith TS x Brighton Beach CGS	J1B	115
14	Keith TS x West Windsor Power CGS	J2N	115
15	Keith TS x Essex TS	J3E	115
16	Keith TS x Essex TS	J4E	115
17	Essex TS x Lauzon TS	Z1E	115
18	Essex TS x Lauzon TS	Z7E	115
19	Essex TS x East Windsor CGS	E8F	115
20	Essex TS x East Windsor CGS	E9F	115
21	Lauzon TS x Kingsville TS	K2Z	115
22	Lauzon TS x Kingsville TS	K6Z	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Enwin Utilities Ltd (Enwin)
2	Hydro One Networks Inc. (Distribution)
3	Essex Powerlines Corporation (Essex Powerlines)
4	E.L.K Energy Inc. (E.L.K. Energy)
5	Entegrus Powerlines Inc. (Entegrus)

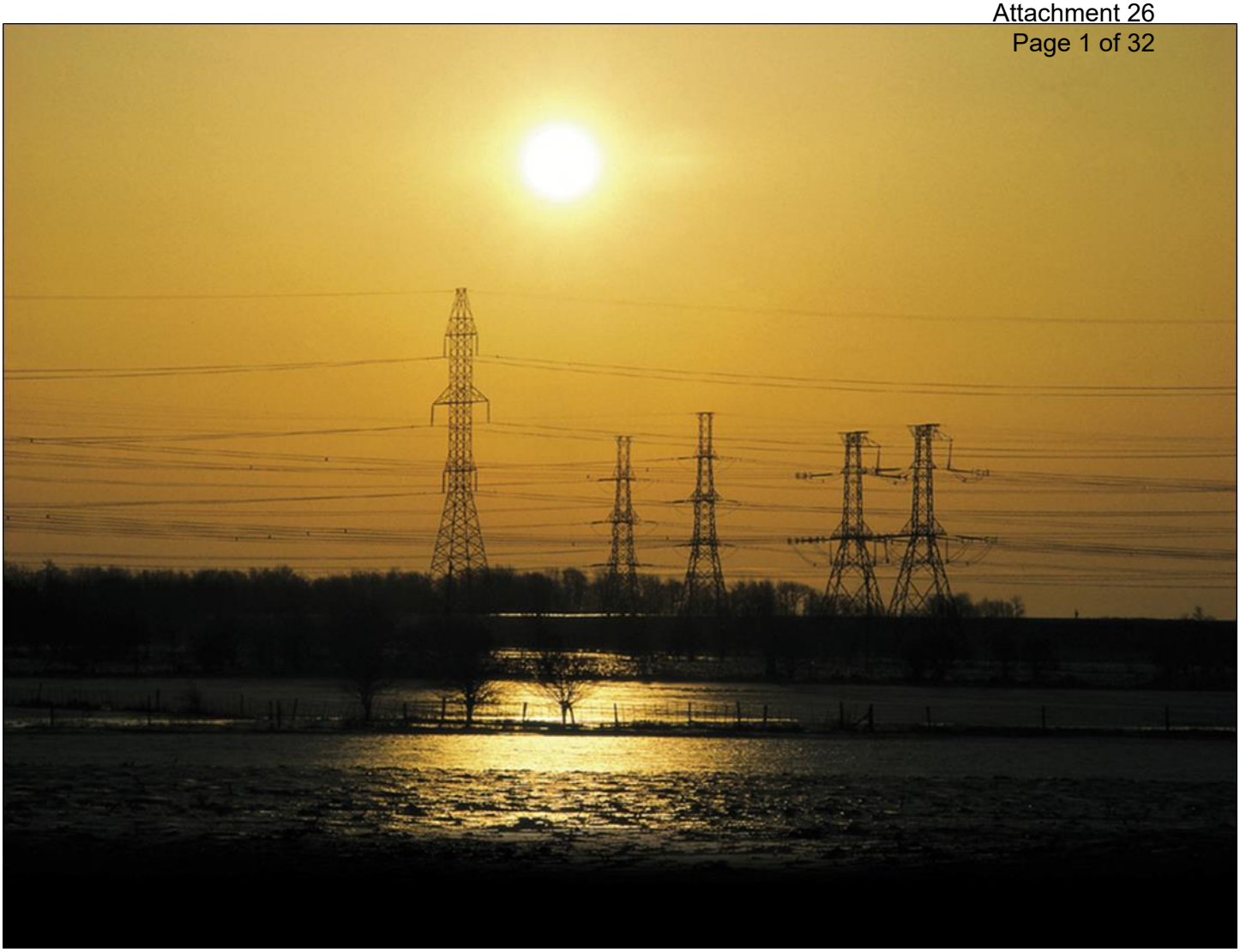
Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Town of Amherstburg
2	Town of Essex
3	Town of Kingsville
4	Municipality of Lakeshore
5	Municipality of Leamington
6	Municipality of Chatham-Kent
7	Town of LaSalle
8	Town of Tecumseh
9	Township of Pelee
10	City of Windsor

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
eDSM	Electricity Demand Side Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt

MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station
TWG	Technical Working Group



London Area
Regional Infrastructure Plan

August 12, 2022

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Prepared and supported by:

Company
Entegrus Power Lines Inc.
ERTH Power Inc.
Hydro One Networks Inc. (Distribution)
London Hydro Inc.
Tillsonburg Hydro Inc.
Independent Electricity System Operator
Hydro One Networks Inc. (Lead Transmitter)

Disclaimer

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

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

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

Executive Summary

This Regional Infrastructure Plan ("RIP") was prepared by Hydro One with support from the RIP Study Team in accordance to the Ontario Transmission System Code requirements. It identifies investments in transmission facilities, distribution facilities, or both, that should be developed and implemented to meet the electricity infrastructure needs within the London Area.

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

- Entegrus Power Lines Inc.
- ERTH Power Inc.
- Hydro One Networks Inc. (Distribution)
- London Hydro Inc
- Tillsonburg Hydro Inc.
- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of the London Area regional planning process, which follows the completion of the London Area Needs Assessment in May 2020 [5] and the Greater London Sub-region Restoration Local Planning Report in October 2021 [6]. Scoping Assessment and Integrated Regional Resource Plan was not carried out in this cycle. This RIP provides a consolidated summary of the needs and recommended plans for London Area Region over the planning horizon (10 years). No new need had been identified at this time.

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

- Aylmer TS transformers and low-voltage switchyard replacement project competed in 2017.
- Strathroy TS failed transformer T1 and low-voltage switchyard replacement project completed in 2019.
- Wonderland TS failed transformer T6 was replaced in 2019.
- St. Thomas TS was decommissioned and 115 kV circuit W14 re-termination work was completed in 2020.
- Sarnia Scott TS to Buchanan TS 230 kV circuits N21W/N22W tower structures refurbishment project was completed in 2021.
- Nelson TS station refurbishment project will be completed in 2022.
- Tillsonburg TS new low-voltage capacitor banks installed in 2021 and switchyard component replacement project to be completed in 2022.
- Longwood TS protection and control replacement project to be completed in 2023.
- Edgeware TS protection and control replacement project to be completed in 2024.

The major infrastructure investments planned for the London Area over the near and mid-term planning horizon are provided in the Table 1 below, along with the planned in-service dates.

TABLE 1 - RECOMMENDED PLANS FOR LONDON AREA OVER THE NEXT 10 YEARS

Need	Stations / Lines	Recommended Action Plan	In-service
Station capacity	Talbot TS	No action required	--
Greater London sub-region restoration need	W36/W37	No action required	--
End-of-life equipment replacement	Buchanan TS	Replacement of autotransformers and associated equipment	2028
	Clarke TS	Replacement of step-down transformers, associated disconnect switches, low-voltage switchyard components	2028
	Talbot TS	Replacement of step-down transformers (T3/T4), associated disconnect switches, low-voltage switchyard components	2028
	Wonderland TS	Low-voltage switchyard components replacement	2026
	M31W/ M32W (Salford Junction x Ingersoll)	London Area East Optical Ground Wire (OPGW) Infrastructure	2027
	W36/W37/W5 NL/W6NL/W2S/ N21W	London Area West Telecom Optical Ground Wire (OPGW) Infrastructure Installation	2029

The Study Team recommends Hydro One to continue with the implementation of infrastructure investments listed in Table 1 above.

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The London Area Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be triggered in advance of the five-year timeline.

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1. Introduction

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE LONDON AREA REGION BETWEEN 2021 AND 2031.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Entegrus Power Lines Inc., ERTH Power Inc., London Hydro Inc., Tillsonburg Hydro Inc., Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO"), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The London Area includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), and the City of St. Thomas. In addition, the facilities located in the London Region supply part of Norfolk County. The boundaries of the London Area are shown below in Figure 1-1.

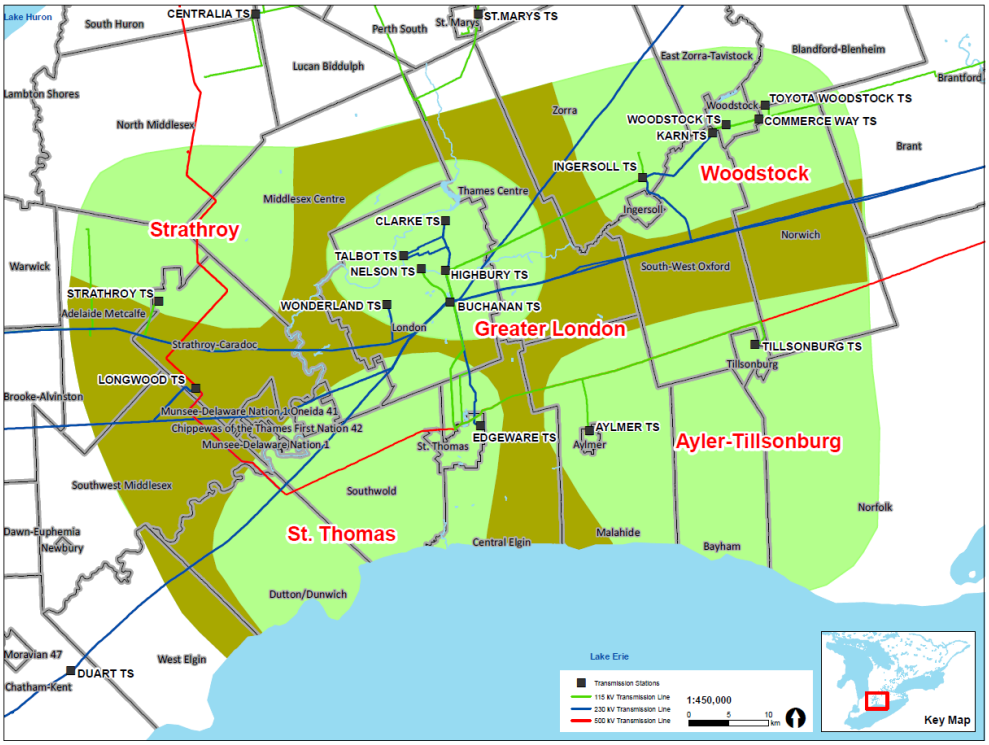


FIGURE 1-1: LONDON AREA REGION MAP

1.1. Objectives and Scope

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

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases i.e., Needs Assessment and Local Planning;
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment needs emerging over the near and medium term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases;
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2. Structure

The rest of the report is organized as follows:

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

2. Regional Planning Process

2.1. Overview

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

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

2.2. Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

The RIP phase is the fourth and final phase of the regional planning process and involves discussion of previously identified needs and plans, identification of any new needs that may have emerged since the start of the planning cycle, and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

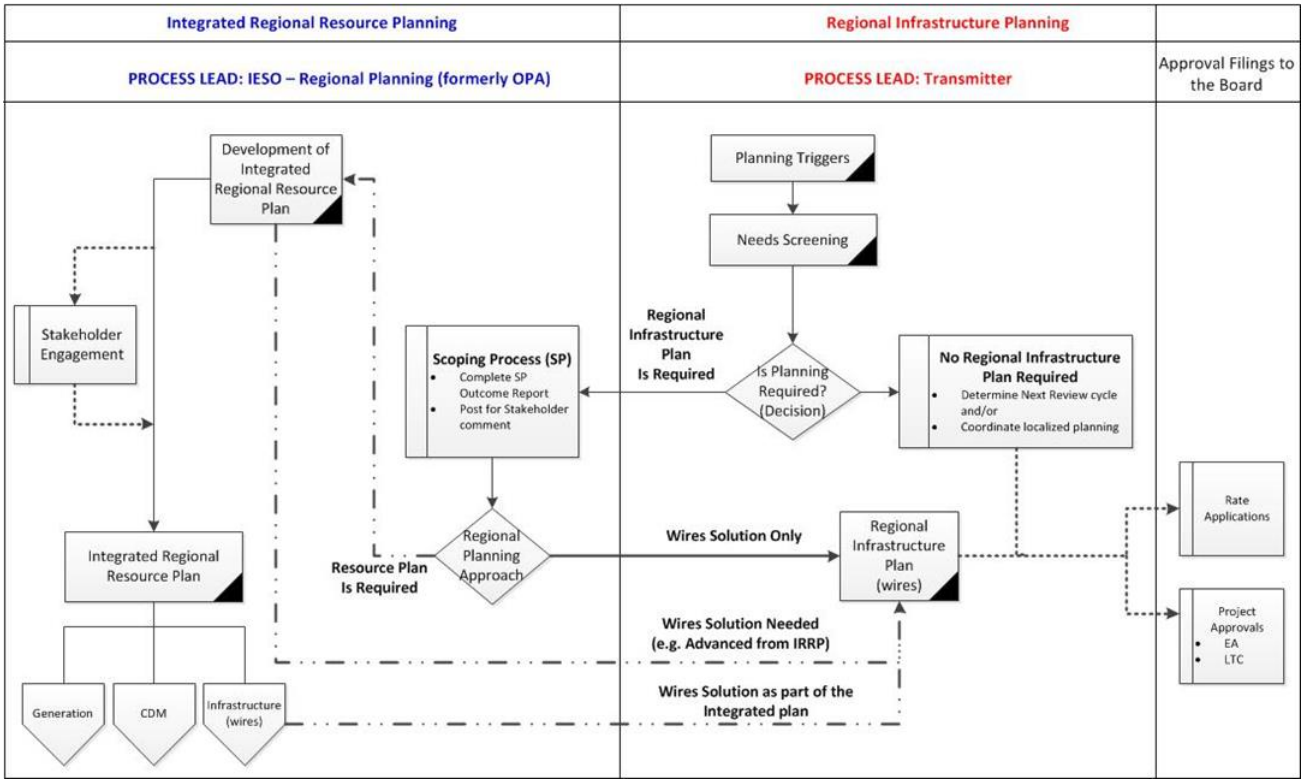


FIGURE 2-2: REGIONAL PLANNING PROCESS FLOWCHART

Upon the conclusion of Needs Assessment, the Study Team agreed that the need in the region (i.e., Greater London sub-region restoration need) was local in nature and no further regional coordination was required. Subsequently, a Local Planning report was completed to specifically address the restoration need. Therefore, Scoping Assessment and Integrated Regional Resource Plan was not carried out for London Area in this cycle.

2.3. RIP Methodology

The RIP phase consists of a four step process (see Figure 2-3) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

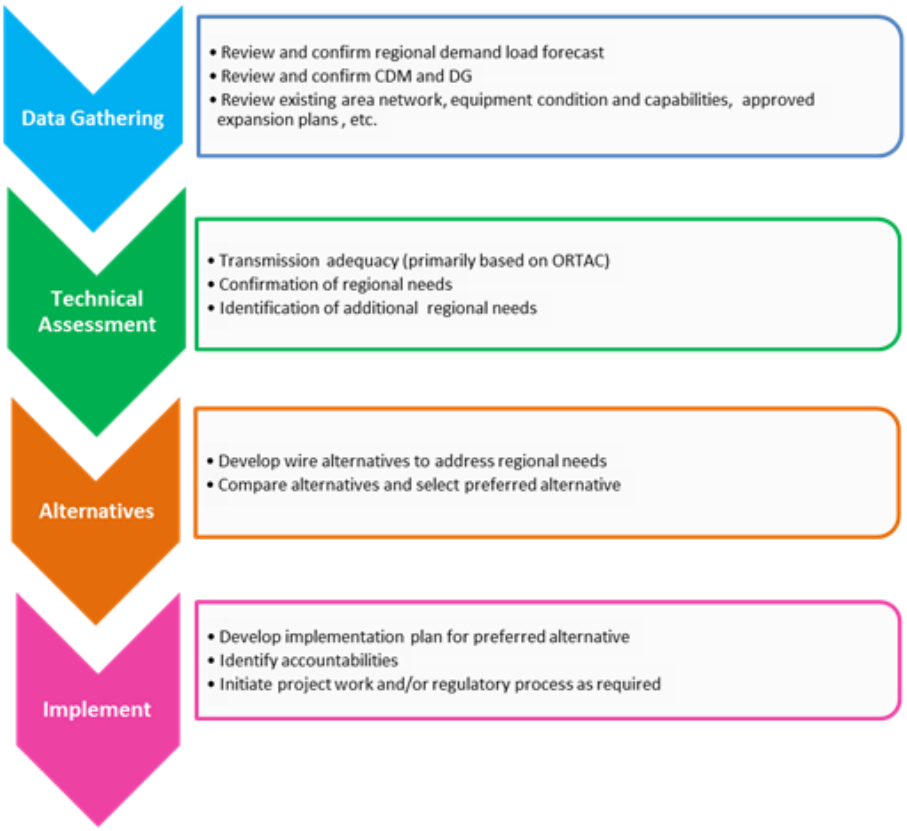


FIGURE 2-3: RIP METHODOLOGY

3. Transmission System Supplying London Area

The hub of the electrical system in London Area is Longwood Transformer Station ("TS"). Longwood TS provides the single connection to the 500 kV system in this area, through which provides majority of the resources to meet the demand in the London Area and rest of southwestern Ontario. The 500 kV system is part of the bulk power system and although it is not studied as part of this RIP, it should be noted that in 2021, the IESO identified a need to expand the 500 kV bulk system to supply the load growth in the Leamington area by 2030. The IESO recommended a new 500 kV single-circuit line connecting Longwood TS and Lakeshore TS and two 500/230 kV autotransformers to be constructed at Lakeshore TS.

London Area is supplied by a network of 230 kV and 115 kV circuits which is connected to Longwood TS through five 500/230 kV autotransformers. Autotransformers at Buchanan TS and Karn TS provide the necessary 230/115 kV autotransformation. Step-down transformer stations are connected to both 230 kV and 115 kV systems to bring the power to distribution level of 27.6 kV to serve the area. There are fourteen Hydro One step-down TS's, three transmission connected industrial load customers and three transmission connected generators in the London Area. The London Area Region summer coincident peak demand in 2021 was about 1152 MW, adjusted to extreme weather.

The existing facilities in the London Area are summarized below and depicted in the single line diagram shown in Figure 3-4:

- Fourteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerce Way TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Nelson TS, Strathroy TS, Talbot TS (two Dual Element Spot Networks, DESN 1 and DESN 2), Tillsonburg TS, Wonderland TS, and Woodstock TS.
- Three directly connected industrial customer loads are connected in the London Area: Enbridge Keyser CTS, Lafarge Woodstock CTS and Toyota Woodstock TS.
- There are three existing transmission-connected generating stations in the London Area as follows:
    - Suncor Adelaide GS is a 40 MW wind farm connected to 115 kV circuit west of Strathroy TS
    - Port Burwell GS is a 99 MW wind farm connected to 115 kV circuit near Tillsonburg TS
    - Silver Creek GS is a 10 MW solar generator connected to 115 kV circuit near Aylmer TS

Although depicted, Duart TS is not included in the London Area study and will be studied as part of the Chatham-Kent/Lambton/Sarnia (CKLS) Area Regional Planning.

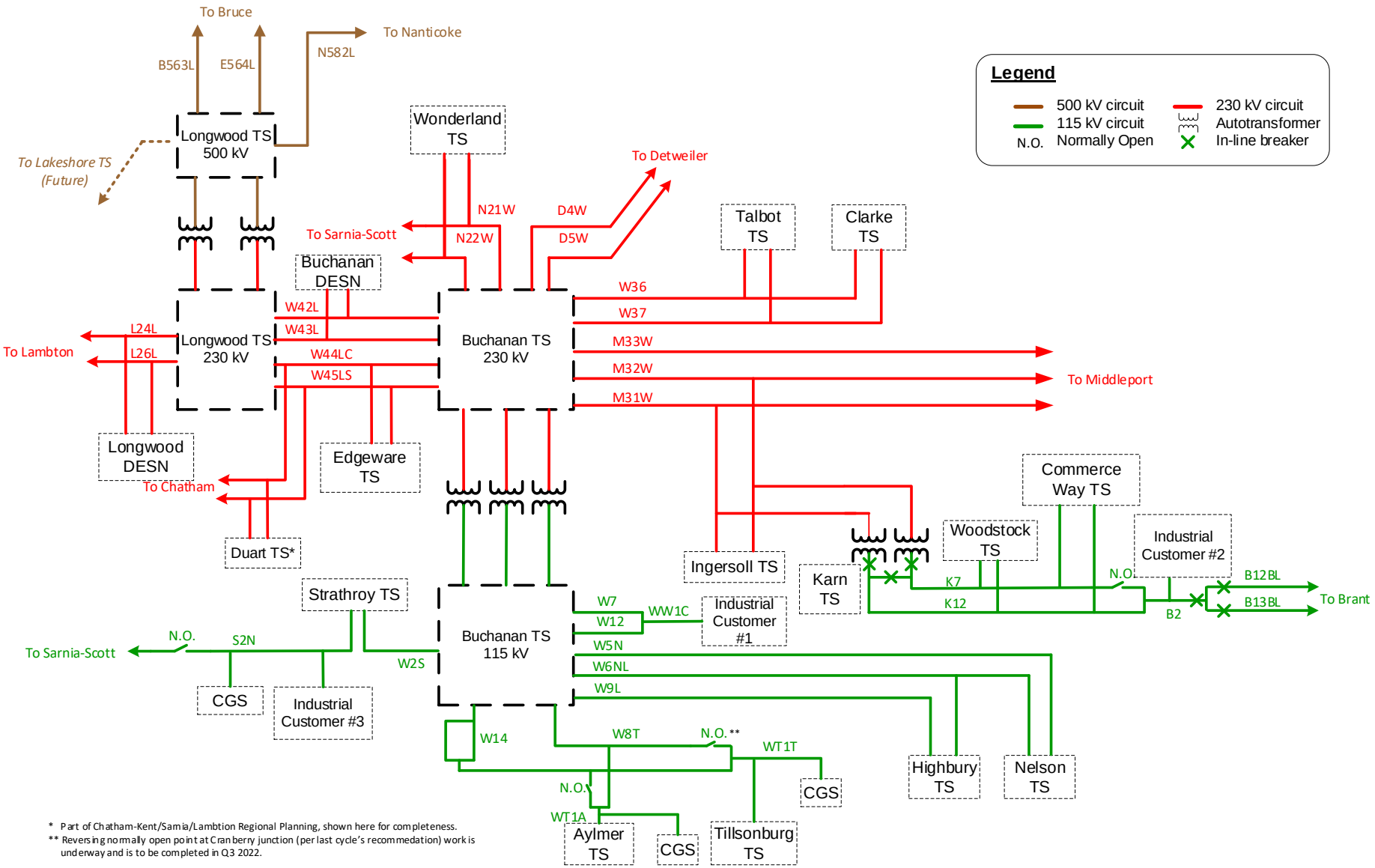


FIGURE 3-4: SIMPLIFIED SINGLE LINE DIAGRAM OF THE LONDON AREA REGION'S TRANSMISSION NETWORK

4. Transmission Projects Completed and/or Underway Over the Last Ten Years

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

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

- Strathroy TS like-for-like replacement of 25/42 MVA 115/27.6 kV transformer T2 due to failure completed in 2012.
- Ingersoll TS like-for-like replacement of 75/125 MVA 230/27.6 kV transformers T5 & T6 that were approximately 35 years old. The transformers were identified to have a design weakness and were replaced to mitigate the risk of failures, improve restoration time and maintain system performance completed in 2012.
- Woodstock TS 50/83 MVA 115/27.6 kV transformers T1 & T2 that were approximately 50 years old and were deemed end-of-life were replace like-for-like in 2014.
- Aylmer TS transformers and low-voltage switchyard replacement project competed in 2017.
- Strathroy TS failed transformer T1 and low-voltage switchyard replacement project completed in 2019.
- Wonderland TS failed transformer T6 was replaced in 2019.
- St. Thomas TS was decommissioned and 115 kV circuit W14 re-termination work was completed in 2020.
- Sarnia Scott TS to Buchanan TS 230 kV circuits N21W/N22W tower structures refurbishment project was completed in 2021.
- Nelson TS station refurbishment project will be completed in 2022.
- Tillsonburg TS new low-voltage capacitor banks installed in 2021 and switchyard component replacement project to be completed in 2022.
- Longwood TS protection and control replacement project to be completed in 2023.
- Edgeware TS protection and control replacement project to be completed in 2024.

5. London Area Demand

5.1. Load Forecast

The electricity demand in the London Area Region is anticipated to grow at an average rate of 1% over the next ten years. The London Area Region has been historically a summer-peaking region. Figure 5-5 shows the London Area Region's summer coincident peak load forecast for the 2022 – 2031 study period (extreme weather corrected peak) developed during the RIP phase. The load forecast prepared for the RIP phase is approximately 5% lower than the Needs Assessment load forecast due to higher forecasted contributions from CDM and DG.

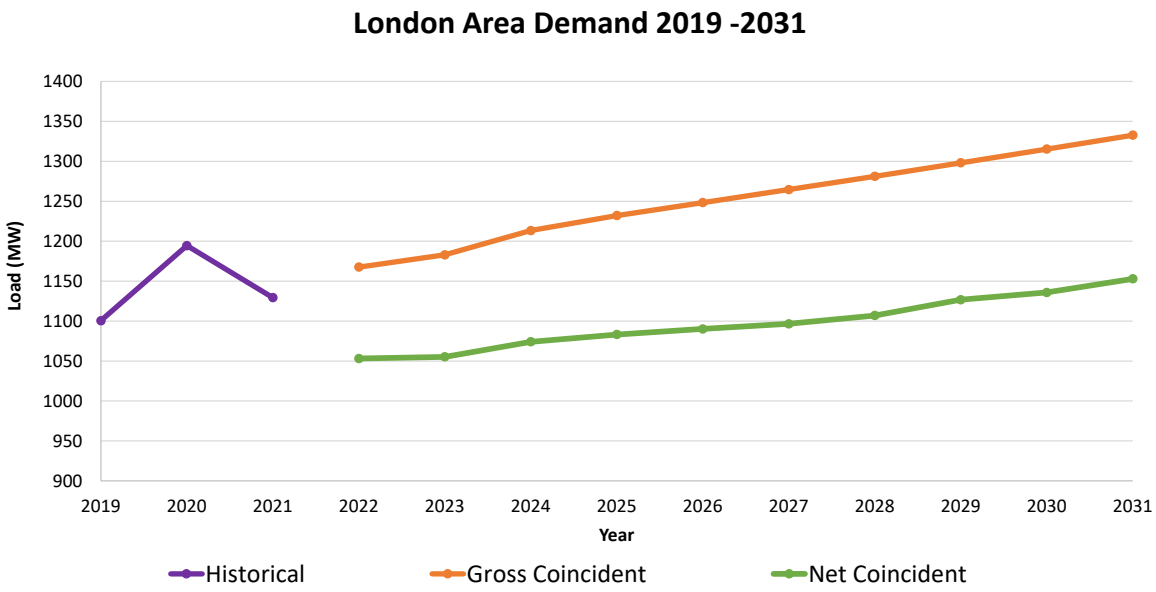


FIGURE 5-5: LONDON AREA REGION LOAD FORECAST

The load forecast shows that the region peak summer load increases from 1053 MW in 2022 to 1153 MW by 2031. The corresponding non-coincident summer peak loads increase from 1159 MW to about 1250 MW over the same period. The non-coincident and coincident net load forecasts for the individual stations in the London Area Region are given in Appendix D, Table D-1 and Table D-2.

LDCs in this region emphasized that impact of electrification have not been factored into the current RIP load forecasts. Should initiatives such as gas furnace conversion and continued electric vehicle adoption accelerate, transmission system adequacy will have to be re-assessed.

5.2. Forecast Assumptions

The following assumptions are made:

- The study period for the RIP assessment is 2022 – 2031.
- The 2021 summer station peak load is considered as a reference point and was adjusted for extreme weather impact (2.12% in 2021). Growth rates were extrapolated from LDCs' load forecasts via linear regression and are applied onto to the reference point to develop a gross load forecast.
- Distributed generation ("DG") refers to small-scale power generation connected in the distribution system which is located close to where the electricity is consumed. Both conservation & demand management ("CDM") as well as DG can reduce the amount of load that needs to be supplied and their contributions, as provided by the IESO, are directly net against the gross load forecast to develop a net load station forecast. A non-coincident version of the net load forecast was used to assess the station capacity.
- Load data for transmission-connected industrial customers in the region was assumed to be consistent with historical peak loads.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.
- Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating ("LTR"), assuming a 90% lagging power factor.

6. Regional Needs and Plans

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

This section outlines and discusses electrical infrastructure needs in the London Area and plans to address these needs for the study period of 2022 – 2031.

Based on the gross regional non-coincident load forecast, Clarke TS is forecasted to exceed its 10-Day LTR in 2023 and Highbury TS and Tillsonburg TS will also exceed station LTR in the medium term. However, these stations are expected to be adequate to meet the net load forecast for the remainder of the study period as planned CDM targets and DG contributions continue to offset the load growth. Overall, as the net load forecast prepared for the RIP phase is approximately 5% lower than the Needs Assessment load forecast, no new need was identified.

During the development of this RIP, issue about available capacity was raised at a number of stations, most notably Strathroy TS and Tillsonburg TS. Available capacity and its allocation among LDCs are governed by OEB's Transmission System Code and are separate from the regional planning process. Hydro One Transmission will continue to engage with its customers following the conclusion of this RIP.

Table 6-2 provides a summary of the needs identified in this cycle and the corresponding sub-sections where recommendations and plans are discussed. The planned in-service dates are tentative and will be finalized closer to project commencement in coordination with impacted LDCs.

TABLE 6-2: IDENTIFIED NEAR AND MID-TERM NEEDS IN LONDON AREA REGION

No.	Need	Need Date	Section
1	Talbot TS station capacity	Today	6.1
2	Greater London sub-region restoration need	Today	6.2
3	End-of-life equipment replacement	Vary	6.3

6.1. Talbot TS

6.1.1. Sustainment Need

The existing Talbot TS comprises two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4) and supplies electricity to London Hydro customers. It is supplied by two 230 kV circuits W36 and W37. Step-down transformers T3 and T4 have been in-service from 1979 and are in poor condition and approaching end-of-life. A number of 27.6 kV breakers and protection equipment have also been identified for replacement.

6.1.2. Station Capacity Need

The station capacity for T1/T2 and T3/T4 are 113 MW and 161 MW respectively. The summer regional non-coincident peak load of the two DESNs in 2021 are 119 MW and 168 MW. According

to the regional non-coincident net load forecast in the study period, Talbot TS T1/T2 DESN is expected to exceed its station capacity throughout the study period and Talbot TS T3/T4 DESN will exceed its capacity in 2029.

6.1.3. Recommendation

The station capacity need was first identified in the 2020 Needs Assessment and was primarily driven by temporary load transfer from neighbouring station (Nelson TS). As noted in Section 4, Nelson TS underwent refurbishment which includes converting the low-voltage supply from 13.8 kV to 27.6 kV. During the construction period, significant portion of the load that was originally supplied by this station was transferred to Clarke TS and Talbot TS. The newly refurbished Nelson TS was placed in-service in December 2018 and as more 27.6 kV distribution feeders becomes available in downtown London, London Hydro confirmed load will be transferred back to Nelson TS and additional transformation capacity is not required at this time.

The Study Team recommends Hydro One to proceed with like-for-like replacement of T3 and T4 at Talbot TS. Project is expected to be completed in 2028. In addition, Hydro One will look for opportunities to coordinate this project with London Hydro for the metalclad switchgear replacement.

6.2. Greater London Sub-region Restoration Need

6.2.1. Description

The 230 kV double-circuit line,W36 and W37, emanates from Buchanan TS and supplies Talbot TS (both DESNs) and Clarke TS. Should the simultaneous loss of W36/W37 occurs, all of the loads supplied by the Clarke TS and Talbot TS, which amounts to over 340 MW[2], would be interrupted by configuration. The potential load loss exceeds the ORTAC 30-minute restoration criteria.

6.2.2. Recommendation

This need was first reported in the first cycle of regional planning for the London Area Region in 2015. The 2017 IRRP working group recommended installing switching devices and feeder extensions on the distribution system. The IRRP working group also acknowledged while these measures will not fully address the restoration need, they will substantially improve the restoration capability in a cost-effective manner.

The restoration need persists in the current regional planning cycle and was further re-assessed with London Hydro via the Local Planning process. The Study Team noted a significant portion of the interrupted load could be restored by a neighbouring unaffected station, Highbury TS, if its station capacity limit is lifted. This option was not pursued further at this time as work required will be extensive and cost prohibitive. Hydro One undertook a detailed historical equipment performance review to assess the probability of common-mode failure that would lead to simultaneous loss of W36 and W37. It was concluded that the only common-mode failure that may result in the simultaneous loss of both W36/W37 is the failure of the steel poles that carry

[2] 2021 historical coincident peak load.

the two circuits and probability of this event is very low. Therefore, the Study Team recommends no action is required at this time.

6.3. End-of-Life Equipment Replacement

6.3.1. Buchanan TS

6.3.1.1. Description

Buchanan TS is a major 230/115 kV transformer station in the area that supplies load stations in London Area. The station houses three 230/115 kV auto-transformers, three 230 kV capacitor banks, one 115 kV capacitor bank and two 230/27.6 kV step-down transformers. There are sixteen 230 kV oil breakers and nine SF6 circuit breakers in the 230 kV switchyard; seventeen oil circuit and three SF6 circuit breakers in the 115 kV switchyard.

Two of the 3 auto-transformers T2 and T3 are 48 and 54 years old respectively, are in poor condition, and approaching the end of life.

6.3.1.2. Recommendation

To address poor equipment performance of deteriorating equipment, Hydro One plans to replace two 230kV autotransformers, spill containment pits, AC and DC station service equipment, as well as some obsolete protection, controls and telecom equipment.

6.3.2. Clarke TS

6.3.2.1. Description

Clarke TS is a DESN station located in the northern part of the London Area. The station is supplied by two 230 kV circuits W36 and W37. The station supplies electricity to London Hydro and Hydro One Distribution customers.

The two 230/27.6 kV 50/83 MVA transformers T3 and T4 are 55 years old, in poor condition, and approaching end of life. Some of the protection equipment is also found to be obsolete.

6.3.2.2. Recommendation

To address the assets in poor condition and end-of-life, Hydro One plans to replace step-down transformers like-for-like, associated disconnect switches, 27.6 kV switchyard components including breakers, station services, capacitors and protections. Replacement plan will be closely coordinated with affected LDCs and the expected completion date is 2028.

6.3.3. Wonderland TS

6.3.3.1. Description

Wonderland TS is a DESN station located in the western part of the London Area. The station is supplied by two 230 kV circuits N21W and N22W. The station supplies electricity to London Hydro and Hydro One Distribution customers.

The Wonderland T5/T6 DESN facility was originally built in the 1960s and its equipment is degrading in condition. The 50/83 MVA T6 power transformer was replaced in 2004 due to failure. The companion transformer, T5, failed in July 2019 and was subsequently replaced. The existing air insulated 27.6 kV switchgear, majority of which are original installations have reached end-of-life due to deteriorated condition and has limited availability of parts for ongoing support and maintenance. All site protection and control equipment, consisting of first generation electro-mechanical relaying are deemed end-of-life, obsolete and require replacement. During the early project development phase, London Hydro and Hydro One Distribution were consulted to assess if there is a capacity need to replace the 50/83 MVA transformers with 75/125 MVA and it was concluded there is no such need at the time.

6.3.3.2. Recommendation

To address the end-of-life need, Hydro One plans to replace the Wonderland 27.6 kV switchyard. Replacement plan will be closely coordinated with affected LDCs and the expected completion date is 2026.

6.3.4. London Area East OPGW Infrastructure

6.3.4.1. Description

M31W and M32W are 230 kV network circuits that connect Buchanan TS and Middleport Port TS. Ingersoll TS and Karn TS are tapped off M31W/M32W at Salford Junction. High voltage 230/115 kV autotransformers are located at Karn TS provide the necessary transformation from the 230 kV system to the Woodstock and Commerce Way 115 kV system.

6.3.4.2. Recommendation

To improve the reliability of power system telecom network, Hydro One plans to install 9km of OPGW fibre from Salford Junction to Ingersoll TS and remove the existing licensed microwave link connects Ingersoll TS to Buchanan TS. Project is expected to be completed in 2027.

6.3.5. London Area West OPGW Infrastructure

6.3.5.1. Description

Several transmission lines in the London area that emanate from Buchanan TS currently rely on leased legacy dedicated metallic cable infrastructure for DC remote trip protections. These include 230kV circuits W36/W37 that connect to Talbot TS and Clarke TS, 115 kV circuits W5N/W6NL that connect to Nelson TS and Highbury TS, 115 kV circuit W2S that connects to Strathroy TS and 230kV circuit N21W connecting to Sarnia Scott TS.

6.3.5.2. Recommendation

To improve the reliability of power system telecom network, Hydro One plans to establish a geographically diverse and fully redundant fibre optic network for protection and SCADA applications. A combination of Hydro One's existing and new OPGW-based fibre and two leased third-party fibre links would be utilized. The existing metallic cable will be removed and the project is expected to be completed in 2029.

7. Conclusions and Next Steps

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE LONDON AREA REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 7-3 below are all end of life needs, along with their planned in-service date. The planned in-service dates are tentative and will be finalized closer to project commencement in coordination with impacted LDCs.

TABLE 7-3: RECOMMENDED PLANS IN LONDON AREA REGION OVER THE NEXT 10 YEARS

Stations / Lines	Scope	In-service
Buchanan TS	Replacement of autotransformers and associated equipment	2028
Clarke TS	Replacement of step-down transformers, associated disconnect switches, low-voltage switchyard components	2028
Talbot TS	Replacement of step-down transformers (T3/T4), associated disconnect switches, low-voltage switchyard components	2028
Wonderland TS	Low-voltage switchyard components replacement	2026
M31W/ M32W (Salford Junction x Ingersoll)	London Area East OPGW Infrastructure	2027
W36/W37/W5 NL/W6NL/W2S/ N21W	London Area West Telecom OPGW Infrastructure Installation	2029

The Study Team recommends Hydro One to continue with the implementation of infrastructure investments listed in Table 7-3.

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be triggered in advance of the five-year timeline.

References

[1] London Area Needs Assessment [2015]
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/london/Documents/Needs%20Assessment%20Report%20-%20London%20Region%20-%20April%202,%202015.pdf

[2] Strathroy TS Transformer Capacity Local Planning [2016]
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/london/Documents/Local%20Planning%20Report%20-Strathroy%20TS.pdf

[3] Woodstock Sub-region Restoration Local Planning [2017]
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/london/Documents/Woodstock%20Restoration%20Local%20Planning%20Report%20(Final)%2020170519.pdf

[4] London Area Integrated Regional Resource Plan [2017]
https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/London-Area/Final-Greater-London-IRRP-20170120.ashx

[5] London Area Needs Assessment [2020]
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/london/Documents/Needs-Assessment-Report-London-2020.pdf

[6] Greater London Sub-region Restoration Local Planning [2021]
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/london/Documents/Local_Planning_Report_Greater_London_Subregion.pdf

Appendix A. Stations in the London Area Region

Station	Voltage (kV)	Supply Circuits
Aylmer TS	115/27.6	W8T
Buchanan TS	230/27.6	W42L/W43L
Clarke TS	230/27.6	W36/W37
Commerce Way TS	115/27.6	K7/K12
Edgeware TS	230/27.6	W44LC/W45LC
Highbury TS	115/27.6	W6NL/W9L
Ingersoll TS	230/27.6	M31W/M32W
Longwood TS	230/27.6	L24L/L26L
Nelson TS	115/27.6	W5N/W6NL
Strathroy TS	115/27.6	W2S
Talbot TS (T1/T2 and T3/T4)	230/27.6	W36/W37
Tillsonburg TS	115/27.6	W14
Wonderland TS	230/27.6	N21W/N22W
Woodstock TS	115/27.6	K7/K12

Appendix B. Transmission Lines in the London Area Region

Circuit Designations	Location	Voltage (kV)
N21W, N22W	Scott TS to Buchanan TS	230
W42L, W43L	Longwood TS to Buchanan TS	230
W44LC	Longwood TS to Chatham TS to Buchanan TS	230
W45LS	Longwood TS to Spence SS to Buchanan TS	230
W36, W37	Buchanan TS to Talbot TS and Clarke TS	230
D4W, D5W	Buchanan TS to Detweiler TS	230
M31W, M32W, M33W	Buchanan TS to Middleport TS	230
W2S	Buchanan TS to Strathroy TS	115
W5N	Buchanan TS to Nelson TS	115
W6NL	Buchanan TS to Highbury TS to Nelson TS	115
W9L	Buchanan TS to Highbury TS	115
W7, W12	Buchanan TS to CTS	115
WW1C	Buchanan TS to CTS	115
W8T	Buchanan TS to ESWF JCT	115
WT1T	Cranberry Junction to Tillsonburg TS	115
W14	Buchanan TS to Cranberry Junction	115
WT1A	Aylmer TS to Lyons JCT	115
K7, K12	Karn TS to Commerce Way TS	115

Appendix C. Distributors in London Area Region

Distributor Names	Station Name	Connection Type
Entegrus Power Lines Inc. [Middlesex]	Edgeware TS	Tx
	Longwood TS	Dx
	Strathroy TS	Dx
		Tx
ERTH Power Corporation	Aylmer TS	Tx
	Buchanan TS	Dx
	Edgeware TS	Dx
	Ingersoll TS	Dx
	Tillsonburg TS	Dx
Hydro One Networks Inc.	Aylmer TS	Tx
	Buchanan TS	Tx
	Clarke TS	Tx
	Edgeware TS	Tx
	Highbury TS	Tx
	Ingersoll TS	Tx
	Longwood TS	Tx
	Strathroy TS	Tx
	Tillsonburg TS	Tx
	Wonderland TS	Tx
	Woodstock TS	Tx
London Hydro Inc.	Buchanan TS	Dx
		Tx
	Clarke TS	Tx
	Edgeware TS	Dx
	Highbury TS	Dx
		Tx
	Nelson TS	Tx
	Talbot TS	Tx
	Wonderland TS	Dx
		Tx
Tillsonburg Hydro Inc.	Tillsonburg TS	Tx

Appendix D. London Area Region Load Forecast

TABLE D1: LONDON AREA REGIONAL NON-COINCIDENT NET LOAD FORECAST

Transformer Station	LTR* (MW)	Quantities	Reference	Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2021**	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Aylmer TS		Gross	32.46	32.98	33.51	34.05	34.61	35.16	35.73	36.31	36.90	37.49	38.10
		DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		CDM		0.67	1.06	1.38	1.66	1.93	2.22	2.49	2.75	2.99	3.04
	40	Net		32.29	32.44	32.65	32.92	33.22	33.49	33.80	34.13	34.48	35.03
Buchanan TS		Gross	131.49	133.22	134.96	136.73	138.52	140.34	142.17	144.04	145.92	147.84	149.77
		DG		14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74
		CDM		2.70	4.26	5.54	6.65	7.69	8.85	9.86	10.87	11.81	11.96
	173	Net		115.77	115.96	116.45	117.12	117.90	118.58	119.44	120.31	121.29	123.07
Clarke TS		Gross	102.45	103.58	104.72	105.88	107.05	108.23	109.43	110.64	111.86	113.10	114.35
		DG		3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40
		CDM		2.10	3.30	4.29	5.14	5.93	6.81	7.57	8.33	9.03	9.13
	103	Net		98.08	98.03	98.20	98.51	98.91	99.22	99.67	100.13	100.67	101.82
Commerce Way TS		Gross	34.55	35.12	35.69	36.27	36.87	37.47	38.08	38.70	39.33	39.97	40.63
		DG		2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
		CDM		0.71	1.13	1.47	1.77	2.05	2.37	2.65	2.93	3.19	3.25
	106	Net		31.46	31.62	31.86	32.15	32.47	32.77	33.11	33.46	33.84	34.44
Edgeware TS		Gross	102.45	103.93	105.43	121.83	126.36	127.92	129.52	131.13	132.77	134.43	136.12
		DG		4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.44
		CDM		2.11	3.33	4.93	6.07	7.01	8.06	8.98	9.89	10.74	10.87
	180	Net		97.35	97.64	112.43	115.81	116.44	116.98	117.68	118.40	119.22	120.81
Highbury TS		Gross	74.76	75.72	76.70	77.69	78.69	79.70	80.72	81.76	82.81	83.88	84.96
		DG		5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
		CDM		1.53	2.42	3.15	3.78	4.37	5.02	5.60	6.17	6.70	6.79
	80	Net		68.68	68.77	69.02	69.39	69.82	70.18	70.65	71.13	71.66	72.67
Ingersoll TS		Gross	69.40	71.92	74.53	77.24	80.05	82.96	85.98	89.10	92.34	95.70	99.17
		DG		12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.93
		CDM		1.46	2.35	3.13	3.85	4.55	5.35	6.10	6.88	7.64	7.92
	158	Net		57.51	59.24	61.17	63.26	65.47	67.68	70.05	72.51	75.11	78.33
Longwood TS		Gross	40.27	41.14	42.04	42.95	43.88	44.83	45.80	46.80	47.81	48.85	49.91
		DG		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.12
		CDM		0.83	1.33	1.74	2.11	2.46	2.85	3.20	3.56	3.90	3.99
	121	Net		39.15	39.55	40.05	40.61	41.21	41.79	42.43	43.09	43.79	44.80
Nelson TS		Gross	53.39	53.78	54.17	54.56	54.95	55.34	55.74	56.14	56.55	56.96	57.37
		DG		17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55
		CDM		1.09	1.71	2.21	2.64	3.03	3.47	3.84	4.21	4.55	4.58
	107	Net		35.14	34.91	34.80	34.76	34.77	34.73	34.75	34.79	34.86	35.24
Strathroy TS		Gross	39.63	40.19	40.77	41.35	41.94	42.54	43.15	43.77	44.39	45.03	45.67
		DG		8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
		CDM		0.81	1.29	1.67	2.01	2.33	2.69	3.00	3.31	3.60	3.65
	56	Net		30.75	30.86	31.05	31.30	31.58	31.84	32.14	32.46	32.80	33.40
Talbot T1/T2		Gross	121.81	122.79	123.77	124.77	125.78	126.79	127.81	128.84	129.87	130.92	131.97
		DG		-	-	-	-	-	-	-	-	-	-
		CDM		2.49	3.90	5.05	6.04	6.95	7.95	8.82	9.68	10.46	10.54
	113	Net		120.30	119.87	119.72	119.73	119.84	119.85	120.02	120.20	120.46	121.43
Talbot T3/T4		Gross	172.17	173.87	175.59	177.33	179.08	180.85	182.64	184.45	186.27	188.11	189.97
		DG		12.28	12.28	12.28	12.28	12.28	12.28	12.28	0.52	0.52	0.45
		CDM		3.52	5.54	7.18	8.60	9.91	11.37	12.63	13.88	15.03	15.18
	161	Net		158.06	157.77	157.86	158.20	158.66	158.99	159.54	171.87	172.56	174.35
Tillsonburg TS		Gross	94.95	96.18	97.42	98.68	99.95	101.25	102.56	103.88	105.23	106.59	107.96
		DG		3.54	3.54	3.54	3.54	3.54	3.54	0.97	0.97	0.97	0.91
		CDM		1.95	3.07	4.00	4.80	5.55	6.38	7.11	7.84	8.51	8.62
	103	Net		90.68	90.80	91.14	91.61	92.16	92.63	95.80	96.42	97.10	98.43
Wonderland TS		Gross	91.36	92.76	94.17	95.61	97.08	98.56	100.07	101.60	103.15	104.73	106.33
		DG		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.87
		CDM		1.88	2.97	3.87	4.66	5.40	6.23	6.95	7.68	8.37	8.49
	115	Net		88.87	89.20	89.74	90.41	91.16	91.84	92.64	93.47	94.36	95.96
Woodstock TS		Gross	64.10	64.68	65.27	65.87	66.47	67.07	67.69	68.30	68.92	69.55	70.19
		DG		2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.23	1.60
		CDM		1.31	2.06	2.67	3.19	3.68	4.21	4.68	5.13	5.56	5.61
	81	Net		61.08	60.92	60.91	60.99	61.11	61.18	61.34	61.50	61.77	62.98
Industrial Customer #1			12	12	12	12	12	12	12	12	12	12	12
Industrial Customer #2			19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Industrial Customer #3			2	2	2	2	2	2	2	2	2	2	2
London Area Total				1159	1161	1181	1191	1199	1206	1217	1238	1248	1267

*Station LTR is based on 90% power factor

** Adjusted to extreme weather

Note (1) Edgeware TS step increases in 2024 & 2025 reflects a new connection request of 20MW.

TABLE D2: LONDON AREA REGIONAL COINCIDENT NET LOAD FORECAST

Transformer Station	Quantities	Reference	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2021^	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Aylmer TS	Gross	25.99	26.41	26.83	27.27	27.71	28.16	28.61	29.07	29.54	30.02	30.51
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	CDM		0.54	0.85	1.10	1.33	1.54	1.78	1.99	2.20	2.40	2.44
	Net		25.85	25.97	26.14	26.36	26.59	26.81	27.06	27.32	27.60	28.05
Buchanan TS	Gross	129.03	130.72	132.43	134.17	135.92	137.70	139.51	141.34	143.19	145.06	146.96
	DG		14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74
	CDM		2.65	4.18	5.43	6.53	7.55	8.68	9.68	10.67	11.59	11.74
	Net		113.33	113.51	113.99	114.65	115.42	116.08	116.92	117.78	118.73	120.48
Clarke TS	Gross	86.32	87.27	88.24	89.21	90.20	91.20	92.20	93.22	94.25	95.29	96.35
	DG		3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40
	CDM		1.77	2.78	3.61	4.33	5.00	5.74	6.38	7.02	7.61	7.70
	Net		82.11	82.06	82.21	82.47	82.80	83.07	83.45	83.84	84.29	85.26
Commerce Way TS	Gross	32.18	32.71	33.24	33.78	34.34	34.90	35.47	36.05	36.63	37.23	37.84
	DG		2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
	CDM		0.66	1.05	1.37	1.65	1.91	2.21	2.47	2.73	2.97	3.02
	Net		29.10	29.25	29.47	29.74	30.04	30.32	30.64	30.96	31.32	31.87
Edgeware TS	Gross	102.45	103.93	105.43	121.83	126.36	127.92	129.52	131.13	132.77	134.43	136.12
	DG		4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.44
	CDM		2.11	3.33	4.93	6.07	7.01	8.06	8.98	9.89	10.74	10.87
	Net		97.35	97.64	112.43	115.81	116.44	116.98	117.68	118.40	119.22	120.81
Highbury TS	Gross	74.61	75.57	76.54	77.53	78.52	79.53	80.56	81.59	82.64	83.71	84.78
	DG		5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
	CDM		1.53	2.41	3.14	3.77	4.36	5.01	5.59	6.16	6.69	6.77
	Net		68.52	68.61	68.87	69.24	69.66	70.03	70.49	70.97	71.50	72.50
Ingersoll TS	Gross	54.92	56.92	58.99	61.13	63.35	65.65	68.04	70.51	73.08	75.73	78.49
	DG		12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.93
	CDM		1.15	1.86	2.48	3.04	3.60	4.23	4.83	5.44	6.05	6.27
	Net		42.82	44.18	45.71	47.36	49.11	50.86	52.74	54.69	56.74	59.29
Longwood TS	Gross	37.74	38.56	39.39	40.25	41.12	42.01	42.93	43.86	44.81	45.78	46.77
	DG		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.12
	CDM		0.78	1.24	1.63	1.98	2.30	2.67	3.00	3.34	3.66	3.74
	Net		36.62	36.99	37.46	37.99	38.55	39.09	39.69	40.31	40.96	41.92
Nelson TS	Gross	37.94	38.22	38.49	38.77	39.05	39.33	39.61	39.90	40.19	40.48	40.77
	DG		17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55
	CDM		0.77	1.21	1.57	1.88	2.16	2.47	2.73	2.99	3.23	3.26
	Net		19.90	19.73	19.65	19.63	19.63	19.60	19.62	19.65	19.70	19.96
Strathroy TS	Gross	30.42	30.86	31.30	31.74	32.20	32.66	33.13	33.60	34.08	34.57	35.06
	DG		8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
	CDM		0.63	0.99	1.29	1.55	1.79	2.06	2.30	2.54	2.76	2.80
	Net		21.60	21.68	21.83	22.02	22.24	22.44	22.67	22.91	23.18	23.63
Talbot T1/T2	Gross	109.09	109.96	110.85	111.74	112.64	113.55	114.46	115.38	116.31	117.25	118.19
	DG		-	-	-	-	-	-	-	-	-	-
	CDM		2.23	3.50	4.53	5.41	6.22	7.12	7.90	8.67	9.37	9.44
	Net		107.74	107.35	107.22	107.23	107.33	107.34	107.49	107.65	107.88	108.75
Talbot T3/T4	Gross	152.03	153.53	155.05	156.58	158.13	159.69	161.27	162.87	164.48	166.10	167.75
	DG		12.28	12.28	12.28	12.28	12.28	12.28	12.28	0.52	0.52	0.45
	CDM		3.11	4.89	6.34	7.60	8.75	10.04	11.15	12.25	13.27	13.40
	Net		138.13	137.87	137.96	138.25	138.66	138.95	139.43	151.70	152.31	153.89
Tillsonburg TS	Gross	94.21	95.43	96.66	97.91	99.18	100.46	101.76	103.07	104.41	105.76	107.12
	DG		3.54	3.54	3.54	3.54	3.54	3.54	0.97	0.97	0.97	0.91
	CDM		1.93	3.05	3.97	4.76	5.50	6.33	7.06	7.78	8.45	8.56
	Net		89.95	90.07	90.40	90.87	91.41	91.88	95.05	95.66	96.34	97.66
Wonderland TS	Gross	87.66	89.00	90.36	91.74	93.14	94.57	96.01	97.48	98.97	100.49	102.02
	DG		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.87
	CDM		1.80	2.85	3.72	4.47	5.18	5.98	6.67	7.37	8.03	8.15
	Net		85.19	85.51	86.02	86.67	87.38	88.04	88.81	89.60	90.46	92.00
Woodstock TS	Gross	64.10	64.68	65.27	65.87	66.47	67.07	67.69	68.30	68.92	69.55	70.19
	DG		2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.23	1.60
	CDM		1.31	2.06	2.67	3.19	3.68	4.21	4.68	5.13	5.56	5.61
	Net		61.08	60.92	60.91	60.99	61.11	61.18	61.34	61.50	61.77	62.98
Industrial Customer #1		12	12	12	12	12	12	12	12	12	12	12
Industrial Customer #2		19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Industrial Customer #3		2	2	2	2	2	2	2	2	2	2	2
London Area Total			1053	1055	1074	1083	1090	1097	1107	1127	1136	1153

^ Adjusted to extreme weather
Note (1) Edgeware TS step increases in 2024 & 2025 reflects a new connection request of 20MW.

TABLE D3: CONSERVATION AND DEMAND FORECAST (SOURCE: IESO)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2.0%	3.2%	4.1%	4.8%	5.5%	6.2%	6.8%	7.4%	8.0%	8.0%

Appendix F. List of Acronyms

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



NEEDS ASSESSMENT REPORT

London Area

November 26, 2024

Needs Assessment Report

London Area

- November 26, 2024 -

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: London Area Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the London Area and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on best available information throughout the planning process.

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Executive Summary

REGION	London Area Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: July 29, 2024	**END DATE:** November 26, 2024

1. INTRODUCTION

The 2nd Regional Planning cycle for the London Area Region was completed in August 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the 3rd cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten (10) years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in July 2024 for the London Area Region. Due to significant load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered one year in advance of the five-year period.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the London Area Region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and RIP, based on updated information available at that time. The planning horizon for this NA is ten (10) years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The London Region includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), and City of St. Thomas. In addition, the transmission facilities in this region also supply part of Norfolk County.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the London Area Region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their ten-year load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the SA and IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the ten-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and operational concerns;

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs and projects have been recently completed:

- Edgeware TS PCT and component replacement (completed in 2024)
- Reversing of the normally open point at Cranberry Junction, per the Aylmer-Tillsonburg Reinforcement project (completed in 2024)
- Tillsonburg TS component replacement (completed in 2023)
- Nelson TS station refurbishment (completed in 2022)
- Tillsonburg TS low voltage capacitor banks installation (completed in 2021)
- Sarnia Scott TS x Buchanan TS 230 kV N21W/N22W circuits tower structures refurbishment (completed in 2021)
- St. Thomas TS decommissioning and 115 kV W14 circuit re-termination work (completed in 2020)
- Strathroy TS T1 and component replacement (completed in 2019)
- Wonderland TS T6 replacement (completed in 2019)

The needs and projects discussed in the London Area 2nd cycle RIP report for the London Area Region are as follows:

- Talbot TS Station Capacity: According to the net load forecast in the study period, Talbot TS T1/T2 DESN and Talbot T3/T4 DESN was expected to exceed its station capacity throughout the study period
- Talbot TS transformers T3 and T4, associated disconnect switches, and low-voltage switchyard components replacement need: Replacement that will allow for maintaining reliability (2032)
- Greater London Sub-Region Restoration Need: The 230 kV double-circuit line, W36 and W37, emanates from Buchanan TS and supplies Talbot TS (both DESNs) and Clarke TS. Should the simultaneous loss of W36/W37 occur, all loads supplied by the Clarke TS and Talbot TS would be interrupted by configuration. The potential load loss would exceed the ORTAC load restoration criteria.
- Buchanan TS Autotransformer T2 and T3 and associated equipment replacement need: Replacement that will allow for maintaining reliability (beyond planning horizon)
- Clarke TS Transformer T3 and T4, associated disconnect switches, and low-voltage switchyard components replacement need: Replacement that will allow for maintaining reliability (beyond planning horizon)

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- No new Asset Renewal Needs

b) Transformation Capacity

- New Transformation Capacity needs were identified at the following stations:
  - Aylmer TS
  - Clarke TS
  - Edgeware TS
  - Nelson TS
  - Strathroy TS
  - Tillsonburg TS
  - Woodstock TS
  - Wonderland TS

c) Transmission System Capacity

- Thermal limitations were observed on 230 kV W44LC/W45LS for the loss of companion circuit
- Thermal limitations were observed on the 115 kV WT1T to Tillsonburg TS, in pre-contingency

d) System Reliability, Operation and Load restoration

- Load restoration limitations on 230 kV M31W/M32W and 115 kV K7/K12/B2 circuits for a single tower contingency caused by the loss of double-circuit line M31W and M32W or for a double contingency with the loss of both autotransformers at Karn TS
- Load restoration limitations on 230 kV M31W/M33W circuits for a single tower contingency
- Load restoration limitations on 230 kV W44LC/W45LS circuits for a single tower contingency

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios was considered relatively minor to near-term need dates for station and line capacity needs.

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

a. Transmission System Capacity

- Thermal limitations on 230 kV W44LC/W45LS for the loss of companion circuit
- Thermal limitations on the 115 kV WT1T to Tillsonburg TS pre-contingency

b. System Reliability, Operation and Load Restoration

- Load restoration limitations on 230 kV M31W/M32W and 115 kV K7/K12/B2 circuits for a single tower contingency causing the loss of double-circuit line M31W and M32W or for a double contingency with the loss of both autotransformers at Karn TS
- Load restoration limitations on 230 kV M31W/M33W circuits for a single tower contingency
- Load restoration limitations on 230 kV W36/W37 circuits for a single tower contingency
- Load restoration limitations on 230 kV W44LC/W45LS circuits for a single tower contingency

c. Transformation Capacity Needs:

- Aylmer TS
- Edgeware TS
- Clarke TS
- Nelson TS
- Strathroy TS
- Talbot T1/T2
- Talbot T3/T4
- Tillsonburg TS
- Wonderland TS
- Woodstock TS

II. Needs that do not require further regional coordination

The TWG recommends reviewing all needs in the region, identified in this needs assessment, proceed to the next phases of this regional planning cycle for further assessment.

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

List of LDC(s) to be involved in further regional planning phases:

- Entegrus Powerlines Inc.
- ERTH Power Inc.
- Hydro One Distribution
- London Hydro Inc.
- Tillsonburg Hydro Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- N/A

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1. INTRODUCTION

The second cycle of the Regional Planning process for the London Area Region was completed in August 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the London Area Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:

i) require further assessment and regional coordination (and hence, proceed to the next phases of regional planning); and,

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

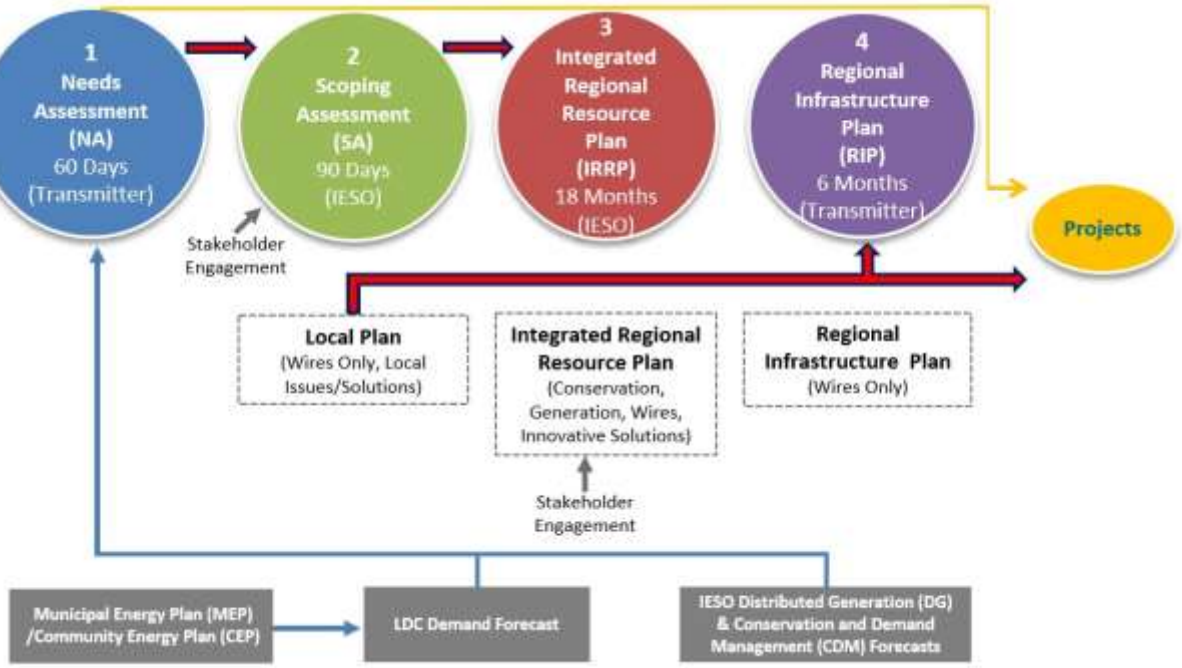


Figure 1: Regional Planning Process

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

Table 1: London Area Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission) – Transmitter
2	Independent Electricity System Operator (IESO) – System Operator
3	Entegrus Powerlines Inc. – LDC
4	ERTH Power Inc. – LDC
5	Hydro One Networks Inc. (Distribution) – LDC
6	London Hydro Inc. – LDC
7	Tillsonburg Hydro Inc. – LDC

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the London Area region. Due to significant load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered one year in advance of the five-year requirement.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the London Area region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,

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

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The geographical boundaries of the London Area region are shown in Figure 2 below. The London Region includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), City of St. Thomas. In addition, the transmission facilities in this region also supply part of Norfolk County.

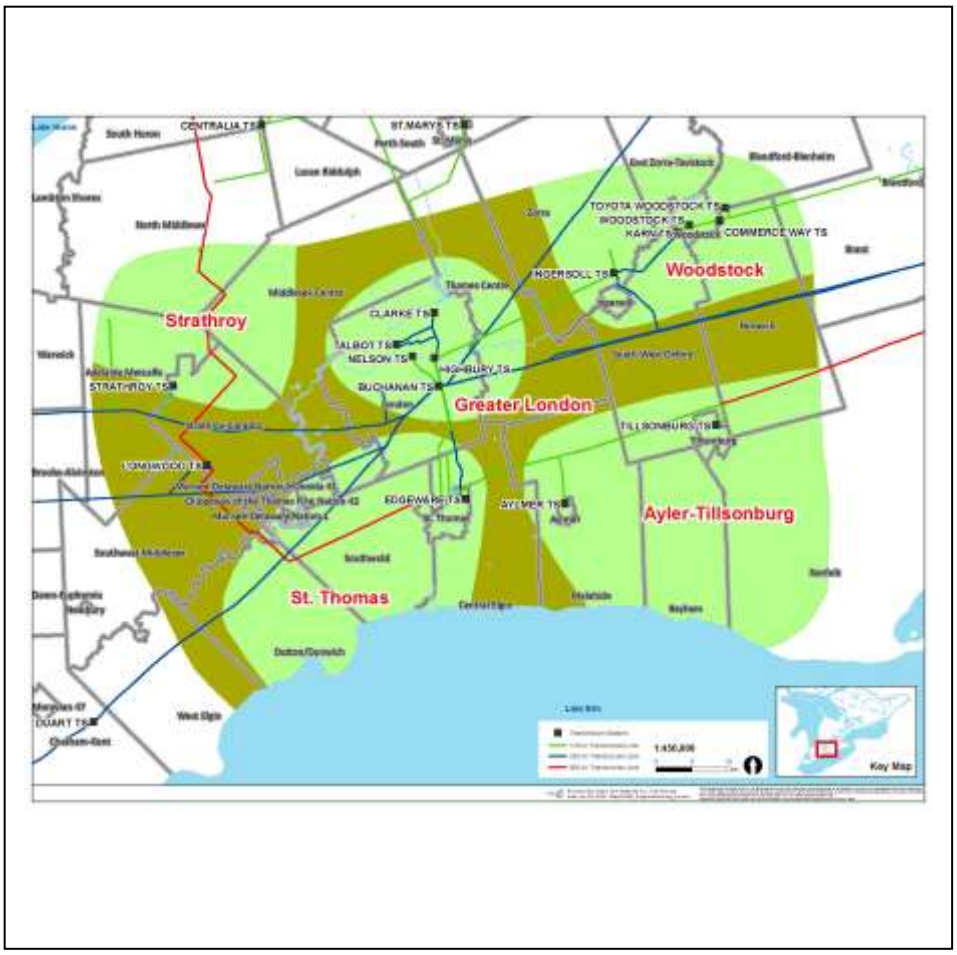


Figure 2: Map of London Area Regional Planning Area

The Bulk Electrical Supply Network in the London Area consists of 500/230kV autotransformers at Longwood TS that supplies a network of 230kV and 115kV circuits. There are 230/115kV autotransformers at Buchanan TS and Karn TS.

London Area transmission system is a network of 230 kV and 115 kV circuits and is connected to Longwood TS through five 500/230 kV autotransformers. Autotransformers at Buchanan TS and Karn TS provide the necessary 230/115 kV auto-transformation. Step-down transformer stations are connected to both 230 kV and 115 kV systems to bring the power to distribution level of 27.6 kV to serve the area. There are fourteen Hydro One step-down TS's, three transmission connected industrial load customers and three transmission connected generators in the London Area.

The existing facilities in the London Area are summarized below and depicted in the single line diagram shown in Figure 3:

- Fourteen step-down transformer stations currently supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerce Way TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Nelson TS, Strathroy TS, Talbot TS (Dual Element Spot Network or DESN 1 and DESN 2), Tillsonburg TS, Wonderland TS, and Woodstock TS.
- One new step-down transformer station is planned to be in-service in 2026/2027: Centennial TS.
- Three directly connected industrial customer loads are connected in the London Area.
- Three existing transmission-connected generating stations in the London Area.

Although depicted, Duart TS is not included in the London Area study and will be studied as part of the Chatham-Kent/Lambton/Sarnia (CKLS) Area Regional Planning.

The single line diagram of the Transmission Network of London Area region is shown in Figure 3 below.

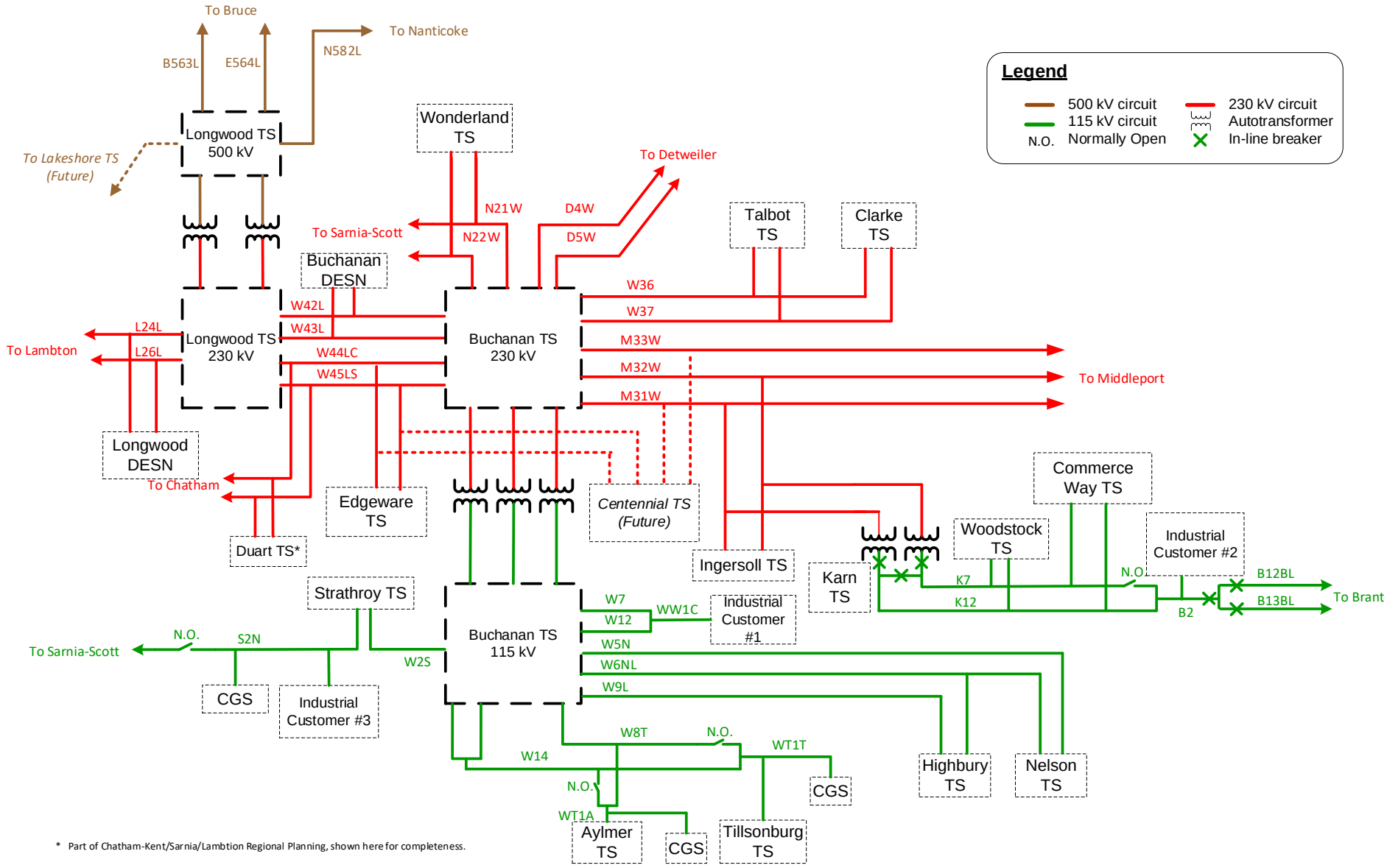


Figure 3: London Area Transmission Single Line Diagram

Table 2: Transmission Station and Circuits in the London Area Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
W2S	W42L	Longwood TS*	CGS (total): 150MW
W14	W43L	Wonderland TS**	
W8T	W44LC	Buchanan TS*	
WT1A	W45LS	Edgeware TS	
WT1T	N21W	Talbot TS	
W9L	N22W	Clarke TS**	
W6NL	D4W	Strathroy TS**	
W5N	D5W	Ingersoll TS	
W7	W36	Aylmer TS**	
W12	W37	Tillsonburg TS**	
WW1C	M31W	Karn TS*	
K7	M32W	Highbury TS**	
K12	M33W	Nelson TS	
B2		Woodstock TS**	
		Commerce Way TS	
		Centennial TS (Future)**	
		CTS1	
		CTS2	
		CTS3	

*Stations with Autotransformers installed

**Stations with low-voltage capacitor banks

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the London Area NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in October 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans ("MEPs") and/or Community Energy Plans ("CEPs"). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix E.

The information provided includes the following:

- London Area 10-year Load Forecast for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs).

- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the London Area.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer peak loads. Three load forecasts were developed i.e. Normal Growth scenario, High & low Growth scenario. The High and low Growth scenario load forecast was developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2033.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering process

6.2.1. Load forecast:

The LDCs provided their historical peaks, starting points with considerations for load transfers, and load forecasts without weather normalization, for all the stations supplying their loads in the London Area region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the London Area region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2023 summer peak corrected for load transfers and extreme weather. The extreme summer weather correction factor for 2023 was provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the London Area region is given in Appendix A.

The CDM savings is estimated based on existing and planned CDM programs, as well as Building Codes & Equipment Standards. The estimated CDM forecasts will be further refined in the next phases of Regional Planning.

Distributed generation is accounted for through values provided by the IESO, based on the known contracted resources.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes**.** This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

The IESO will identify any known system reliability and operational issues for the London Area region.

7. NEEDS

This section describes emerging new needs identified in the London Area Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates. These projects include:

1. W36/W37 Load Restoration: This need was reported in the previous Regional Planning cycles and the impacted LDC, London Hydro, and Hydro One undertook further planning and analysis as part of Local Planning process. A detailed historical equipment performance review was performed to assess the probability of common-mode failure that would lead to simultaneous loss of W36 and W37. It was concluded that the only common-mode failure that may result in the simultaneous loss of both W36/W37 is the failure of the steel poles that carry the two circuits and probability of this event is very low.

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Talbot TS	Talbot TS Transformers T3 and T4 and associated switchyard equipment replacement	6.1.1	7.1.1
Buchanan TS	Buchanan TS Autotransformers T2 and T3 and associated switchyard equipment replacement	6.3.1	N/A*
Clarke TS	Clarke TS Transformer T3 and T4 and associated switchyard equipment replacement	6.3.2	N/A*
Station Capacity Needs			
Aylmer TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.1
Clarke TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.2
Edgeware TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.3
Strathroy TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.4
Nelson TS	The load forecast exceeds the station supply capacity in the medium term	N/A	7.2.5

Talbot T1/T2	The load forecast exceeds the station supply capacity in the near term	6.1.2	7.2.6
Talbot T3/T4	The load forecast exceeds the station supply capacity in the near term	6.1.2	7.2.7
Tillsonburg TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.8
Wonderland TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.9
Woodstock TS	The load forecast exceeds the station supply capacity in the near term	N/A	7.2.10
Transmission Line Capacity Needs			
W44LC/W45LS	Transmission Line Capacity limitation on 230 kV W44LC/W45LS for the loss of companion circuit in the medium term	N/A	7.3.1
WT1T/W14	Transmission Line Capacity limitation on the 115 kV WT1T to Tillsonburg TS pre-contingency in the near term	N/A	7.3.2
System Reliability, Operation and Load restoration Needs			
M31W/M32W K7/K12/B2	Load restoration limitation on 230 kV M31W/M32W and 115 kV K7/K12/B2 circuits for a single tower contingency causing the loss of double-circuit line M31W and M32W or for a double contingency with the loss of both autotransformers at Karn TS	N/A	7.4.1
M31W/M33W	Load restoration limitation on 230 kV M31W/M33W circuits for a single tower contingency	N/A	7.4.2
W36/W37	Load restoration limitation on 230 kV W36/W37 circuits for a single tower contingency	6.2	7.4.3
W44LC/W45LS	Load restoration limitation on 230 kV W44LC/W45LS circuits for a single tower contingency.	N/A	7.4.4
Voltage Performance			
N/A	N/A		

*Current planned date of replacement beyond the planning horizon of this Needs Assessment

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the London Area Region. The complete list of major HV transmission equipment requiring replacement in the London Area Region is provided in table 4 in this section. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The Asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages. Hydro One will continue to assess asset priorities based on recent operational performance to determine the appropriate timing for replacement.

Table 4: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Talbot TS	Talbot TS Transformer T3 and T4 and associated switchyard equipment replacement	2032

7.1.1 Talbot TS (T3/T4)

The existing Talbot TS comprises two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4) and supplies electricity to London Hydro customers. It is supplied by two 230 kV circuits W36 and W37. Step-down transformers T3 and T4 have been in-service from 1979 and as per asset condition assessment, are identified for replacement. In recent years, Talbot TS has experienced several failures with the breakers in the medium-voltage switchyard. Hydro One will continue to assess asset priorities based on recent operational performance to determine the appropriate timing for replacement. A station capacity need has also been identified for the Talbot T3/T4 DESN (Section 7.2.7)

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period **2024-2033** for the 230kV and 115kV Transforming stations in the **London Area** Region using the summer non-coincident peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified in the during the study period

7.2.1 Aylmer TS – 115/27.6 kV

Aylmer TS is a DESN station located in Aylmer-Tillsonburg. The station is supplied by the 115 kV circuit W8T and supplies electricity to ERTH Power and Hydro One Distribution customers. The station had a 2023 non-coincident summer peak of 30.2 MW. The station forecast exceeds the station LTR of 43.0 MW within the near term (within 5 years).

7.2.2 Clarke TS – 230/27.6 kV

Clarke TS is a DESN station located in the northern part of London. The station is supplied by two 230 kV circuits W36 and W37 and supplies electricity to London Hydro and Hydro One Distribution customers. The station had a 2023 non-coincident summer peak of 101.7 MW. The station forecast exceeds the station LTR of 109.7 MW within the near term (within 5 years).

7.2.3 Edgeware TS – 230/27.6 kV

Edgeware TS is a DESN station located in the St. Thomas area. The station is supplied by the 230 kV circuits W44LC and W45LS and supplies electricity to Entegrus, Hydro One Distribution, and London Hydro customers. The station had a 2023 non-coincident summer peak of 100.9 MW. The station forecast exceeds the station LTR of 180.9 MW within the near term (within 5 years).

7.2.4 Nelson TS – 115/27.6 kV

Nelson TS is a DESN station located in London. The station is supplied by the 115 kV circuits W5N and W6NL and supplies electricity to London Hydro customers. The station had a 2023 non-coincident summer peak of 57 MW. The station forecast exceeds the station LTR of 107 MW in the medium term (5-10 years).

7.2.5 Strathroy TS – 115/27.6 kV

Strathroy TS is a DESN station located in Strathroy. The station is supplied by the 115 kV circuits S2N and W2S and supplies electricity to Entegrus and Hydro One Distribution customers. The station had a 2023 non-coincident summer peak of 38.1 MW. The station forecast exceeds the station LTR of 61.1 MW within the near term (within 5 years).

7.2.6 Talbot T1/T2 DESN – 230/27.6 kV

Talbot TS comprises of two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4) and supplies electricity to London Hydro customers. The Talbot T1/T2 DESN is supplied by two 230 kV circuits W36 and W37. The station is supplied by the 230 kV circuits S2N and W2S. The station supplies electricity to London Hydro customers. The station had a 2023 non-coincident summer peak of 115.5 MW. The station forecast exceeds the station LTR of 113.5 MW within the near term (within 5 years).

7.2.7 Talbot T3/T4 DESN – 230/27.6 kV

Talbot TS comprises of two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4) and supplies electricity to London Hydro customers. The Talbot T3/T4 DESN is supplied by two 230 kV circuits W36 and W37. The station is supplied by the 230 kV circuits S2N and W2S. The station supplies electricity to London Hydro customers. The station had a 2023 non-coincident summer peak of 163.4 MW. The station forecast exceeds the station LTR of 161.6 MW within the near term (within 5 years).

7.2.8 Tillsonburg TS – 115/27.6 kV

Tillsonburg TS is a DESN station located in Tillsonburg. The station is supplied by the 115 kV WT1T (tapped from W14) and supplies electricity to Hydro One Distribution and Tillsonburg Hydro customers. The station had a 2023 non-coincident summer peak of 93.4 MW. The station forecast exceeds the station LTR of 108.9 MW within the near term (within 5 years).

7.2.9 Wonderland TS – 230/27.6 kV

Wonderland TS is a DESN station located in the southwest part of London. The station is supplied by the 230 kV circuits N21W/N22W and supplies electricity to London Hydro and Hydro One Distribution customers. The station had a 2023 non-coincident summer peak of 115.9 MW. The station forecast exceeds the station LTR of 122.4 MW within the near term (within 5 years).

7.2.10 Woodstock TS – 115/27.6 kV

Woodstock TS is a DESN station located in Tillsonburg. The station is supplied by the 115 kV circuits K7/K12/B2 and supplies electricity to Hydro One Distribution customers. The station had a 2023 non-coincident summer peak of 60.8 MW. The station forecast exceeds the station LTR of 86.3 MW within the near term (within 5 years).

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transmission line circuits in the London Area Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 W44LC/W45LS – 230 kV – Thermal Limits

The W44LC/W45LS double circuit line, of which the portion from Buchanan JCT to Edgeware TS is about 16 km and supplies Edgeware TS and will supply the future Centennial TS. For the loss of one of the W44LC or W45LS, the loading on the Buchanan JCT to Edgeware TS section exceeds its post-contingency rating in the Medium-Term.

7.3.2 WT1T/W14 – 115 kV – Thermal Limits

The WT1T radial circuit is about 3.5 km tapped from the W14 circuit. The loading on the Cranberry JCT to ESWF JCT and the ESWF JCT to Tillsonburg JCT exceeds its pre-contingency rating in the Near-Term.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2024-2033 to cater this need**.** Based on the results, some system reliability, operating and restoring issues have been identified for this Region.

As per the load security criteria (ORTAC Section 7.1), with one element out of service, planned load curtailment or load rejection is permissible only to account for local generation outages; and not more than 150MW of load may be interrupted by configuration, planned load curtailment or rejection. With two elements out of service, not more than 600 MW of load may be interrupted by configuration, planned load curtailment or rejection.

As per the load restoration criteria (ORTAC Section 7.2), interrupted load must be restored within the following timelines:

- Load above 250 MW, within 30 minutes;
- Load above 150 MW, within 4 hours; and
- All load, within 8 hours.

7.4.1 M31W/M32W 230 kV – K7/K12/B2 115 kV – Load Restoration

Based on the net coincident load forecast at Ingersoll TS and stations connected along the 115 kV circuits K7/K12/B2, the load interrupted by configuration may reach up to 267 MW for the loss of double-circuit line M31W and M32W or loss of both autotransformers at Karn TS. Ingersoll TS up to 95 MW, Woodstock TS up to 92 MW, Commerce Way TS up to 68 MW and Toyota Woodstock CTS up to 20 MW.

In accordance with ORTAC, the system is required to restore 17 MW within 30 mins, 100 MW within 4 hours and the remaining 150 MW within 8 hours. This need was identified in previous Regional Planning cycles and remains in this cycle.

Approximately 20 MW of load can be transferred to the B2 circuit from Brant TS.

7.4.2 M31W/M33W– 230 kV – Load Restoration

Based on the load forecast at the new Centennial TS, the load interrupted by configuration will reach approximately 189 MW in 2027 for the loss of double-circuit line M31W and M33W.

In accordance with ORTAC, the system is required to restore 39 MW within 4 hours and the remaining 150 MW within 8 hours.

7.4.3 W36/W37 – 230 kV – Load Restoration

Based on the net coincident load forecast at Clarke TS, Talbot T1/T2 and Talbot T3/T4, the load interrupted by configuration will reach up to 414 MW in 2033 for the loss of double-circuit line W36 and W37. Clarke TS up to 126 MW, Talbot T1/T2 up to 119 MW and Talbot T3/T4 up to 166 MW.

In accordance with ORTAC, the system is required to restore 164 MW within 30 minute, 100 MW within 4 hours and the remaining 150 MW within 8 hours. This need was reported in the previous Regional Planning cycles and the impacted LDC, London Hydro, and Hydro One undertook further planning and analysis as part of Local Planning process. A detailed historical equipment performance review was performed to assess the probability of common-mode failure that would lead to simultaneous loss of W36 and W37. It was concluded that the only common-mode failure that may result in the simultaneous loss of both W36/W37 is the failure of the steel poles that carry the two circuits and probability of this event is very low.

7.4.4 W44LC/W45LS – 230 kV – Load Restoration

Based on the net coincident load forecast at Edgeware TS, Duart TS and the future Centennial TS, the load interrupted by configuration will reach up to 486 MW in 2033 for the loss of double-circuit line W44LC and W45LS. Edgeware TS area up to 247 MW, Duart TS approximately 50 MW, and the future Centennial TS approximately 189 MW.

The simultaneous loss of double-circuit line W44LC and W45LS will interrupt approximately 486 MW of load at Edgeware TS, Duart TS and the new Centennial TS by configuration.

In accordance with ORTAC, the system is required to restore 236 MW within 30 minute, 100 MW within 4 hours and the remaining 150 MW within 8 hours.

Approximately 50 MW of load can be transferred from Duart TS.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the London Area region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4 in Appendix A.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Aylmer TS Station Capacity	2025	2025	Long Term
2	Clarke TS Station Capacity	2026	2025	2027
3	Edgeware TS Station Capacity	2025	2025	2033
4	Nelson TS Station Capacity	2030	2028	Long Term
5	Strathroy TS Station Capacity	2028	2024	Long Term
6	Talbot T1/T2 DESN Station Capacity	2024	2024	2024
7	Talbot T3/T4 DESN Station Capacity	2024	2024	2024
8	Tillsonburg TS Station Capacity	2024	2024	2027
9	Wonderland TS Station Capacity	2027	2026	Long Term
10	Woodstock TS Station Capacity	2025	2025	Long Term

11	W44LC/W45LS Transmission Line Capacity	2029	2029	2029
12	WT1T Transmission Line Capacity	2025	2025	2025
13	M31W/M32W/K7/K12/B2 Load Restoration	Ongoing	Ongoing	Ongoing
14	M31W/M33W Load Restoration	2027	2027	2027
15	W36/W37 Load Restoration	Ongoing	Ongoing	Ongoing
16	W44LC/W45LS Load Restoration	Ongoing	Ongoing	Ongoing

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 7: Needs which require further regional coordination

Sr.no.	Need	Recommendation
1	Talbot T3/T4 DESN Asset Renewal	To be considered in addition to capacity needs in the next Regional Planning phases.
2	Aylmer TS Station Capacity	To be further assessed in the next Regional Planning phases.
3	Clarke TS Station Capacity	To be further assessed in the next Regional Planning phases.
4	Edgeware TS Station Capacity	To be further assessed in the next Regional Planning phases.
5	Nelson TS Station Capacity	To be further assessed in the next Regional Planning phases.
6	Strathroy TS Station Capacity	To be further assessed in the next Regional Planning phases.
7	Talbot T1/T2 Station Capacity	To be further assessed in the next Regional Planning phases.
8	Talbot T3/T4 Station Capacity	To be further assessed in the next Regional Planning phases.
9	Tillsonburg TS Station Capacity	To be further assessed in the next Regional Planning phases.
10	Wonderland TS Station Capacity	To be further assessed in the next Regional Planning phases.
11	Woodstock TS Station Capacity	To be further assessed in the next Regional Planning phases.
12	W44LC/W45LS post-contingency capacity limitation (Buchanan JCT x Edgeware JCT)	To be further assessed in the next Regional Planning phases.
13	WT1T/W14 pre-contingency capacity limitation (Cranberry JCT x ESWF JCT and ESWF JCT x Tillsonburg JCT)	To be further assessed in the next Regional Planning phases.
14	Load restoration limitation – M31W/M32W / K7/K12/B2 due to	To be further assessed in the next Regional Planning phases.

	the loss of double-circuit line M31W and M32W or for a double contingency with the loss of both autotransformers at Karn TS	
15	Load restoration limitation – M31W/M33W for a single tower contingency	To be further assessed in the next Regional Planning phases.
16	Load restoration limitation – W36/W37 for a single tower contingency	To be reassessed in the next Regional Planning phases.
17	Load restoration limitation – W44LC/W45LS for a single tower contingency	To be further assessed in the next Regional Planning phases.

List of LDC(s) to be involved in further regional planning phases:

- Entegrus Powerlines Inc.
- ERTH Power Inc.
- Hydro One Distribution
- London Hydro Inc.
- Tillsonburg Hydro Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- N/A

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: London Area Region – Non-Coincident- Normal Growth Net Load Forecast

Station	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Aylmer TS	43.0	30.2	38.8	44.6	45.4	41.9	42.7	43.6	44.5	45.6	46.7	47.9
Buchanan TS	173.5	119.5	122.0	126.7	128.0	129.5	130.7	131.8	133.1	134.7	139.4	145.2
Clarke TS	109.7	101.7	107.1	108.8	109.8	128.1	129.2	130.3	131.5	133.0	134.7	136.5
Commerce Way TS	106.0	36.2	51.1	54.0	65.7	67.9	70.1	71.2	72.4	73.7	75.1	76.5
Edgeware TS	180.9	100.9	122.8	187.3	187.8	196.8	204.0	219.4	228.6	232.0	239.9	247.7
Highbury TS	85.0	64.3	64.7	65.5	66.4	67.4	68.2	69.1	70.0	71.0	72.3	73.6
Ingersoll TS	158.6	69.3	75.0	84.8	100.7	103.1	106.6	110.1	113.7	117.6	119.9	122.7
Longwood TS	121.7	36.9	52.6	53.6	64.6	75.1	75.6	76.5	77.2	78.1	79.3	80.4
Nelson TS	107.0	57.0	56.1	57.7	59.4	61.1	91.7	94.1	118.2	121.4	124.7	128.2
Strathroy TS	61.1	38.1	54.4	55.9	59.1	60.6	62.2	64.7	66.6	67.7	69.8	71.4
Talbot T1/T2	113.5	115.5	120.7	122.4	120.1	107.4	109.0	110.3	112.8	114.7	116.9	119.6
Talbot T3/T4	161.6	163.4	166.6	168.2	179.2	174.1	175.9	188.5	174.1	176.1	178.6	181.6
Tillsonburg TS	108.9	93.4	109.1	115.8	122.8	128.6	134.8	139.1	142.8	147.6	152.2	156.8
Wonderland TS	122.4	115.9	95.0	98.1	114.1	124.1	126.2	128.3	130.6	133.1	136.2	139.2
Woodstock TS	86.3	60.8	67.5	86.8	90.7	91.2	91.7	89.1	89.6	90.6	91.6	92.6

Table A.2: London Area Region – Coincident – Normal Growth Net Load Forecast

Station	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Aylmer TS	43.0	27.0	34.6	40.3	41.0	37.3	38.1	38.8	39.6	40.5	41.5	42.6
Buchanan TS	173.5	118.0	120.4	125.1	126.4	127.8	129.0	130.1	131.4	132.9	137.6	143.4
Clarke TS	109.7	94.4	99.3	100.9	101.8	118.7	119.7	120.7	121.8	123.1	124.7	126.4
Commerce Way TS	106.0	29.1	43.6	46.6	58.3	60.5	62.7	63.7	64.8	65.9	67.1	68.4
Edgeware TS	180.9	100.9	122.8	187.2	187.7	196.7	203.8	219.2	228.4	231.8	239.7	247.5
Highbury TS	85.0	58.7	58.8	59.6	60.4	61.3	62.0	62.7	63.5	64.5	65.6	66.8
Ingersoll TS	158.6	51.2	54.3	61.8	77.3	79.4	82.5	85.2	88.0	91.0	92.8	95.0
Longwood TS	121.7	36.9	52.6	53.6	64.6	75.1	75.6	76.5	77.2	78.1	79.3	80.4
Nelson TS	107.0	39.6	53.3	54.8	56.3	58.0	87.3	89.5	112.7	115.7	118.9	122.2
Strathroy TS	61.1	32.9	46.5	47.9	50.8	52.1	53.5	55.6	57.2	58.2	60.0	61.4
Talbot T1/T2	113.5	115.5	120.5	122.2	119.8	107.1	108.6	109.8	112.3	114.1	116.3	118.9
Talbot T3/T4	161.6	150.0	151.8	153.3	163.4	158.6	160.2	172.7	159.5	161.3	163.6	166.3
Tillsonburg TS	108.9	93.4	109.1	115.8	122.8	128.7	134.8	139.1	142.8	147.7	152.2	156.9
Wonderland TS	122.4	103.8	95.2	98.4	114.5	124.6	126.8	129.0	131.4	134.0	137.2	140.2
Woodstock TS	86.3	60.8	67.5	86.7	90.6	91.1	91.6	88.9	89.4	90.4	91.4	92.4

Table A.3: London Area Region Non-Coincident – High Growth Net Load Forecast

Station	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Aylmer TS	43.0	30.2	39.3	48.1	49.5	46.4	47.8	49.2	50.7	52.3	54.1	55.9
Buchanan TS	173.5	119.5	124.6	132.1	134.5	137.0	139.3	141.5	143.9	146.5	152.4	159.3
Clarke TS	109.7	101.7	108.4	111.3	113.1	140.7	142.8	144.9	147.0	149.4	152.2	155.0
Commerce Way TS	106.0	36.2	59.6	64.2	81.8	85.2	88.5	90.4	92.3	94.3	96.4	98.5
Edgeware TS	180.9	100.9	132.9	229.9	231.0	244.8	256.0	279.5	293.7	299.2	310.9	322.6
Highbury TS	85.0	64.3	65.4	66.9	68.4	70.0	71.5	73.0	74.6	76.3	78.3	80.3
Ingersoll TS	158.6	69.3	78.8	93.7	117.7	122.0	127.4	133.0	138.6	144.6	148.1	152.1
Longwood TS	121.7	36.9	60.1	61.7	78.4	94.3	95.2	96.6	97.8	99.2	101.1	102.7
Nelson TS	107.0	57.0	57.0	59.6	62.2	65.0	110.9	114.7	151.0	155.9	161.0	166.2
Strathroy TS	61.1	38.1	63.6	65.9	70.9	73.3	75.8	79.6	82.6	84.4	87.6	89.7
Talbot T1/T2	113.5	115.5	121.8	124.7	121.7	102.9	105.7	108.1	112.3	115.3	118.8	122.9
Talbot T3/T4	161.6	163.4	167.8	170.8	188.0	180.7	184.0	198.1	177.1	180.5	184.4	189.0
Tillsonburg TS	108.9	93.4	117.1	127.4	138.3	147.3	155.5	162.3	168.2	175.7	182.6	189.6
Wonderland TS	122.4	115.9	96.7	101.6	126.1	141.3	144.9	148.5	152.2	156.3	161.0	165.6
Woodstock TS	86.3	60.8	70.3	99.4	105.5	106.4	107.5	103.8	104.9	106.4	107.9	109.5

Table A.4: London Area Region – Coincident – High Growth Net Load Forecast

Station	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Aylmer TS	43.0	27.0	35.0	43.7	44.9	41.7	43.0	44.2	45.5	46.9	48.5	50.1
Buchanan TS	173.5	118.0	123.0	130.5	132.8	135.3	137.5	139.7	142.0	144.6	150.4	157.3
Clarke TS	109.7	94.4	100.5	103.3	104.9	130.6	132.5	134.3	136.3	138.5	141.1	143.7
Commerce Way TS	106.0	29.1	52.2	56.8	74.4	77.8	81.1	82.8	84.5	86.3	88.1	90.0
Edgeware TS	180.9	100.9	132.8	229.9	230.9	244.7	255.9	279.4	293.5	298.9	310.7	322.4
Highbury TS	85.0	58.7	59.5	60.8	62.2	63.7	65.0	66.4	67.8	69.3	71.1	73.0
Ingersoll TS	158.6	51.2	57.3	68.7	92.2	96.0	100.9	105.2	109.6	114.2	117.0	120.2
Longwood TS	121.7	36.9	60.1	61.7	78.4	94.3	95.2	96.6	97.8	99.2	101.1	102.7
Nelson TS	107.0	39.6	54.2	56.6	59.0	61.6	105.9	109.4	144.3	149.0	153.9	158.9
Strathroy TS	61.1	32.9	54.5	56.7	61.2	63.3	65.5	68.8	71.3	72.8	75.6	77.5
Talbot T1/T2	113.5	115.5	121.6	124.5	121.4	102.6	105.3	107.6	111.7	114.7	118.1	122.2
Talbot T3/T4	161.6	150.0	153.0	155.7	171.4	164.7	167.7	181.5	162.2	165.3	168.9	173.1
Tillsonburg TS	108.9	93.4	117.1	127.4	138.3	147.3	155.5	162.4	168.2	175.7	182.7	189.7
Wonderland TS	122.4	103.8	96.9	102.0	126.5	141.8	145.6	149.2	153.1	157.3	162.0	166.6
Woodstock TS	86.3	60.8	70.3	99.4	105.4	106.3	107.3	103.7	104.7	106.2	107.7	109.2

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Longwood TS	500/230	B563L, E564L, N582L, L24L, L26L, W42L, W43L, W44LC, W45LS
2	Wonderland TS*	230	N21W, N22W
3	Buchanan TS	230/115	N21W N22W, D4W, D5W, W36, W37, M31W, M32W, M33W, W2S, W7, W12, W5N, W6NL, W9L, W8T, W14
4	Edgeware TS	230	W44LC, W45LS
5	Talbot TS	230	W36, W37
6	Clarke TS*	230	W36, W37
7	Strathroy TS*	115	W2S, S2N
8	Ingersoll TS	230	M31W, M32W
9	Aylmer TS*	115	W8T, WT1A
10	Tillsonburg TS*	115	W14, WT1T
11	Karn TS	230/115	M31W, M32W, K7, K12
12	Highbury TS*	115	W6NL, W9L
13	Nelson TS	115	W5N, W6NL
14	Woodstock TS*	115	K7, K12
15	Commerce Way TS	115	K7, K12
16	Centennial TS (Future)*	230	W44LC, W45LS, M31W, M33W
17	CTS1	115	WW1C
18	CTS2	115	B2
19	CTS3	115	S2N

* Stations with low-voltage capacitor banks

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Longwood TS to Buchanan TS	W42L	230
2	Longwood TS to Buchanan TS	W43L	230
3	Longwood TS to Chatham TS to Buchanan TS	W44LC	230
4	Longwood TS to Spence SS to Buchanan TS	W45LS	230
5	Scott TS to Buchanan TS	N21W	230
6	Scott TS to Buchanan TS	N22W	230
7	Buchanan TS to Detweiler TS	D4W	230
8	Buchanan TS to Detweiler TS	D5W	230
9	Buchanan TS to Talbot TS and Clarke TS	W36	230
10	Buchanan TS to Talbot TS and Clarke TS	W37	230
11	Buchanan TS to Middleport TS	M31W	230
12	Buchanan TS to Middleport TS	M32W	230
13	Buchanan TS to Middleport TS	M33W	230
14	Buchanan TS to Strathroy TS	W2S	115
15	Buchanan TS to Cranberry JCT	W14	115
16	Buchanan TS to Cranberry JCT	W8T	115
17	Lyons JCT to Aylmer TS	WT1A	115
18	Cranberry JCT to Tillsonburg TS	WT1T	115
19	Buchanan TS to Highbury TS	W9L	115
20	Buchanan TS to Highbury TS to Nelson TS	W6NL	115
21	Buchanan TS to Nelson TS	W5N	115
22	Buchanan TS to CTS	W7	115
23	Buchanan TS to CTS	W12	115
24	Buchanan TS to CTS	WW1C	115

25	Karn TS to Commerce Way TS	K7	115
26	Karn TS to Commerce Way TS	K12	115

Appendix D: List of LDC's

No.	Name of LDC
1	Entegrus Powerlines Inc. - LDC
2	ERTH Power Inc. - LDC
3	Hydro One Networks Inc. (Distribution) - LDC
4	London Hydro Inc. - LDC
5	Tillsonburg Hydro Inc. - LDC

Appendix E: List of Municipalities in the London Area Region

No.	Name of Municipality
1	Oxford County (comprising of Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra)
2	City of Woodstock
3	Middlesex County (comprising of Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury)
4	City of London
5	Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold)
6	City of St. Thomas
7	Norfolk County

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



Peterborough to Kingston Integrated Regional Resource Plan

November 4, 2021

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Connecting Today.
Powering Tomorrow.

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Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed 47
Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs 47
Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations 47
Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study 48
Replace Port Hope TS T3/T4 with the closest available standard size transformers 48
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List of Abbreviations

CDM	Conservation Demand Management
DER	Distributed Energy Resources
DESN	Dual Element Spot Network
DG	Distributed Generation
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TS	Transformer Station
TSC	Transmission System Code
Working Group	Technical Working Group of the Peterborough to Kingston Region

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Peterborough to Kingston region, which is composed of the following licensed transmitters and licensed distributors:

- Elexicon Energy Inc. (Elexicon)
- Hydro One Networks Inc. (Distribution) (Hydro One (Distribution))
- Hydro One Networks Inc. (Transmission) (Hydro One (Transmission))
- Independent Electricity System Operator (IESO)
- Lakefront Utilities Inc. (Lakefront Utilities)
- Utilities Kingston
- Eastern Ontario Power

The Working Group assessed the adequacy of electricity supply to customers in the Peterborough to Kingston region over a 20-year period beginning in 2019; developed a plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

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

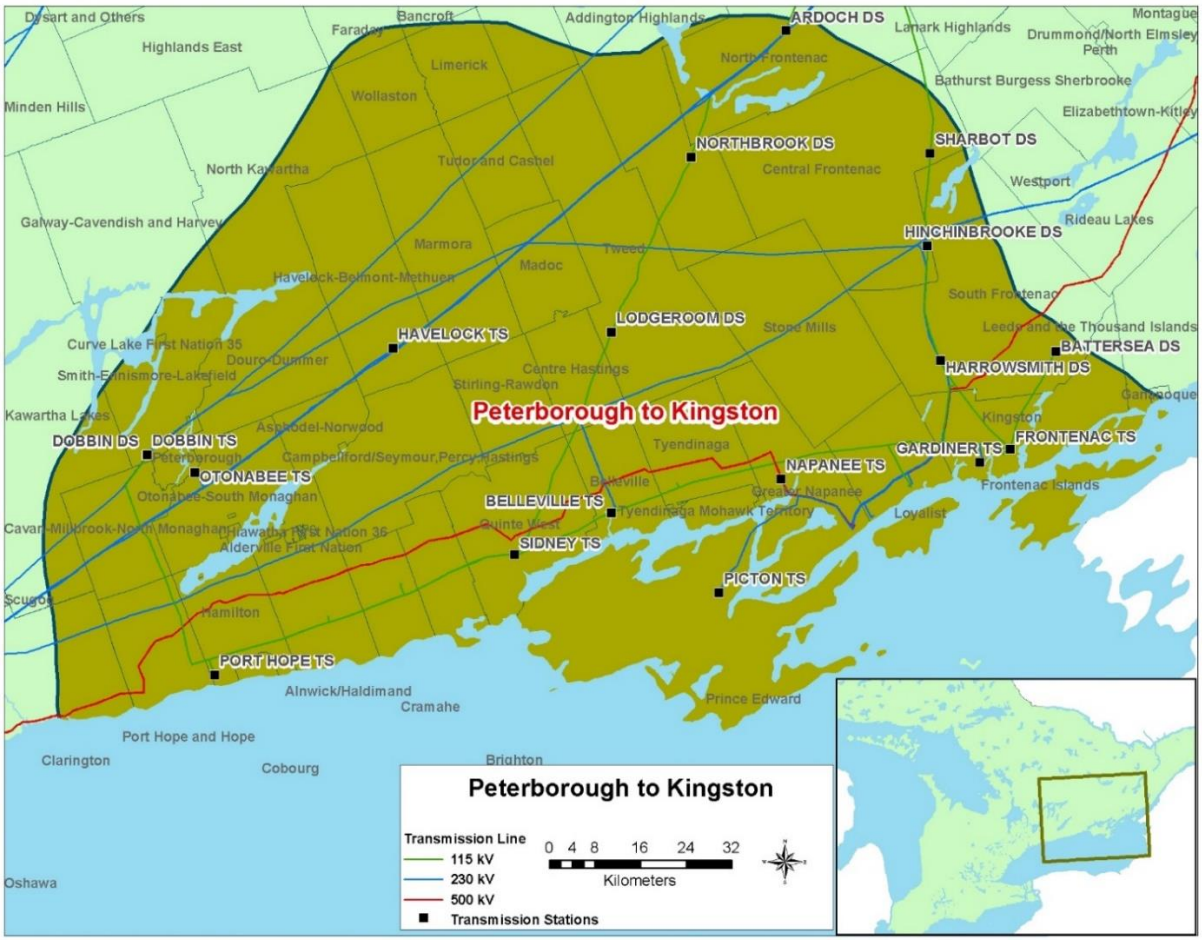
The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community engagement and consultations.

1 Introduction

The Peterborough to Kingston region is located in eastern Ontario as shown in

Figure 1-1. It includes Frontenac County, Hastings County, Northumberland County, Peterborough County, Prince Edward County, parts of Lennox and Addington County, and related municipalities. Peterborough, Belleville and Kingston are the three largest population centres in the region. The region also comprises several Indigenous communities including Alderville First Nation, Hiawatha First Nation, Curve Lake First Nation, Mohawks of the Bay of Quinte, Tyendinaga Mohawk, Kawartha Nishnawbe and the traditional territory of the Huron Wendat.

Figure 1-1 | Overview of the Peterborough to Kingston Region and Transmission System



The region is supplied by the following local distribution companies:

- Elexicon which serves Port Hope and Belleville;
- Eastern Ontario Power, which is embedded to Hydro One Distribution, serves over 3,500 distribution customers in Gananoque, Ontario;
- Lakefront Utilities, embedded to Hydro One Distribution, serves 10,000 distribution customers across the Town of Cobourg and the Village of Colborne;

- Kingston Utilities serves 28,000 distribution customers in Central Kingston; and
- Hydro One Distribution[1], which supplies distribution customers in the surrounding areas of the region.

These LDCs receive power at the step-down transformer stations and distribute it to end users, i.e., industrial, commercial and residential customers.

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

This IRRP identifies needs pertaining to power system capacity, reliability requirements, and end-of-life asset replacement and coordinates options to meet customer needs in the area over a 20-year period. Given forecast uncertainty, the longer development lead time and the potential for technological change, the plan does not recommend specific investments or projects to meet mid- and long-term needs, but maintains the flexibility to evolve in step with emerging developments. Instead, this IRRP focuses both on recommendations to meet near-term needs, and on the near-term actions required to lay the groundwork for determining options to meet mid- and long-term needs.

The focus of this IRRP is providing an adequate reliable supply to support community growth. A key consideration in this analysis is whether near-term actions maintain, or act as a barrier to, long-term options. The recommended near-term actions are intended to be completed before the next IRRP cycle, scheduled for 2025, or sooner, depending on demand growth or other factors. In some cases, the scope of near-term actions includes the continuation of defined planning activities coordinated among key stakeholders to develop and complete recommendations within a specific time period. The completion of these actions will inform decisions for the next scheduled planning cycle, or sooner, particularly around integrated solutions that address multiple needs, as well as demand-side options and capabilities for which sufficient information is not currently available.

This report is organized as follows:

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

[1] Includes former Peterborough Distribution which was sold to Hydro One Distribution serves distribution customers in Peterborough, Lakefield, and Norwood.

2 The Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) provides recommendations to address the electricity needs of the Peterborough to Kingston region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)[2] and reliability standards governed by the North American Electric Reliability Corporation (NERC).

This IRRP identifies three planning horizons: from the base-year (2019)[3] through the near term (up to 2024), medium term (year 6 to 10, through to 2029), and longer term (year 11 to 20, or through to 2038). These planning horizons reflect the inverse relationship between the length of time and demand certainty (in that the longer the outlook, the less certain it is), lead time for electricity resource development, and planning commitment required.

This IRRP identifies and recommends specific projects for implementation in the near term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions. This IRRP also identifies possible long-term electricity needs, some of which may advance to the near or medium term for a high growth scenario. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to commit specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time or so the Working Group can respond in a timely manner, if a high growth scenario were to materialize.

2.1 Near- to Medium-Term Plan

The plan to meet the near-and medium-term needs of electricity customers in the Peterborough to Kingston region was developed to maximize the use of the existing electricity system in consideration of planning criteria such as reliability, cost, and feasibility. The near-term plan was also developed to be consistent with the long-term development of the region's electricity system.

The Working Group's recommendations for the near- and medium-term plan focus on addressing both station capacity needs in Belleville and Kingston and supply capacity needs on pockets of the 115 kV system. The area's near-term supply capacity needs in the Peterborough and Quinte West area are impacted by ongoing bulk system planning activities in the area. Further planning studies to assess bulk system impacts are also identified. The recommendations are summarized below.

Recommended Actions

1. **Build a new 230 kV Dual Element Spot Network (DESN) transformer station at Belleville TS**

[2] Refer to ORTAC for details: http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[3] To be consistent with Regional Plan's Needs Assessment, the 2019 was used as a base year

To address today's station capacity need at Belleville TS, as well as to serve the growing electricity demand in the region, Elexicon will work with Hydro One (Transmission) to initiate the development of a new Dual Element Spot Network (DESN) transformer station at Belleville, with an expected in-service date of 2025. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS until the end of the planning horizon.

2. Hydro One Distribution load transfer – Gardiner TS DESN #1 to Gardiner TS DESN #2

There is an immediate need for new capacity at Gardiner TS DESN #1. As a first step, performing a load transfer of 11 MW between Gardiner TS DESN #1 and Gardiner TS DESN #2 by 2022 is the cost-effective way to reduce load at Gardiner TS DESN #1. Although, a second load transfer of 11 MW can be performed, it comes with a high cost. Therefore, instead of performing a second load transfer, the next part of the solution is recommended action #3 - to advance end-of-life replacement of transformers at Gardiner TS DESN #1. After implementing first load transfer and recommended action #3, the Working Group will continue to monitor load at Gardiner TS DESN #1 and, evaluate if a second 11 MW load transfer is needed.

3. Hydro One Transmission to advance end-of-life replacement of transformers at Gardiner TS DESN #1

The station transformers at Gardiner TS DESN #1 are reaching end-of-life in the mid-2020s. Replacement of these transformers with units of a higher limited time emergency rating (LTR) is recommended as soon as possible (2024-2025), as the need is imminent. Advancing the replacement date, combined with the load transfer in recommended action #2, will address the Gardiner TS DESN #1 capacity need for the duration of the planning horizon for the reference load forecast and for the mid-term horizon for the high growth load forecast

4. Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed

Building a new 230 kV station in Kingston will address the local need for station capacity at both Frontenac TS and Gardiner TS over the long term and for multiple growth scenarios. Due to the uncertainty in the forecast, the timing of the need for the new station could be in the near- to medium term or as late as 2029. Hence, Hydro One Distribution and Utilities Kingston will work together to monitor the load growth in their service areas, and work with Hydro One Transmission to commence the development work and subsequent construction of a new 230 kV station and required line connection, either transmitter or distributor owned, when it is deemed to be appropriate.

5. Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs

The development of a non-wire alternative, specifically additional energy efficiency or a local storage solution, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station.

6. Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations

The outcomes of the Gatineau Corridor End-of-Life Study will improve the supply capability in the Peterborough to Kingston region. Namely, addressing the identified supply capacity need to the Peterborough and Quinte West area. By implementing the recommendations of the Gatineau Corridor End-of-Life study this need should be addressed.

7. Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study

Upgrading the autotransformers' secondary conductors will increase the thermal capacity of these autotransformers from 250 MW to 285 MW and will resolve the thermal violation after losing one of the autotransformers. A future Lennox to St. Lawrence bulk system study will reassess the need with this solution in place and study if additional capacity is required.

8. Replace Port Hope TS T3/T4 with the closest available standard size transformers

Port Hope TS T3/T4 are reaching end-of-life and there are no opportunities for end-of-life optimization at this time. This IRRP recommends like-for-like replacements with the closest available standard size transformers of equal or greater capacity.

2.2 Long-Term Plan

A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. This IRRP sets out near-term actions required to ensure that options remain available to address future needs, if and when they arise.

Recommended Actions

1. Implement Conservation

The implementation of provincial conservation targets is a key near-term action of the Peterborough to Kingston region's long-term plan. In developing the demand forecast, peak demand impacts associated with meeting provincial targets were assumed before identifying the residual needs.

Meeting provincial conservation targets amounts to approximately 73 MW, or 5% of the total forecast demand growth, by the end of the study period.

To ensure these savings materialize, it is recommended that conservation efforts be focused as much as possible on measures that will contribute to meeting program energy targets while also maximizing peak demand reductions. The monitoring of conservation success will lay the foundation for the long-term plan by evaluating the performance of specific conservation measures in the sub-region and assessing potential for additional conservation.

2. Study the potential bulk system impact of future supply reinforcement to Belleville TS

After building a new 230 kV station at Belleville, the transmission system supply into Belleville is expected to meet the load growth over the 20-year planning horizon. However, beyond this time horizon, the system supply capability will be limited due to excessive voltage change violations during contingency conditions. To solve this issue, transmission reinforcement to Belleville might be necessary. Before the next planning cycle, the bulk system impact of transmission reinforcement to Belleville TS should be included in the scope of a relevant individual bulk planning study for the area.

3. Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau corridor end-of-life study

Low voltage violations are observed during contingency conditions in the long-term planning horizon on the 115 kV system in the Peterborough to Quinte West area. These violations may naturally be resolved by the outcome of recommendations in the forthcoming Gatineau corridor end-of-life study; therefore, this need will be monitored and re-assessed during the next planning cycle.

4. Monitor demand growth, conservation achievement and distributed generation uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial DG projects, and actual demand growth in the Peterborough to Kingston Region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on CDM and DG is also a useful input into the ongoing development of non-wires alternatives as potential long-term solutions.

5. Initiate the next regional planning cycle early, if needed

Along with the indices outlined above, the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast (the high demand forecast in Belleville and Kingston, or the reference demand forecast in the remainder of the region), it may be necessary to initiate the next iteration of the regional planning process earlier than 2025 given the lead time for the long-term supply options.

3 Development of the Plan

3.1 The Regional Planning Process

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

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

The process consists of four main components:

1) A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2) A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and
4) A Regional Infrastructure Plan (RIP) led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix B - Development of the Plan.

In addition to regional planning process, there are bulk planning and distribution planning processes. Distribution system planning is for system at 44 kV and lower, while bulk and regional planning are for higher voltages. Furthermore, regional planning focuses more on a particular, local part of the grid, while bulk planning reviews electricity transfers across the province. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.2 Peterborough to Kingston IRRP Development

Development of the Peterborough to Kingston IRRP was initiated in 2020 with the release of the Needs Assessment report. This product was prepared by Hydro One (Transmission) with participation from the IESO, Elexicon Energy, Hydro One (Distribution), Lakefront Utilities, Eastern Ontario Power, and Utilities Kingston. Screening for needs was carried out to identify needs that may require coordinated regional planning. The subsequent Scoping Assessment Outcome Report, which was prepared by the IESO, recommended that an IRRP should be developed to address previously identified and new needs in this region due to the potential for coordinated solutions.

In 2020, the Working Group was formed to develop finalize Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the region, and recommend actions to address them.

4 Background and Study Scope

This is the second cycle of regional planning for the Peterborough to Kingston region. During the first cycle of regional planning, a Needs Assessment[4] was conducted for the Peterborough to Kingston region in February 2015 that was led by Hydro One Networks Inc. Transmission, and included representatives from the IESO, the former Veridian Connections Inc., Kingston Hydro, and the former Peterborough Distribution Inc. and Hydro One Networks Inc. Distribution. After reviewing the needs identified in the report, the participants recommended that further regional coordination was not required, and instead the needs would be addressed through a local study.

This cycle of regional planning identified a number of needs requiring further regional coordination and recommended an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019[5].

4.1 Study Scope

This IRRP, prepared by the IESO on behalf of the Working Group, recommends options to meet the electricity needs of Peterborough to Kingston region over near- to medium-term timeframe and sets out near-term actions required to ensure that options remain available to address long-term needs. Guided by the principle of maintaining an adequate level of reliability performance as per the Ontario Resource and Transmission Assessment Criteria (ORTAC)[6], this IRRP reviews needs identified and discussed as part of the Scoping Assessment, with the focus on:

- Providing an adequate, reliable supply to support community growth;
- Minimizing the impact of supply interruptions; and
- Coordinating and aligning end-of-life asset replacements with evolving needs.

Given that parts of the Peterborough to Kingston region's 230 kV and 115 kV transmission networks also serve as major pathways for the flow of power to and from adjacent regions (Greater Toronto Area and Ottawa) and the connection of large generation facilities, the IRRP assesses the Peterborough to Kingston region 230 kV and 115 kV networks under certain system conditions. A detailed assessment of the bulk electricity system examining various bulk system conditions is typically undertaken through a separate planning process, as described in section 4.2, and is beyond the scope of this IRRP.

The following transmission facilities were included in the scope of this study:

230 kV connected stations: Belleville TS, Dobbin TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS and a customer owned station.

115 kV connected stations: Ardoch DS, Battersea DS, Dobbin DS, Frontenac TS, Harrowsmith DS, Hinchinbrooke DS, Lodgeroom DS, Northbrook DS, Port Hope TS, Sharbot DS, Sidney TS, and four customer owned stations.

[4] The 2015 Needs Assessment Report for the Peterborough to Kingston Region is available on the Hydro One website (link)

[5] To be consistent with Regional Plan's Needs Assessment, the 2019 was used as a base year

[6] The Ontario Resource and Transmission Assessment Criteria is available on the IESO website (link)

230 kV transmission lines: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X21, X22, X2H, X3H and X4H.

115 kV transmission lines: B1S, B5QK, P3S, P4S, Q3K, Q3M6, Q6S and S1K.

230/115 kV autotransformers: Dobbin T1, T2[7], T5 and Cataraqui T1 & T2.

Electricity to the Peterborough to Kingston region is supplied primarily through the 500 kV station Lennox TS, located in Lennox and Addington County, in conjunction with a number of 230 kV transmission lines from Clarington TS and Cherrywood TS, both located in the GTA East area. A large portion of the load in the Peterborough to Kingston region is connected to a regional 115 kV system, supplied by the 230 kV transmission system through five (5)[7] 230-115 kV autotransformers located at Dobbin TS and Cataraqui TS.

The Peterborough to Kingston region can be broken out into a number of sub-systems or areas with common supply points/limitations, which includes Peterborough, Port Hope to Quinte West, Belleville, and Kingston.

- The Peterborough area is supplied by two step-down transformer stations, Dobbin TS and Otonabee TS. Power is delivered into this area through the 230 kV transmission circuits P15C, C27P, T22C and T31H running between GTA East and the Ottawa area.
- The Port Hope to Quinte West area is supplied by two step-down transformer stations, Port Hope TS and Sidney TS which are both served by the regional 115 kV system.
- The Belleville area is supplied by one step-down transformer station, Belleville TS which is supplied via the 230 kV transmission circuits T25B and H23B.
- Lastly, the Kingston area is supplied by three step down transformer stations, Frontenac TS, Gardiner TS #1 and Gardiner TS #2. Frontenac TS is supplied by the regional 115 kV system, whereas Gardiner TS (#1 & #2) are supplied by the 230 kV transmission circuits X2H and X4H.
- Together, the Peterborough area and the Port Hope to Quinte West area, form part of a larger electrical sub-system within the Peterborough to Kingston region, referred to as the Peterborough to Quinte West sub-system or area.

The Peterborough to Kingston IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC planning criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;

[7] Normally, Dobbin T2 is operated out of service

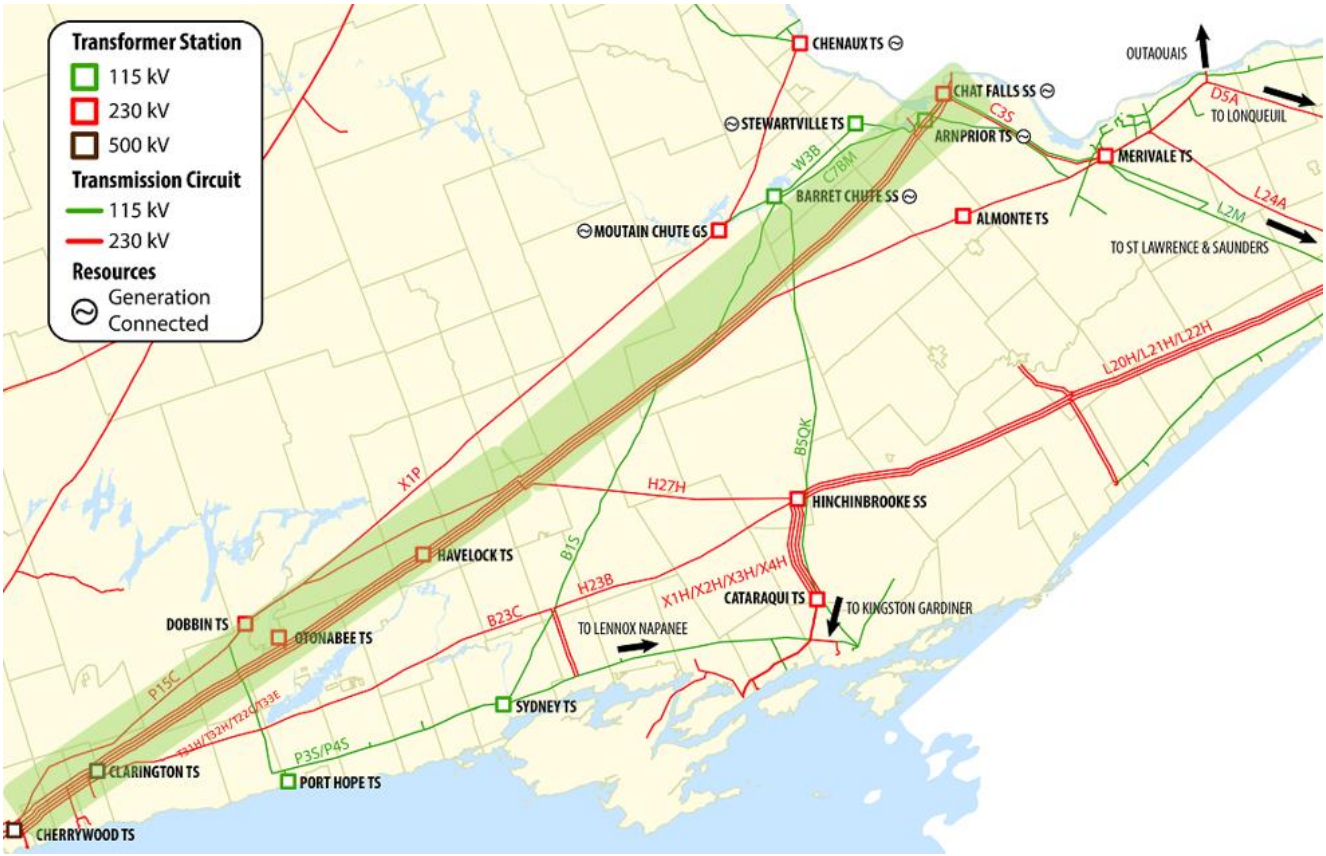
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

4.2 Related Bulk System Planning Studies

Gatineau Corridor End-of-Life Study

As shown in Figure 4-1, the Gatineau corridor consists of five (5) 230 kV transmission circuits stretching between GTA East and Ottawa area. As shown, these circuits form a major pathway on the bulk transmission system and provide or support supply to Ottawa and Peterborough, connection of Chats Falls area generation and imports from Quebec. The study assesses transmission equipment end-of-life needs forecast to arise over the next five to ten years, in addition to forecast reliability needs in the areas of Ottawa and Peterborough to Quinte West.

Figure 4-1 | Gatineau Corridor



The Gatineau corridor circuits are critical in supporting the regional 115 kV supply system, and in some cases directly supply step-down transformer stations (Dobbin TS and Otonabee TS). The options being assessed as part of the study have a direct impact on the supply to the Peterborough to Kingston region. Forecast needs between the Gatineau Corridor End-of-Life study and the Peterborough to Kingston regional planning studies have been coordinated, seeking opportunities for integrated solutions addressing both bulk and regional needs. The IESO's participation on the Working Group in the next stage of regional planning, the RIP, will help ensure recommendations are aligned with the latest bulk system information.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. In order for the Working Group to plan for the future electricity needs of the region, a 20-year planning demand forecast was developed. This section outlines the demand forecast methodology, discusses historical electricity demand trends, development of the planning demand forecasts (both coincident and non-coincident) as well as the expected contributions of CDM and DG towards reducing the peak demand in the region. By taking all of these factors into consideration the planning demand forecast is developed and it is used to plan the transmission grid such that the grid can operate reliably and economically in the long term.

Furthermore, high growth forecast scenarios were developed to provide insight into the system's capability when faced with higher load than projected by the reference planning demand forecast. Two demand forecast sensitivity scenarios have been established and outlined in sections 5.9 and 5.10: a scenario where DG resources were expected to be out of service following their contract expiration, and a scenario to account for increased load growth, particularly in Kingston and Belleville, due to electrification.

5.1 Demand Forecast Methodology

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs. Transmission infrastructure supplying an area is sized to meet peak-demand requirements (rather than energy demand requirements). Peak demand requirements are first determined at the station or DESN[8] level, allowing capability in pockets where there is load growth, or where existing equipment has been historically close to its load supply capability, to be more accurately assessed. These forecasts are then aggregated to understand the limits of the transmission system and identify overall regional electricity needs during regional coincident peak times.

The planning forecast is divided notionally into four time horizons: present day, near, medium, and long term. The near term (one to five years) has the highest degree of certainty; any near-term needs are typically met using regional transmission or distribution solutions. Other methods (i.e., conservation and demand management (CDM) or DG) are considered in the near- to mid-term (six to 10 years), since lead times to develop and incorporate these options depend on the size of the need.

The long-term forecast covers the 10- to 20-year period and has the lowest degree of certainty. It is used to identify potential longer-term needs, and for the consideration and development of integrated solutions, including CDM, DG, and major transmission upgrades. Early identification of potential needs and possible solutions enables engagement with the local community and all levels of government long before the need is triggered, maximizes opportunities for input to inform decision-making, and helps ensure local planning can account for new infrastructure.

[8] A dual-element spot network, or DESN, refers to a standard station layout used throughout the province, where two supply transformers are configured in parallel to supply one or two low-voltage switchgear which the distributor uses to supply load customers. This paralleled dual supply ensures a standard level of reliability where one supply transformer can be lost due to an outage or planned maintenance but supply to the customer can be maintained. A single local transformer station can have one, two, or more individual DESNs.

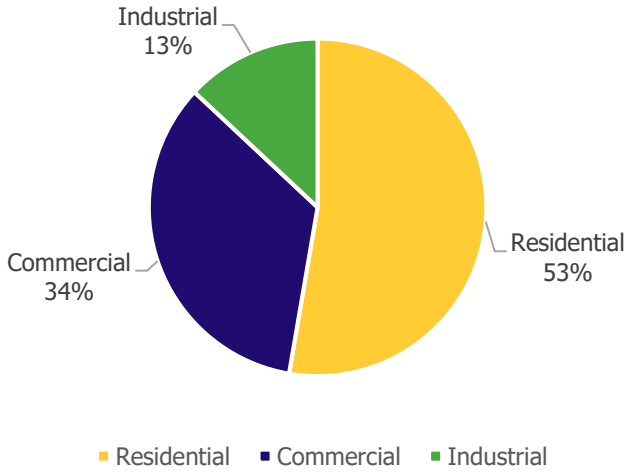
To address the long-term uncertainty in the electricity demand outlook, the robustness of the existing system was assessed to determine the capability of the existing system and its ability to supply customers, given possible outages and system states (e.g., contingencies).

Additional details on the demand outlook assumptions can be found in Appendix A - Methodology and Assumptions for Demand Forecast. The demand outlook was used to assess any growth-related electricity needs in the region.

5.2 Historical Electricity Demand

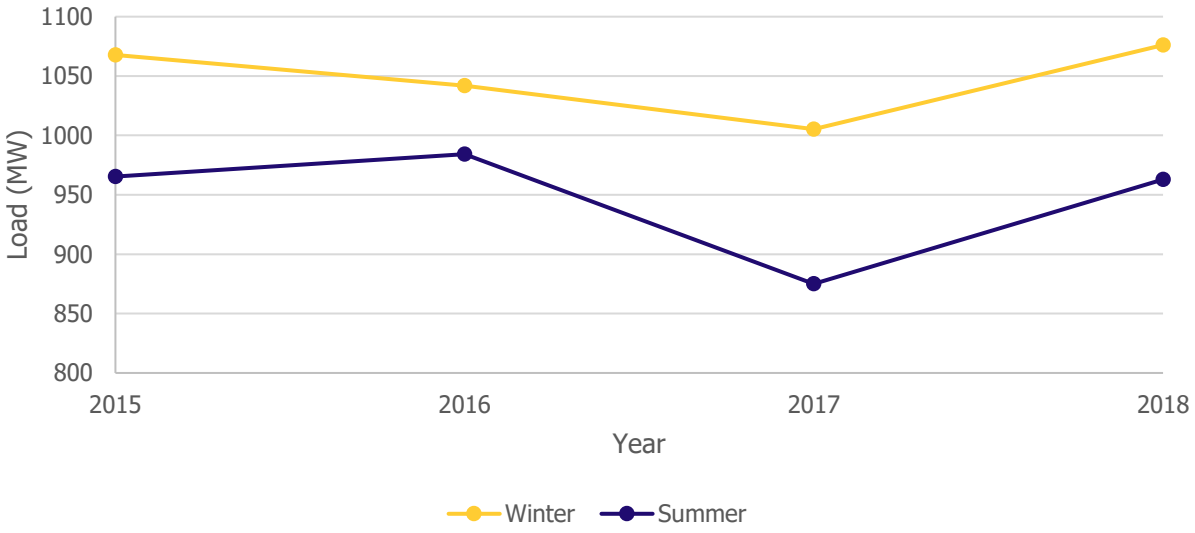
The Peterborough to Kingston region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to large business parks. As seen in Figure 5-1, the region's residential sector is the largest consumer of electricity accounting for approximately 50% of the peak load. The commercial and industrial sectors also have impactful contributions to the region's peak load, accounting for approximately 35% and 15% respectively. Peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of extreme temperatures. In addition to weather, factors affecting commercial and industrial energy demand, such as increased economic activity, improvements in energy efficiency, and on-site generation development have impacts on the regional peak.

Figure 5-1 | Regional Sector Segmentation Data (Winter)



The regional historical loading data from 2015 to 2018 shows that the electricity system in the region has typically been winter-peaking. As shown in Figure 5-2, the coincident net peak demand in the region has been around 950 MW and 1050 MW in the summer and winter respectively. Upon review of the data, the Working Group determined that 2018 loading data would prove to be the most effective base year to use for the purposes of developing the planning load forecast. The regional peak in 2018 was approximately 1080 MW in the winter and 960 MW in the summer.

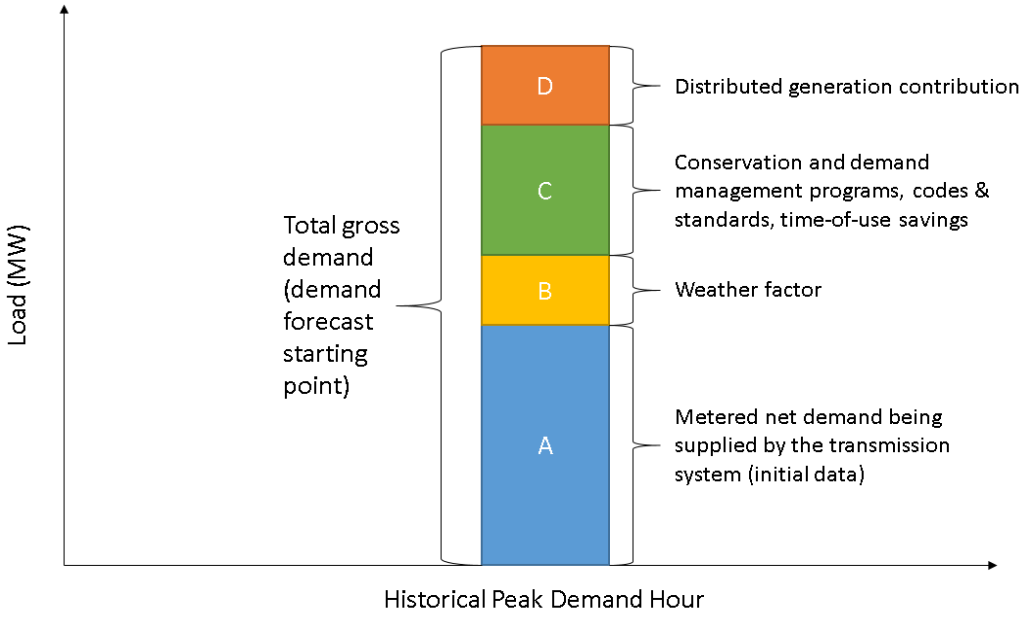
Figure 5-2 | Historical Net Peak Demand in the Peterborough to Kingston Region



5.3 Gross Demand Forecast Starting Point

To develop a forecast starting point, a net metered load data was obtained for all LDCs at each station within the region for both the summer and winter peak hours of 2018. The historical metered data is not a satisfactory representation of the true demand in the region as it does not account for the impacts of DG, CDM, and the effects of weather during a particular year. In order to account for the aforementioned factors, through a procedure known as the "unbundling" process, the Working Group established a new starting point to reflect the actual gross demand under median weather conditions. Having a gross demand starting point allows the LDCs to forecast growth from a starting point which represents the actual demand in the region, as opposed to simultaneously forecasting net load growth, DG, and CDM savings. This approach is summarized in Figure 5-3. Note that for the Peterborough to Kingston region, unbundling gross load was achieved to the extent for which the necessary data was available. For a more detailed look at the weather correction methodology see Appendix A.1 - Method for Accounting for Weather Impact on Demand.

Figure 5-3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the Peterborough to Kingston Region



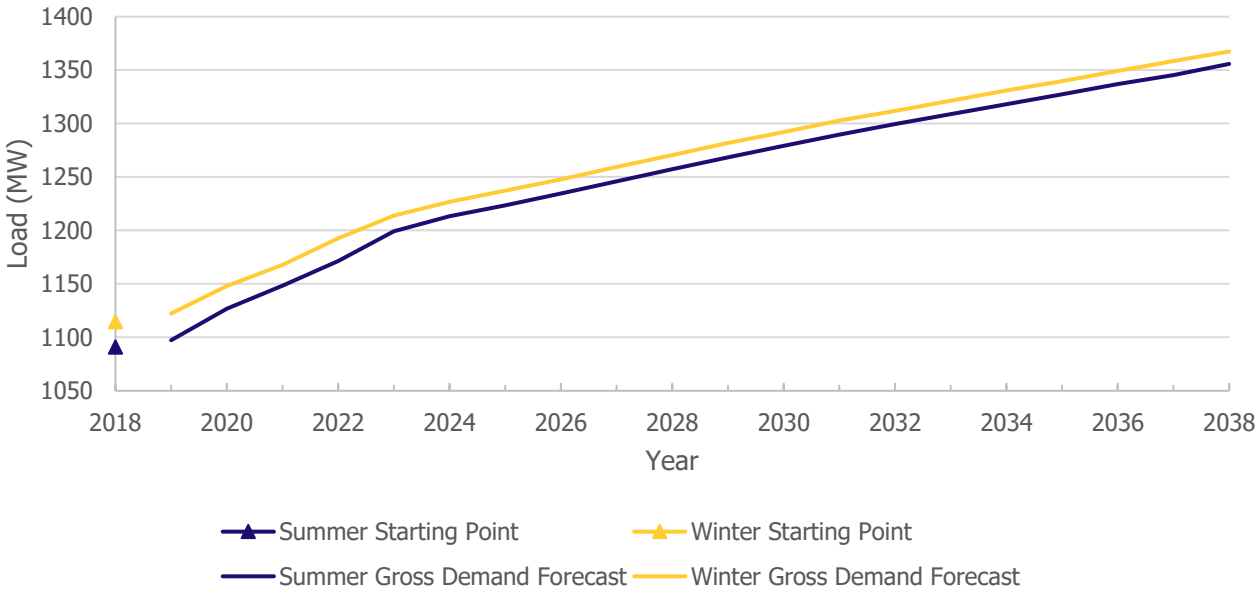
5.4 Gross Demand Forecast

Utilizing the established gross demand, median weather starting points, the LDCs provided 20-year forecasts at a station level. LDCs are tasked with the development of their own gross load forecasts at each station. This is due to the fact that LDCs have strong insights into customer and regional growth expectations over the planning horizon due to their direct relationship with customers. This insight includes known connection applications and knowledge regarding typical electrical demand for various types of customer groups.

The LDC forecasts account for increases in demand due to various factors such as new or intensified development, economic growth, population growth, changes in consumer behaviour, etc. It is noted that the gross demand forecast that was developed did not account for future DG or new conservation measures, such as codes and standards and demand response programs. These components were accounted for in later portions of the demand forecasting process as described in section 5.1. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. For a more detailed look into each LDCs forecast methodology see Appendix A - Methodology and Assumptions for Demand Forecast.

Both the summer and winter median weather, gross demand forecasts are depicted in Figure 5-4.

Figure 5-4 | Coincident, Median Weather, Gross Demand Forecasts



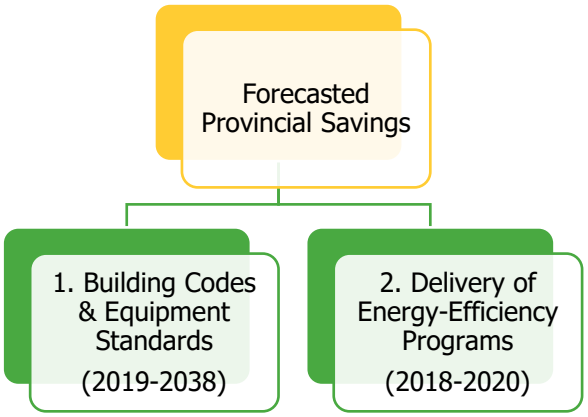
5.5 Contribution of Conservation to the Forecast

Conservation and Demand Management (CDM) is a clean and cost effective resource for helping to meet Ontario's electricity needs and has played an integral part in ensuring the development of a reliable and sustainable electricity system through provincial and regional planning. CDM is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's demand growth, and helping to ensure it does not exceed equipment capability.

Future CDM savings for the Peterborough to Kingston region have been projected out over the course of the 20-year planning horizon to take into account both policy-driven conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

To estimate the peak-demand impact of existing and committed CDM savings in the region, the forecast for provincial savings were divided into two main categories, as shown in Figure 5-5.

Figure 5-5 | Categories of Conservation & Demand Management Savings



For the Peterborough to Kingston region, the IESO worked with the LDCs to identify the breakdown of load per customer sector on a station level. The breakdown of load was divided into three categories: residential, commercial and industrial. This provided higher resolution when forecasting energy efficiency, as energy efficiency potential estimates vary by sector due to differing energy consumption characteristics and applicable measures.

The estimated impact of existing or committed CDM programs and codes and standards for the Peterborough to Kingston region have been applied to the gross demand extreme weather forecast, along with DG (as described in Section 5.7), to determine the net peak demand for the region. Additional details are provided in Appendix A - Methodology and Assumptions for Demand Forecast.

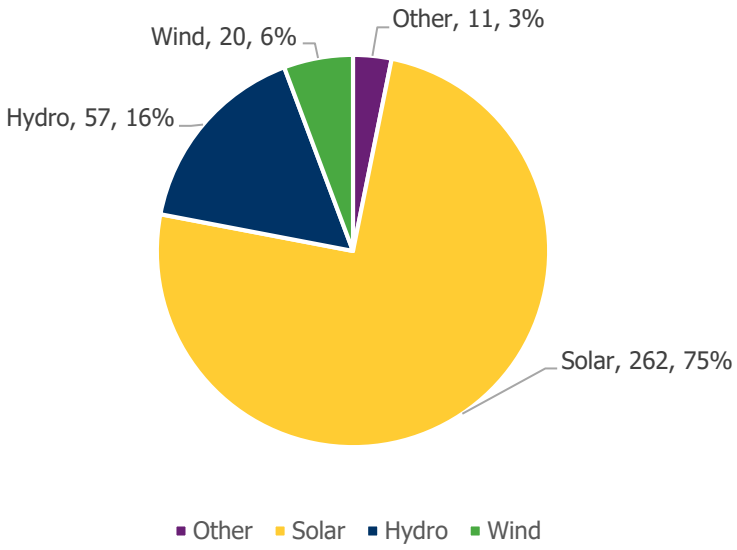
Table 5-1 | Reduction to Summer Demand Forecast due to Conservation

Year	2020	2022	2024	2026	2028	2030	2032	2034	2036	2038
Savings (MW)	15	35	61	74	80	82	80	75	72	72

5.6 Contribution of Distributed Generation to the Forecast

The IESO has contracts with several distributed generators in the Peterborough to Kingston region. For the purposes of the planning demand forecast only IESO contracted DG and significant behind the meter resources noted by the LDCs have been included when accounting for the DG resources in the region. A breakdown by fuel type of distributed generation resources in the region for the year 2019 is shown in Figure 5-6.

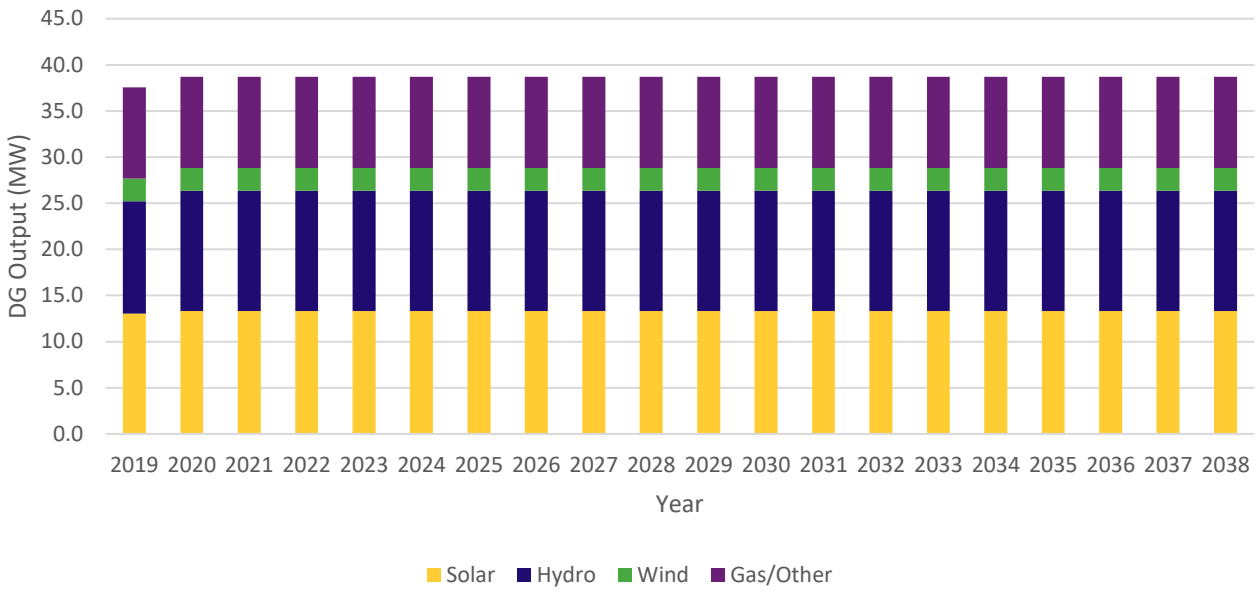
Figure 5-6 | Installed DG Capacity (MW,%) in the Peterborough to Kingston Region (2019) by Resource Type



The resources that were included in the DG forecast were comprised of a mix of solar, wind, hydroelectric and other (biogas, landfill gas and natural gas) projects. The majority of distributed generation in the region consists of solar resources (75% of total contracted installed DG capacity in 2019). Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output. Figure 5-7 shows the contribution of DG output at the time of region's peak in the Peterborough to Kingston region by Resource Type.

Various DG contracts that have been administered by the IESO are set to expire during the 20-year planning horizon with the majority of those that will expire coming off contract in the final five years of the forecast period. For the purposes of the planning demand forecast, the Working Group decided to assume that contracts coming to the end of their terms will be reacquired by the IESO. Thus, the planning demand forecast assumed that all contracts will persist throughout the planning horizon. However, it was also deemed beneficial to create a sensitivity forecast scenario to explore how the needs identified through the technical study would evolve if all contracts did truly expire and behind the meter generation was not accounted for in the planning forecast. The sensitivity forecast is outlined in section 5.9.

Figure 5-7 | Contribution of DG output at the time of region's peak in the Peterborough to Kingston Region by Resource Type



5.7 Planning Demand Forecast

The final planning demand forecast was used to carry out system studies, and was the primary input for identifying potential needs. It was prepared by first taking the gross median weather demand forecasts prepared by LDCs and adjusting them to account for the expected impact of extreme weather conditions (as described in section 5.5), thereby increasing demand. Furthermore, the impacts of CDM savings and DG were added (as described in the sections 5.6 and 5.7), which resulted in reducing the demand. The outcome of these steps results in the final planning demand forecast, which is an extreme weather net demand forecast. For a more detailed look into each LDCs forecast methodology see Appendix A - Methodology and Assumptions for Demand Forecast.

Figure 5-8 and Figure 5-9 shows the summer and winter planning demand forecast, aggregated for the entire Peterborough to Kingston region. For comparison, the figure also shows the net metered historical peaks from 2015-2018, the 2018 median weather corrected starting point, the gross median weather forecast and the gross extreme weather forecast.

Figure 5-8 | Summer, Extreme Weather, Net Demand Forecast

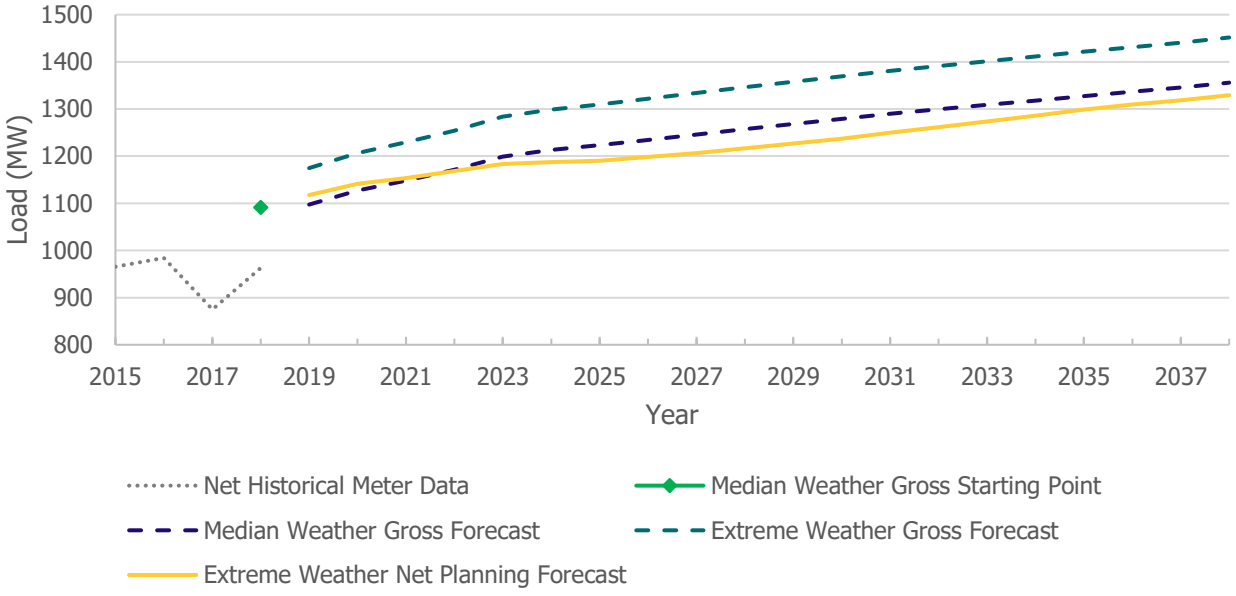
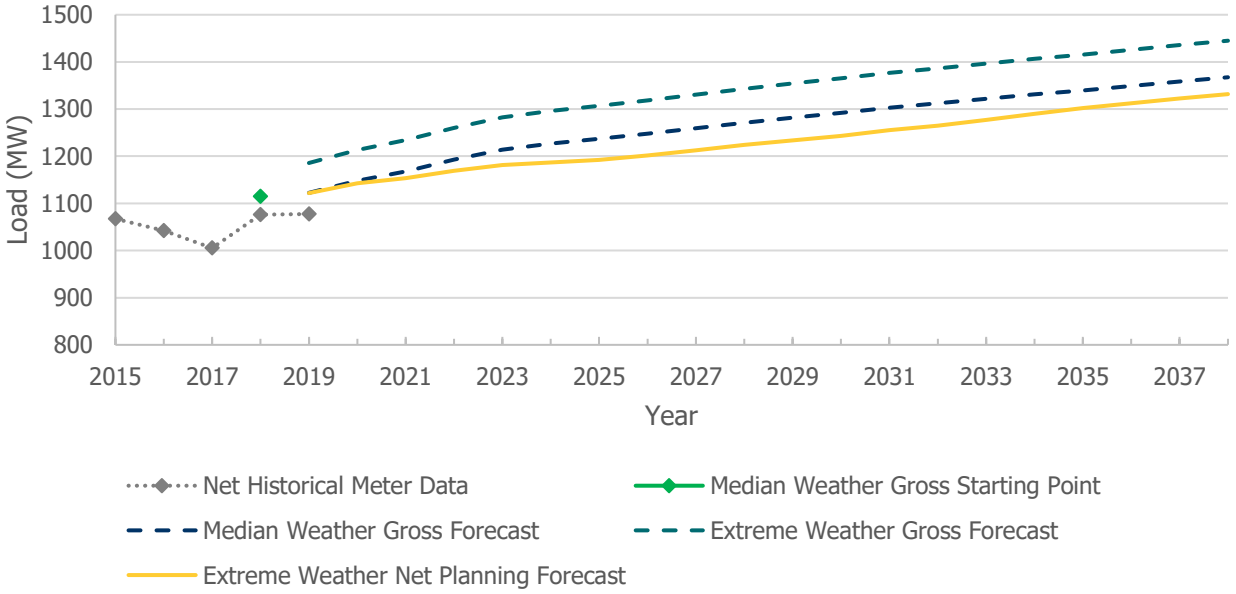


Figure 5-9 | Winter, Extreme Weather, Net Demand Forecast

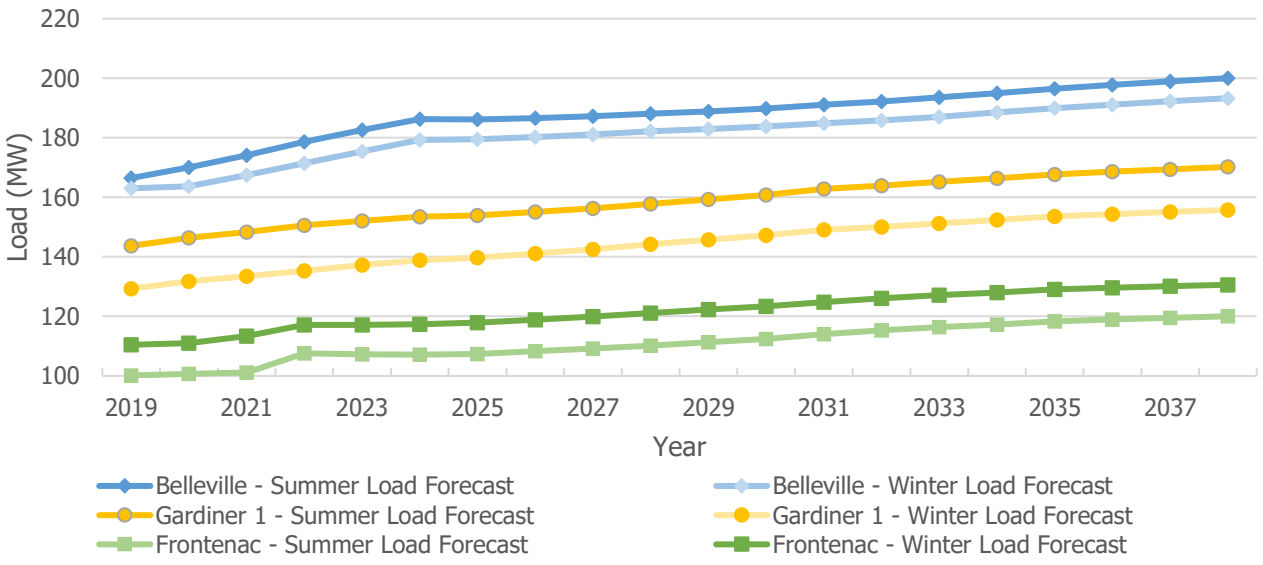


5.8 Non-Coincident Station Forecasts

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum, also called the coincident peak demand. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether the stations' peaks occur at different times. Apart from assessing the adequacy of the electrical grid, the adequacy of each station is assessed as part of the regional planning process. For this assessment, non-coincident forecasts is created, as shown in Figure 5-10. If a station's non-coincident forecast loading exceeds the capability of each transformer at the station, this is indication of a station capacity need.

The Scoping Assessment completed prior to the start of the IRRP had identified three stations which were likely to have station capacity needs over the course of the planning horizon; Belleville TS, Frontenac TS and Gardiner TS DESN #1. A further screening was completed by the Working Group during the IRRP to establish these needs.

Figure 5-10 | Summer and Winter Non-coincident Station level Planning Demand Forecast



5.9 Sensitivity Scenario: Retirement of Distributed Generation Resources

The development of the planning demand forecast assumed that contracts coming to the end of their terms will be reacquired by the IESO. The Working Group identified the need to look at the other bookend scenario; i.e., creating a sensitivity forecast which assumes that all DG resources are taken out of service following the expiry of their contracts. This scenario also assumed that non-IESO contracted behind the meter generators, accounted for by LDCs in the planning forecast, would not contribute towards reducing the gross demand forecast. This was due to the fact that there was little to no certainty with regards to the operation of these resources during times of regional peak.

With the assumption that expired contracts will retire, it was determined that it will not have a significant impact to region's demand as the DG contribution at the time of region's peak is approximately 40 MW as shown in Figure 5-7.

5.10 Sensitivity Scenario: High Growth Forecasts

The Working Group, in consultation with key customers, developed a high demand scenario. While the scenario developed is most impacted by the incorporation of potential impacts of electrification in the Kingston area (identified through stakeholder feedback), the rest of the region was also reviewed by the applicable LDCs to capture any relevant long-terms growth plans or any currently foreseeable electrification impacts for their areas.

The City of Kingston had many stakeholders who were able to provide input into high growth forecast scenarios. This included projects ranging from electric vehicle charging infrastructure to electrified space heating installations. High growth forecasts for the City of Kingston thus added considerable load to the reference forecast.

Two high growth scenarios were developed, with high growth scenario 1 representing a more moderate impact from electric heating than high growth scenario 2. To develop the high growth scenario 2 winter demand scenario, the rated output of existing natural gas heating appliances (BTUh) was converted to the equivalent electric resistive heating demand (kW). For the high growth scenario 1 winter demand scenario the electric resistive heating demand of high growth scenario 2 was converted to an equivalent electric heat pump demand. Since the differentiating factor between high growth scenario 1 and 2 was the assumption on the efficiency of conversion to electric space heating, only one high growth scenario (scenario 1) was developed for summer demand. Further details of the input to both forecast scenarios are presented in Appendix A.

Stakeholders serviced from Belleville TS were not able to provide detailed load growth information pertaining to electrification projects. As such, industry reports and data pertaining to electric vehicle demand as well as city growth statistics were used to create a high growth forecast resulting in an increase of another 3 MW by the year 2038. Further details on the high growth scenario for Belleville TS can also be found in Appendix A.

Table 5-2 | Different Forecast Scenarios - Summer

Summer Load Forecast	2020	2030	2038
Belleville - Reference Forecast	170	190	200
Belleville - High Growth Forecast	170	191	203
Kingston - Reference Forecast	247	273	290
Kingston - High Growth 1 Forecast	247	297	332

Table 5-3 | Different Forecast Scenarios - Winter

Winter Load Forecast	2020	2030	2038
Belleville - Reference Forecast	164	184	193
Belleville - High Growth Forecast	164	185	196
Kingston - Reference Forecast	243	270	287
Kingston - High Growth 1 Forecast	243	296	329
Kingston - High Growth 2 Forecast	243	347	415

5.11 Load Profiling

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20 year forecast horizon) for certain stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. As described in section 7.1, these profiles are used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; the intent in this application is not to deterministically specify the precise hourly energy requirements. Further, the purpose of this data is to enable the selection of suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of plan implementation.

6 Power System Needs

Based on the demand outlook, system capability, application of provincial planning criteria, and the transmitter's identified end-of-life asset replacement needs, the Peterborough to Kingston IRRP Working Group determined electricity needs in the near, medium, and long term. This section describes end-of-life, capacity, and reliability needs in the Peterborough to Kingston region.

6.1 Needs Assessment Methodology

Based on the application of ORTAC[9] and North American Electric Reliability Corporation (NERC) TPL 001-4 Standard[10], the Working Group identified electricity needs local or regional reliability requirements for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Replacement Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

[9] https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[10] https://www.nerc.com/files/TPL-001-4.pdf

- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC. No load security and restoration needs were identified as part of this IRRP.

6.2 Near/Medium-Term Needs

Station Capacity Needs

Station capacity needs have been identified for Belleville TS, Frontenac TS and Gardiner TS DESN #1 in the near or medium term. The following sections describe these capacity needs, along with the sensitivity of the need date to high growth forecasts (as described in section 5.10).

Belleville TS Station Capacity Need

Belleville TS consists of one DESN connected to the 230 kV system. The station has a summer capacity of 130 to 161 MW[11], depending on the load composition when transmission circuit H23B and the companion transformer are both lost. Currently, the station has reached the capability of the existing station transformers, be it 130 MW or 161 MW. Furthermore, the station's load is similar in summer and winter seasons, however, the transformer's summer ratings are lower than winter.

While the Belleville TS transformers are currently undergoing an end-of-life replacement, targeted in-service 2022, this refurbishment is not expected to result in a material improvement to the station's capacity. Based on historical and forecast demand, there is a capacity need at Belleville TS today.

Another 30 MW of load is forecast to connect to Belleville TS over the next 20 years. Figure 6-1 and Figure 6-2 show the various non-coincident forecast scenarios that were developed for Belleville TS for the summer and winter, respectively, along with the current capacity of the station. If a high growth scenario materializes, this capacity need would worsen.

[11] The 130 MW is a voltage limitation, while the 161 MW is a thermal limitation, and which one becomes more limiting is subject to the load composition.

Figure 6-1 | Summer Non-Coincident Demand Forecast Scenarios for Belleville TS

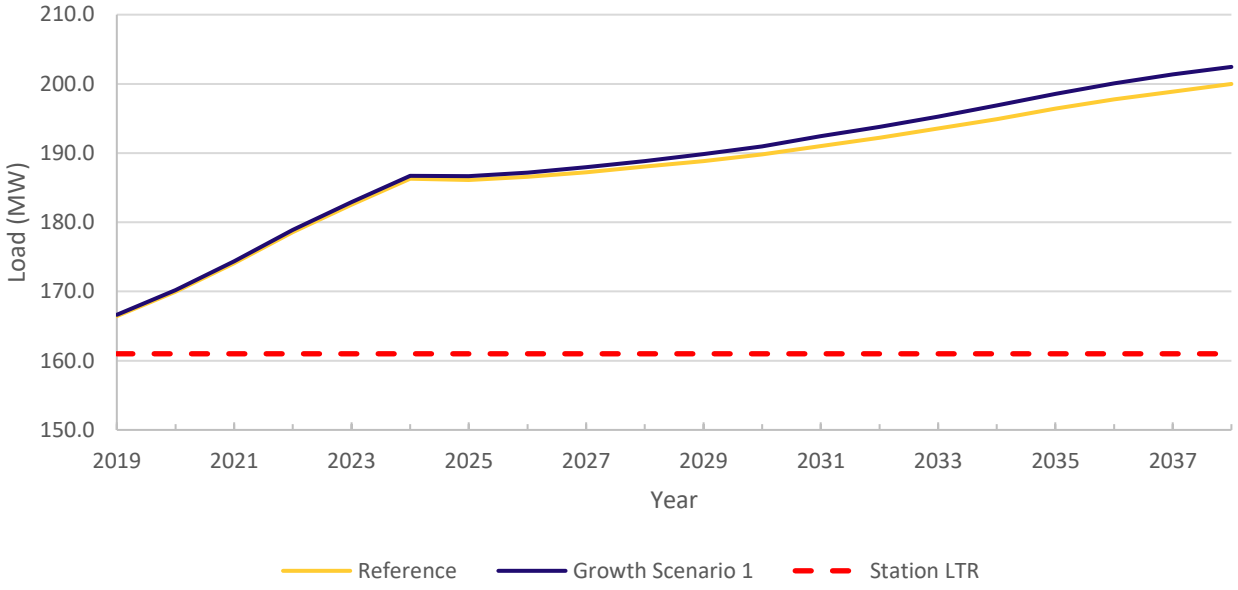
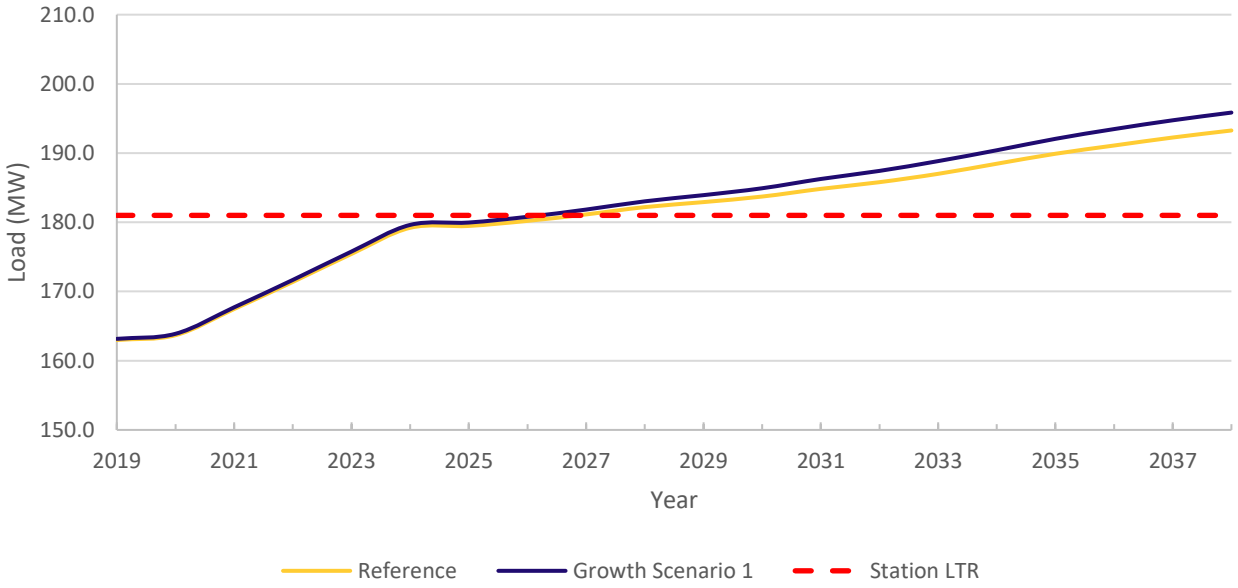


Figure 6-2 | Winter Non-Coincident Demand Forecast Scenarios for Belleville TS



Station Capacity Needs in the Kingston area

The City of Kingston is supplied by two station sites, Frontenac TS and Gardiner TS (which contains two DESNs, #1 and #2). These stations have overlapping service territories, and so, capacity needs in the region should be looked at holistically. There is significant growth forecast within the City of Kingston over the 20 year planning horizon, however, the magnitude varies considerably based on the forecast scenario considered – reference, high growth 1, and high growth 2. As can be expected, the station capacity needs can arise earlier under the high growth scenarios than for the reference forecast. The next two sections provide further details on the Frontenac TS and Gardiner TS station capacity needs.

Frontenac TS Station Capacity Need

The Kingston area distribution system is divided into two territories supplied by two different LDCs. The central area that contains the Kingston downtown core is supplied by Utilities Kingston while the remaining area to the west of Kingston's downtown core, as well as area the developments east of the Cataraqui River, are supplied by Hydro One (Distribution).

While the load growth is distributed throughout the area, the system is electrically supplied from two separate paths:

(1) Frontenac TS is supplied from the 115 kV circuits B5QK and Q3K; and
(2) Gardiners TS DESN #1 and #2 are supplied from the 230 kV circuits X2H and X4H.

The forecast load for Frontenac TS and Gardiner TS DESN #1 are both expected to exceed the stations' respective LTR in the near to mid term. The configuration of the distribution system in Kingston is such that there are frequent load transfers between Frontenac and Gardiner TS DESN #1 via 44 kV feeder ties which allow for added reliability during planned and emergency work. This flexibility will become more rigid if either Frontenac TS or Gardiner TS DESN #1 are loaded to their maximum capability. As a result, the reliability benefits of timely load restoration, the operational benefits for outage planning, and the identified capacity needs have to be balanced when planning an adequate system for the long term.

Throughout the planning process it became evident that the potential for rapid load growth is a risk for the area as a whole. High growth scenarios were developed which include the impact of future electrification programs such as electrification of fleet vehicles, thermal heat pumps, and fuel switching incentives. These high growth scenarios advance and amplify the two major capacity needs in the area.

Frontenac TS is supplied by two transformers with a total summer capacity of 111 MW. Figure 6-3 and Figure 6-4 show the various non-coincident demand forecast growth scenarios developed for Frontenac TS for the summer and winter seasons, respectively. The station's capacity (LTR) is included in the figure to identify the need. The figures illustrate the area is anticipated to exceed the current capacity by between 10 to 110 MW by 2038, depending on the forecast scenario. The station capacity need is anticipated to materialize as late as 2029 or as early as 2022, depending on the forecast scenario.

Figure 6-3 | Summer Non-Coincident Demand Forecast Scenarios for Frontenac TS

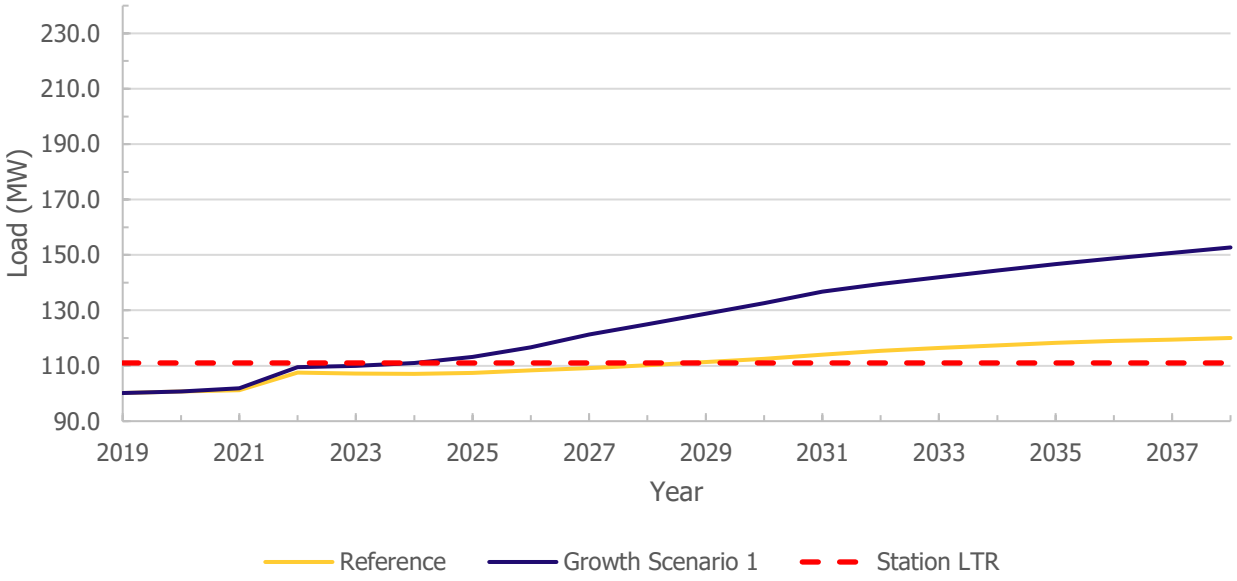
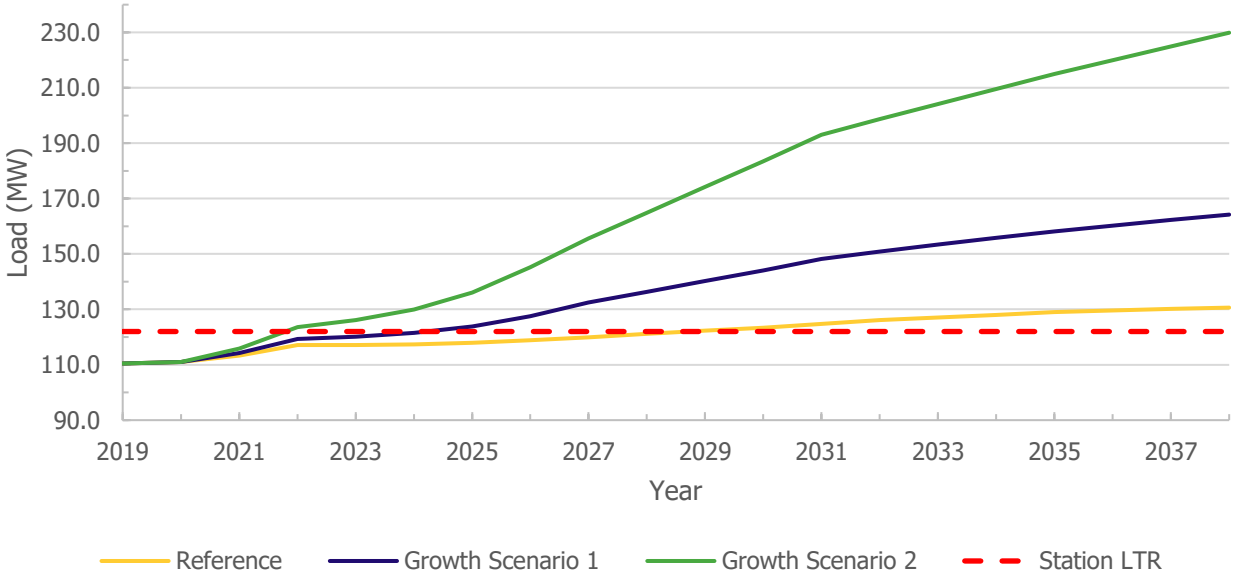


Figure 6-4 | Winter Non-Coincident Demand Forecast Scenarios for Frontenac TS



Gardiner TS (DESN #1) Station Capacity Need

A local capacity need was identified at the Gardiner TS DESN #1 within the Peterborough to Kingston region. Gardiner TS currently consists of two DESNs connected to the 230 kV system. The T1/T2 DESN (#1) has a summer capacity of 125 MW, while the T3/T4 DESN (#2) has a summer capacity of 85 MW. Gardiner TS DESN #2 is the newer of the two DESNs and has ample station capacity, while Gardiner TS DESN #1 has reached its capacity. Another 25 to 50 MW of load growth is forecast for Gardiner TS DESN #1, depending on the forecast scenario. Figure 6-5 and Figure 6-6 show the various forecast scenarios developed for Gardiner TS DESN #1 for the summer and winter, respectively. The station's capacity (LTR) is included in the figure to identify the need. It is also to be noted that Hydro One Transmission has identified that Gardiner TS DESN #1 is approaching end-of-life.

The figures illustrate that Gardiner TS DESN #1 has a summer capacity need today, and the magnitude of need increases for the high growth scenarios.

Figure 6-5 | Summer Non-Coincident Demand Forecast Scenarios for Gardiner TS DESN#1

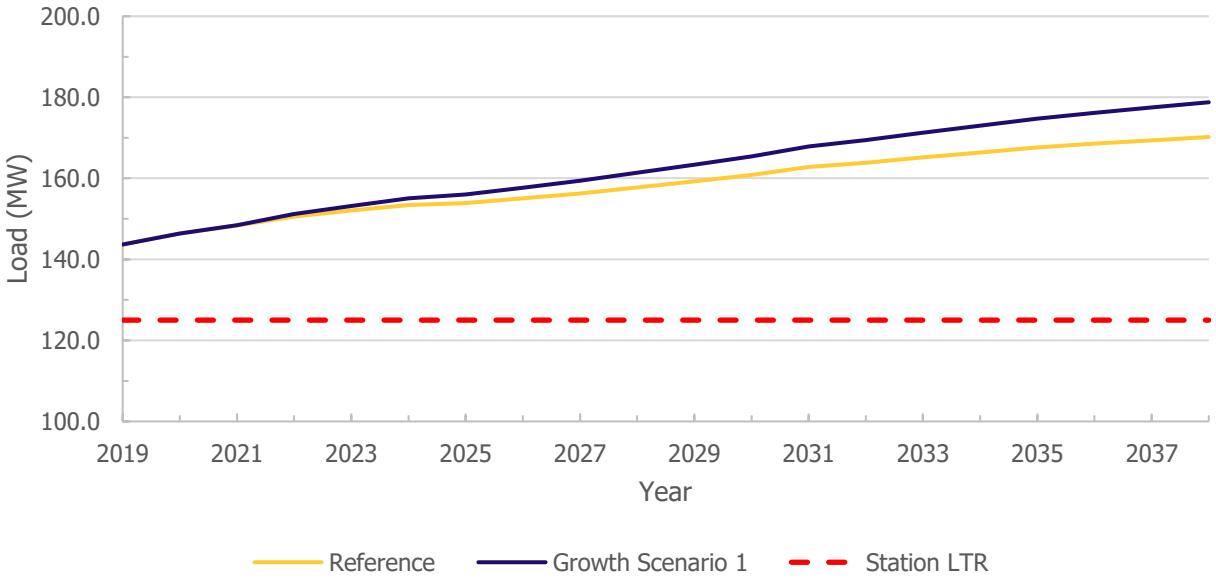
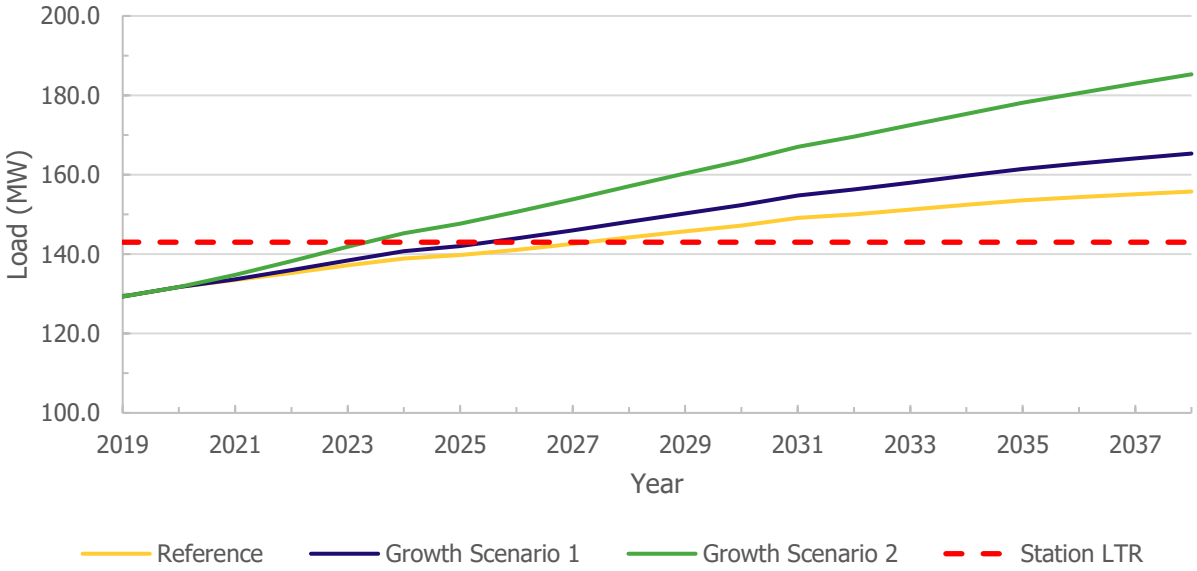


Figure 6-6 | Winter Non-Coincident Demand Forecast Scenarios for Gardiner TS DESN#1



Supply Capacity Needs

The Peterborough to Kingston region's electricity demand growth affects the 230 kV transmission supply capability to serve the 115 kV local area. While load growth is distributed throughout the area, two bulk supply capacity needs were observed, these are:

1. Supply lines affecting Peterborough to Quinte West load

2. Cataraqui autotransformer capability to support Frontenac and other 115 kV loads

These two bulk supply needs observed are described next. The impact of DG retirement is negligible as the region's demand increases slightly – ~40 MW.

Peterborough to Quinte West Supply Capacity needs

The load growth in the Peterborough to Quinte West sub-system is expected to introduce supply capacity needs in the area. There are 230 kV and 115 kV supply lines that serve load in that pocket. Specifically, P15C, a 230 kV single circuit from Cherrywood TS to Dobbin TS, and Q6S, a 115 kV single circuit supplying Sidney TS from Cataraqui TS, are two critical circuits supplying this load pocket. The limitation on these two circuits dictates a Load Meeting Capability (LMC) of 270 MW for the sub-system, shown on Figure 6-8. As shown in this figure, the sub-system load is expected to increase by approximately 60 MW over the 20-year planning horizon.

This need is being coordinated with bulk planning system study activities in the area to ensure impacts from the broader system are considered when reviewing and resolving this need.

Figure 6-7 | Critical Supply to Dobbin by Sidney (P15C and Q6S)

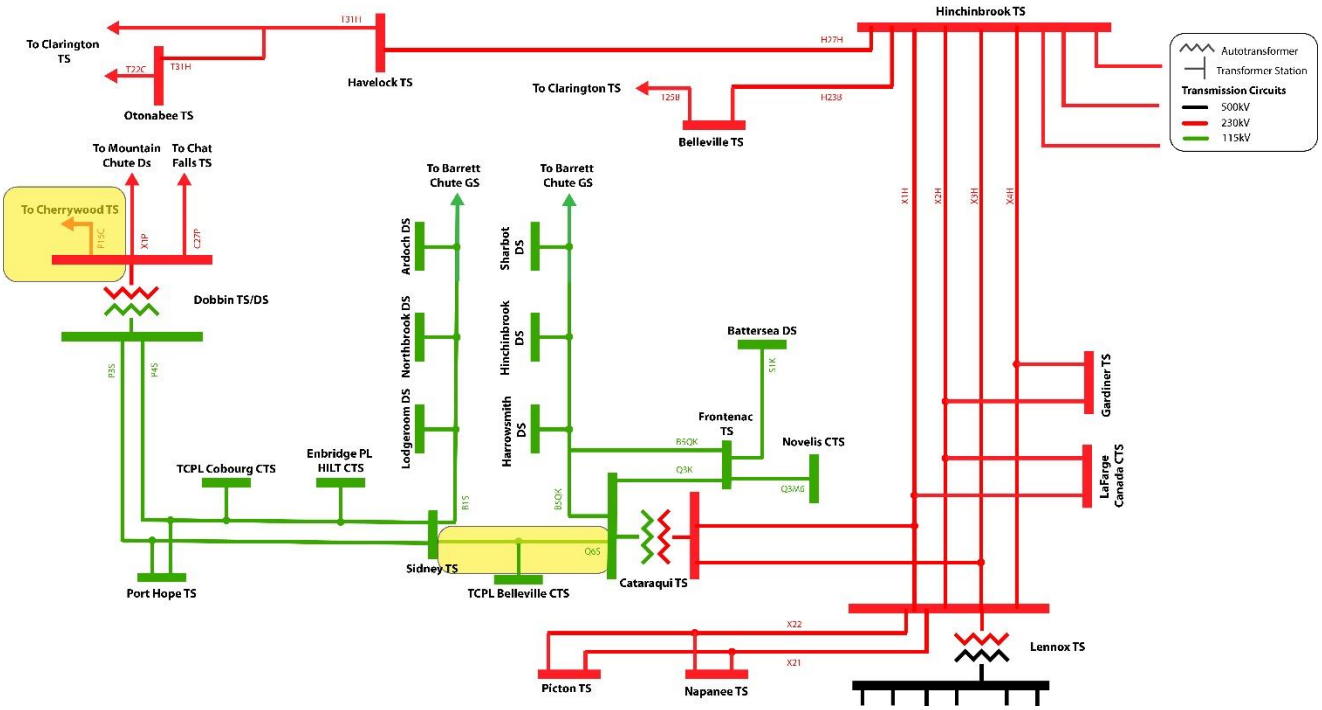
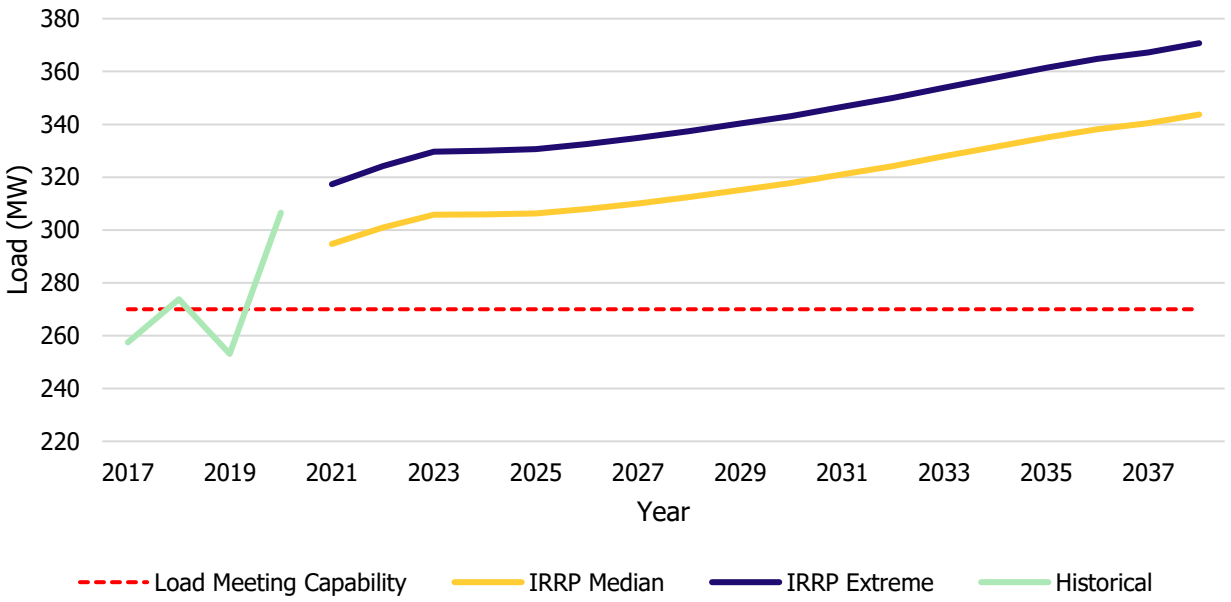


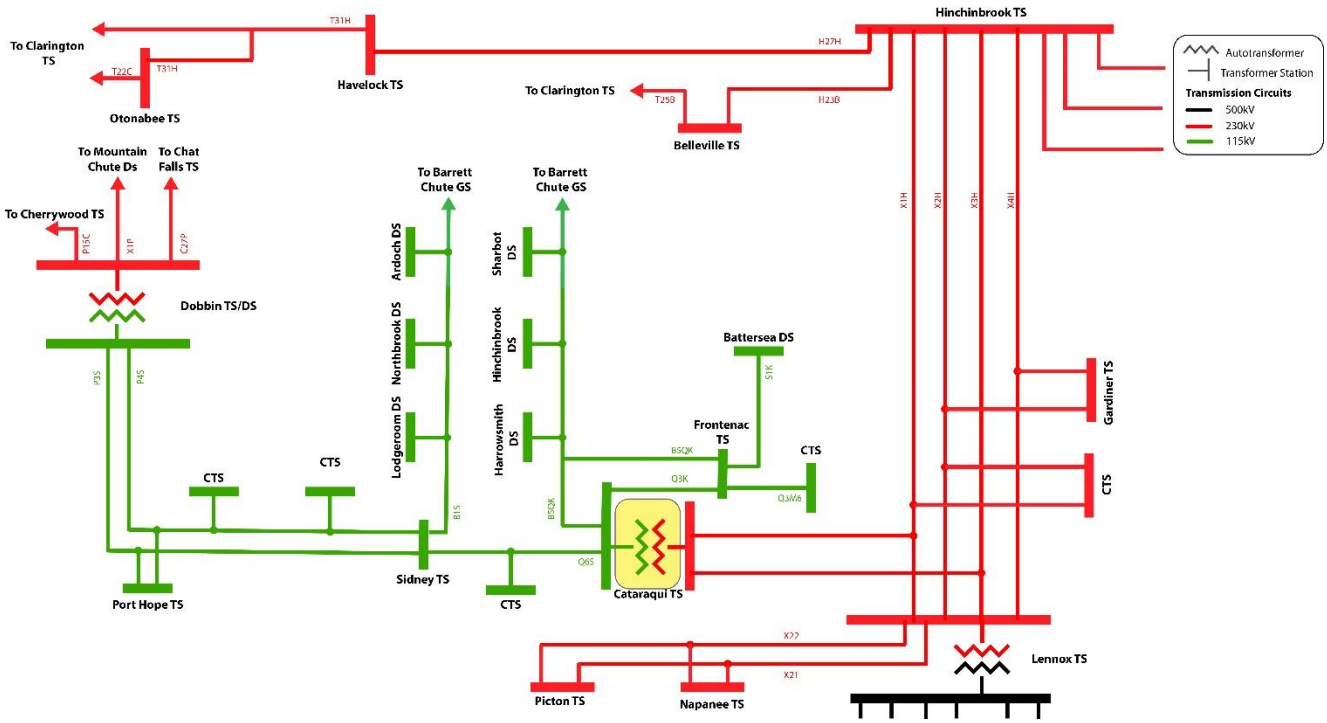
Figure 6-8 | Peterborough to Quinte West Forecast and LMC



Cataraqui Autotransformers Supply Capacity Need

The load growth at Frontenac TS and other 115 kV supply stations is expected to result in a supply capacity need at Cataraqui TS in 2023. The load is expected to continue to increase over the 20-year planning horizon.

Figure 6-9 | Cataraqui Autotransformers



End-of-Life Refurbishment Needs

The transmitter identified some end-of-life asset replacement needs for the Peterborough to Kingston region, with several needs arising in the near to medium term. These consisted of station transformer replacement needs. Based on the outcomes of the Needs Assessment and the Scoping Assessment, only one end-of-life need was identified as requiring further coordinated planning in the IRRP. Port Hope TS T3/T4 transformer replacement, currently expected to be needed in 2025 based on the latest asset condition information, was included in the IRRP. The end-of-life needs are based on the best available asset condition information at the time of each stage of the planning cycle, timing of asset needs can change as new information becomes available.

Summary of Near/Medium-Term Needs

	Needs	Location	Need Date[12]
1	Station Capacity	Belleville TS	Today
2	Station Capacity & End-of-Life Refurbishment	Gardiner TS DESN #1	Today
3	Supply Capacity	Peterborough to Quinte West	Today
4	Supply Capacity	Cataraqui Autos	2023
5	End-of-Life Refurbishment	Port Hope TS	2025
6	Station Capacity	Frontenac TS	2029

6.3 Long-Term Needs

Supply Capacity Needs

The long-term load growth for the Peterborough to Kingston region results in supply capacity needs on the 115 kV system. While load growth is distributed throughout the area, the sub-system is electrically supplied from two separate paths:

1. 115 kV circuits supplying the Port Hope, Sidney, Lodgeroom DS area
2. B5QK circuit supplying the Frontenac TS area.

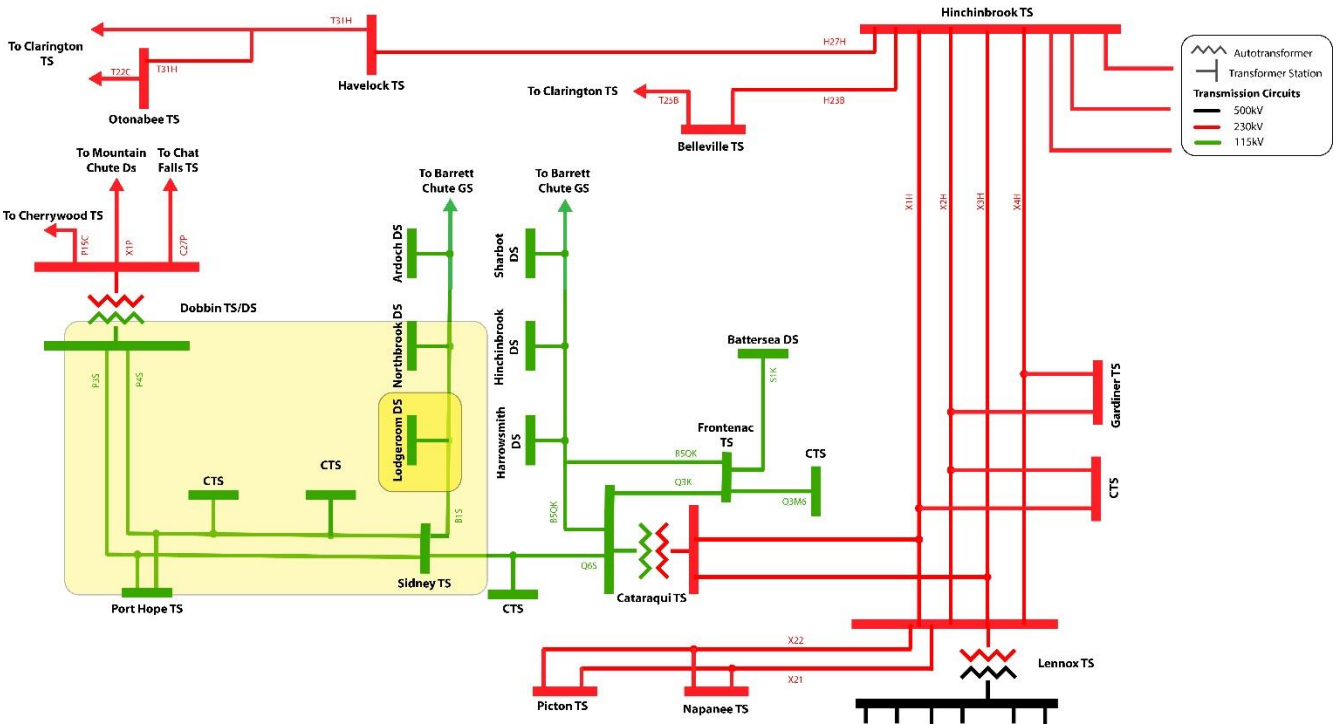
The local supply needs observed are described next. The impact of DG retirement is negligible as the region's demand increases slightly ~40 MW.

[12] Based on reference forecast. Impact of high growth is discussed within the relevant section.

Peterborough to Quinte West Voltage Need

The load on the 115 kV system is expected to grow by 60 MW over the 20 year planning horizon. It is expected to introduce voltage criteria violations in the area. During a pre-existing outage on circuit C27P, the loss of circuit P15C will result in under-voltage violations starting in 2033 at Lodgeroom DS. These conditions worsen and appear at additional stations on the 115 kV system in later years as load continues to grow, as depicted in Figure 6-10.

Figure 6-10 | 115 kV Pocket Voltage Need



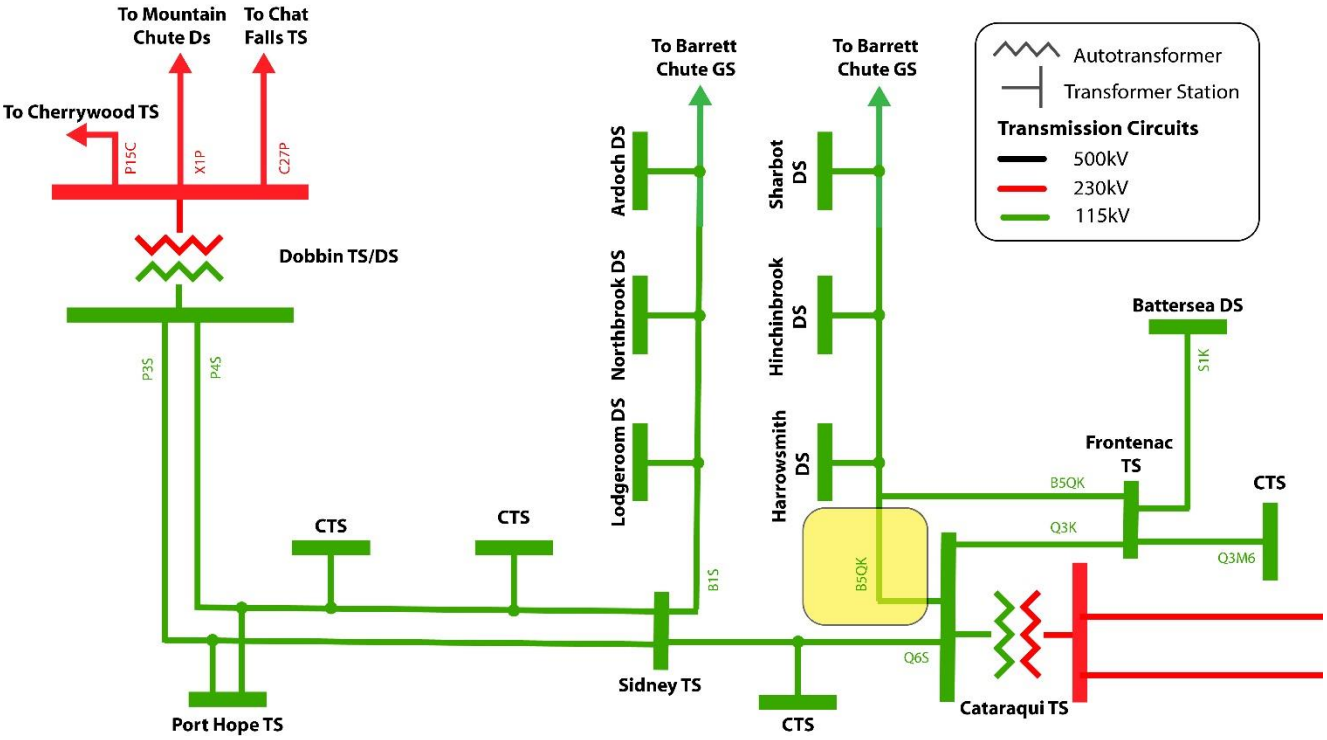
Kingston Transmission Supply Capacity Needs

The forecast load growth in Kingston, specifically at Frontenac TS, is expected to introduce supply capacity needs in the area. There are two upstream 115 kV supply lines serving Frontenac TS and one of them – B5QK[13] highlighted on Figure 6-11– is forecast to exceed its capacity in the long term as the load grows by 27 MW to 165 MW[14]. This limit isn't expected to be exceeded until the end of the planning horizon for the reference forecast, but a need can emerge as early as 2027 or 2025, for high growth scenarios 1 and 2, respectively.

[13] 1.1 KM section of B5QK from Cataraqui TS to the Railton JCT

[14] Battersea DS, Frontenac TS, Harrowsmith DS, Hinchinbrooke DS, Sharbot DS, and 1 CTS

Figure 6-11 | B5QK overloaded section



Summary of Long-Term Needs

	Needs	Location	Need Date[12]
1	Supply Capacity	Peterborough to Quinte West	2033
2	Supply Capacity	Kingston Area	2038

6.4 Needs Summary

The majority of the needs in the region are near- and medium-term station and supply capacity needs. Station capacity needs occur in the Belleville and Kingston areas and the supply capacity needs present on multiple portions of the 115 kV system in the region. The table below provides an overview of the needs considered in the development of options for the plan.

Table 6-1 | Summary of Needs

Area/Facility	Need	Description	Need Date[12]
Belleville TS	Station Capacity	An existing capacity need was identified for Belleville TS, limited by voltage issues for the loss of one transmission supply as well as transformer capacity.	Today
Gardiner TS	Station Capacity & End-of-Life Refurbishment	An existing transformer capacity need was identified for DESN #1 (T1/T2) as well as an End-of-Life refurbishment need	Today
Peterborough to Quinte West	Supply Capacity	The load meeting capability of the system is currently exceeded. The outcomes of the Gatineau Corridor End-of-Life Study are forecast to address this need.	Today
Cataraqui TS	Supply Capacity	The autotransformers at Cataraqui is currently forecast to be exceeded.	2023
Port Hope TS	End-of-life	The station transformers at Port Hope TS have been identified as reaching end-of-life in 2025 and requiring replacement.	2025
Frontenac TS	Station Capacity	The transformers at Frontenac TS are forecast to exceed their capability.	2029
Peterborough to Quinte West	Supply Capacity	The load meeting capability of the system is currently exceeded. The outcomes of the Gatineau Corridor End-of-Life Study are forecast to address this need.	2033
Kingston Area	Supply Capacity	The thermal capability of B5QK, which supplies Frontenac TS, is forecast to be exceeded.	2038

7 Plan Options and Recommendations

In developing the plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
2. Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as "non-wires" alternatives and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need.

Through this initial screening exercise, it was determined that non-wires alternatives should be assessed for the Frontenac TS capacity need.

7.1 Options for Meeting Near- to Medium-Term Needs

Options for Meeting Station Capacity Needs

Options for Meeting the Belleville TS Station Capacity Need

The options that were considered for Belleville included but were not limited to the following:

1. An addition of a third transformer and station bus at Belleville TS,
2. A new Dual Element Spot Network (DESN) transformer station at Belleville, or
3. Load Transfers

Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers were not explored further.

Each of the first two options are estimated to cost approximately $30-35 M. For a similar cost, option 2 provides more long-term capability and would also perform better under outage conditions.

The high-level cost estimates for wires options are provided by the transmitter, Hydro One. The intention of these high-level (or "planning") estimates are to enable comparison between options and are typically within an accuracy of +100%/-50%. The Regional Infrastructure Plan (RIP) following the IRRP will perform additional detailed analysis and refine these cost estimates before implementation work begins. The IESO will continue to participate in the Working Group during the RIP and revisit these recommendations if costs estimates differ significantly.

Installing a second DESN at Belleville TS will resolve the need until the end of the planning horizon (20 years). To fully utilize the additional capacity beyond the planning horizon, new supply lines into Belleville would be required. A reinforcement option considered beyond the 20 year planning horizon is to extend X21/X22 (radial lines to Picton/Napanee from Lennox) to Belleville. An initial network study was performed to assess the feasibility of this option and the results of the preliminary study showed that the new station's capacity can be fully utilized following this reinforcement. However, there might be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts.

Options to Meet the Kingston Area Station Capacity Needs

The Working Group has determined that the limitations of the existing supply to the area poses a risk to accommodating future load growth in the Kingston area. There is a risk that load will materialize sooner than expected as the Working Group is aware of several electrification initiatives on the horizon, identified by both the City and the LDCs for the area. There is also a risk that some of these initiatives may not take place or that they may not have as large an impact as forecast. In either scenario, there is a need for additional capacity at Gardiner TS DESN #1 and Frontenac TS.

Many options and combinations of options were explored by the Working Group and the most relevant ones will be described here.

- Non-wires alternatives: Simple Cycle Gas Turbine (SCGT) generator, Battery Storage
- Distribution load transfers - Permanent load transfers to a station with available capacity
- Increase capacity of the existing station(s) – through asset refurbishment and/or uprates
- A new station (new or existing site)

The capacity at Gardiner TS DESN #1 has already been exceeded today. However, Gardiner TS DESN #2 is adjacent to the station which allows for less complicated load transfers. It is important to note that Gardiner TS DESN #2 is a new transformer station, built in the last 15 years, and has capacity available on the order of 40 MW. The option of load transfers is usually the first avenue pursued as it is preferable to building additional transmission assets.

Hydro One Distribution has identified two load transfer options from Gardiner TS DESN #1 to Gardiner TS DESN #2, each transferring up to 11 MW of load. The first is relatively simple and low in cost while the second load transfer would require a new feeder position, increasing the relative cost.

Hydro One Transmission has identified a replacement plan for Gardiner TS DESN #1 as it is approaching end-of-life. The transformers will be replaced for a like to like replacement with new transformers however, the new transformer units will have a higher LTR and as such, will increase the capacity at the Gardiner TS DESN #1. The simpler 11 MW load transfer, paired with an uprate resulting from a "like-for-like" replacement of the station at Gardiner TS DESN #1, would completely address the reference forecast need over the 20-year planning horizon. With the second 11 MW load transfer the high growth forecast need can be met as well.

Turning to the need at Frontenac TS, the load transfer options available would be to transfer load from Frontenac TS to either Gardiner TS DESN #1 to Gardiner TS DESN #2. Currently, the distribution system in Kingston is operated in such a way that temporary load transfers between stations, ranging from 5 to 20 MW, are regularly utilized as a part of planned and emergency work. Performing a 10 MW load transfer to alleviate the need at Frontenac TS would compromise this flexibility and reduce the reliability of the system. Furthermore, net present value analysis suggests the load transfer would have to delay the need for a new transmission station by at least four years in order for this option to be economically favourable. Therefore, load transfer is an unfavorable option.

This IRRP maintains the long-term flexibility to respond to changes in demand for electricity in the future using cost-effective solutions, such as non-wires alternatives. In particular, smaller scale initiatives could have the potential to cost-effectively defer the need for a conventional solution (i.e. "wires" options), especially when paired with other measures such as energy efficiency. These cost-effective solutions can also be deployed to help delay or reduce large capital investments in transmission and distribution infrastructure. Value is created by delaying the date at which transmission and distribution equipment needs to be expanded, providing optionality. Timing permitting, optionality value allows more time to understand load growth and emerging trends prior to making significant infrastructure investments which reduces the risk of underutilized and/or stranded assets.

The Working Group also examined the feasibility of implementing non-wires resources to reduce the forecast demand in the area and defer the need for a new station or existing station expansion. These potential resources were considered both on an individual basis and as a package of solutions. Figure 7-1 shows that a capacity need exists at all times in the year 2038 at Frontenac station which means the solution will need to address a large scale need.

Figure 7-1 | Need Characterization Heat Map Frontenac 2038

9	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%
8	3%	5%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%
7	3%	5%	0%	0%	0%	0%	0%	3%	3%	0%	0%	0%
6	3%	10%	0%	0%	0%	0%	0%	3%	8%	0%	0%	0%
5	5%	10%	0%	0%	0%	0%	3%	3%	8%	0%	0%	5%
4	5%	10%	0%	0%	0%	0%	3%	3%	8%	0%	0%	8%
3	8%	13%	0%	0%	0%	0%	3%	3%	13%	0%	0%	10%
2	10%	15%	0%	0%	0%	0%	3%	3%	13%	0%	0%	15%
1	15%	23%	0%	0%	0%	0%	8%	5%	13%	0%	0%	18%
0	15%	25%	0%	0%	0%	0%	10%	5%	20%	0%	0%	25%
MNTH	1	2	3	4	5	6	7	8	9	10	11	12

The analysis for non-wires alternatives identified that an SCGT, battery storage, and energy efficiency as viable solutions for the reference scenario need at Frontenac station. In the year 2038, there is a 10 MW need at Frontenac station under reference forecast, and the station capacity need starts to arise in the year 2029.

Cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in this region are resources with performance and costs on par with SCGT generators, depending on the relative size of the capacity versus energy requirements. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation. In some cases, battery storage such as lithium nickel manganese cobalt oxide (NMC) batteries are also becoming competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other distributed energy resources, which are typically distribution-connected are also considered. The most cost-effective distributed options are typically a combination of smaller-scale storage and demand response. For each of the above options, the system capacity value is "credited" back to arrive at the net cost to meet local reliability needs. This is done to ensure a level playing field comparison between resources that provide capacity and wires options that address the local need but do not provide system capacity benefits.

Both the upfront and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs ($/kW-yr) over the lifespan of the asset in question for each option. The net present value (NPV) of these levelized costs are the primarily basis through which options are compared.

The costs to implement an SCGT (10 MW) is on the order of $20 M and would defer the need by 10 years, if implemented in 2029. A battery storage solution (10 MW) could defer the need by 10 years as well at an estimated cost of $7 M[15]. After which, a new station is needed. Further, results show that targeted incremental energy efficiency in the area could provide upwards of 15 MW of peak capacity savings by 2030. The costs mentioned here are inclusive of system benefits and present the net value and cost.

To evaluate the combination of these alternatives to delay larger investments, the Working Group considered costs, in terms of NPV. The outcome, in order of highest cost to lowest cost of the combinations are as follows: SCGT [2029] & Station [2038] ($42M), Station [2029] ($30M), Battery [2029] and Station [2038] ($28M). Non-wires solutions for the reference scenario may be useful in addressing the mid-term need and delaying the need for a station, however, barriers exist to both implementation and appropriate allocation of costs to ensure these solutions are cost effective for the local area.

The discussion above only applies to the reference scenario and if a higher growth scenario were to occur then the individual non-wires solutions would no longer be sufficient to meet the need. For the high growth scenarios, the SCGT option was screened out due to high costs. Two different approaches were considered for the high growth scenario in terms of battery solutions: the longest possible deferral of need and the maximised ratio between cost and time of deferral. The order according to cost, from highest to lowest, for combinations of options is: 26 MW Battery [2025] and Station [2032] ($50M), 10 MW Battery [2025] and Station [2027] ($43M), and Station [2025] ($35M).

The Working Group acknowledges that the deferment benefit that a non-wires alternative could provide is highly dependent on how load growth materializes. For the reference forecast, the non-wires alternatives are close in cost to the traditional wires option but if a high growth scenario materializes overall cost would then increase.

[15] After accounting for system benefit achieve by providing support to meet system adequacy/capacity needs

The Working Group next considered some high level review of how a new transformer station should be supplied. In the vicinity, there are two stations – Frontenac TS supplied from the 115 kV system and Gardiner TS supplied from the 230 kV. Frontenac TS is supplied by two 115 kV circuits on separate tower lines. Frontenac TS supplies the Central downtown Kingston area south of Highway 401 as well as the area north of Highway 401 and East of the Cataraqui River. Gardiner TS (DESN #1 & #2) is supplied by the 230 kV system via a double circuit tower line. Gardiner TS supplies the area east of Cataraqui River as well as the area north of Highway 401 and west of the Cataraqui River.

When assessing the options for a new 115 kV supplied station versus a new 230 kV supplied station the analysis showed the 230 kV station to be more favourable for the following reasons. First, in order to build a 115 kV station the two circuits would need to be reinforced in order to meet transmission criteria and ensure load can be supplied during a contingency event. Second, due to upstream constraints on the 115 kV system, it would not be possible to supply the load of an uprated Frontenac TS or a new 115 kV station without considerable upgrades to the Cataraqui autotransformers. Third, building a new 230 kV station in close proximity to the existing 230 kV double circuit tower line may require less additional transmission line work than the 115kV system and also, the 230 kV system can fully supply a new station, without capacity constraints.

The Working Group has confirmed that a new 230 kV station site west of Frontenac TS appears to be the most cost effective option that could help meet the identified needs into the long term, however this option will require Hydro One Distribution to build long feeders to supply customers east of the Cataraqui River. The Working Group has also confirmed that a new 230 kV station east of Frontenac TS would be preferable from a distribution upgrade perspective, however this option has high cost of transmission line extensions within the urban area of Kingston. The Working Group acknowledges that the citing of a new station requires a consideration to balance the cost required to extend 230 kV transmission lines to supply the station versus extending distribution lines required to serve the load. The timing and citing of the station is to be coordinated between the transmitter and the LDCs at which point the trade offs, which could include consideration of how to distribute load between the new and existing stations to manage overall distribution costs, will be considered.

Options for Addressing Supply Capacity Needs

Options for Addressing the Peterborough to Quinte West Supply Capacity Need

The IRRP considered a number of options to address the Peterborough to Quinte West supply capacity need that included and were not limited to the following:

1. Building new transmission supply capacity supplying Dobbin TS
2. Building new transmission supply capacity supplying Sidney TS
3. Siting a new generating resource at Sidney TS

However, this need requires a coordination with the Gatineau Corridor End-of-Life Study to ensure the broader system is considered when reviewing and resolving this need and will be addressed through that study.

Options for Addressing the Cataraqui Autotransformers Supply Capacity Need

The Cataraqui autotransformers have a summer long-term emergency rating of 250 MW. This rating is currently limited by the transformer secondary conductors. A cost effective way to increase the thermal ratings on these autotransformers is to upgrade the transformer secondary conductors, improving the long-term emergency rating without having to upgrade the autotransformers. Upgrading the transformer secondary conductor increases the long-term emergency rating to 285 MW for an estimated cost of $0.5M.

Non-wires alternatives were screened out at an early stage due to the low cost and low impact of the identified secondary conductor replacement solution. Therefore, this IRRP recommends upgrading the transformer secondary conductors and reassessing whether additional capacity will be required as part of the Lennox to St. Lawrence bulk system study.

End-of-Life Refurbishment Options and Recommendations

Port Hope TS is supplied by the 115 kV system between Dobbin TS and Frontenac TS. Port Hope TS is reaching end-of-life in 2025. Generally, options considered for end-of-life replacements include:

- Replacement of the assets "like-for-like" or with the closest available standard;
- Reconfiguration of the existing assets to "right-size" the replacement option based on: the forecast load growth, changes to the use of the asset since it was originally installed, and reliability or other system benefits that an alternate configuration may provide; or
- Retirement of a facility, considering the impact on load supply and reliability.

Working Group assessments indicated that there are no opportunities for end-of-life optimization at this time and like-for-like replacements with the closest available standard can best address the End-of-Life need at Port Hope TS Recommended Near- to Medium-Term Plan

To address the needs identified, the Working Group recommends the actions described below to meet the near-and medium-term electricity needs of the Peterborough to Kingston region. Successful implementation of these actions, in addition to achievement of existing targeted conservation measures, is expected to address the region's electricity needs until the late 2020s /early 2030s under the reference forecast.

Build a new 230 kV DESN transformer station at Belleville TS and monitor load growth

To address today's station capacity need at Belleville TS, as well as serve the growing electricity demand in the region, Elexicon and Hydro One (Transmission) are to initiate the development of a new DESN transformer station at Belleville, with an expected in-service date of 2025. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS until the end of the planning horizon.

Between planning cycles, the Working Group will continue to monitor the load growth at Belleville TS and re-visit the capacity need in the next regional planning cycle, in order to re-assess whether/when a re-enforcement to Belleville is required. Non-wires alternative such as energy efficiency can delay the implementation, and will be reviewed as part of the next regional planning cycle.

Furthermore, before the next planning cycle, the IESO should assess the bulk system impact of transmission reinforcement to Belleville TS should be included in the scope of a relevant individual bulk planning study for the area.

Hydro One (Distribution) load transfer and advance end-of-life replacement at Gardiner TS DESN #1

To address the near-term capacity need at Gardiner TS DESN #1, Hydro One (Distribution) will complete a relatively low cost and low lead-time load transfer of 11 MW between Gardiner TS DESN #1 and Gardiner TS DESN #2 by 2022 as a first step.

In addition, Hydro One will explore advancing the end-of-life replacement of Gardiner TS DESN #1 transformers to increase the station capacity. Advancing the replacement date, combined with the load transfer, will address the Gardiner TS DESN #1 capacity need for the duration of the planning horizon for the reference load forecast.

The Working Group will continue to monitor load growth in the area to evaluate if a second 11 MW load transfer to Gardiner TS DESN #2 is required.

Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed

Building a new 230 kV station in Kingston, supplied by 230 kV circuits X2H and X4H, will address the local need for station capacity at both Frontenac TS and Gardiner TS over the long term and for multiple growth scenarios. Due to the uncertainty in the forecast, the timing of the need for the new station could be in the near to medium term, as late as 2029. Hence, Hydro One Distribution and Utilities Kingston will work together to monitor the load growth in the area, and trigger the development work, and ultimately the construction, of a new 230 kV supply station when there is sufficient certainty in the timing of new demand materializing.

Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs

The development of a non-wire alternative, specifically additional energy efficiency or a local storage solution, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if both benefiting LDCs were to implement a part of the solution. The IESO will work with impacted LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station.

Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations

The outcomes of the Gatineau Corridor End-of-Life Study will improve the supply capability in the Peterborough to Kingston region. Namely, addressing the identified supply capacity need to Peterborough and Quinte West. By implementing the recommendations of the Gatineau Corridor End-of-Life study this need should be addressed.

Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study

Upgrading the autotransformers' secondary conductors will increase the thermal capacity of these autotransformers from 250 MW to 285 MW and will resolve the thermal violation after losing one of the autotransformers. A future Lennox to St. Lawrence bulk system study will reassess the need with this solution in place and study if additional capacity is required.

Replace Port Hope TS T3/T4 with the closest available standard size transformers

Port Hope TS T3/T4 are reaching end-of-life and there are no opportunities for end-of-life optimization at this time. This IRRP recommends like-for-like replacements with the closest available standard size transformers of equal or greater capacity.

7.2 Options for Meeting Long-Term Needs

For needs appearing in the long term, there is an opportunity to develop and explore options, as specific projects do not need to be committed immediately. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential conservation measures in the study area; test emerging technologies; engage with communities and stakeholders; and lay the foundation for informed decisions in the future.

Option for Meeting Supply Capacity Needs

Options for Meeting the Peterborough to Quinte West Supply Capacity Needs

Similar to the Cataraqui autotransformers need, the Peterborough to Quinte West pocket voltage need relates to the Peterborough to Quinte West supply need where it is expected that any reinforcement made to the Peterborough to Quinte West area supply, such as those contemplated in the Gatineau Corridor End-of-Life Study, will naturally resolve the under voltage violations observed in this pocket.

Options for Meeting the Kingston Transmission Supply Capacity Needs

Since this need starts to substantiate beyond the planning horizon following the reference forecast, early development work for a transmission line upgrade is not required at this time.

There may be opportunities for the Working Group to work with communities and local utilities to manage future electricity demand through the development of community-based solutions under the IESO's new CDM Framework or other mechanisms or opportunities that may evolve between planning cycles.

7.3 Recommended Long-Term Plan

A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

The recommended actions for the long-term plan are outlined below.

Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau Corridor End-of-Life Study

Low voltage violations are observed in the long-term planning horizon in the Peterborough to Quinte West 115 kV pocket. These violations may naturally be resolved by the outcome of the Gatineau Corridor End-of-Life Study; therefore, this need will be monitored and re-assessed following the Gatineau Corridor End-of-Life Study plan during the next planning cycle.

Monitor Kingston Area Transmission Supply Capacity Needs

The IESO should re-evaluate the capacity need on B5QK periodically and explore non-wire solutions with the Working Group and communities as appropriate.

Monitor demand growth, conservation achievement and distributed generation uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial distributed generation (DG) projects, and actual demand growth in the Peterborough to Kingston Region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on CDM and DG is also a useful input into the ongoing development of non-wires alternatives as potential long-term solutions.

Initiate the next regional planning cycle early, if needed

Along with the indices outlined above, the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast (the high demand forecast in Belleville and Kingston, or the reference demand forecast in the remainder of the region), it may be necessary to initiate the next iteration of the regional planning process earlier than 2024 given the lead time for the long-term supply options.

7.4 Summary of Recommended Actions and Next Steps

Table 7-1, below, summarizes the specific recommendations that should be implemented immediately to address the most imminent electricity supply needs in the Peterborough to Kingston region.

Table 7-1 | Summary of 2021 Peterborough to Kingston IRRP Recommendations

Need	Recommendation	Lead Responsibility	Estimated Cost	Timeline
Belleville Station Capacity	Build a new Dual Element Spot Network (DESN) transformer station at Belleville	Elexicon and Hydro One Transmission	~$30-35M	Beginning in 2021
Kingston Area Station Capacity – Frontenac TS	Monitor load and trigger development work, and ultimately construction, for a new 230 kV transformer station, when required. Continue development of energy efficiency programs for the area	Utilities Kingston, Hydro One Distribution, Hydro One Transmission IESO	~$30-35M	Station needed between 2025 and 2029 depending on forecast scenario.
Kingston Area Station Capacity – Gardiner TS DESN #1	Perform permanent 11 MW load transfer to Gardiner TS DESN #2. Hydro One transmission to perform end-of-life refurbishment of the station, therby increasing LTR. LDCs to monitor load and evaluate the second 11 MW load transfer, if required, as it has a high cost ($5.5M), which is not included in the estimate).	Hydro One Distribution, Hydro One Transmission	~$0.5M	First Load transfer: 2022 Refurbishment: as soon as possible (2024-2025) Second Load Transfer: explore it, if required
Port Hope TS	Replace Port Hope TS T3/T4 with the closest available standard size transformers	Hydro One Transmission	Cost of refurbishment incurred by Hydro One Transmission	Beginning in 2025
Cataraqui Autos Supply Capacity	Upgrade Cataraqui Autotransformers' secondary conductors	Hydro One Transmission	~$0.5M	Early 2024

The Working Group has also identified the following additional planning activities to address ongoing regional planning needs

Need	Recommendation	Lead Responsibility	Timeline
Peterborough to Quinte West Area	Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations	IESO	Early 2022
Cataraqui Autos Supply Capacity	Following the conductor upgrade, review this need in further detail as part of Lennox to St. Lawrence bulk study.	IESO	2023

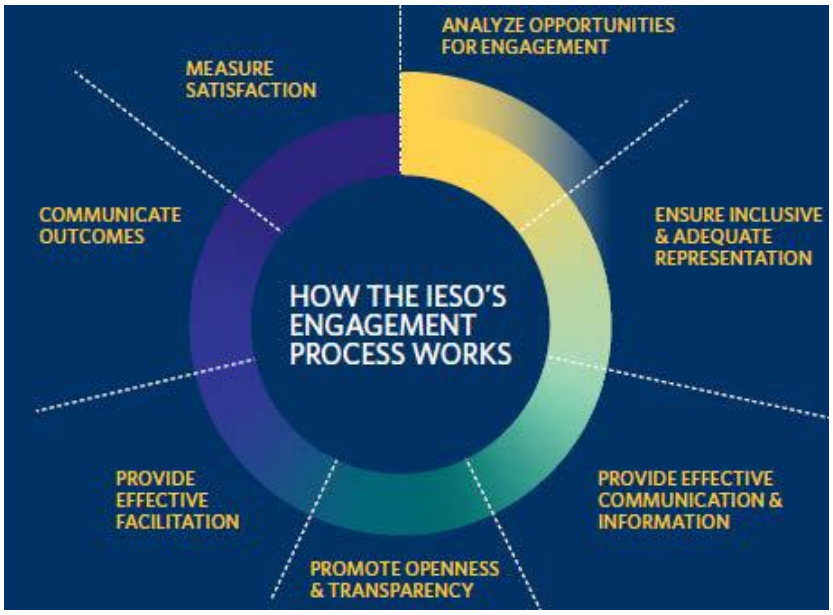
8 Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Peterborough to Kingston IRRP.

8.1 Engagement Principles

The IESO's engagement principles[16] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8-1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Peterborough to Kingston

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region. Creating the engagement plan for this IRRP involved:

- Discussions to help inform the engagement approach for the planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

[16] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

- Identifying specific stakeholders and communities who may have a direct impact on this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region

As a result, the engagement plan[17] for this IRRP included:

- A dedicated webpage[18] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities, rights-holders and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Web-conferencing meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.4 Bringing Municipalities to the Table).

8.3 Engage Early and Often

Early communication and engagement activities began with invitations to all subscribers, municipalities, Indigenous communities and rights-holders in the Peterborough to Kingston Region to learn about and provide comments on the draft Scoping Assessment Outcome Report. The IESO also held preliminary discussions to help inform the engagement approach for this first active cycle of formal regional planning. This started with an invitation to targeted municipalities, Indigenous communities, rights-holders and those with an identified interest in regional issues to help inform the engagement approach and. learn more about how to provide comments on the Peterborough to Kingston Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to consider local economic development and impacts to service when undertaking planning activities as part of implementation of recommended work. Feedback in early discussions also emphasized the importance of aligning community energy and climate action plans, electrification targets and other planning initiatives in the development of the IRRP. Along with a response to the feedback received, the final Scoping Assessment was posted in May 2020 which identified the need for a coordinated regional planning approach done through an IRRP for the Peterborough to Kingston Region. The final Scoping Assessment, identified the need for an IRRP for the Peterborough to Kingston Region. Following a written comment window, the final Scoping Assessment Outcome Report was published in May 2020.

[17] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/KWCG-Region/KWCG-Engagement-Plan.ashx

[18] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Kitchener-Waterloo-Cambridge-Guelph

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the Peterborough to Kingston region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at critical stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on key components of the plan. All webinars received strong participation with cross-representation of stakeholders and community representatives attending the webinar, and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement focused on the following major themes:

• Consideration should be given to local developments and growth plans

• Alignment and coordination is needed with other community planning and projects in the region. Future infrastructure and/or electricity supply should consider the priorities of energy and climate action plans and, in particular, plans for fuel switching in the municipal, commercial and residential sector, as well as vehicle electrification

• Incorporate shifting economies into planning assumptions and cost benefit analysis

• Integrated options that provide both local and broader provincial system benefit should be considered

• Recommendations for the near and mid term should be based on a high demand growth scenario, and provide flexibility for the long term should additional increased demand materialize as a result of electrification plans

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations. This includes using a high-demand forecast scenario to shape the development of the IRRP as a result of community feedback on local plans for electrification.

All interested parties were kept informed throughout this engagement initiative via email to Peterborough to Kingston region subscribers, municipalities and communities as well as the members of the East Regional Electricity Network.

Based on the discussions both through the Peterborough to Kingston IRRP engagement initiative and broader network dialogue, it is clear that there is broad interest in several East Ontario communities to further discuss the potential for alternative energy solutions. The near- to medium-term nature of the Peterborough to Kingston region's future electricity needs presents a valuable opportunity for communities to mobilize projects and initiatives to meet local growth targets and energy priorities. To that end, ongoing discussions will continue through the IESO's East Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Peterborough to Kingston IRRP engagement web page.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning priorities and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; community energy and climate action plans, options for meeting the region's future needs; and, broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities and rights-holders within the Peterborough to Kingston electricity planning region throughout the development of the plan. This includes the communities of Alderville First Nation, Hiawatha First Nation, Curve Lake First Nation, Mohawks of the Bay of Quinte, Tyendinaga Mohawk, Kawartha Nishnawbe and the traditional territory of the Huron Wendat.

The IESO remains committed to an ongoing, effective dialogue with communities and First Nation rights-holders to help shape long-term planning in regions all across Ontario.

9 Conclusion

This report documents an IRRP that has been developed for the Peterborough to Kingston region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. The IRRP makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth and efficiency achievements. Responsibility for these actions will be undertaken by the appropriate members of the Working Group.

The Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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Peterborough to Kingston

REGIONAL INFRASTRUCTURE PLAN

May 27, 2022

hydro one

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DISCLAIMER

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

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

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EXECUTIVE SUMMARY

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

The participants of the RIP Technical Working Group (TWG) included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Eastern Ontario Power Inc.
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Kingston Hydro
- Lakefront Utilities Inc.

This RIP is the final phase of the second cycle of the Peterborough to Kingston regional planning process. It follows the completion of the Peterborough to Kingston Integrated Regional Resource Plan ("IRRP") in November 2021 and the Peterborough to Kingston Needs Assessment ("NA") in February 2020.

The Peterborough to Kingston RIP provides a consolidated summary of the needs and recommended plans for the region based on available information. It discusses the needs identified in the previous and current regional planning cycle, , any new needs identified as part of this RIP phase, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway from the previous planning cycle, including:

- Load transfer from Gardiner TS DESN 1 to Gardiner TS DESN 2 to provide transformation capacity relief at Gardiner TS DESN 1 (completed in 2019)

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

Table 1-1: Recommended Plans in Peterborough to Kingston over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate[1] ($Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard[2]	2028*	$30
	Load transfer from DESN1 to DESN2	2022	$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	$30-$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	$35-$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

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

[1] Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

[2] The new standard units are expected to have a higher LTR of about 160 MW

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Technical Working Group (TWG) that consists of Hydro One Inc. (Transmission), Eastern Ontario Power Inc., Elexicon Energy Inc. ("Elexicon"), Hydro One Inc. (Distribution), Independent Electricity System Operator ("IESO"), Kingston Hydro, and Lakefront Utilities Inc., in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The Peterborough to Kingston region is comprised of the area bordered approximately by Clarington on the West, North Frontenac county on the North, Frontenac County on the East and Lake Ontario on the South. The boundaries of the Region are shown in Figure 1-1 below.

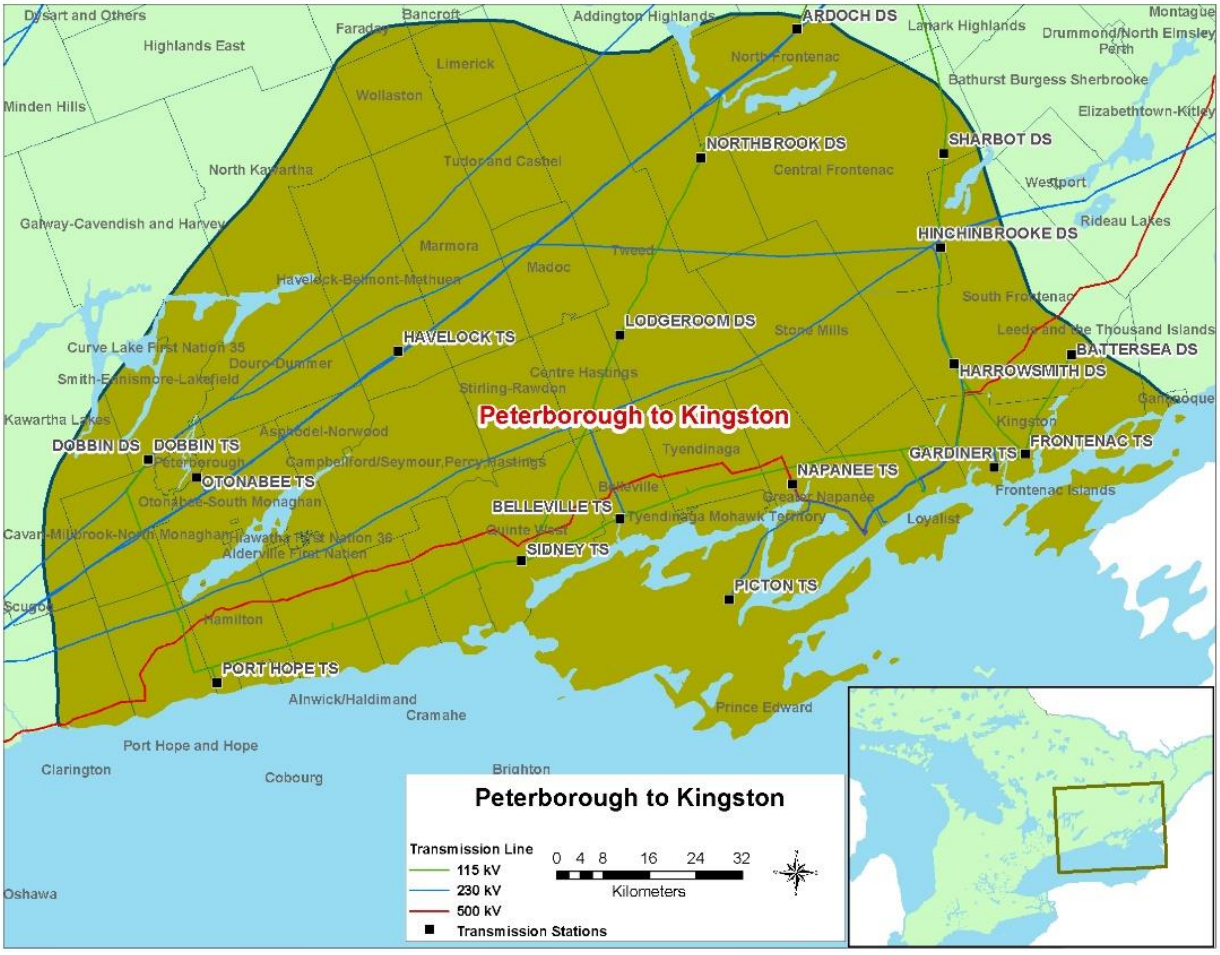


Figure 1-1: Peterborough to Kingston Region

1.1. Objectives and Scope

This RIP report examines the needs in the Peterborough to Kingston Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and,
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and wires plans to address them
- Consideration of long-term needs identified in the Peterborough to Kingston IRRP or identified by the TWG.

1.1. Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [3] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the TWG determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[3] Also referred to as Needs Screening

the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, LP, and IRRP phases of regional planning;
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

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

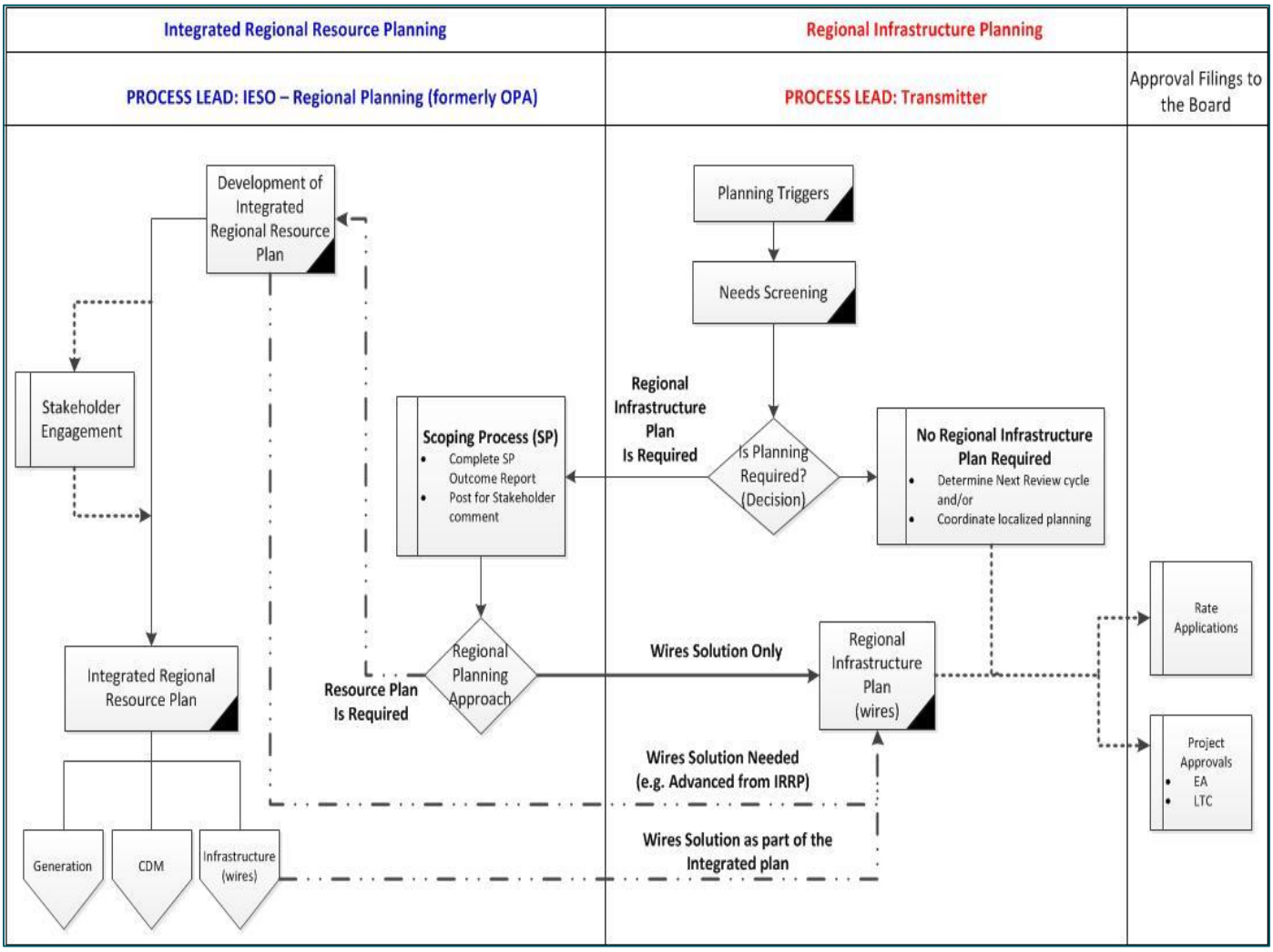


Figure 1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous phases of the regional planning process. Hydro One collects this information and reviews it with the TWG to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon any changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to a specific issue(s) only. Additional needs may be identified in this phase.

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

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

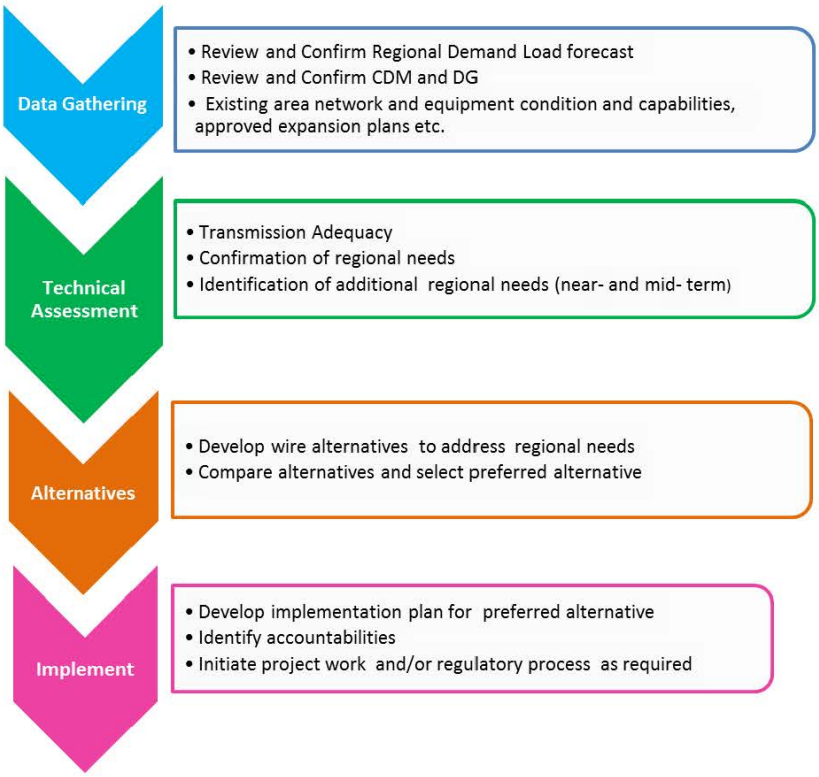


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE PETERBOROUGH TO KINGSTON REGION IS COMPRISED OF THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY THE MUNICIPALITY OF CLARINGTON ON THE WEST, NORTH FRONTENAC COUNTY ON THE NORTH, FRONTENAC COUNTY ON THE EAST, AND LAKE ONTARIO ON THE SOUTH. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TEN STEP-DOWN TRANSFORMER STATIONS AND EIGHT HIGH VOLTAGE DISTRIBUTION STATIONS.

Electrical supply to the region is provided through 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS, and a 230kV and 115kV transmission network supplying the various step-down TS's and HVDS's in the region. The main generation facility in the region is the 2000 MW Lennox Generation Station connected to Lennox TS.

The Local Distribution Customers (LDC) in the Peterborough to Kingston Region are Hydro One Distribution, Eastern Ontario Power, Elexicon, Kingston Hydro, and Lakefront Utilities. The high-voltage system in this Region also provides supply to five other direct transmission connected load customers.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.

- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight HVDS that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS

- Five Customer Transformer Stations (CTS) are supplied in the Region
- There are 7 existing Transmission connected generating stations in the Region as follows:
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
    - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS
    - Napanee GS is a 910 MW gas-fired plant connected to Lennox TS at the 500 kV system

- Kingston Solar CGS is a 100 MW solar generation facility connected to 230 kV circuit X2H
- Stone Mills CGS is a 60 MW solar generation facility connected to 230 kV circuit H23B
- Amherst Island CGS is a 76 MW wind farm connected to 115kV circuit Q6S

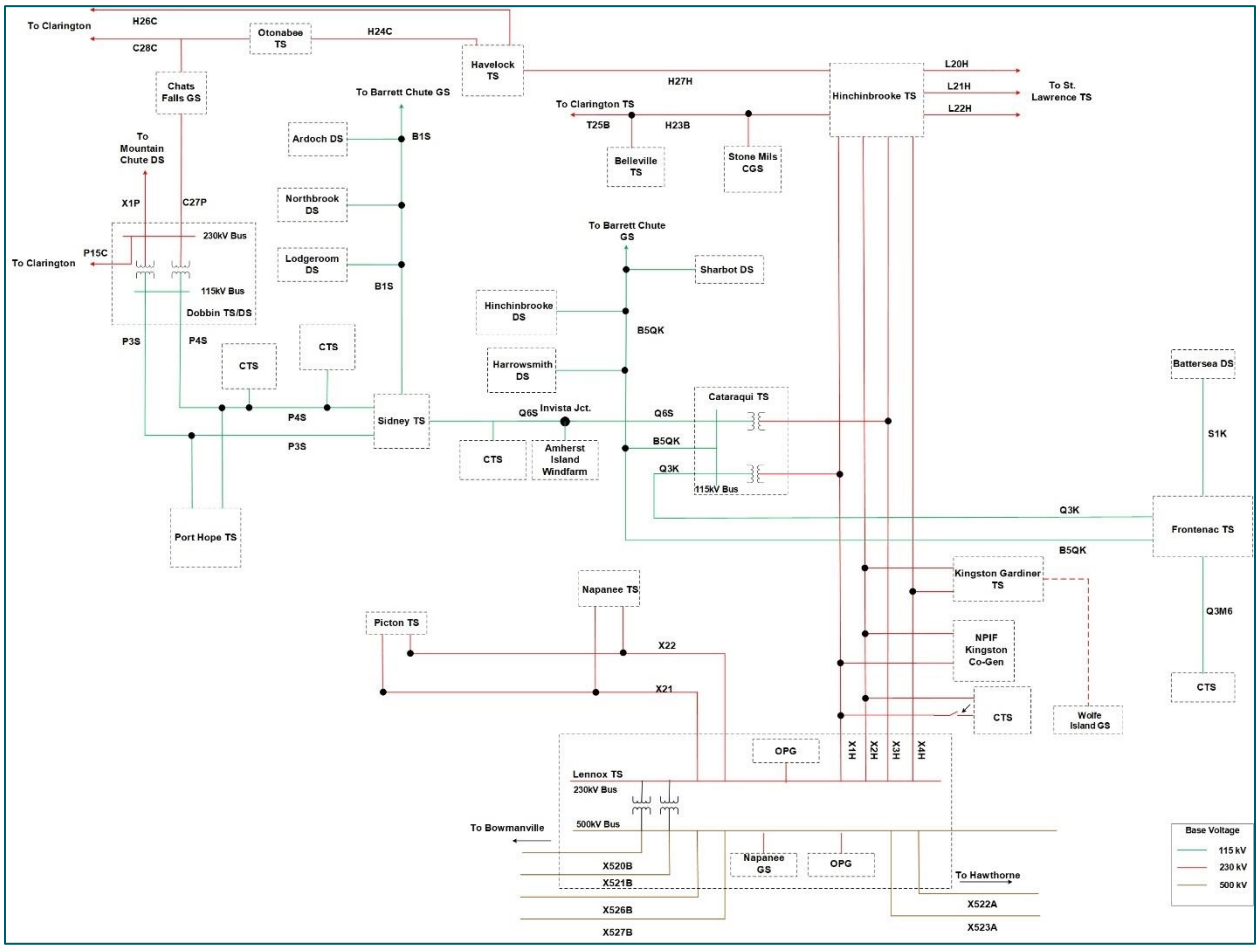


Figure 3-1: Single Line Diagram of Peterborough to Kingston's Transmission Network

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

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

A summary and description of the major projects completed over the last 10 years is provided below:

- Connect Napanee GS (2017) – A 910 MW gas turbine (Napanee GS) was connected to the 500 kV bus in the Lennox TS switchyard

- Transformation capacity relief at Gardiner TS DESN 1 (2019) – Gardiner TS DESN 1 load exceeded its normal supply capacity. Hydro One Distribution transferred load from Gardiner TS DESN 1 to Gardiner TS DESN 2.

The following projects are currently underway:

- Lennox TS 230kV & 500kV Breaker Replacement (2026/27)
- Belleville TS T1/T2 Transformer Replacement (2022)

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Peterborough to Kingston Region is anticipated to grow about .8% annually from 2021 to 2031.

Figure 5-1 shows the Peterborough to Kingston Region's extreme weather coincident peak net load forecast ("load forecast") for summer and winter. The load forecast for the individual stations in the Peterborough to Kingston Region is given in Appendix D.

As per the new regional planning process requirement, the load forecast used in the RIP is same as the IRRP phase unless there is a material change or if a LDC(s) member of the TWG requests to update their load forecast.

In the case of the Peterborough to Kingston Region, the TWG decided to use the load forecast in the recently completed Peterborough to Kingston Region IRRP (Nov. 2021) for the purposes of the RIP load forecast. Note that the TWG reviewed the extreme summer non-coincident peak net load forecast from the IRRP against the actual historical peak load observed in 2020 for the stations that have been identified to have a capacity need, namely Belleville TS, Frontenac TS, Gardiner TS DESN 1, and Otonabee TS (discussed in Section 6.4). Although, the actual 2020 peak load for these stations is slightly lower than what was forecasted in the IRRP, the TWG decided to proceed with the IRRP 2020 forecasted load since it does not materially change the planning outcome. The need dates will continue to be monitored throughout the regional planning process.

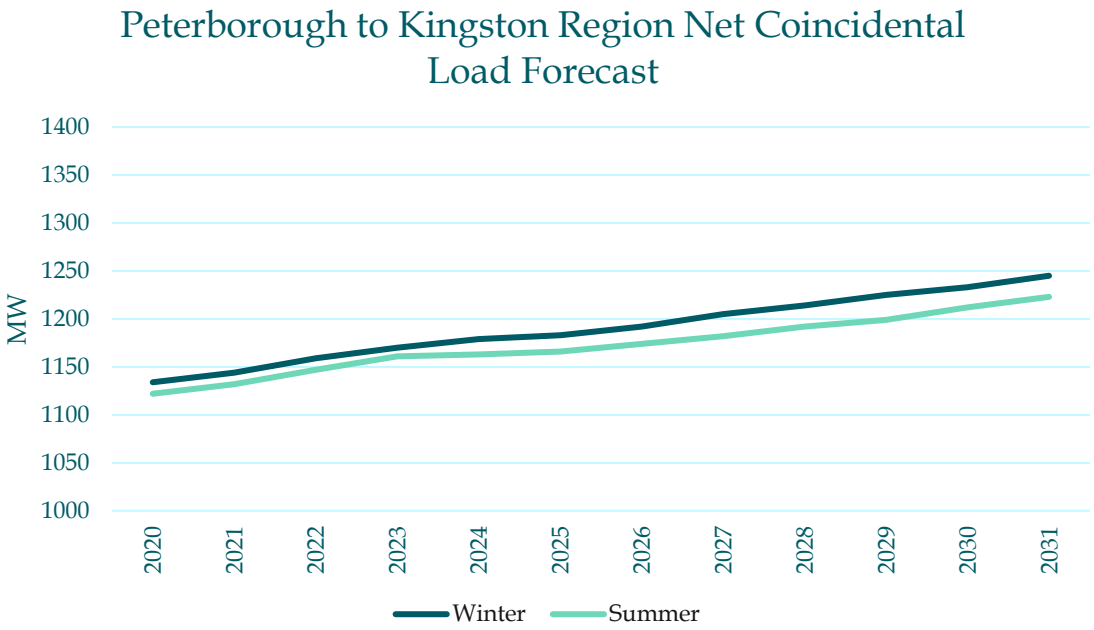


Figure 5-1: Peterborough to Kingston Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP adequacy assessment is 2020-2031.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for all stations for stations having no low voltage capacitor banks and .95% lagging power factor for stations having low voltage capacitor banks
- Normal planning supply capacity for transformer stations is determined by the summer 10-Day Limited Time Rating (LTR).
- Line capacity adequacy is assessed using peak loads in the area.
- Output of generating stations in the area is based on 98% dependable generation availability for transmission connected run of river hydro-electric stations as per Ontario Resource Transmission Assessment Criteria (ORTAC) criteria.
- Adequacy assessment is conducted as per ORTAC and using the load forecast described in section 5.1.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE PETERBOROUGH TO KINGSTON REGION OVER THE PLANNING PERIOD (2021-2031).

Within the current regional planning cycle, three regional planning reports have been completed for the Peterborough to Kingston Region. The findings of these reports are inputs to this Regional Infrastructure Plan. These reports are:

- 2020 Peterborough to Kingston Region Needs Assessment ("NA") Report;
- 2020 Peterborough to Kingston Region Scoping Assessment ("SA") Report; and,
- 2021 Peterborough to Kingston Region Integrated Regional Resource Plan ("IRRP")

This section provides a review of the adequacy of the transmission lines and stations in the Peterborough to Kingston Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D and assumes all projects currently underway (described in section 4) are in-service. Sections 6.1 to 6.5 present the results of this review. Asset renewal needs for major HV transmission equipment were identified in previous phases of this regional planning cycle and are also addressed in Section 7 of this RIP report.

6.1 230/115 kV Autotransformers

Bulk power supply to the Peterborough to Kingston Region is provided by Hydro One's 500kV/230kV and 230 kV/115kV autotransformers. The number and location of these autotransformers are as follows:

a) Two 500/230 kV autotransformers at Lennox TS
b) Two 230/115 kV autotransformers at Cataraqui TS
c) Three 230/115 kV autotransformers at Dobbin TS

The 500/230 kV autotransformers at Lennox TS are part of the bulk system and outside the scope of this RIP.

Based on the RIP load forecast, the load growth at Frontenac TS and other 115kV supply stations is expected to result in a supply capacity need at Cataraqui TS in 2023. The load is expected to increase over the long-term.

The 230/115 kV autotransformers at Dobbin TS are expected to be adequate over the study period.

6.2 230 kV Transmission Lines

All 230 kV transmission circuits, with the exception of circuits X21 and X22 in the Peterborough to Kingston Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and to the load centers in the Greater Ottawa regions. These circuits are as follows:

- 230kV circuits: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X2H, X3H and X4H.

These 230kV transmission lines can be divided into the main corridors as summarized below:

a) Clarington TS to Otonabee TS, Havelock TS, Chats Falls SS 230kV circuits T22C, T31H, T32H
   - Supplies Otonabee TS, Havelock TS
b) Clarington TS to Hinchinbrooke SS 230kV circuits T25B and H23B
   - Supplies Belleville TS
c) Lennox TS to Hinchinbrooke SS 230 kV circuits, X1H, X2H, X3H, X4H
   - Supplies Gardiner TS and a Customer CTS
d) Cherrywood TS to Dobbin TS, Chat Falls SS 230kV circuits P15C and C27P

From the circuits listed above, P15C is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits X1P or C27P. This supply capacity need is being assessed as part of the bulk system planning.

6.3 115 kV Transmission Lines

The Peterborough to Kingston Region consists of several 115 kV lines. This 115 kV network serves local area load. The 115 kV transmission facilities can be divided into the main corridors as summarized below:

a) Dobbin TS to Sidney TS 115kV transmission circuits P3S/P4S
   - Supplies Port Hope TS, Sidney TS, and two Customer CTS

b) Sidney TS to Cataraqui TS 115kV transmission circuit Q6S
   - Supplies Sidney TS and a Customer CTS

c) Cataraqui TS to Frontenac TS 115kV transmission circuits Q3K/B5QK
   - Supplies Sharbot DS, Hinchinbrooke DS, Harrowsmith DS, and Frontenac TS

d) Barrett Chute GS to Sidney TS 115kV transmission circuit B1S
   - Supplies Ardoch DS, Northbrook DS, Lodgeroom DS

From the circuits listed above, Q6S is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits 230kV circuits X1P, C27P, or P15C.

This supply capacity need is being assessed as part of the bulk system. The remaining 115 kV circuits are within their thermal limits and within the voltage range as per ORTAC for the loss of a single 115 kV circuit in the Region.

6.4 230 kV and 115 kV Connection Facilities

There is a total of ten step-down transformer stations and eight high voltage distribution stations that supply the Peterborough to Kingston load as shown in Table 6-1 below:

Table 6-1: Step-Down Transformer Stations and High Voltage Distribution Stations

Dobbin TS	Port Hope TS	Sidney TS	Picton TS
Otonabee TS	Havelock TS	Belleville TS	Napanee TS
Gardiner TS	Frontenac TS	Dobbin DS	Ardoch DS
Northbrook DS	Lodgeroom DS	Hinchinbrooke DS	Harrowsmith DS
Sharbot DS	Battersea DS		

A station capacity assessment was performed over the study period for the above stations in the Region using either the summer or winter station peak load forecasts as appropriate. The results are as follows:

6.4.1 Belleville TS T1/T2 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Belleville TS was forecasted to be 170 MW[4]. The Summer 10-Day LTR of Belleville TS is about 161 MW.

Based on the RIP load forecast, Belleville TS is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term. In addition to normal load growth in the area, Elexicon has recently received approximately 30 MW of new load connection inquiries to be connected at Belleville TS.

6.4.2 Frontenac TS T3/T4 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is 101 MW[5]. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the RIP load forecast, Frontenac TS is expected to reach its Summer 10-Day LTR by 2029.

[4] The 2020 extreme summer weather non-coincident peak net load at Belleville TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual, weather corrected 2020 summer peak load at Belleville TS was 157 MW, but still forecasted to exceed the 161MW LTR in 2022.

[5] The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Frontenac TS was 104 MW.

6.4.2 Gardiner TS DESN 1 (T1/T2) Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 was forecasted to be 146 MW[6]. The Summer 10-Day LTR of Gardiner TS DESN 1 and DESN 2 is about 125 MW and 85 MW, respectively.

Based on the RIP load forecast, the loading on Gardiner TS DESN 1 is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.3 Otonabee TS (T1/T2) 44kV Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV is 97 MW.

Based on the 2020 net loading and load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.4 Other TSs and HVDSs in the Region

Based on the RIP load forecast, all the other TSs and HVDSs in the Region are expected to be within their normal supply capacity during the study period. Therefore, any capacity needs for these TSs and HVDSs will be reviewed in the next regional planning cycle.

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

Station	Summer 10-Day LTR Capacity (MW)	2020 Summer Peak Net Forecast (MW)	Need Date
Belleville TS T1/T2	161	170	Today
Frontenac TS T3/T4	111	101	2029
Gardiner TS DESN 1 (T1/T2)	125	146	Today
Otonabee TS 44kV Bus	97	103	Today

[6] The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Gardner TS DESN 1 was 130 MW.

6.5 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

6.6 Other Needs

6.6.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Peterborough to Kingston Region. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

These needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Asset replacement work planned over the study period in the region is summarized in Table 6-3.

Table 6-3: Peterborough to Kingston Region – Planned Asset Replacement Work

No.	Station	Description	in-service Timing
1	Picton TS	T1/T2 Replacement	2025
2	Port Hope TS	T3/T4 Replacement	2026
3	Lennox TS	230kV & 500kV Breaker Replacement. Part of Bulk system	2026/27
4	Dobbin TS	Auto Transformers T1/T2/T5 Replacement	2029
5	Gardiner TS DESN 1	T1/T2 Replacement	2028*

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

7. REGIONAL PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE PETERBOROUGH TO KINGSTON REGION AND PRESENTS WIRES ALTERNATIVES AND PREFERRED WIRES SOLUTIONS FOR ADDRESSING THESE NEEDS. TABLE 7-1 LISTS NEEDS PREVIOUSLY IDENTIFIED IN THE NA AND IRRP FOR THE PETERBOROUGH TO KINGSTON REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THIS RIP REPORT.

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

Table 7-4: Identified Near and Mid-Term Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-service Timing
Supply Capacity	7.1	Peterborough to Quinte West	Today
	7.2	Cataraqui TS Autotransformers	2023
Station Capacity	7.3	Belleville TS	Today
	7.4	Frontenac TS	2029
Station Capacity	7.5	Gardiner TS DESN 1 (T1/T2)	Today
Station Capacity	7.6	Otonabee TS 44kV Bus	Today

Table 7-5: Major Asset Renewal Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-Service Timing
Asset Renewal for Major HV Transmission Equipment	7.7	Picton TS T1/T2 transformers	2025
	7.8	Port Hope TS T3/T4 transformers	2025
	7.9	Gardiner TS T1/T2 (DESN 1) transformers	2028*
	7.10	Dobbin Auto Transformers T1/T2/T5	2029

*Hydro One is exploring if and how Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

Maintaining status quo is not an option for any of the end of life autotransformers or station transformers due to risk of equipment failure and would result in increased maintenance cost and prolonged customer outages and interruptions. These transformers will be replaced with standard units.

No other lines or HV station equipment in the Peterborough to Kingston region than listed above, have been identified for major replacement/refurbishment at this time.

7.1 Supply Capacity – Peterborough to Quinte West

7.1.1 Description

The Peterborough to Quinte West sub region mainly consists of Port Hope TS and Sidney TS. The area is supplied from Dobbin TS to the North West, Cataraqui TS from the East, and Barrett Chute SS to the North East. During low water conditions and contingency situations, the thermal capacity on circuits P15C and Q6S can be exceeded.

7.1.2 Alternatives and Recommendation

IESO is currently undertaking a bulk study of the area and the recommendations from the study is expected to resolve the thermal loading limits of P15C and Q6S.

7.2 Supply Capacity – Cataraqui TS Autotransformers

7.2.1 Description

Cataraqui TS supplies the 115kV stations in the Eastern sub region of the region through two 230/115kV auto transformers. It is forecasted that in 2023 the coincidental loading of the stations in the sub region will reach the supply capacity of the Cataraqui TS auto transformers.

7.2.2 Alternatives and Recommendation

The current limitation of the Cataraqui TS auto transformers are due to a short span of copper conductors connected the secondary side of the auto transformers within the station. Upgrading the conductors will allow the long term emergency to increase by 35 MW and resolve this need in the near term.

7.3 Station Capacity – Belleville TS

7.3.1 Description

Belleville TS consists of one DESN supplied by 230kV circuits, H23B and T25B. The station has a summer 10-Day LTR of 161 MW. The station is also limited by voltage drop limitations when transmission circuit H23B is lost along with the companion transformer by configuration and the maximum loading can be as low as 130 MW, depending on the load composition at the station.

Based on the 2020 net load forecast, the station will exceed its capacity in 2022. In addition, Elexicon has also recently received approximately 30 MW of load connection inquiries to be connected at Belleville TS, but not including in the current load forecast. Hence, there is an immediate need for additional transformation capacity at Belleville TS today.

While the Belleville TS T1/T2 transformer replacement is currently underway, with an expected in-service date of 2022, this refurbishment is not expected to result in any significant improvement to the station's capacity and does not solve the voltage limitation issue.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the Belleville TS station capacity need:

1. **Alternative 1 – Install a new DESN with two 75/125 MVA transformers with two 32 MVAR Capacitor banks and assess transmission line capacity**: Installing a second DESN at Belleville TS with two 32 MVAR capacitor banks will help mitigate the voltage drop at the Belleville TS LV bus and will resolve the station capacity need over the long-term (20 years) based on the current load forecast. Belleville TS switchyard also has space for a second DESN. The estimated cost for this option is approximately $35-40 M. However, it should be noted that preliminary studies indicate that there will be voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency, which will restrict the full utilization of the additional station capacity in the long term as the total load at Belleville TS DESN1 and the new Belleville TS DESN2 is expected to be limited to 210 MW total, but should be sufficient capacity to meet the forecasted demand in the next 20 years. To fully utilize the capacity of the second DESN and increase the capacity beyond 210 MW, new supply lines into Belleville will be required to alleviate the voltage drop limits at Belleville TS. A possible reinforcement option is to extend X21/X22 from Napanee TS to Belleville TS along an existing Q6S Right of Way. There may also be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts when looking beyond 20 years.

2. **Alternative 2 – Install an additional third 75/125 MVA transformer at Belleville TS and assess transmission line capacity**: Installing a third transformer at Belleville TS would resolve the need over the study period, however it is not a long term solution as compared to alternative 1 as it does not provide reliability of a full DESN, will significantly increase short circuit level at the 44kV bus, and does not alleviate the current voltage limitation. The estimated cost for this option is also similar to alternative 1 at approximately $30-35 M.

3. **Alternative 3 – Load transfers:** Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers was not recommended by the TWG.

Considering the above alternatives, the TWG recommends Alternative 1. To address today's station capacity need at Belleville TS, as well as the growing electricity demand in the region,

Hydro One (Transmission and Distribution) and Elexicon have started development of a new DESN transformer station at Belleville, with an expected in-service date of 2026. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS in the near and mid term.

The TWG will continue to monitor the load growth at Belleville TS and revisit the capacity need in the next regional planning cycle in order to re-assess whether/when a transmission line reinforcement to Belleville is required in the long term. In case of a H25B contingency where voltage violations are exceeded, operational measures will be taken to resolve the issue. Furthermore, IESO will undertake any necessary bulk system studies regarding the transmission reinforcement to Belleville TS.

7.4 Station Capacity – Frontenac TS

7.4.1 Description

Frontenac TS consists of one DESN supplied by 115kV circuits, Q3K and B5QK. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the 2020 net load forecast, Frontenac TS is expected to exceed its Summer 10-Day LTR by 2029 but can be as early as 2022 for a high growth scenario. As there is limited load transfer capability between Frontenac TS and Gardiner TS DESN1 and excess load in Eastern Kingston area may not be able to supply from Gardiner TS DESN1, there is a need for additional transformation capacity at Frontenac TS in the mid-term.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the Frontenac TS station capacity need:

1. **Alternative 1 – Upgrade Frontenac T3/T4 transformers**: The transformers at Frontenac TS are already the largest size for a 115/44kV DESN and therefore upgrading these transformers is not feasible.

2. **Alternative 2 – Install a new DESN with 50/83MVA transformers at Frontenac TS**: As the 115kV circuits supplying Frontenac TS have little thermal capacity, adding a second DESN at Frontenac TS will require significant upgrades to the existing 115kV transmission circuits. In addition, the cost of converting 115 kV transmission line to 230 kV is large and has been a deterrent due to low load growth in the area.

3. **Alternative 3 – Extend 230kV circuits X2H and X4H 13 km to the East of St. Lawrence River and install a new 75/125 MVA DESN**
   This option was assessed and reject due to the high cost and many environmental and real estate issues with the line extension.

4. **Alternative 4 –Build a new 230kV 75/125 MVA DESN near Gardiner TS**
   Load transfer capability exists between Frontenac TS and Gardiner TS DESN 1 via 44kV feeder ties but is limited and for operation measures and is not be suitable for permanent new loads forecasted in Eastern Kingston. Building a new 230 kV DESN near the current X2H/X4H corridor can alleviate this constraint by supplying new load in the area as well as providing an extra station where load can be transferred from Frontenac TS to the new DESN, as needed.

Considering the above alternatives, the TWG recommends Alternative 4. Hydro One transmission will work with Kingston Hydro and Hydro One Distribution to undertake development work for a new station in the area in the near term, which may be built by the Transmitter or the LDC.

The development of additional energy efficiency, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station

7.5 Station Capacity – Gardiner TS DESN 1 (T1/T2)

7.5.1 Description

Gardiner TS DESN 1 is supplied by 230 kV circuits X2H and X4H. The Summer 10-Day LTR of Gardiner TS DESN1 is 125 MW.

Based on the 2020 net load forecast, Gardiner TS has exceeded its Summer 10-Day LTR. Hence, there is a need for additional transformation capacity at Gardiner TS DESN1 in the near term.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the Gardiner TS DESN1 station capacity need:

1. **Alternative 1 – Expedite Gardiner TS DESN1 refurbishment**:
   As the current transformers 10 Day LTR is 125 MW, replacing it with new standard 75/125 MVA transformers will increase the LTR to about 160 MW. This will provide enough capacity to meet the load growth at DESN 1 until 2033.

2. **Alternative 2 – Load Transfer from Gardiner TS DESN1 to Gardiner TS DESN2**:
   Gardiner TS DESN2 was built within the last 15 years and has a 10 day LTR of 85 MW. DESN2 has available capacity at the station to supply additional loading. Hydro One distribution has confirmed that an permanent additional 11 MW load transfer from Gardiner TS DESN1 to Gardiner TS DESN2 is possible by reconfiguring its distribution system.

Considering the above alternatives the TWG recommends to proceed with both Alternatives 1 and 2. As the cost of the distribution load transfer is low and the load transfer work is much faster than the Gardiner TS DESN1 refurbishment, Hydro One Distribution can proceed with the work to alleviate the immediate loading constraint on Gardiner TS DESN1 with an expected completion date end of 2022, while Hydro One Transmission will explore opportunity to accelerate the Gardiner TS DESN1 refurbishment. The combination of these two options will address the current capacity limit at Gardiner TS DESN1. Hydro One Transmission will provide an update to the Technical Working Group for Gardiner TS DESN1 refurbishment in Q3 2022.

7.6 Station Capacity – Otonabee TS 44kV bus (T1/T2)

7.6.1 Description

The 2020 non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV winding is 97 MW.

Based on the 2020 net load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today. Hence, there is a need for additional transformation capacity at Otonabee TS 44 kV bus in the near term.

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the Otonabee TS 44kV station capacity need:

1. **Alternative 1 – Transfer load from Otonabee TS 44kV to Dobbin TS**:
   Dobbin TS is nearby station that have over 50MW of remaining capacity and is not expected to reach its LTR of 160 MW in the long term. The secondary voltage is also 44kV, which allows load transfer between the two stations. Although there is an existing plan to transfer 4 MW of load from Otonabee TS 44kV bus to Dobbin TS, that is not enough to alleviate the capacity limits at Otonabee TS 44kV bus. Hydro One Distribution has confirmed that an additional 8 MW of load can be transfer from

Otonabee TS 44kV to Dobbin TS. This will provide enough capacity to meet the load growth forecast at Otonabee TS 44 kV bus until 2030.

2. **Alternative 2 – Transfer load from Otonabee TS 44kV to Otonabee 27.5kV**: As the voltage levels are different between the 2 low voltage winding of the bus, transferring the load between the different voltages is extremely difficult, costly, and time consuming as it requires all the downstream DS's to be converted to 27.6kV, and in many cases due to distance is not feasible.

The TWG recommends that Hydro One Distribution proceed with the above work in Alternative 1 to ensure continued supply reliability to customers at Otonabee TS 44 kV. Otonabee TS 44kV bus will be monitored after the load transfer and plans should be made if more load transfer from Otonabee TS 44kV bus to Dobbin TS is needed in the long term.

7.6 Asset Renewal Need – Picton TS T1/T2 Transformer Replacement

7.6.1 Description

Picton TS is a 230/44kV transformer station serving Hydro One Distribution. The station comprises two 50/83MVA transformers, T1/T2. The station's 2020 actual peak load was 59 MW and it has a Summer 10-Day LTR of approximately 78MW.

Transformers T1 and T2 are currently about 60 years old and are planned for similar standard units based on their asset condition assessment and taking "right sizing" into consideration. The tentative in-service date is expected in 2025.

The TWG recommends that Hydro One proceed with the above work to ensure continued supply reliability to customers.

7.6.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment: Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Picton TS T1/T2. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.7 Asset Renewal Need – Port Hope TS T3/T4 Transformer

7.7.1 Description

Port Hope TS is located in the city of Port Hope, Ontario and supplies Hydro One Distribution and Elexicon loads. Port Hope TS T3/T4 are 50/83 MVA transformers with a 10 day LTR of 104 MW. T3/T4 currently supplies about 70 MW of load and the long term forecast is well within the current LTR.

The T3/T4 transformers were built in 1959 and have been identified as has reached the end of service life and requiring replacement. The scope of this project is to replace T3/T4 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2025.

The Study Team has assessed right sizing approach to downsizing and/or upsizing these transformers based on needs. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is not decreasing. Upsizing is also not an option as the long term forecast does not justify upgrade. Accordingly, it is recommended to replace these transformers with similar size.

7.7.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:
This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment:
Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Port Hope TS T3/T4. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.8 Asset Renewal Need – Gardiner TS T1/T2 (DESN 1) Transformer

7.8.1 Description

Gardiner TS is located in the city of Kingston, Ontario and supplies Hydro One Distribution and Kingston Hydro loads. Gardiner TS DESN1 T1/T2 are 75/125 MVA transformers with a 10 day LTR of 125 MW. The current loading on T1/T2 have exceeded its 10 day LTR.

The T1/T2 transformers were built in mid 1970s and has reached the end of service life requiring replacement in the previous planning cycle. Following recent inspections of the transformers, the conditions of the transformers were found to be acceptable and the plan to replace the transformers were deferred to 2028.

The Study Team has assessed downsizing and/or upsizing need for these transformers. As the 10 day LTR of the current transformers are substandard, the Working Group concluded that replacing the current transformers which new standard 75/125 MVA units will increase the supply capacity to about 160 MW and alleviate the current overloading at DESN1. Reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option as the current units are already the largest size for a 230/44kV step-down transformers.

7.8.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:
This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment:
Expedite this end of life asset replacement as the current transformers are already overloaded. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.9 Asset Renewal Need – Dobbin TS T1/T2/T5 Auto Transformers

7.9.1 Description

Dobbin TS is located near the city of Peterborough, Ontario and supplies Peterborough to Quinte loads. Dobbin TS consists of three 230/115 kV auto transformers. T1 is rated at 150/250 MVA and T5 is rated at 115 MVA. T2 is rated at 36/78 MVA and currently out of service.

During the previous planning cycle, T2 and T5 were planned to be replaced with one 150/250 MVA unit. However, as T1 has also reached the end of service life, it would be more efficient and cost effective to replace all three transformers with two 150/250 MVA units.

7.9.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:
This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 – Replace three existing autotransformers with two units:
Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Dobbin TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE PETERBOROUGH TO KINGSTON REGION.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon are provided in Table 8-1 below. As the industry is currently witnessing supply chain issues and delays in procurement of equipments, it can impact the near term planning horizon if left unresolved.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-1.

Table 8-1: Recommended Plans in Peterborough to Kingston Region over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate[7] ($Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard[8]	2028*	$30
	Load transfer from DESN1 to DESN2	2022	$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	$30-$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	$35-$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

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

[7] Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

[8] The new standard units are expected to have a higher LTR of about 160 MW

9. REFERENCES

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[5]. 2nd Cycle Peterborough to Kingston Needs Assessment Report (2020) https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/peterboroughtokingston/Documents/RIP%20Report%20-%20Peterborough%20to%20Kingston%20Region.pdf

APPENDIX A: STATIONS IN THE PETERBOROUGH TO KINGSTON REGION

Station	Voltage (kV)	Supply Circuits
Ardoch DS (T1)	115	B1S
Battersea DS (T1/T2)	115	S1K
Belleville TS (T1/T2)	230	T25B, H23B
Dobbin DS (T1/T2)	115	P3S, P4S
Dobbin TS (T3/T4)	115	Q20H, Q20A
Frontenac TS (T3/T4)	115	B5QK, Q3K
Gardiner TS (T1/T2)	230	X4H, X2H
Gardiner TS (T3/T4)	230	X2H, X4H
Harrowsmith DS (T1/T2)	115	B5QK
Hinchinbrooke DS (T1)	115	B5QK
Lodgeroom DS (T1/T2)	115	B1S
Napanee TS (T1)	230	X21, X22
Northbrook DS (T1)	115	B1S
Otonabee TS (T1/T2)	230	T22C, T31H
Otonabee TS (T1/T2)	230	T22C, T31H
Picton TS (T1/T2)	230	X21, X22
Port Hope TS (T1/T2)	115	P3S, P4S
Port Hope TS (T3/T4)	115	P3S, P4S
Sharbot DS (T1)	115	B5QK
Sidney TS (T1/T2)	115	Q12AT, Q6S

APPENDIX B: TRANSMISSION LINES IN THE PETERBOROUGH TO KINGSTON REGION

Location	Circuit Designations	Voltage (kV)
Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
Picton TS – Lennox TS	X21, X22	230
Belleville TS – Hinchinbrooke SS	H23B	230
Hinchinbrooke SS – Havelock TS	H27H	230
Dobbin TS – Chenaux TS	X1P	230
Dobbin TS – Chat Falls GS	C27P	230
Clarington TS – Havelock TS	T32H	230
Chat Falls GS – Havelock TS	C25H	230
Clarington TS – Chat Falls GS	T22C	230
Cherrywood TS – Dobbin TS	P15C	230
Clarington TS – Belleville TS	T25B	230
Dobbin TS – Sidney TS	P3S, P4S	115
Cataraqui TS – Sidney TS	Q6S	115
Barrett Chute TS – Sidney TS	B1S	115
Cataraqui TS – Frontenac TS	Q3K	115
Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

APPENDIX C: DISTRIBUTORS IN THE PETERBOROUGH TO KINGSTON REGION

Distributor Name	Station Name	Connection Type
Eastern Ontario Power Inc.	Frontenac TS	Dx
Elexicon Energy Inc. – Veridian Connections Inc.	Belleville TS	Tx
	Port Hope TS	Dx
Hydro One Distribution	Ardoch DS	Tx
	Battersea DS	Tx
	Belleville TS	Tx
	Dobbin DS	Tx
	Dobbin TS	Tx
	Frontenac TS	Tx
	Gardiner TS	Tx
	Harrowsmith DS	Tx
	Hinchinbrooke DS	Tx
	Lodgeroom DS	Tx
	Napanee TS	Tx
	Northbrook DS	Tx
	Otonabee TS	Tx
	Otonabee TS	Tx
	Picton TS	Tx
	Port Hope TS	Tx
	Sharbot DS	Tx
	Sidney TS	Tx
	Dobbin DS	Dx
	Dobbin TS	Dx
	Otonabee TS	Dx
Kingston Hydro Corporation	Frontenac TS	Tx
	Frontenac TS	Dx
	Gardiner TS	Dx
Lakefront Utilities Inc.	Port Hope TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1: Net Summer Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	2	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	9	9	9	9	9	9	9	9	9	9	9	9
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	111	111	117	122	123	123	125	126	127	129	131	132
Frontenac TS	97	96	100	102	104	104	105	107	108	109	111	112
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Gardiner TS (T3/T4)	25	28	28	28	28	28	28	28	28	28	28	28
Harrowsmith DS	16	16	16	16	16	16	16	16	16	16	17	17
Havelock TS	74	74	74	75	74	74	75	75	76	76	76	77
Hinchinbrooke DS	6	6	6	6	6	6	6	6	6	6	6	6
Lodgeroom DS	9	9	9	9	9	9	9	9	9	9	9	9
Napanee TS	61	62	62	63	63	64	64	65	66	66	67	68
Northbrook DS	6	6	6	6	6	6	6	6	6	6	6	6
Otonabee TS	123	124	119	119	115	115	116	118	119	120	122	124
Picton TS	43	43	44	44	44	45	45	45	46	46	47	47
Port Hope TS	121	121	122	122	122	122	123	123	124	124	125	126
Sharbot DS	4	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	79	79	79	79	79	79	79	80	80	81	81	82
CTS	14	14	14	14	14	14	14	14	14	14	14	14
Total	1122	1132	1147	1161	1163	1166	1174	1182	1192	1199	1212	1223

Table D-2: Net Winter Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	3	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	11	11	11	11	11	11	11	11	11	11	11	11
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	87	87	93	98	99	100	101	102	104	105	106	107
Frontenac TS	101	101	104	106	109	109	111	112	113	115	116	118
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Gardiner TS (T3/T4)	29	32	32	32	32	32	32	33	33	33	33	33
Harrowsmith DS	19	19	19	19	19	19	19	19	19	19	19	19
Havelock TS	69	69	69	69	70	70	70	71	71	72	72	73
Hinchinbrooke DS	7	7	7	7	7	7	7	7	7	7	7	7
Lodgeroom DS	10	10	10	10	10	10	10	11	11	11	11	11
Napanee TS	70	70	71	71	72	72	73	74	75	75	76	77
Northbrook DS	7	7	7	7	7	7	7	7	7	7	7	7
Otonabee TS	145	146	146	142	138	139	140	142	143	146	147	149
Picton TS	48	49	49	50	50	50	51	51	52	52	53	53
Port Hope TS	127	128	128	129	130	130	130	131	132	132	133	134
Sharbot DS	4	4	4	4	4	5	5	5	5	5	5	5
Sidney TS	69	69	68	68	68	68	69	70	70	71	71	72
CTS	26	26	26	26	26	26	26	26	26	26	26	26
Total	1134	1144	1159	1170	1179	1183	1192	1205	1214	1225	1233	1245

Table D-3: Net Summer Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Frontenac TS	101	101	108	107	107	107	108	109	110	111	112	114
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Otonabee TS 44 kV	102	102	98	98	95	95	96	97	98	99	100	102

Table D-4: Net Winter Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Frontenac TS	111	113	117	117	117	118	119	120	121	122	123	125
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Otonabee TS 44 kV	115	116	116	113	109	110	111	113	114	115	116	118

Table D-5: Net Summer Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	187	187	187	188	189	190	191	192
Frontenac TS	101	102	109	110	111	113	117	121	125	129	133	137
Gardiner TS (T1/T2)	146	148	151	153	155	156	158	159	161	163	165	168

Table D-6: Net Winter Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	114	119	120	121	124	128	132	136	140	144	148
Gardiner TS (T1/T2)	132	134	136	138	141	142	144	146	148	150	152	155

Table D-7: Net Winter Non-Coincidental Load Forecast Growth Scenario 2 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	116	124	126	130	136	145	155	165	174	183	193
Gardiner TS (T1/T2)	132	135	138	142	145	148	151	154	157	160	163	167

APPENDIX E: LIST OF ACRONYMS

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



NEEDS ASSESSMENT REPORT

Peterborough to Kingston Region

Date: December 20, 2024

Needs Assessment Report

Peterborough to Kingston

December 20, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Prepared by: Peterborough to Kingston Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston (the "region") and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on best available information throughout the planning process.

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

Executive Summary

REGION	Peterborough to Kingston Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: September 05, 2024 **END DATE:** December 20, 2024

1. INTRODUCTION

The second Regional Planning cycle for the Peterborough to Kingston Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is ten years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. Electrical supply to this region is provided by 3 "Three" major Transmission Stations with Autotransformers that feeds, 10 "Ten" step-down Transformer Stations, 8 "Eight" HV Distribution Stations and 5 "Five" Customer transformer Stations.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecasts.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The needs assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and operational concerns;

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing;" and,

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle.

The following needs and projects discussed in the region's second cycle RIP have been completed:

- Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
- Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.

- Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle.

The following needs and projects discussed in the region's second cycle RIP are currently underway:

- Otonabee TS 44kV (Station Capacity) – 8 MW of load transfer will be transferred to Dobbin TS in 2025.
- Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
- Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.
- Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
- Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
- Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
- Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by two new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
- Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
- Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
- B5QK (Long-term Capacity need in 2038) – As recommended in the previous cycle IRRP, IESO will re-evaluate this capacity need in next phases of this Regional Planning cycle, when 20 year load forecast will be developed.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Cataraqui TS (T1/T2)

b) Transmission Station Capacity

- Dobbin TS
- Gardiner TS
- Napanee TS
- Belleville TS
- Cataraqui TS
- Picton TS
- Hinchinbrooke DS
- Frontenac TS

c) Transmission Line Capacity

- 115 kV B1S line under Q6S contingency

d) System Reliability, Operation and Load restoration

- No new System Reliability, Operation and Load restoration needs identified in this NA.

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to new station capacity needs:

- Sidney TS (2031), Otonabee TS 27.6kV (2026), Otonabee TS 44kV (2028) and 115kV P4S (2031).

These needs will be assessed again during the next phases of this Regional Planning cycle.

9. RECOMMENDATIONS

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Needs which do not require further regional coordination.

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

Needs which require further regional coordination.

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028
Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA as potential options in addressing these needs during the IRRP phase.

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Peterborough to Kingston (P to K) Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the P to K Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

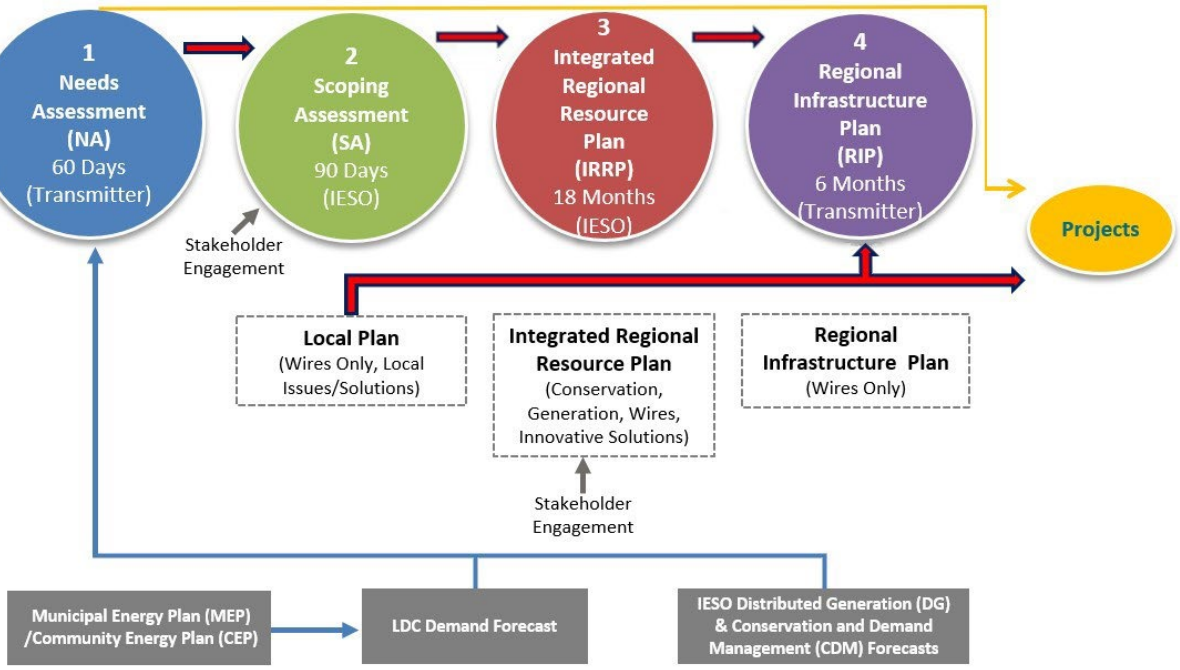


Figure 1: Regional Planning Process

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

Table 1: Peterborough to Kingston Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Transmission (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Distribution
4	Elexicon Energy Inc.
5	Kingston Hydro Corporation
6	Lakefront Utilities Inc.
7	Eastern Ontario Power Inc.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Peterborough to Kingston region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no

regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Peterborough to Kingston (P to K) region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. The region includes Frontenac County, City of Kingston, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The geographical boundaries of the P to K region are shown in Figure 2 below.

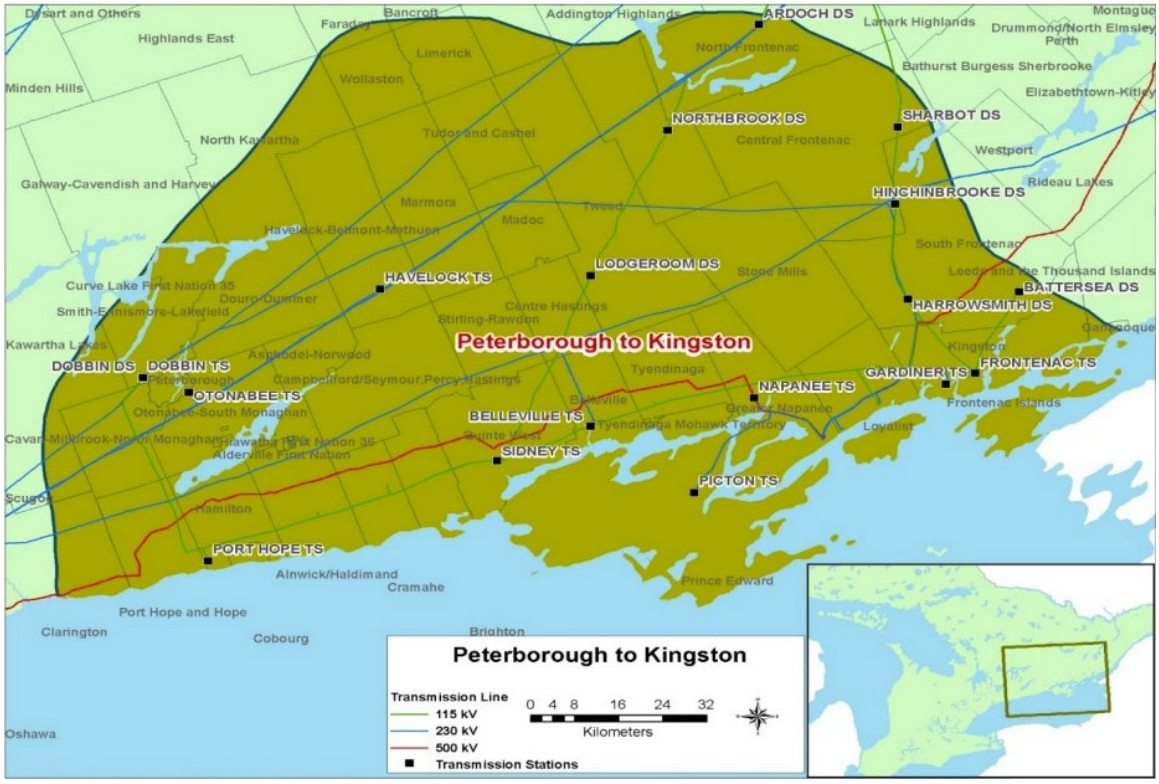


Figure 2: Map of P to K Regional Planning Area

Electrical supply to all five (5) Local Distribution Customers (LDC) listed in table -1 and five (5) Customer Transformer Stations (CTS) in the P to K region is provided by 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS through a 230kV and 115kV transmission lines network. There are seven (7) Generation Stations that generates a total of 3474 MW. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment.

The details of existing facilities in the region are summarized below and depicted in the single line diagram shown in figure 3.

- 500/230kV Autotransformer: Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two autotransformers.
- 230/115kV Autotransformer: Cataraqui TS and Dobbin TS are the two (2) transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Ten (10) step-down transformer stations and eight (8) High Voltage Distribution Stations (HVDS) are connected to 230 and 115 kV lines that supply load in the Region.
- Five Customer Transformer Stations (CTS) are supplied in the Region.
- Seven Generating stations are also connected.

The circuits and stations names are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the P to K Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
P3S, P4S, Q6S, B1S, Q3K & B5QK.	X1H, X2H, X3H, X4H, X21, X22, H23B, H27H, X1P, C27P, T32H, C25H, T22C, P15C & T25B.	Dobbin TS*, Cataraqui TS*, Lennox TS*, Belleville TS, Dobbin TS, Frontenac TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS, Sidney TS, Port Hope TS, CTS -1, CTS-2, CTS-3, CTS-4 & CTS-5.	Seven (7) Generating Stations with total capacity of 3474 MW.

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of P to K region is shown in Figure 3 below.

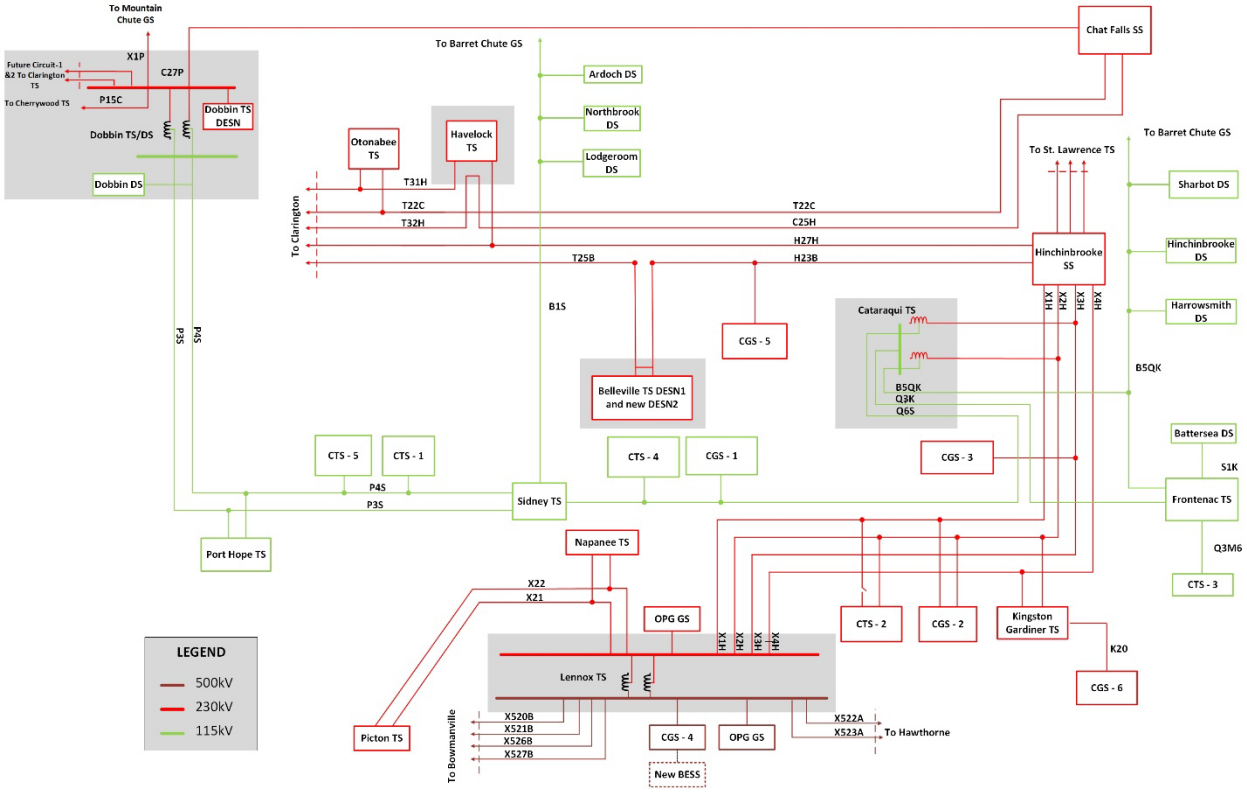


Figure 3: P to K region Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the P to K NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called “Load Forecast Guideline for Ontario” in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC’s load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- P to K 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g., through their MEPs & CEPs).
- Known capacity and reliability need, operating issues, and/or major assets requiring replacement/ refurbishment; and

- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the P to K region.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing;" and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer and winter peak loads. Three load forecasts were developed i.e., Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

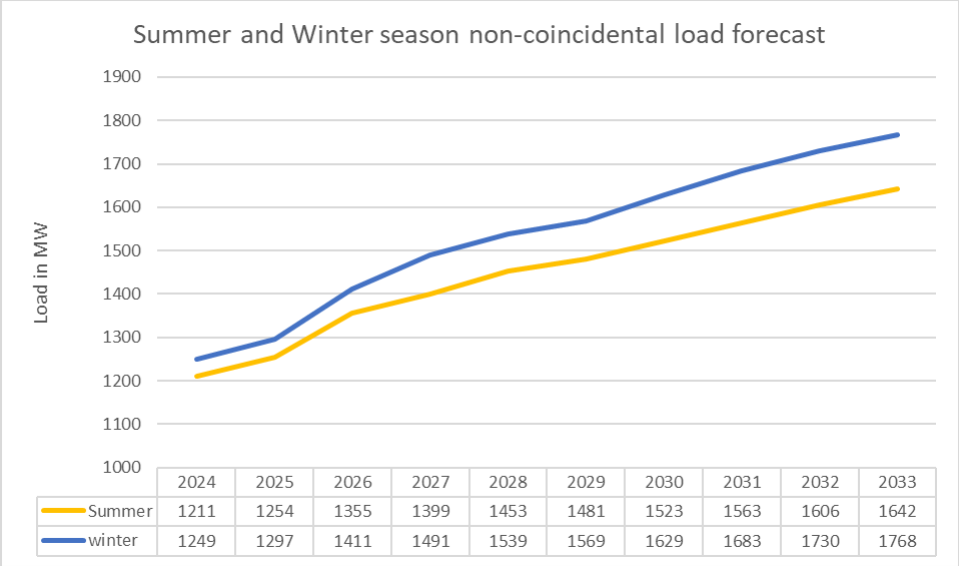
The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2033.
- The Region is winter peaking, but station LTRs are more limiting during the summer season. So, this assessment is based on both summer and winter peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the P to K region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM"), and Distributed Generation ("DG") forecast for the P to K region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the weather corrected forecast starting point. The overall 10-year load forecast growth rate for summer season is 3.6% and 4.2% for winter season. The extreme summer and winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer and winter weather corrected net load forecast for the individual stations in the P to K region is given in Appendix A. The graphical representation of the regional net non-coincidental load growth for both summer and winter season over the study period is shown in figure 4 below.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	1211	1254	1355	1399	1453	1481	1523	1563	1606	1642
winter	1249	1297	1411	1491	1539	1569	1629	1683	1730	1768

Figure 4: P to K region net summer and winter season non-coincidental load

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not

necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

7. NEEDS

This section describes emerging new needs identified in the P to K Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle (Regional Infrastructure Plan ("RIP") report) with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

1. Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
2. Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.
3. Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle. This station capacity need should be further assessed in conjunction with Frontenac TS in the next phases of this Regional Planning cycle.
4. Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
5. Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One

Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.

6. Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
7. Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
8. Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
9. Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
10. Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
11. Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
12. B5QK (Long-term Capacity need in 2038) – As recommended in the second cycle IRRP, IESO will re-evaluate this capacity need in next phases of current Regional Planning cycle, when 20 year load forecast will be developed.

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

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or are updated from previous RIP

Need location	Need description/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cataraqui TS	T1/T2 renewal based on asset condition assessment.	7.2	7.1.1
Transmission Station Capacity Needs			
Dobbin TS (T3/T4)	Projected to reach capacity in 2032	New	7.2.1
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028	7.5 & 7.8	7.2.2
Napanee TS (T1/T2)	Projected to reach capacity in 2026	New	7.2.3
Cataraqui TS	Update on need identified in previous cycle RIP	7.2	7.2.4

Picton TS	Projected to reach capacity in 2026	7.6	7.2.5
Hinchinbrooke DS	Projected to reach capacity in 2028	New	7.2.6
Belleville TS	Capacity limitation due to transmission voltage restrictions	7.3	7.2.7
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle	7.4	7.2.8
Transmission Line Capacity Needs			
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency, high hydro output	New	7.3.1
System Reliability, Operation and Load restoration Needs			
No new system Reliability, Operation and Load restoration need is identified in this NA.			

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the P to K Region. The complete list of major HV transmission equipment requiring replacement in the P to K Region is provided in table 4 in this section. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD*
Gardiner TS	T1/T2 replacement with like for like 75/100/125 MVA units.	2027
Port Hope	T3/T4 replacement with like for like 50/67/83 MVA units.	2033
Picton TS	T1/T2 replacement with like for like 50/67/83 MVA units.	2026
Dobbin TS	T1/T2 Autotransformers to be replaced by two bigger 150/250MVA units and decommissioning existing T5.	2028
Lennox TS	Ten (10) 230kV ABCB & Oil breakers to be replaced by new SF6 breakers.	2026
Cataraqui TS	T1 and T2 230/115kV Autotransformers to be replaced with 150/200/250 MVA units.	2034

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

7.1.1 Cataraqui TS – T1/T2 Autotransformers

The existing T1/T2, 230/115 kV, 150/200/250 MVA autotransformers were built in 1968 and are identified to be replaced based on asset condition assessment. The existing autotransformers have substandard rating due to internal limitations and will be replaced by similar size modern units which is expected to have a higher LTR. This replacement will also help resolve the station capacity need identified in previous cycle RIP and is discussed in section 7.2.4 of this report. The planned in-service date is 2034.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transforming stations in the P to K Region using the summer and winter non-coincidental peak net load forecasts that were provided by the Technical Working Group. Based on the results, the following Station[2] capacity needs have been identified in the during the study period:

7.2.1 Dobbin TS (T3/T4)

Dobbin TS is located near the city of Peterborough, Ontario, and supplies load to Hydro One Distribution through its two 75/100/125MVA, T3/T4 step down transformers. The 2032 non-coincident peak net load is expected to exceed its summer and winter LTRs of 156 MW and 177 MW, respectively.

While the need for additional capacity is projected toward the end of the study period, it depends on several factors, including whether the load increases as anticipated. There is a possibility that this overload could be managed through load transfers to nearby stations. It is recommended that Hydro One Transmission and Distribution collaborate to address this potential issue, and no regional planning coordination is required at this time.

7.2.2 Gardiner TS (T1/T2)

Gardiner TS DESN 1 is located in city of Kingston, Ontario, and is supplied by 230kV, X2H/X4H circuits and supplies load to Hydro One Distribution and Kingston Hydro Corporation (embedded) currently through its two 75/100/125 MVA, T1/T2 step down transformers. These transformers were identified for replacement in previous regional planning cycle and are planned to be replaced in 2027 and will have a better LTR (~170MW). The non-coincident peak net load summer load at this station is exceeding its LTR of 121 MW now.

Kingston Hydro Corporation has projected significant load growth in 2026, driven by an industrial development project, and again in 2032, due to a customer transitioning from a conventional gas heating system to geothermal heating. These new contributions will lead to exceed the new transformer to exceed its LTRs by 2028. It is recommended that a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.3 Napanee TS (T1/T2)

Napanee TS is located in Greater Napanee area, Ontario, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 101.7 MW and 116.9 MW, respectively.

Hydro One Distribution has projected significant load growth in 2026, driven by two large customers. These new loads are expected to exceed the new transformer LTRs by 2026. However, as these load

[2] Belleville TS and Frontenac TS capacity needs were already identified in the 2nd cycle RP and there are no changes to the recommendations made in the RIP by TWG. Updates to all previously identified needs is provided in beginning of section-7 of this report.

forecasts are not committed load, the station capacity need may be shifted accordingly. It is recommended the load growth shall be monitored and a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.4 Cataraqui TS

Cataraqui TS is a 230/115kV autotransformer station that supplies the 115kV stations in the Eastern sub region of the P to k region. It was recommended upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment performed by Hydro One, the conductor in the 115kV yard was found to be sufficient. T1/T2, 230/115 kV, 150/200/250 MVA autotransformers will be replaced with similar size units in 2034. The new autotransformers are expected have higher LTRs and will further address the issue of overload at the station. The replacement of existing autotransformers is based on asset condition assessment and hence it is recommended that no further regional planning coordination is required at this time.

7.2.5 Picton TS

Picton TS is located in Picton area, Ontario, between Bay of Quinte and Prince Edward Bay, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 75 MW and 89 MW, respectively.

The existing T1/T2 transformers have been identified for replacement based on asset condition assessments. The replacement units will be of similar size but will have higher LTRs (~100MW) due to modern designs, which will be enough to supply the load throughout the study period. It is recommended that no further regional planning coordination is required at this time.

7.2.6 Hinchinbrooke DS

Hinchinbrooke DS is located in Central Frontenac area, Ontario and is supplied by 115kV B5QK circuit and supplies Hydro One Distribution Load through its 115/13.2 kV T1 transformer. The 2028 non-coincident peak net load is expected to exceed its winter LTRs of 8.4 MW. The load growth in the area is not significant and can be monitored and addressed within Hydro One Transmission and Distribution. No further regional planning coordination is recommended at this time.

7.2.7 Belleville TS

Belleville TS is located in Belleville area and is supplied by two 230 kV T25B and H23B lines and supplies load to Hydro One Distribution and Elexicon Energy Inc. through its DESN1 two 75/100/125 MVA, 230/44kV, T1/T2 step down transformers. A new Belleville TS DESN2 will be in service by the end of 2026 to address the supply capacity need in the region. Based on the load forecast, and the existing voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency at the Belleville TS, limiting the total loading by the year 2028-2031, depending on the load and LV configuration at Belleville TS DESN2. This undervoltage cannot be mitigated without a partial loss of load at DESN2 post 2028 loading. Therefore, it is recommended to conduct a comprehensive assessment in the next phases of the regional planning cycle to manage this need as well as a full bulk planning study as identified in the previous regional planning cycle.

7.2.8 Frontenac TS

Frontenac TS is located in Kingston area and is supplied by two 115kV B5QK and Q3K lines and supplies Hydro One Distribution, Utilities Kingston, and Eastern Ontario Power Inc. load through its two 50/67/83 MVA, 230/44kV, T3/T4 stepdown transformers. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new station in the area in the near term, which may be built by the Transmitter or the LDC. The Frontenac station capacity need should be further assessed in the next phases of this Regional Planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transmission line circuits in the P to K Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 115kV B1S

B1S is a long 145km 115kV single-circuit radial line which extends between Barrett Chute GS and Sidney TS and serving Ardoch DS, Northbrook DS and Lodgeroom DS in between. The supply capacity of the line could exceed its continuous rating in in the near to medium timeline following a contingency on Q6S line and high hydro output from generators in the region. The B1S line is limited by a low sag temperature which is the main reason of this line could be overloaded. Hydro One Transmission will perform an internal assessment to see if there is room for improving the sag temperature to address the issue in near time, but it is also recommended to do a full assessment during the next phases of this regional planning cycle.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2024-2033 to cater this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the P to K region

to be considered in this sensitivity analysis is the new Industrial load and expansion of urban areas from municipalities, electric vehicle (EV) penetration, and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed the new Industrial load and expansion of urban areas from municipalities, EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer and winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The normal and high growth forecasts are shown in Appendix A.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new station capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Dobbin TS (T3/T4)	2032	2029	2032
2	Gardiner TS (T1/T2)	Current and 2028	Current	Current and 2033
3	Gardiner (T3/T4)	NA	NA	NA
4	Napanee TS (T1/T2)	2026	2026	NA
5	Picton TS	2026	2026	NA
6	Hinchinbrooke DS	2028	2027	NA
7	Sydney TS	NA	2031	NA
8	Otonabee TS 25.6kV	NA	2026	NA
9	Otonabee TS 44kV	NA	2028	NA
10	B1S	2028	2028	2028
11	P4S	NA	2031	NA
12	Belleville TS (undervoltage)	2028	2027	NA
13	Frontenac TS	2027	2026	2030

In addition, the radial tap from 230kV circuits X2H and X4H serving Kingston through Gardiner TS DESN1 and DESN2 have a summer Long Term Emergency (LTE) rating of about 395 MW. Current normal summer loading forecast for Gardiner TS DESN1 and DESN2 total 293 MW by 2033, leaving about 102 MW of

thermal capacity remaining. If the area experiences a higher load growth as per the scenario above and/or large transmission customer connection up to 100 MWs, there will be capacity need in this area.

The sensitivity analysis identified the additional capacity needs at towards the end of the study period. The sensitivity analysis and these needs will be assessed again during the next phases of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Table 7: Needs which do not require further regional coordination

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[3] of the regional planning cycle. A list of these needs are as follows:

Table 8: Needs which require further regional coordination

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028

[3] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

10. REFERENCES

[1] P to K 2nd cycle Regional Infrastructure Plan ("RIP") report (issue May 27, 2022)

[2] P to K 2nd cycle Integrated Regional Resource Plan report (issue November 4, 2021)

[3] Gatineau Corridor End-of-Life Study published in December 2022.

[4] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[5] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. October 1, 2024)

[6] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer and Winter Weather Adjusted Net Load Forecast

Table A.1: P to K Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Battersea DS	T1/T2	21.9	8.9	9.2	9.1	9.1	9.0	9.1	9.1	9.2	9.2	9.3	9.3
Belleville TS	T1/T2	170.05	164.9	166.6	175.4	183.5	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	55.3	68.0	72.5	77.5	84.1	91.1	101.1
Dobbin DS	T1/T2	16.9	15.9	15.9	15.9	6.2	6.2	6.6	7.0	7.4	7.8	8.2	8.4
Dobbin TS	T3/T4	156.8	70.1	72.7	82.2	111.1	119.9	127.5	133.9	145.9	155.2	159.8	163.9
Frontenac TS	T3/T4	109.3	98.6	102.3	105.2	109.2	113.1	115.8	118.3	123.6	128.2	131.7	135.3
Gardiner TS	T1/T2	121.6	130.3	125.3	128.2	162.6	168.0	170.5	171.9	175.8	177.7	195.4	200.8
Gardiner TS	T3/T4	111.2	46.8	57.1	57.4	57.7	57.9	79.9	84.9	86.6	88.4	90.3	92.3
Harrowsmith DS	T1/T2	21.9	15.8	15.7	15.5	15.6	15.5	15.6	15.7	15.7	15.8	15.9	16.1
Havelock TS	T1/T2	86.4	63.1	62.5	65.2	64.8	64.5	65.0	65.1	65.6	66.0	66.3	66.7
Hinchinbrooke DS	T1	6.8	6.1	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.5	6.5	6.5
Lodgeroom DS	T1/T2	21.9	8.6	8.5	8.6	8.6	8.6	8.6	8.5	8.6	8.5	8.6	8.6
Napanee TS	T1/T2	101.7	66.6	75.2	82.4	108.4	110.9	105.2	108.3	111.6	113.0	114.3	118.2
Northbrook DS	T1	8.4	6.0	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	6.0	6.0
Otonabee TS 27.6kV	T1/T2	92.52	81.7	82.6	83.9	74.5	75.3	75.7	76.0	76.4	76.9	77.5	78.2
Otonabee TS 44kV	T1/T2	97.2	81.2	82.0	77.3	79.3	82.3	85.0	85.7	88.3	89.7	90.9	91.6
Picton TS	T1/T2	75.6	64.3	69.7	71.8	79.2	85.7	88.4	90.8	93.1	95.6	97.5	99.4
Sharbot DS	T1	6.2	3.9	4.0	4.0	4.0	3.9	4.0	4.0	4.0	4.0	4.0	4.1
Sidney TS	T1/T2	111.8	80.6	83.0	88.4	95.8	96.2	100.2	100.3	100.7	102.6	103.2	103.9
Port Hope TS	T1/T2	122.6	52.0	54.2	58.3	59.6	60.3	61.1	61.5	65.2	72.2	73.0	73.9

Port Hope TS	T3/T4	101.7	73.4	73.7	74.5	74.7	74.8	74.9	74.9	75.0	75.3	75.7	76.3
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.2: P to K Region – Winter Non-Coincident – Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5
Battersea DS	T1/T2	24.3	11.9	12.2	12.2	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.6
Belleville TS	T1/T2	183.4	158.5	159.9	172.9	184.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4	0.0	0.0	0.0	0.0	59.2	75.6	82.2	90.0	98.2	107.3	119.6
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.4	10.5	11.6	12.6	13.7	14.7	15.8	16.3
Dobbin TS	T3/T4	177.7	80.2	83.5	93.5	105.6	117.5	127.8	136.3	164.7	177.0	183.0	188.4
Frontenac TS	T3/T4	123.5	101.8	110.0	112.7	116.3	120.0	122.6	124.7	129.4	132.2	135.2	138.3
Gardiner TS	T1/T2	143.5	128.4	123.4	126.5	159.8	165.3	168.1	169.4	173.2	175.1	192.0	197.4
Gardiner TS	T3/T4	138.7	41.5	51.7	52.1	52.6	80.0	85.8	87.5	89.4	91.3	93.3	95.5
Harrowsmith DS	T1/T2	24.3	19.7	20.2	20.5	20.7	20.9	21.1	21.2	21.4	21.5	21.7	21.9
Havelock TS	T1/T2	97.2	78.2	80.5	81.5	82.7	83.5	84.3	84.7	85.3	87.5	88.3	89.2
Hinchinbrooke DS	T1	8.6	8.2	8.4	8.5	8.6	8.7	8.7	8.8	8.9	8.9	9.0	9.1
Lodgeroom DS	T1/T2	24.3	11.1	11.4	11.5	11.7	11.8	12.0	12.0	12.1	12.4	12.5	12.7
Napanee TS	T1/T2	116.9	81.0	89.0	95.9	120.2	122.7	117.8	120.7	121.9	123.2	124.4	125.7
Northbrook DS	T1	10.8	8.7	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.5	9.6	9.8
Otonabee TS 27.6kV	T1/T2	109.8	54.9	55.8	57.1	58.1	58.9	59.3	59.5	59.7	60.0	60.3	60.8
Otonabee TS 44kV	T1/T2	109.8	77.8	78.8	74.0	76.1	79.2	81.9	82.6	85.1	94.3	95.3	96.0
Picton TS	T1/T2	89.1	60.9	68.6	70.8	78.3	85.0	87.8	90.2	92.5	94.9	96.6	98.6

Sharbot DS	T1	8.4	5.4	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1
Sidney TS	T1/T2	111.8	77.1	76.6	82.4	96.8	97.2	102.4	103.1	104.5	107.3	108.4	109.6
Port Hope TS	T1/T2	139.7	61.3	63.4	67.4	68.7	69.6	70.6	71.0	74.5	81.0	81.8	82.7
Port Hope TS	T3/T4	115.9	75.6	76.1	77.1	77.6	77.9	78.3	78.3	78.5	78.9	79.3	79.9
CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Table A.3: P to K Region Summer Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	3.0
Battersea DS	T1/T2	21.9	8.9	9.4	9.5	9.6	9.7	9.7	9.7	9.8	9.9	10.0	10.1
Belleville TS	T1/T2	170.05	164.9	167.4	180.7	192.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	70.4	89.5	96.3	103.8	113.7	124.2	139.2
Dobbin DS	T1/T2	16.9	15.9	15.9	16.0	6.0	6.0	6.6	7.2	7.8	8.4	9.1	9.3
Dobbin TS	T3/T4	156.8	70.1	73.9	88.2	131.6	144.8	156.1	165.8	183.8	197.8	204.7	210.7
Frontenac TS	T3/T4	109.3	98.6	104.2	108.5	114.5	120.3	124.4	128.2	136.1	143.0	148.2	153.6
Gardiner TS	T1/T2	121.6	130.3	137.7	142.1	193.7	201.7	205.5	207.6	213.4	216.3	242.9	251.0
Gardiner TS	T3/T4	111.2	46.8	62.2	62.6	63.1	63.4	96.4	103.9	106.4	109.1	112.0	115.0
Harrowsmith DS	T1/T2	21.9	15.8	16.0	16.3	16.5	16.7	16.8	16.9	16.9	17.1	17.4	17.6
Havelock TS	T1/T2	86.4	63.1	63.8	67.9	68.4	69.0	69.8	69.9	70.6	71.2	71.7	72.2
Hinchinbrooke DS	T1	6.8	6.1	6.7	6.7	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1
Lodgeroom DS	T1/T2	21.9	8.6	8.7	8.7	8.8	8.8	8.8	8.9	8.9	9.0	9.1	9.2
Napanee TS	T1/T2	101.7	66.6	79.5	90.3	129.4	133.0	141.5	146.1	151.1	153.1	155.1	161.0
Northbrook DS	T1	8.4	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5
Otonabee TS 27.6kV	T1/T2	92.52	81.7	83.0	85.0	99.0	100.2	100.8	101.3	101.8	102.6	103.5	104.5
Otonabee TS 44kV	T1/T2	97.2	81.2	82.4	89.6	92.7	97.2	101.2	102.3	106.1	108.3	110.0	111.1
Picton TS	T1/T2	75.6	64.3	72.4	75.5	86.6	96.5	100.4	104.1	107.5	111.2	114.1	117.0
Sharbot DS	T1	6.2	3.9	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.4
Sidney TS	T1/T2	111.8	80.6	84.1	92.3	103.4	104.0	109.9	110.1	110.7	113.5	114.5	115.6
Port Hope TS	T1/T2	122.6	52.0	55.3	61.5	63.3	64.4	65.6	66.2	71.7	82.3	83.5	84.9
Port Hope TS	T3/T4	101.7	73.4	73.8	75.1	75.4	75.5	75.7	75.7	75.9	76.3	76.9	77.7
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9

CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.4: P to K Region – Winter Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7
Battersea DS	T1/T2	24.3	11.9	12.3	12.4	12.5	12.6	12.6	12.6	12.7	12.7	12.8	12.9
Belleville TS	T1/T2	183.4	158.5	160.6	180.2	196.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4		0.0	0.0	0.0	79.6	104.1	114.0	125.8	138.1	151.6	170.1
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.5	10.5	12.2	13.7	15.3	16.9	18.6	19.2
Dobbin TS	T3/T4	177.7	80.2	85.2	100.2	118.2	136.1	151.5	164.3	206.9	225.4	234.4	242.4
Frontenac TS	T3/T4	123.5	101.8	114.0	118.1	123.6	129.0	133.0	136.2	143.2	147.4	151.8	156.6
Gardiner TS	T1/T2	143.5	128.4	135.9	140.5	190.4	198.7	202.9	204.9	210.6	213.4	238.8	246.9
Gardiner TS	T3/T4	138.7	41.5	56.8	57.4	58.1	99.2	107.9	110.5	113.3	116.2	119.3	122.5
Harrowsmith DS	T1/T2	24.3	19.7	20.5	20.9	21.2	21.5	21.8	22.0	22.2	22.4	22.7	23.0
Havelock TS	T1/T2	97.2	78.2	81.7	83.2	84.9	86.1	87.4	88.0	88.8	92.1	93.3	94.7
Hinchinbrooke DS	T1	8.6	8.2	8.5	8.6	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5
Lodgeroom DS	T1/T2	24.3	11.1	11.6	11.8	12.0	12.2	12.4	12.5	12.7	13.0	13.2	13.5
Napanee TS	T1/T2	116.9	81.0	93.0	103.3	139.8	143.6	150.9	155.3	157.0	159.0	160.7	162.8
Northbrook DS	T1	10.8	8.7	9.0	9.2	9.3	9.5	9.6	9.7	9.8	10.0	10.1	10.3
Otonabee TS 27.6kV	T1/T2	109.8	54.9	56.3	58.2	59.8	61.0	61.5	61.8	62.1	62.5	63.1	63.8
Otonabee TS 44kV	T1/T2	109.8	77.8	79.3	86.5	89.7	94.2	98.4	99.5	103.2	116.9	118.5	119.6
Picton TS	T1/T2	89.1	60.9	72.5	75.8	87.0	97.0	101.2	104.8	108.3	111.9	114.5	117.4
Sharbot DS	T1	8.4	5.4	5.7	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4
Sidney TS	T1/T2	111.8	77.1	77.8	86.5	108.1	108.6	116.5	117.5	119.6	123.8	125.5	127.2
Port Hope TS	T1/T2	139.7	61.3	64.5	70.4	72.5	73.8	75.2	75.8	81.0	90.8	92.0	93.4
Port Hope TS	T3/T4	115.9	75.6	76.3	77.9	78.6	79.0	79.6	79.7	80.0	80.5	81.2	82.1

CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Ardoch DS (T1)	115	B1S
2	Battersea DS (T1/T2)	115	S1K
3	Belleville TS (T1/T2)	230	T25B, H23B
4	Dobbin DS (T1/T2)	115	P3S, P4S
5	Dobbin TS (T3/T4)	115	Q20H, Q20A
6	Frontenac TS (T3/T4)	115	B5QK, Q3K
7	Gardiner TS (T1/T2)	230	X4H, X2H
8	Gardiner TS (T3/T4)	230	X2H, X4H
9	Harrowsmith DS (T1/T2)	115	B5QK
10	Havelock TS T1/T2	115	T31H, H27H
11	Hinchinbrooke DS (T1)	115	B5QK
12	Lodgeroom DS (T1/T2)	115	B1S
13	Napanee TS (T1)	230	X21, X22
14	Northbrook DS (T1)	115	B1S
15	Otonabee TS (T1/T2) 27.6	230	T22C, T31H
16	Otonabee TS (T1/T2) 44	230	T22C, T31H
17	Picton TS (T1/T2)	230	X21, X22
18	Sharbot DS (T1)	115	B5QK
19	Sidney TS (T1/T2)	115	Q12AT, Q6S
20	Port Hope TS (T1/T2)	115	P3S, P4S
21	Port Hope TS (T3/T4)	115	P3S, P4S

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
2	Picton TS – Lennox TS	X21, X22	230
3	Belleville TS – Hinchinbrooke SS	H23B	230
4	Hinchinbrooke SS – Havelock TS	H27H	230
5	Dobbin TS – Chenaux TS	X1P	230
6	Dobbin TS – Chat Falls GS	C27P	230
7	Clarington TS – Havelock TS	T32H	230
8	Chat Falls GS – Havelock TS	C25H	230
9	Clarington TS – Chat Falls GS	T22C	230

10	Cherrywood TS – Dobbin TS	P15C	230
11	Clarington TS – Belleville TS	T25B	230
12	Dobbin TS – Sidney TS	P3S, P4S	115
13	Cataraqui TS – Sidney TS	Q6S	115
14	Barrett Chute TS – Sidney TS	B1S	115
15	Cataraqui TS – Frontenac TS	Q3K	115
16	Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

Appendix D: List of LDC's

No.	Name of LDC
1	Hydro One Distribution
2	Elexicon Energy Inc.
3	Kingston Hydro Corporation
4	Lakefront Utilities Inc.
5	Eastern Ontario Power Inc.

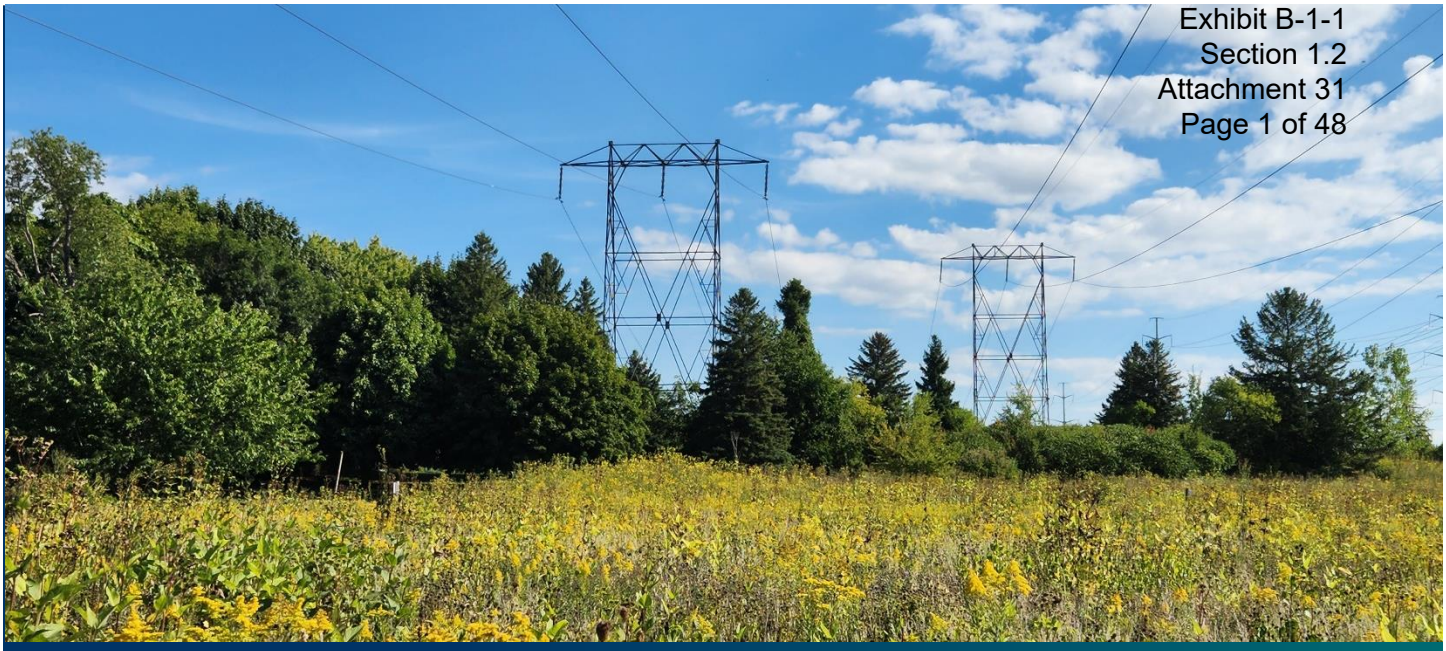
Appendix E: List of Municipalities in the P to K Region

No.	Name of Municipality
1	Municipality of Clarington
2	City of Kingston
3	County of Frontenac
4	Township of North Frontenac
5	Township of South Frontenac
6	Township of Central Frontenac
7	Township of Frontenac Islands
8	City of Belleville
9	City of Quinte West
10	Municipality of Centre Hastings
11	Municipality of Hastings Highlands
12	Municipality of Marmora and Lake
13	Municipality of Tweed
14	Town of Bancroft
15	Town of Deseronto
16	Township of Carlow/Mayo
17	Township of Faraday
18	Township of Limerick
19	Township of Madoc
20	Township of Stirling-Rawdon
21	Township of Tudor & Cashel
22	Township of Tyendinaga
23	Township of Wollaston
24	Municipality of Brighton
25	Town of Cobourg
26	Municipality of Port Hope
27	Municipality of Trent Hills
28	Township of Alnwick/Haldimand
29	Township of Cramahe
30	Township of Hamilton
31	City of Peterborough
32	Township of Asphodel-Norwood
33	Township of Cavan Monaghan
34	Township of Douro-Dummer
35	Township of Havelock-Belmont-Methuen
36	Township of North Kawartha
37	Township of Otonabee-South Monaghan
38	Township of Selwyn

39	Municipality of Trent Lakes
40	Prince Edward
41	Town of Greater Napanee
42	Township of Addington Highlands
43	Township of Loyalist
44	Township of Stone Mills

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



Gatineau Corridor End-of-Life Study

December 2022

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List of Abbreviations

Abbreviation	Description
APO	Annual Planning Outlook
APS	Achievable Potential Study
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbine
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
ENS	Energy Not Served
EOL	End of Life
FIDS	Flow into Dobbin and Sidney interface
FIO	Flow into Ottawa interface
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
MTS	Municipal Transformer Station
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource Transmission Assessment Criteria
RAS	Remedial Action Scheme
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station

1. Executive Summary

The Gatineau Corridor End-of-Life Study examines transmission equipment reaching end-of-life (EOL) in the Gatineau transmission corridor along with forecast reliability concerns in the areas supplied by those transmission circuits, Ottawa and Peterborough to Quinte West. Consideration of replacement options for significant EOL transmission facilities through an IESO-led integrated planning process can ensure assets are renewed in a cost-effective manner that aligns with the evolution of the electricity system (e.g. decarbonisation of the electricity sector and the economy) and reflects potential new or emerging needs that have arisen in an area since the assets were first installed. The reliability issues identified through the study include:

- Approximately 800 km of the 230 kV circuits on the Gatineau Corridor (Oshawa to Ottawa) are expected to reach end-of-life over the next 5 to 10 years
- The Load Meeting Capability (LMC) for the Ottawa area is forecast to be exceeded in the mid 2020's
- The LMC for the Peterborough to Quinte West area is insufficient today

To minimize cost, minimize land-use impacts, mitigate forecast risk, preserve options to increase system capability in the future and due to lack of cost effective stand-alone resource or energy efficiency alternatives, the following integrated solution package is recommended to address the transmission equipment EOL needs and accommodate the demand forecast for the Ottawa and the Peterborough to Quinte West areas over the long-term:

- Refurbish all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing EOL
- Build a new double circuit 230 kV transmission line into Dobbin TS (in Peterborough) from either Cherrywood TS (in Pickering) or Clarington TS (in Oshawa) with a planned in-service of 2029
- Pursue up to 230 MW of additional system cost-effective energy efficiency in the Ottawa area over the 20 year planning horizon, while monitoring demand growth and resource acquisition activities in the Ottawa zone
- Update and expand the use of remedial action schemes (RAS) in the Peterborough and Ottawa areas to meet planning standards and further improve both areas' LMCs

This solution package represents the lowest cost option, with transmission reinforcements estimated to cost approximately $650 M. The transmission reinforcements ensure reliability in the Peterborough to Quinte West area is sufficient for the next 20 years and reliability in the Ottawa area is sufficient until 2037. If the 230 MW of additional energy efficiency is implemented, Ottawa area's reliability would also be sufficient over the 20 year planning horizon. The solution package maintains the capacity of the existing circuits being refurbished and avoids the need to address localized issues that would result from retiring the circuits (i.e. reconfiguration of stations and short line builds in the Ottawa area).

2. Introduction

2.1 Power System Planning in Ontario

The Independent Electricity System Operator (IESO) is responsible for conducting independent planning for electricity generation, demand management, conservation and transmission in the Province of Ontario. In carrying out this mandate, the IESO undertakes planning activities to ensure that the province has, and will continue to have, an adequate and reliable supply of resources and transmission to meet Ontario's electricity needs.

The IESO's planning generally consists of regional planning and bulk system planning. These are two separate but inter-related planning activities. Regional planning is carried out according to a regional planning process endorsed by the Ontario Energy Board (OEB). Regional planning produces plans that address system issues that are local in nature, within 21 planning regions covering the province. Bulk System Planning is carried out by the IESO to address system issues which are more provincial in nature, such as the province-wide need for generation capacity, and transmission system solutions to enable transporting power reliably and economically across the province. Also covered are regulatory compliance studies and reporting requirements, such as required by the North American Electric Reliability Corporation (NERC) reliability standards and the Northeast Power Coordinating Council (NPCC) criteria.

2.2 Gatineau Corridor End-of-Life Study

The Gatineau Corridor End-of-Life Study examines transmission equipment reaching end-of-life (EOL) in the Gatineau transmission corridor along with forecast reliability concerns in the areas of Ottawa and Peterborough to Quinte West which are supplied by the circuits located within the corridor. Consideration of replacement options for EOL transmission facilities through an integrated planning process can ensure assets are renewed in a cost-effective manner that aligns with the evolution of the electricity system (e.g. decarbonisation of the electricity sector and the economy) and new or emerging issues that have arisen in an area since the assets were originally constructed.

2.3 Gatineau Corridor and Key Areas of Interest

Gatineau Corridor

The Gatineau corridor is a 300 km long transmission corridor that runs from Durham region to Peterborough and onto Ottawa. The Gatineau corridor was originally constructed in the late 1920's to early 1930's primarily to transfer power from hydro electric facilities in eastern Ontario and Quebec to the Toronto load centre. The Gatineau corridor consists of five (5) 230 kV transmission lines (P15C/C27P, T22C, T32H/C25H, T33E/E34M, and T31H/H27H), and have a combined length of 1,300 line-kms. Today, the corridor serves a number of purposes which include facilitating generation, transferring bulk system flows across eastern Ontario, and supplying loads in the Peterborough to Quinte West and Ottawa areas.

Peterborough to Quinte West Area

The Peterborough to Quinte West area is located in eastern Ontario and includes Peterborough County, Northumberland County, Prince Edward County, and the City of Quinte West. The electricity demand of this area is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions, large business parks, health care, national defence bases, manufacturing and industrial processes.

This area is supplied by a number of 230 and 115 kV transmission lines coming from the directions of Durham region and the County of Lennox and Addington. The area is served by four supply stations which include Otonabee TS, Dobbin TS, Port Hope TS, and Sidney TS. While Otonabee TS is in close proximity to Dobbin TS which is the other supply station in Peterborough, the upstream electricity system serving Otonabee TS is distinct from the system serving the other three stations. When describing system capability and demand forecasts in this report, the definition of the Peterborough to Quinte West area excludes Otonabee TS.

Electricity demand in this summer peaking Peterborough to Quinte West area has been fairly constant and has historically reached approximately 310 MW. There is approximately 300 MW of transmission connected hydro-electric generation located in the Greater Madawaska and Renfrew areas supporting the load in Peterborough to Quinte West.

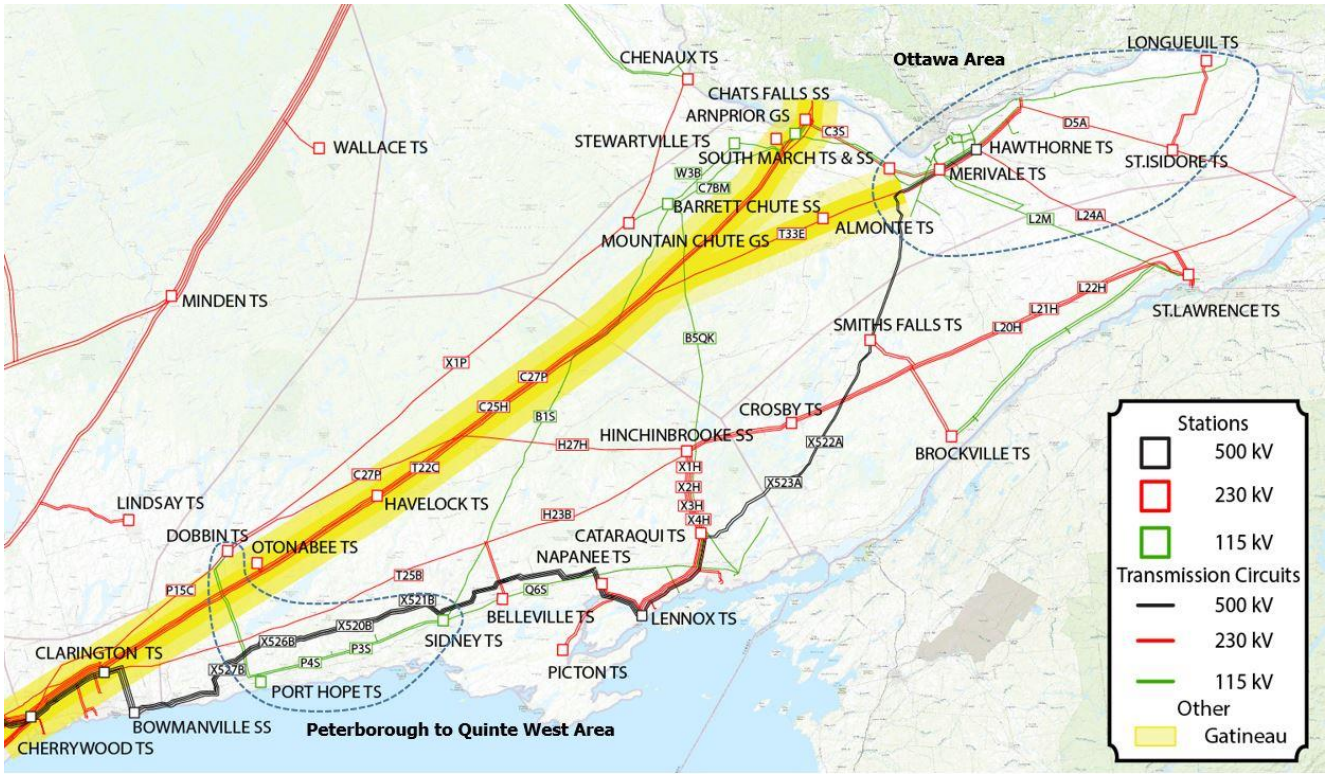
Ottawa Area

The City of Ottawa is the second largest city in Ontario with a population of approximately 1 million people. The city has seen its population grow steadily by approximately 1.5% annually since 2015, and with that has also seen a steady growth of its developed lands. This development is primarily focused in five areas: the downtown core, Nepean & Riverside South, South Kanata & Stittsville, the Village of Richmond, and Orleans. This growth is primarily being seen through the development of new mixed commercial/residential communities, intensification of existing communities, and major projects like the Ottawa Light Rail Transit system. In rural Ottawa, the economy contributes over $1 billion to the GDP. Rural economic activity includes such things as agriculture, retail sales, construction, forestry and mining (aggregates), tourism, manufacturing, personal and business services, and transportation.

Ottawa is supplied by a number of 500, 230 and 115 kV transmission lines coming from the directions of Peterborough County and the County of Lennox and Addington. Electricity demand in this summer peaking area has been steadily growing and has historically reached approximately 1,800 MW. There are a number of different electricity supply resources in the surrounding area that help support the Ottawa load, including approximately 600 MW of hydro-electric generation located on the Madawaska and Ottawa rivers, 70 MW of gas generation located in the city, and three interties with Quebec system.

A map of the area highlighting the Gatineau corridor and the areas of Peterborough to Quinte West and Ottawa are shown in Figure 1.

Figure 1 | Map of Gatineau Corridor, Highlighting Areas of Interest



3. Planning for Transmission Asset End-of-Life in the Gatineau Corridor

3.1 Transmission Asset End-of-Life

Consideration of end-of-life (EOL) transmission asset replacement needs is an integral part of transmission planning. When an asset reaches EOL, a decision must be made to either replace it ("like-for-like" or "right-size") or, in some cases, decommission it to meet safety, reliability, environmental, and customer requirements. While the length of time varies, many transmission assets remain in use and deliver value for 40 years or more. Over such a long period of time, the functional requirements of the transmission system could change, as customer needs, system conditions, sector trends, and government policy evolve. Coordination of transmission asset replacement needs with other forecast reliability and security needs over the long-term is critical to maximizing the benefits and value of transmission system investments.

End-of-Life

EOL represents the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. EOL is determined by the asset owner's risk-based assessments, taking into account such factors as reliability, loss of load, environmental considerations, and safety.

EOL is different from the "useful life" of asset which is an accounting estimate of the number of years it is likely to remain in service considering factors such as manufacturer guidelines, and historical asset performance, failure and retirement data.

As assets age and begin to approach their "useful life", assessments are carried out to determine their overall condition by examining asset-specific health metrics, along with performance history. Based on the results, equipment is scheduled to be replaced when it reaches EOL.

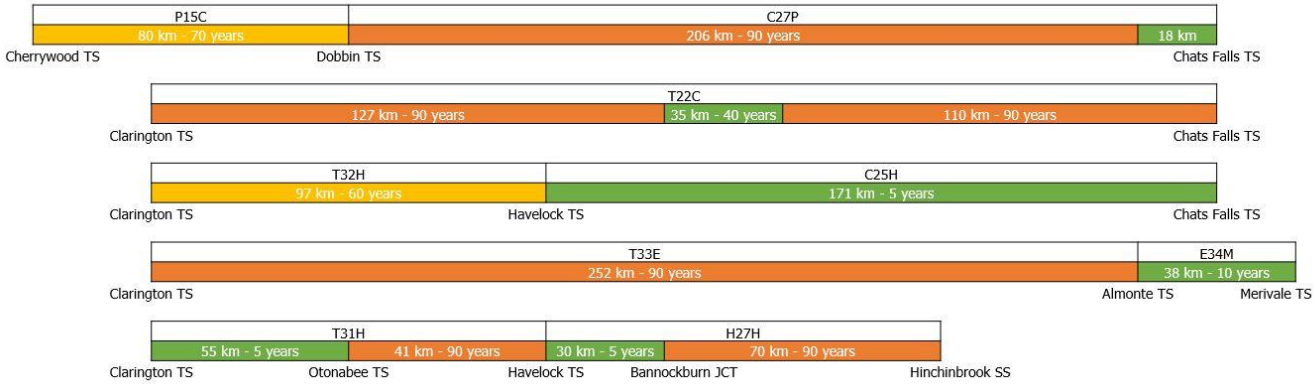
3.2 Gatineau Corridor Transmission Asset End-of-Life

The Gatineau Corridor was originally constructed in the late 1920's to early 1930's. At over 90 years since its original construction, large portions of corridor and specifically the transmission line conductors are nearing EOL, and in some instances have already been partially refurbished to maintain safety and reliability of the transmission system.

Transmission line conductors have a "useful life" of approximately 90 years. The facility owner, Hydro One Networks Inc. (HONI) has identified that the conductors on transmission lines C27P, T22C and T33E are nearing EOL based on asset condition assessments and require replacement before 2028. A decision to either refurbish the EOL facilities "like-for-like" or decommission and replace them with new cost effective facilities that provide additional value must be made now, as new transmission lines typically take 7 years to design, approve and construct.

While HONI has only identified the three transmission lines (C27P, T22C and T33E) as nearing EOL, other transmission lines in the corridor were examined in this study to identify potential candidates for right-sizing or decommissioning. Asset demographic age information for the Gatineau corridor transmission lines are illustrated in Figure 2.

Figure 2 | Age of Gatineau Corridor Transmission Line Conductors



GREEN Recently refurbished, the plan assumes continued service

YELLOW Intermediate age

ORANGE Sections that are ~90 years old total 806 km

3.3 Potential Opportunities for Right-sizing or Decommissioning

As noted earlier, while HONI has only identified the three transmission lines, C27P, T22C and T33E as nearing EOL, all transmission lines in the corridor were screened to identify potential candidates for right-sizing or decommissioning. The screening considered various qualitative factors such as the criticality of the facility on reliability, stranding recently refurbished facilities, and potential for other cost effective alternatives. The screening identified transmission lines T22C and T33E as potential candidates for decommissioning, as alternatives exist that are potentially more cost effective and/or provides greater system value. The transmission lines C27P, T32H, T31H, and H27H are recommended to be refurbished when they reach EOL as cost effective alternatives are not evident. The last remaining circuit in the corridor P15C, is essential to supplying Peterborough to Quinte West and also the eastern Ontario system. For this reason, the circuit P15C can either be refurbished or upgraded to help accommodate the forecast demand for Peterborough to Quinte West and Ottawa areas. A summary of the considerations for each transmission line is provided in

Table 1.

Table 1 | Opportunities for Right-sizing or Decommissioning in the Gatineau Corridor

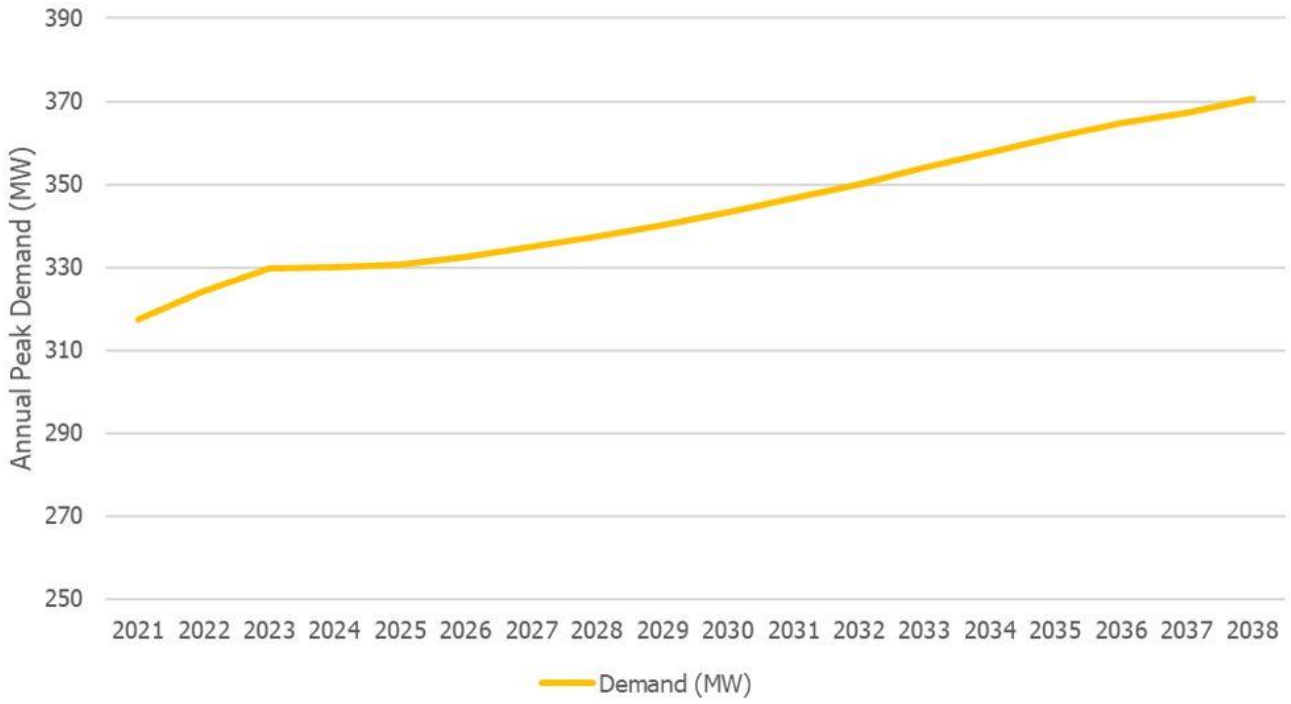
Transmission Line	Considerations	Opportunity for Right-sizing or Decommissioning
P15C/C27P	• The transmission lines P15C and C27P are critical supply circuits for the Peterborough to Quinte West area, P15C is a limiting constraint for the area's load meeting capability, as well as an upstream constraint for Ottawa's load meeting capability • The transmission line P15C runs between Pickering and Peterborough, passing by northern part of Durham region where load growth is expected most in the future • The transmission line C27P provides transmission connection for the 85 MW hydro-electric Arnprior Generating Station; if C27P were to be decommissioned, a portion of C27P would still need to maintained (~15 km) • The vast majority of the C27P transmission line is approaching its "useful life" or has been identified as nearing EOL	P15C: Opportunity for upgrading C27P: No
T22C	• The transmission line T22C is critical in supporting the Ottawa area during certain transmission outage conditions • The transmission line T22C provides transmission connection for Otonabee TS; if T22C were to be decommissioned, supply to Otonabee TS would need to reconfigured to one of the remaining circuits in the corridor • The majority of the transmission line has been identified as nearing EOL	T22C: Opportunity for decommissioning and replacing with a new transmission line that can offer additional system value
T32H/C25H	• The transmission line T32H/C25H is critical in supporting the Ottawa area during certain transmission outage conditions • The transmission lines T32H/C25H are critical supply circuits for Havelock • A portion of the transmission line (60%) was recently refurbished, and the remaining portion of the transmission line still has 30 years before reaching its average "useful life".	T32H/C25H: No
T33E/E34M	• The transmission line T33E/E34M is critical in supporting the Ottawa area during certain transmission outage conditions • The transmission lines T33E/E34M supply Almonte TS, Terry Fox TS, and Cambrian MTS; if T33E were to be decommissioned, a portion of T33E would still need to be maintained (~55km) and reconnected to one of the remaining circuits in the corridor • The entire T33E has been identified as nearing EOL	T33E: Opportunity for decommissioning and replacing with a new transmission line that can offer additional system value E34M: No
T31H/H27H	• The transmission line T31H/H27H helps support the loads in the areas of Lennox and Addington county, City of Kingston and Hinchinbrooke Township during certain transmission outage conditions • The transmission lines T31H/H27H are critical supply circuits for Havelock • A portion of the transmission line (40%) was recently refurbished, and the remaining portion of the transmission line has been identified as nearing EOL	T31H: No H27H: No

4. Demand Forecasts

4.1 Peterborough to Quinte West Area Demand

The Peterborough to Quinte West electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities including educational institutions, large business parks, manufacturing and Canadian Forces bases. As shown in Figure 3, loads in this summer-peaking area are forecast to grow from 310 MW to 370 MW over the next 20 years.

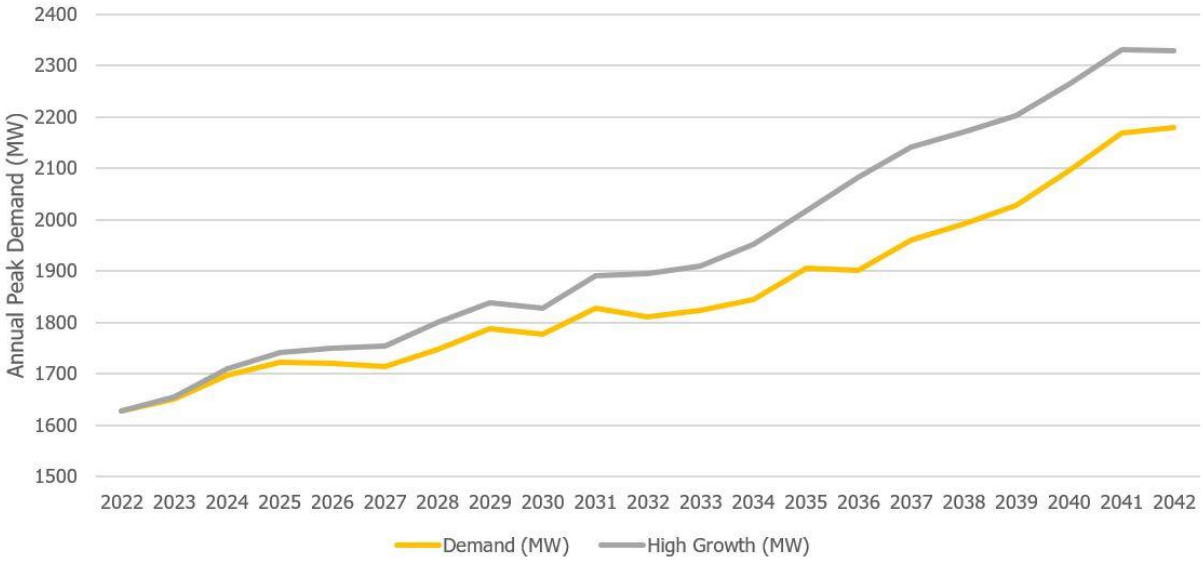
Figure 3 | Peterborough to Quinte West Demand Forecast



4.2 Ottawa Area Demand

The Ottawa electricity load growth is primarily being seen through the development of new mixed commercial/residential communities, intensification of existing communities, and major projects like the Ottawa Light Rail Transit system. As shown in Figure 4, loads in this summer-peaking area are forecast to grow from approximately 1650 MW to 2200 MW and 2350 MW over the next 20 years under the reference forecast and high growth scenario respectively.

Figure 4 | Ottawa Demand Forecast



Energy Evolution - Ottawa's Community Energy Transition Strategy

Energy Evolution[1] is the action plan for how Ottawa will meet its targets to reduce greenhouse gas emissions to zero by 2040 within the corporation, and by 2050 Ottawa-wide. Its vision is to transform Ottawa into a thriving city powered by clean, renewable energy. To achieve Ottawa's emission reduction targets will require:

- Significantly reduce energy demand for existing end-uses
- Phase out fossil fuels
- Increase use of renewable resources

Some of the identified actions to help achieve these targets will have an interdependency with planning the electricity system supplying the City of Ottawa, such as electrification of personal and commercial vehicles, electrification of heating, and new renewable resources.

The Energy Evolution strategy was approved by Ottawa's City Council on October 28, 2020. The impact of Energy Evolution on the peak electricity demand has yet to be quantified and is not included in the demand forecast shown in Figure 4. The IESO will work with the City of Ottawa and the Greater Ottawa regional planning working group during the next cycle of regional planning for Greater Ottawa (expected to commence in Q4 2022), to determine the how the strategy would impact the development of planning forecasts and scenarios, and what additional planning activities are necessary to support the City of Ottawa's Energy Evolution strategy. It's anticipated that to achieve energy evolution targets, Ottawa demand would grow beyond the high growth scenario and this uncertainty was considered when evaluating options.

[1] More information regarding Energy Evolution is available on the City of Ottawa's website (link)

5. Supply Capability to Focus Areas

Supply capability to the areas of Peterborough to Quinte West and Ottawa is provided by a number of internal generation resources, as well as external resources accessed through the 500 kV and 230 kV transmission system (connecting the area to the rest of the Ontario)[2].

Planning of the transmission system focuses on ensuring that the system will operate reliably over a broad spectrum of system conditions and following a wide range of probable system contingencies. These planning events and performance requirements are established through a number of planning criteria and standards by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the IESO. The planning events examined are aimed to stress the transmission system (i.e. adjusting hydro-electric generation output for drought conditions, adjusting the load forecast for extreme weather, loss of one or more transmission and/or generation elements, etc.), and the performance requirements are intended to set a baseline for designing the electricity system.

As Ontario's electricity grid is made up of a variety of different energy resource types, it's important to note that the capability of each resource type at the time of peak loading conditions will vary. Variable generators such as wind and solar are modelled to historical output coincident with the time of peak. Hydro-electric generators are modelled to their historical output available during drought conditions.

5.1 Peterborough to Quinte West Supply

5.1.1 Peterborough to Quinte West Internal Resources

Transmission-connected resources currently comprise of mostly hydro-electric generation along the Madawaska and Ottawa rivers. These resources represent a combined total of 300 MW of installed generation capacity[3], however the generation output is expected to be closer to 40 MW during drought conditions.

5.1.2 Peterborough to Quinte West Load Meeting Capability

Supply to Peterborough to Quinte West is also provided through the Flow into Dobbin and Sidney (FIDS) transmission interface which is bounded by two 115 kV circuits from Cataraqui TS (Q6S) and from Barrett Chute TS (B1S), and two 230 kV circuits in the Gatineau Corridor (P15C and C27P), providing supply from broader provincial resources.

[2] The mixture of resources used to supply the region's and the province's energy needs at any time is determined by the real-time energy market.

[3] The region also has a significant number of distribution connected resources, mainly solar. The impact of these distributed resources has been considered as part of the reference load forecast.

The FIDS interface is thermally limited by 230 kV circuit P15C from Cherrywood TS to Dobbin TS in the summer. Generally, losing one or more of the interface circuits will lead to overloads of the remaining circuit(s). In the existing system, the load meeting capability of Peterborough to Quinte west area is limited to 270 MW today, the limiting phenomena is illustrated in Table 2.

Table 2 | Peterborough to Quinte West Load Meeting Capability

Transmission Equipment Out of Service	Phenomena	Peterborough to Quinte West LMC
Q6S	Thermal overload on P15C	270 MW
P15C	Thermal overload on Q6S	280 MW

5.2 Ottawa Supply

5.2.1 Ottawa Internal Resources

Transmission-connected resources currently comprise of a significant amount of hydro-electric generation along the Madawaska and Ottawa rivers, one natural-gas generation plant in the City of Ottawa, and one wind generator to the east of the city. These resources represent a combined total of 800 MW of installed generation capacity[4]. Over the next 20 years, contracts for the natural gas-fired and wind generators are expected to expire, which needs to be considered when identifying local supply needs.

5.2.2 Ottawa Load Meeting Capability

Supply to Ottawa is also provided through the Flow into Ottawa (FIO) transmission interface, defined as two 500 kV circuits from Lennox TS (X522A, X523A), and four 230 kV transmission circuits from Beauharnois (B5D), St. Lawrence TS (L24A), Chats Falls TS (C3S) and Almonte TS (E34M), providing supply from broader provincial resources.

Under normal operating conditions, the Ottawa load is primarily supplied by the two 500 kV circuits from Lennox TS. However, when these two primary supply circuits are unavailable, the Ottawa load relies on the 230 kV electricity system to supply the load. The FIO interface is thermally limited by the 230 kV circuit L24A from St. Lawrence TS to Hawthorne TS, and the upstream 230 kV circuit P15C from Cherrywood TS to Dobbin TS. In the existing system, the load meeting capability of Ottawa is limited to 1700 MW today due to thermal limitations. While not the most limiting, Ottawa's load meeting capability is also limited by voltage instability. Information regarding Ottawa's load meeting capability and limiting phenomena is shown in Table 3.

[4] The region also has a significant number of distribution connected resources, mainly hydro-electric and solar. The impact of these distributed resources has been considered as part of the reference load forecast.

Ottawa is also interconnected with Quebec through three (3) 230 kV interconnections and three (3) 115 kV interconnections. The six interties facilitate mostly economic energy transactions between Ontario and Quebec through the Ontario electricity market. The current interties between Quebec and Ontario have a combined capacity of 2,775 MW; however, transmission constraints in Ontario limit the available transfer capability between the two areas[5]. Real-time transactions with Quebec have reached a maximum of about 1,800 MW.

Table 3 | Ottawa Load Meeting Capability

Transmission Equipment Out of Service	Phenomena	Ottawa LMC
Loss of X522A & X523A	Thermal overload on P15C	1700
Loss of X522A & X523A	Voltage Instability	1800

[5] More information about the Ontario-Quebec interconnection is available in the IESO's 2017 report – "Ontario-Quebec Interconnection Capability: A Technical Review" (link)

6. Need for Additional Supply

The IESO has conducted an assessment of the system's capability to supply the areas of Peterborough to Quinte West and Ottawa. Planning criteria were applied in accordance with North American Electric Reliability Corporation standards and the Northeast Power Coordinating Council reliability directories to determine system capacity needs. In the context of the bulk system, adequacy is defined as the ability to supply regional demand, while respecting transfer capability limits across the bulk system and interconnections.

This assessment considered both the contribution of existing internal generation and resources external to the area.

6.1 Capacity Requirement

A deterministic approach was used to evaluate the need for additional capacity behind the Flow into Dobbin and Sidney, and Flow into Ottawa interfaces. A need was identified where the annual coincident load forecast exceeded the interface transfer limits and the total capacity of internal transmission-connected generation.

6.1.1 Flow into Dobbin and Sidney

Based on this assessment, to supply Peterborough to Quinte West there is a capacity need of 100 MW in the summer by 2035. The capacity need is an existing issue, that arises during periods of high demand coinciding with low water conditions. The annual capacity requirement for FIDS is shown in Figure 5.

In addition to the annual capacity shortfall, the estimated frequency, duration, and magnitude of unserved energy events were also investigated and used to inform options development. Figure 6 contains heat maps to visually demonstrate these characteristics. Each cell in the heat map indicates the expected frequency, of all hours of unserved energy, that may occur in that specific hour or month. By 2035, unserved energy is expected to occur mostly in the months of April through October, with the largest impact observed during the summer peaks.

There is a significant amount of distribution connected solar generation within the Peterborough to Quinte West area. The effects of the solar generation can be seen in the heat maps, as the solar generation helps offset the demand during the hours of 8:00 AM to 5:00 PM and reduces the energy needs during those hours.

Figure 5 | Flow into Dobbin and Sidney Capacity Requirement

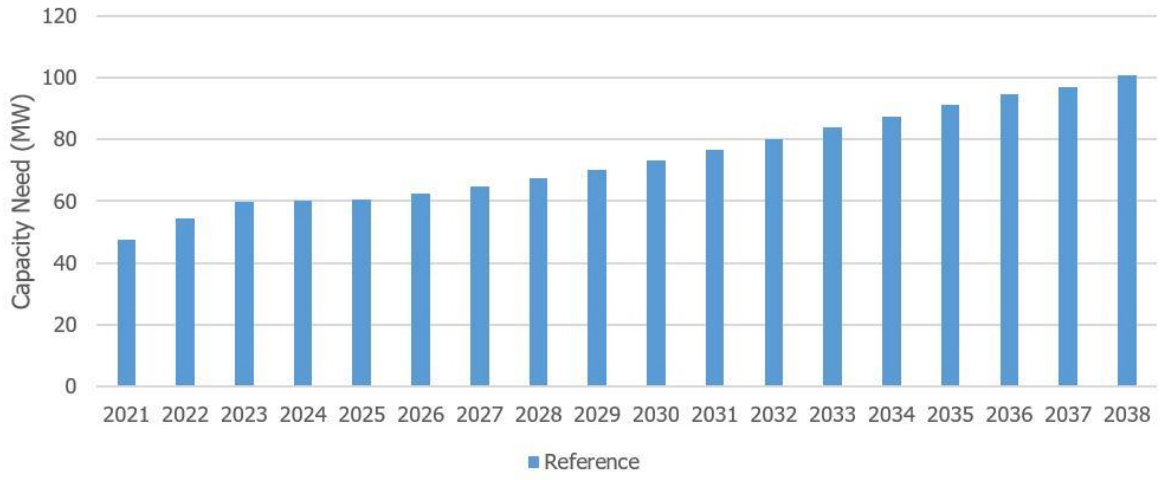


Figure 6 | Heat Maps Showing Possible Energy Need behind FIDS in 2035

Need (MW)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
89	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
78	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%
67	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%
56	0%	0%	0%	0%	0%	1%	2%	3%	1%	0%	0%	0%
44	0%	0%	0%	1%	0%	2%	4%	5%	3%	1%	0%	0%
33	0%	0%	0%	3%	3%	3%	6%	7%	5%	2%	0%	0%
22	0%	0%	0%	4%	6%	6%	9%	9%	7%	3%	0%	0%
11	0%	0%	0%	7%	10%	9%	12%	14%	10%	4%	0%	0%
0	1%	1%	0%	10%	15%	14%	16%	21%	15%	7%	0%	0%

Month

Need (MW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
100	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
89	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
78	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
67	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%
56	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%	1%	0%	0%	0%
44	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	5%	4%	2%	1%	0%	0%
33	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	6%	7%	6%	5%	2%	1%	0%
22	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	8%	9%	9%	8%	4%	2%	0%
11	1%	0%	0%	1%	2%	4%	4%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	9%	10%	10%	9%	7%	5%	0%
0	3%	2%	2%	3%	6%	8%	7%	1%	0%	0%	0%	0%	0%	0%	0%	1%	5%	11%	11%	10%	10%	9%	8%	0%

Hour Ending

6.1.2 Flow into Ottawa

Based on this assessment, a capacity need first emerges in 2025 and grows to 475 MW in the summer by 2042 under the reference scenario. Under the high growth scenario, the capacity need increases to 625 MW by 2042. When considering generation coming off contract, the capacity need becomes 550 MW and 700 MW respectively (approximately 75 MW of transmission connected generation coming off contract during the 20 year planning horizon). The annual capacity requirement is shown in Figure 7. In addition to the annual capacity shortfall, the estimated frequency, duration, and magnitude of unserved energy events were also investigated and used to inform options development. Figure 8 contains heat maps to visually demonstrate these characteristics. While Ottawa is a summer peaking area today, its expected that Ottawa will gradually shift to being winter peaking over the next 20 years due to decarbonisation efforts.

Figure 7 - Flow into Ottawa Capacity Requirement

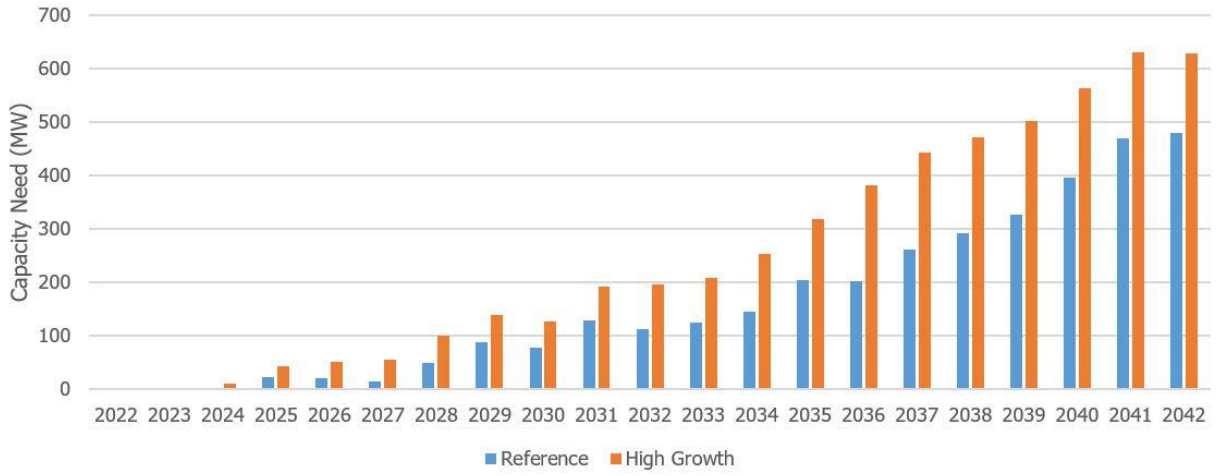


Figure 8 |Heat Maps Showing Possible Energy Need behind FIO in 2035

Need (MW)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
215	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
191	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%
167	0%	0%	0%	0%	0%	0%	0%	7%	0%	0%	0%	0%
143	0%	0%	0%	0%	0%	0%	0%	12%	0%	0%	0%	0%
119	2%	0%	0%	0%	0%	0%	0%	20%	0%	0%	0%	0%
96	3%	0%	0%	0%	0%	0%	0%	24%	0%	0%	0%	0%
72	7%	5%	0%	0%	0%	0%	2%	25%	0%	0%	0%	0%
48	15%	10%	0%	0%	0%	0%	5%	31%	0%	0%	0%	0%
24	20%	12%	0%	0%	0%	0%	10%	36%	0%	0%	0%	0%
0	29%	15%	0%	0%	0%	0%	15%	41%	0%	0%	0%	0%
	Month											

Need (MW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
215	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
191	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%
167	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	2%	0%	0%	0%	0%	0%	0%	0%
143	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	2%	2%	0%	0%	0%	0%	0%	0%
119	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%	5%	3%	3%	0%	0%	0%	0%	0%	0%
96	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	3%	5%	7%	3%	0%	0%	0%	0%	0%	0%
72	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	3%	7%	12%	7%	2%	0%	0%	0%	0%	0%
48	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%	5%	8%	15%	15%	7%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%	3%	7%	10%	20%	17%	10%	0%	0%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%	5%	7%	14%	22%	22%	14%	7%	0%	0%	0%	0%
	Hour Ending																							

7. Analysis of Alternatives

This study compares alternatives to meeting the identified near-, mid-, to long-term supply capacity requirements for the areas of Peterborough to Quinte West and Ottawa. The alternatives considered include both traditional transmission wires type reinforcements aimed at improving the FIDS and FIO interface transfer limits as well as non-wire alternatives (NWAs) such as generation, battery energy storage systems (BESS), demand response, etc.

Non-wire Alternatives

For each need where NWAs are potentially suitable, the demand profiling methodology is used to characterize the need and inform options analysis. The development of NWAs takes into consideration a number of factors, such as:

- Maximizing the use of existing infrastructure and resources in the region (e.g., merchant generation, generators with expiring contracts, etc.) to defer transmission and/or generation investment.
- New generation and/or storage with the attributes that most closely meet the need, or integrated solutions in combination with demand response or energy efficiency measures.
- New transmission facilities to deliver provincial resources.

NWA selection is based on capacity (MW) and energy requirements (MWh). The need characteristics are quantified by capacity factors and the energy-not-served (ENS) profile which is the forecast hourly demand above the load meeting capability that can be served by the existing power system in a specified area. The ENS profile is not static over the planning horizon, allowing NWAs to be installed in modular and discrete blocks as demand grows. Transmission solutions and non-energy-limited resources can primarily be sized based on the power capacity requirements alone, however energy-limited resources must also consider the energy requirement and temporal patterns. For example, BESS must be sized such that the energy reservoir has enough storage capability to withdraw enough energy overnight, and inject it the next day with enough capacity to meet demand.

The capacity and energy requirements evolve as demand grows and influences the feasibility and economics of various NWAs. In general, potential options that are known to satisfy technical requirements and have the lowest cost tend to be screened for suitability first. The NWA should aim to cost-effectively meet the need on an equivalent dollar and reliability basis. Calculating the levelized unit capacity cost provides a means of assessing alternative options for planning purposes and is generally used as a screening tool to shortlist resources for more detailed analysis. The calculation considers factors such as overnight capital costs, fixed operating, maintenance and administrative (OM&A) costs, variable OM&A costs, etc.) amortized across the NWAs lifetime.

Cost estimates for NWAs are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs are resources with costs on par with simple cycle gas turbines (SCGT) generators or BESS, depending on the relative size of the facility and the capacity factor. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation. BESS are also becoming cost competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy.

NWAs also provide bulk system capacity and energy benefits and are taken into consideration as part of the cost analysis. Bulk system capacity benefits are considered in each year capacity is required and is based on the capacity auction reference price. The reference price is the estimated Net Cost of New Entry (Net CONE) of the anticipated lowest cost marginal resource in Ontario that would be developed when new generation is required. Bulk system energy benefits are considered for any instance where the NWA displaces higher marginal cost resources.

Energy Efficiency

Energy efficiency is a low cost resource that offers tremendous benefits for individuals, businesses and the power system as a whole. Energy-efficiency programs help reduce the need for new investments in power plants and transmission lines.

The IESO offers a number of Conservation and Demand Management (CDM) programs as part of the 2021-2024 CDM Framework under the Save on Energy brand. In order to address regional and local system needs, the IESO can also assess the potential for savings opportunities incremental to these current initiatives that are cost effective based on system benefits and can be leveraged to help defer or compliment wires infrastructure and ensure system reliability.

As described in Section 6, a capacity requirement exists in Peterborough to Quinte West area today and is forecast to appear in the Ottawa area by 2025. As the timing of the needs are in the near-term and with the magnitude of the needs being substantial (upwards of 100 MW within the first 10 years), incremental energy efficiency was considered in this assessment as a potential compliment to other solutions, not as a stand-alone solution.

7.1 Alternatives Considered

In total there were six packages of solutions put together to form the basis of the alternatives considered. Each package comprises of a combination of solutions described in this report. The packages are shown in Table 4**Error! Reference source not found.**.

Table 4 | Gatineau Corridor EOL Study Solution Packages

	T22C & T33E	Peterborough to Quinte West Area Improvements	Peterborough to Quinte West LMC	Ottawa Area Improvements	Ottawa LMC	Cost (2021 $M)
1	Refurbish	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	Pursue targeted energy efficiency	1950 MW	$600M-$650M
2	Retire	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	Two 230 kV circuits from St. Lawrence TS to Merivale TS Pursue targeted energy efficiency	2050 MW	$725M-$775M
3	Retire	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	One 500 kV circuit from St. Lawrence TS to Hawthorne TS	2150 MW	$875M-$925M
4	Refurbish	175 MW resource at/near Dobbin TS	390 MW	Pursue targeted energy efficiency	1950 MW	$1,150M-$2,000M
5	Retire	Two 230 kV circuits from Dobbin TS to Clarington TS/Cherrywood TS	440 MW	480 MW resource at/near Hawthorne TS	2180 MW	$875M-$1,725M
6	Retire	225 MW resource at/near Dobbin TS	390 MW	480 MW resource at/near Hawthorne TS	2180 MW	$2,150M-$4,150M

Transmission Reinforcement into Peterborough

Transmission reinforcement into Peterborough involves a new transmission line between Dobbin TS in Peterborough and either Cherrywood TS in Pickering or Clarington TS in Oshawa. With four (4) 230 kV transmission circuits interconnecting Cherrywood TS and Clarington TS, and the presence of 500-230 kV auto-transformation at both stations, the two stations are quite similar from an electrical supply perspective.

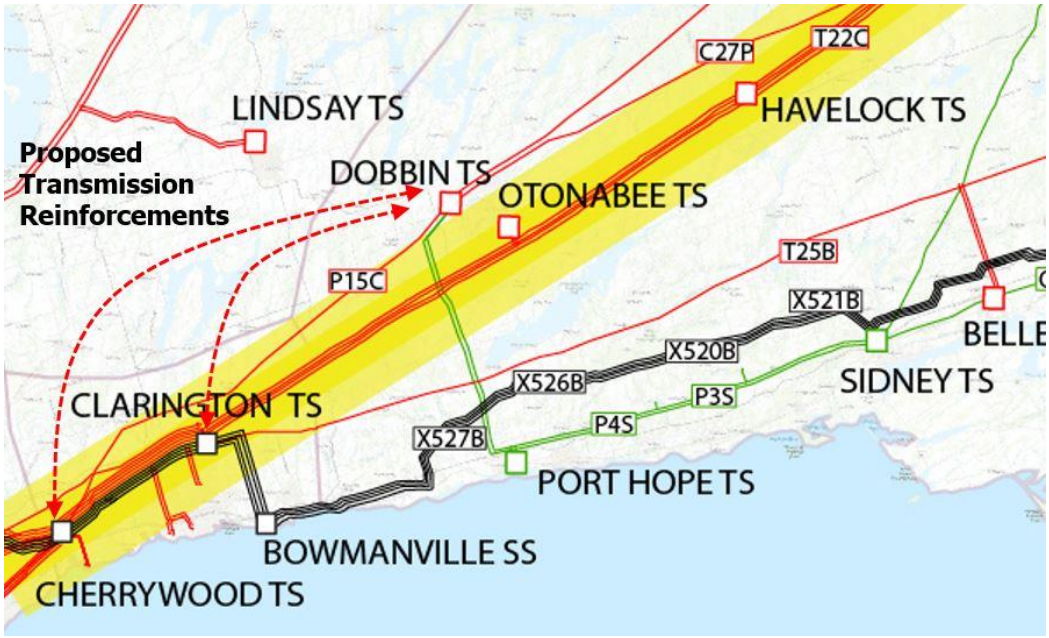
There are different variations to how this transmission reinforcement could be achieved. Each variation comparably increases the Peterborough to Quinte West LMC to approximately 440 MW. This improved capability sufficiently accommodates the 20-year planning forecast which reaches a maximum of 370 MW. As such, in addition to accommodating the planning forecast, the transmission reinforcement alternative provides additional flexibility and resiliency in meeting future changes in demand. The transmission reinforcement into Peterborough also mitigates the upstream thermal constraints limiting Ottawa for the duration of the 20-year planning forecast.

The variations of this transmission reinforcement include:

- Rebuild an existing single circuit 230 kV line from Cherrywood TS (Pickering) to Dobbin TS (Peterborough) into a double circuit 230 kV line
- Build a new double circuit 230 kV transmission line from Cherrywood (Pickering) TS to Dobbin TS
- Build a new double circuit 230 kV transmission line from Clarington TS (Oshawa) to Dobbin TS

A map showing the transmission reinforcement to Peterborough is shown in Figure 9.

Figure 9 | Map of Proposed Transmission Reinforcement Options into Peterborough



As the variations are currently comparable from a cost, scope[6], and capability perspective, each variation should be further examined during the project development and project approval stages led by the transmitter[7] in order to select the preferred variation.

Resource in Peterborough to Quinte West

A new resource located in the Peterborough to Quinte West area was considered as a NWA to the transmission reinforcement into Peterborough. The resource requirements can range depending on whether the transmission lines T22C and T33E are refurbished or decommissioned. Decommissioning the transmission lines will increase the flows from GTA east to Ottawa and through the P15C and C27P transmission lines. The analysis identified a SCGT facility (175 MW) as the most feasible non-wire alternative if T22C/T33E are refurbished. Alternatively, the analysis identified a CCGT (225 MW) as the most feasible non-wire alternative if T22C/T33E are decommissioned. Additional alternatives involving hybrid BESS and wind were also examined. A BESS solution would be deployed modularly in discrete blocks as demand grows.

Refurbishment of T22C and T33E into Ottawa

This option involves refurbishing the EOL transmission lines T22C from Clarington TS to Chats Falls TS, and T33E from Clarington TS to Almonte TS. While this option appears to maintain the existing transmission supply to Ottawa, the LMC for Ottawa is improved to 1950 MW through the addition of a new RAS, and the mitigation of the upstream thermal limitations on P15C through either the transmission reinforcement into Peterborough or a new resource in the Peterborough to Quinte West area. A new LMC of 1950 MW accommodates the forecast demand in Ottawa up to year 2037 based on the reference forecast.

Transmission Reinforcement into Ottawa

The transmission reinforcement into Ottawa involves a new transmission line between St. Lawrence TS in Cornwall and either Merivale TS (230 kV transmission line) or Hawthorne TS (500 kV transmission line) which are both in Ottawa. The two variations to how this transmission reinforcement can be achieved are comparable as they both strengthen the tie between the Ottawa area and the Cornwall area which has a sizeable amount of hydro-electric generation. The variations of this transmission reinforcement include:

- Build a new double circuit 230 kV transmission line from St. Lawrence TS (Cornwall) to Merivale TS (Ottawa)
- Build a new single circuit 500 kV transmission line from St. Lawrence TS (Cornwall) to Hawthorne TS (Ottawa)

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[6] A new transmission line originating from Cherrywood TS is assumed to repurpose existing breaker positions at Cherrywood TS currently serving Pickering GS which is planned for retirement between 2024-2026.

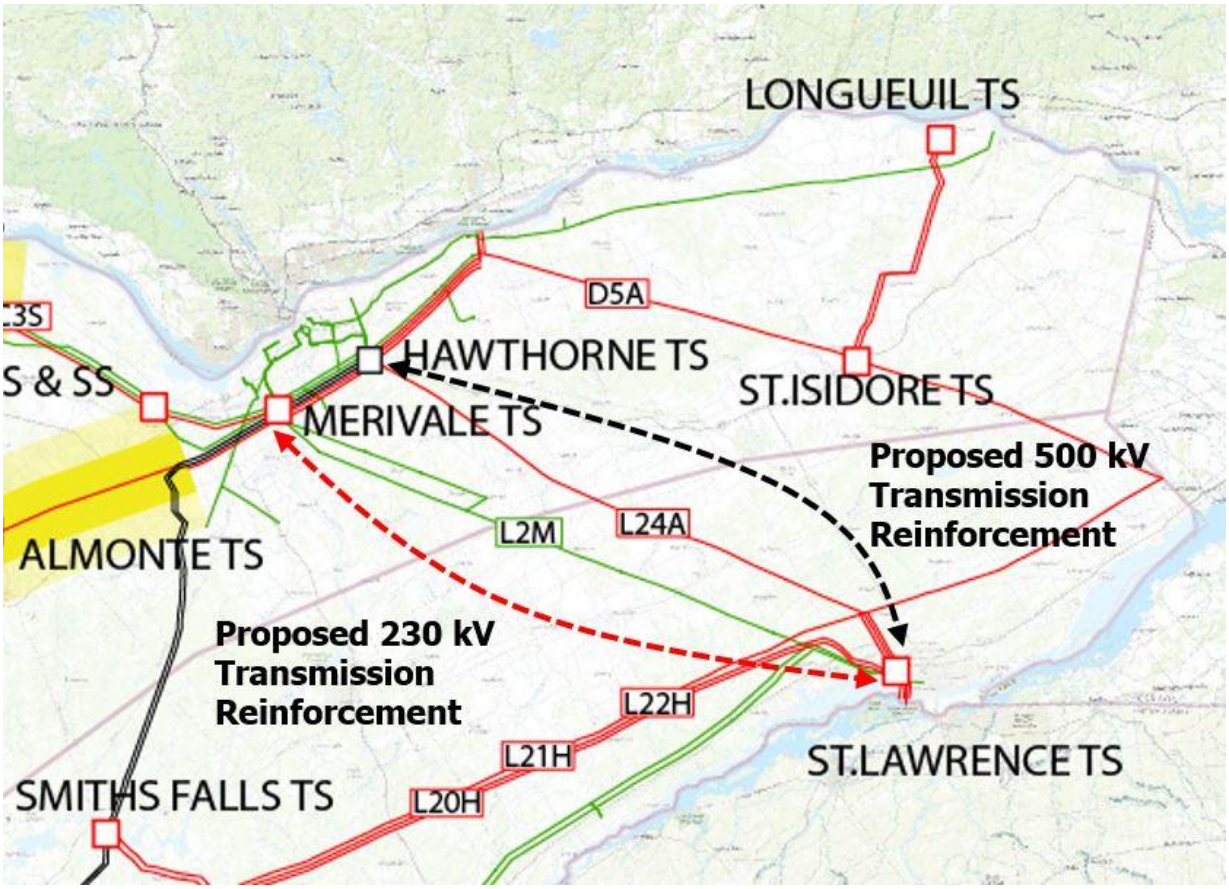
[7] New transmission lines in Ontario are subject to the Environmental Assessments ("EA") Process where line routing will be assessed and evaluated, interested parties will have an opportunity to provide input on line routing to the transmitter as part of the EA (Ontario Government Website link)

Both variations enable the opportunity for decommissioning the two EOL transmission lines T22C and T33E. The variations are quite comparable to each other, the 500 kV transmission line option offers an incremental capacity improvement of 100 MW at an incremental cost of approximately $150M.

A new 230 kV transmission line into Merivale TS will increase the Ottawa LMC to 2050 MW which will accommodate the forecasted demand in Ottawa up to year 2039, while a new 500 kV transmission line into Hawthorne TS increases the Ottawa LMC to 2150 MW which will accommodate the forecasted demand in Ottawa up to year 2041.

A map showing the Ottawa transmission reinforcements is shown in Figure 10.

Figure 10 | Map of Transmission Reinforcement Options for Ottawa



Resource in Ottawa

A new resource located in the Ottawa area was considered as a NWA to the refurbishment of T22C/T33E or the transmission reinforcement into Ottawa. The analysis identified a SCGT facility (480 MW) as the most feasible non-wire alternative. Additional alternatives involving hybrid BESS and wind were also examined. A BESS solution would be deployed modularly in discrete blocks as demand grows.

Remedial Action Schemes

For all solution packages, a Remedial Action Scheme (RAS) will be relied upon to help accommodate the forecasted demand. RASs (formerly named Special Protection Systems) are utilized to expand the capability of the transmission system and maximize the benefits of the transmission system equipment. The use of RAS's are governed by applicable planning criteria[8]. The two RASs identified, one for Peterborough to Quinte West and another for Ottawa, are both load rejection based schemes that will disconnect up to 150 MW when two or more power system elements are out of service (i.e. two transmission circuits are unavailable). Load rejection or load shedding schemes exists in both areas today, however the schemes will require modifications/updates to accommodate the forecasted demand.

7.2 Energy Efficiency

As discussed earlier, incremental energy efficiency was considered in this assessment as a compliment to other solutions. This section aims to quantify the energy efficiency opportunities in Ottawa.

In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS)[9]. The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, GHG emission reductions and associated costs from demand side resources for the period from 2019-2038. The study shows a significant and sustained potential for energy efficiency across all sectors and is used to inform:

- future energy efficiency policy and/or frameworks;
- program design and implementation; and
- assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning.

The APS study is used to determine an estimate of the remaining system cost-effective energy efficiency potential for planning study areas when accounting for existing provincial programs, federal program and savings from codes and standards.

In order to determine which needs should be evaluated for the use of energy efficiency as a solution, a screening mechanism was applied, in accordance with the IESO's standard criteria which includes consideration of factors such as the timing and magnitude of the need, its size relative to total forecasted demand, and coincidence with provincial system peak. The potential for energy efficiency to help address the identified needs was assessed for the Ottawa area supply capacity need, but not the Peterborough to Quinte West need, due to the timing and magnitude of the need identified.

[8] Usage of RAS is governed by IESO's Ontario Resource Transmission Assessment Criteria (link), NERC's Transmission System Planning Performance Requirements – (link), and NPCC's Directory # 1 Design and Operation of the Bulk Power System (link).
[9] More information about the 2019 Conservation Achievable Potential Study is available on the IESO website (link)

7.2.1 Energy Efficiency Potential in Ottawa

As part of the analysis developed for the 2020 Integrated Regional Resource Plan for the Ottawa sub-region, the IESO estimated that energy efficiency has the potential to reduce demand by approximate 1% per year on average in the Ottawa zone based on the 2019 APS results. These opportunities are reduced in the near term by existing CDM commitments while new opportunities increase in the medium term, following conclusion of the 2021-2024 CDM framework. The cumulative maximum achievable potential savings is shown in Figure 11 and Figure 12.

Note that the portion of the maximum achievable potential that is committed is included in the planning forecast shown in Figure 4.

Figure 11 | Cumulative Maximum Achievable Zonal Potential as a Share of Consumption

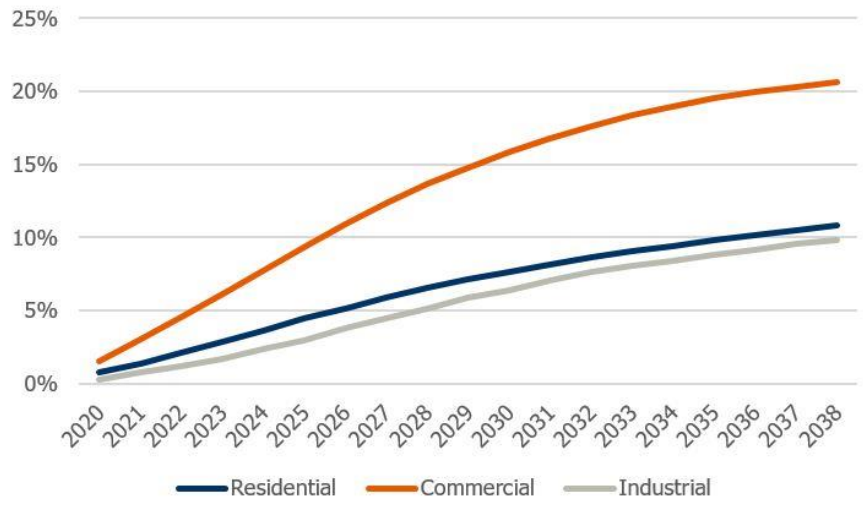
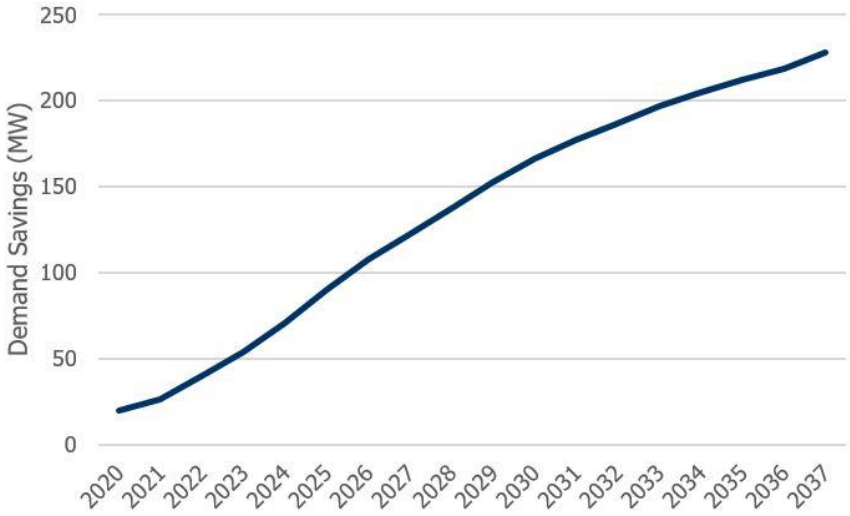


Figure 12 | Cumulative Maximum Achievable Zonal Potential as a Share of Consumption Net of Committed Savings

Uncommitted cumulative CDM potential that is cost effective based on avoided provincial system energy and capacity costs for stations within the FIO interface is presented in Figure 13. The estimated cost to deliver these savings is $587 million dollars over the forecast period.

Figure 13 | Uncommitted CDM Potential in Ottawa



Ongoing Energy Efficiency Activities in Ottawa

The IESO is currently delivering province-wide Save on Energy-branded CDM programs in the Ottawa area as part of the 2021-2024 CDM Framework to encourage the adoption of energy efficiency process and technologies in businesses and communities.

Additionally, as part of the 2021-2024 CDM Framework,[10] the IESO was directed to deliver a new competitive program to target additional CDM incremental to the province-wide programs to address regional and/or local system needs. The Local Initiative Program,[11] is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. The IESO is currently working with Hydro Ottawa to develop a Local Initiative Program procurement in order to begin targeting incremental savings opportunities described above and previously highlighted in the 2020 Ottawa IRRP.

As part of the 2021-2024 CDM Framework Mid-Term Review[12] published in December 2022, the IESO reviewed the scale of the opportunity for CDM to be targeted to address regional or local needs, available tools for targeting CDM, and the opportunities for LDCs to building on IESO CDM programs where they can add value to the distribution system. Based on accelerated findings, the Minister of Energy approved a number of IESO recommendations in October 2022, including Local Initiative Program enhancements to reduce barriers to participation and to add flexibility for incentives for DER solutions. The IESO should continue to explore opportunities to target savings in the Ottawa and Peterborough to Quinte regions in order to help address these emerging bulk and regional system needs.

[10] More information about the 2021-2024 CDM Framework is available on the IESO website (link).
[11] More information about the Local Initiative Program is available on the IESO website (link).
[12] More information about the 2021-2024 CDM Framework Mid-Term Review is available on the IESO website (link).

7.3 Comparison of Alternatives

7.3.1 Technical Comparison

A transmission reinforcement to Dobbin TS in Peterborough, regardless of whether the transmission line comes from Cherrywood TS in Pickering or Clarington TS in Oshawa, accommodates the 20-year long-term forecast for Peterborough to Quinte West. In addition, the transmission reinforcement provides an additional 70 MW of supply capacity for the area beyond the current demand forecast. This margin will allow for additional growth beyond the forecast and enables the area to better respond to demand forecast changes (i.e. greater penetration of electrification, industrial/manufacturing growth).

Furthermore, the current limiting constraint to Ottawa's LMC is the upstream thermal overload of P15C. The transmission reinforcement to Dobbin TS in Peterborough not only addresses the Peterborough to Quinte West need, but also addresses this upstream thermal limitation for Ottawa.

Lastly, if the proposed transmission reinforcement originates from Cherrywood TS in Pickering, the new transmission line may potentially benefit new load connections in the northern areas of Pickering, Whitby, and Oshawa around and north of highway 407 further into the future.

In comparison, the resource alternative to address this upstream thermal overload will require a resource between 175 and 225 MW, which will need to run frequently (30% of hours by year 10 of the forecast and 80% of hours by year 20 of the forecast). The analysis considered a CCGT facility and hybrid storage facility (BESS with wind) as the most feasible NWA alternatives due to the energy requirements.

With the upstream thermal overload of P15C resolved, either by the transmission reinforcement to Dobbin TS or the resource alternative, the focus becomes addressing the voltage instability issue and the forecast capacity requirements in Ottawa. Refurbishing the EOL transmission lines T22C and T33E mostly maintains the status quo. The improvement in the LMC to 1950 MW is mostly attributed to mitigating the upstream thermal overload of P15C and the addition of a load rejection RAS in Ottawa.

The second transmission alternative, building a new double circuit 230 kV transmission line from St. Lawrence TS in Cornwall to Merivale TS in Ottawa provides a small improvement to the voltage instability issue and increases the Ottawa LMC to 2050 MW. While this alternative introduces a new 230 kV supply into west Ottawa which would help in the resiliency of supplying west Ottawa loads, by not refurbishing T22C and T33E, part of that improvement is counteracted by the decommissioning.

The third transmission alternative, building a new single circuit 500 kV transmission line from St. Lawrence TS in Cornwall to Hawthorne TS in Ottawa, provides another small improvement to the voltage instability issue and increases the Ottawa LMC to 2150 MW.

The three transmission alternatives result in varying Ottawa LMCs of 1950, 2050, and 2150 MW. With the three alternatives, the improvement in LMC will be able to accommodate the reference Ottawa demand forecast up to year 2037, 2039, and 2041 respectively. While the alternative to refurbish T22C and T33E results in the lowest Ottawa LMC out of the three, maintaining the status quo helps preserve the capacity that T22C and T33E provides to Ottawa, which in the future can be combined with a new transmission line reinforcing Ottawa that may be needed in the future to accommodate a high growth scenario (i.e. such as electrification).

The resource alternative is sized to meet the demand forecast. Depending on the technology, if a BESS were implemented, the resource could also be installed in modules as the demand grows.

7.3.2 Cost Comparison

The IESO compared the net present value (NPV 2021$) of total costs and benefits for various alternatives required to address the Peterborough to Quinte West and Ottawa supply capacity requirements.

This economic evaluation was based on available cost estimates for similar sized resources and planning estimates for the proposed transmission facilities constructed based on similar past projects. The costs for each solution package are summarized in Table 4. More information regarding cost assumptions is described in Appendix D.

The three transmission only packages (1 through 3) are very comparable in cost, with incremental steps in cost resulting in incremental steps in supply capacity for Ottawa.

The three other packages (4 through 6) represent a hybrid comprising of both transmission and resources (SCGT/CCGT, BESS, and wind) and also an all resources based solution (SCGT/CCGT, BESS, and wind). The wide range in costs shown here reflects the cost difference between a SCGT/CCGT and a BESS and wind combination.

As mentioned earlier, both NWSs and EE provide bulk system capacity and energy benefits and have been taken into consideration as part of the cost analysis.

Based on the technical and cost comparison presented in this section, the IESO recommends solution package #1 to address the EOL needs in the Gatineau corridor and the supply capacity needs in Peterborough to Quinte West and Ottawa. This is further described in section 10 of the report.

8. Linkages with Regional Planning

Bulk system planning as shown in Figure 14 is just one form of electricity planning that is undertaken in Ontario, with the others being regional planning and distribution planning.

Figure 14 | Electricity Planning in Ontario



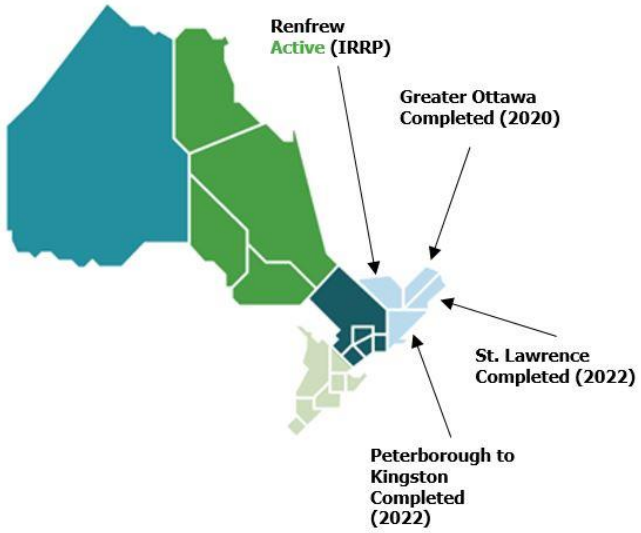
Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires," bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by local distribution companies (LDCs), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region, making it important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages between bulk, regional and distribution system planning, and coordinating the multiple needs identified over the long term, a comprehensive assessment of electricity needs can be carried out to develop integrated solutions that can address multiple needs.

As a result of the Gatineau corridor being approximately 350 km long, it has linkages with a number of different regions in southern Ontario including Greater Toronto Area East, Peterborough to Kingston, Renfrew, and Ottawa. In this section, key linkages to some of these regions are described. A map illustrating the 21 planning regions in Ontario is shown in Figure 15, with the regions in the east highlighted.

Figure 15 | Planning Regions in Eastern Ontario



8.1 Peterborough to Kingston Region

Regional planning for Peterborough to Kingston was most recently completed in May 2022. This was the first cycle of regional planning for Peterborough to Kingston to reach the integrated regional resource planning and regional infrastructure planning stage where a more in depth examination of power system needs was carried out.

The regional studies identified transmission system issues that have linkages with the upstream transmission system and specifically the Gatineau Corridor EOL Study. The recommended option also addresses the voltage issues on the 115 kV system identified in the 2021 Peterborough to Kingston IRRP[13].

In addition to the coordinated approach to issue identification, the regional planning activities allowed the IESO to obtain very detailed load forecasts that were developed by the Peterborough to Kingston regional planning working group along with valuable insight from the local distributors. The Peterborough to Kingston regional planning load forecast directly informed the load forecast used for the Peterborough to Quinte West area in the Gatineau Corridor End-of-Life study.

8.2 Greater Ottawa Region

Regional planning for Greater Ottawa was most recently completed in December 2020. Through those regional studies, capacity issues with the bulk transmission supply to the Ottawa 115 kV system were identified. This led to a series of near-term actions being recommended through the Ottawa Area IRRP which included:

[13]More information about these transmission issues are available in section 6 of the Peterborough to Kingston IRRP (link).

- Advancing the EOL replacement of the 230-115 kV auto-transformer T22 at Merivale TS which will result in a slightly higher supply capacity
- Triggering of a broader Ottawa 115 kV System Study to be carried out by the IESO (study ongoing)
- Pursue system cost effective energy efficiency in the Ottawa 115 kV system area

In recent months, through discussion with the Greater Ottawa regional planning working group, the IESO was informed of substantial load growth emerging in various areas across the City of Ottawa. The size and aggressive timing of the load growth resulted in the working group's decision to trigger the next cycle of regional planning early (expected to commence in Q4 2022).

Through the next cycle of regional planning, a new detailed 20-year planning forecast will be developed to assess transmission system supplying Greater Ottawa. Further, as described earlier in section 4.2, Ottawa's city council approved the Energy Evolution strategy on October 28, 2020. The impact of Energy Evolution on the peak electricity demand has yet to be quantified and has not been incorporated into the various bulk or regional planning forecasts. The impacts of Energy Evolution on electricity demand will be further explored as part of this next cycle of regional planning.

Depending on the outcomes of regional planning, additional reinforcements to the bulk transmission system may need to be triggered earlier then currently forecast.

8.3 Greater Toronto Area East

One of the alternatives to addressing the supply capacity issues for Peterborough to Quinte West involves a new transmission line between Dobbin TS in Peterborough and either Cherrywood TS in Pickering or Clarington TS in Oshawa. As indicated in section 7.3.1 the two stations Clarington TS and Cherrywood TS are electrically quite similar in terms of their ability to provide capacity improvements to the Peterborough to Quinte West areas.

However, the option to terminate at Cherrywood TS may have the added benefit of improving the load meeting capability of the local area, namely northern Pickering and Whitby. Based on recent discussion between the IESO and Elexicon Energy, the LDC for this area, updated growth forecasts may trigger the need for additional supply meeting capability in the mid term.

Although growth rates and preferred alternatives for meeting any ensuing needs have not been established through the regional planning process, the Cherrywood connection option offers additional flexibility by accommodating a greater range of future load growth scenarios.

The IESO will continue discussions with the GTA East regional working group members to determine if there is need to trigger the next cycle of regional planning early.

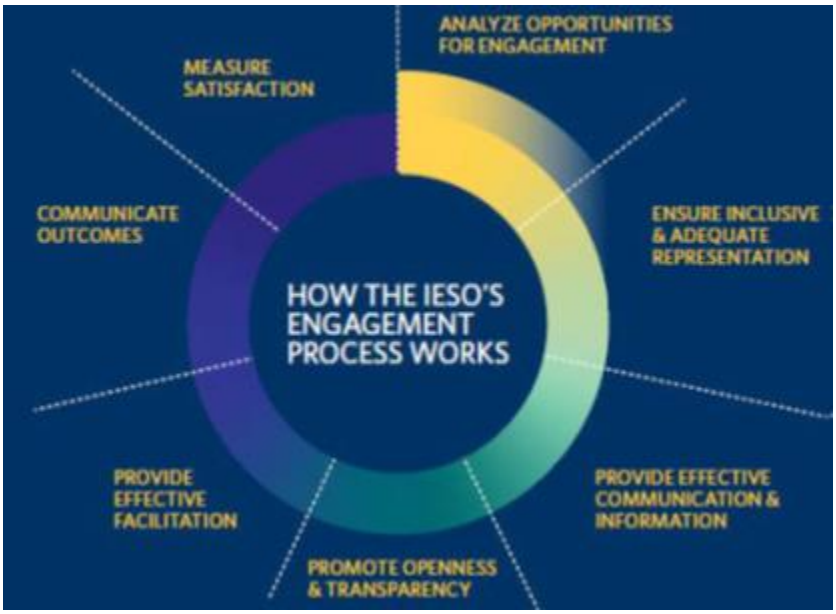
9. Engagement

The IESO has developed and is transitioning to a formalized process[14] for bulk system planning to enhance transparency and opportunities for purposeful engagement and input. As part of that work, defining how stakeholders can participate in the electricity planning process and be kept informed has been identified as a critical component of the process design. Providing opportunities for input in the transmission planning process enables the views and preferences of communities and stakeholders to be considered in the development of the plan, and helps lay the foundation for successful implementation. The IESO has endeavored to encompass those principles throughout the Gatineau Corridor EOL study work. This section outlines the engagement principles as well as the activities

9.1 Engagement Principles

The IESO's engagement principles[15] help ensure that all interested parties are kept informed and enables opportunities for purposeful engagement to contribute to electricity planning initiatives such as the development of this Gatineau Corridor EOL planning study. The IESO adheres to these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 16 | The IESO's Engagement Principles



[14] More information about the bulk planning process is available on the IESO website (link).
[15] More information about the IESO's engagement principles are available on the IESO website (link).

9.2 Engagement Approach

To ensure that the bulk plan reflects the needs of Indigenous communities, community members and interested stakeholders, engagement involved:

- Leveraging the East Ontario Bulk Planning Initiatives[16] engagement webpage on the IESO website to post updated information, engagement opportunities, meeting materials, input received and IESO responses to the feedback;
- Regular communication with communities, stakeholders and interested parties through email, East Ontario Electricity Network updates[17], and IESO weekly Bulletin;
- Public webinars; and
- Targeted outreach throughout plan development with municipalities, customers, Indigenous communities and rights-holders, and those with an identified interest in the Gatineau Corridor area.

The Gatineau Corridor EOL study was initiated prior to the IESO implementing a formalized bulk planning process. However, as part of implementation of the new process, three public webinars (two targeting all interested parties and one specifically targeting Indigenous Communities) were held at the remaining major junctures of plan development to give interested parties an opportunity to understand the scope of the study and provide comments on the proposed recommendations.

The webinars received strong participation with cross-representation of stakeholders and municipal and Indigenous community representatives in attendance, and submitting written feedback during a 21-day comment period.

Comments received during this engagement focused on the following major themes:

- **Forecast Risk in Ottawa:** Interest was expressed in better understanding how the study will ensure that Ottawa is positioned to meet emerging electricity needs, in particular needs driven by the City's decarbonisation plans.
- **Resource Cost Assumptions:** Feedback received indicated that updated market information should be incorporated into the study's cost assumptions. A suggestion was provided that the upcoming procurements may allow the IESO to gain a better sense of the current cost of storage for use in future assessments.
- **Scope of Transmission Alternatives:** Questions from engagement participants indicated a general desire to better understand the scoping of the study, and the associated options analysis. In particular, interested parties wanted to understand why the IESO did not consider various wires and non-wire alternative transmission options as part of the study.
- **Consideration of Emerging Growth in GTA East:** Targeted outreach with Elexicon and Durham Region identified emerging load growth in north Whitby that may trigger new load station development.

Based on the engagement discussions and feedback received, it is clear that interested parties want to ensure that the IESO is incorporating the best available information into the study analysis and

[16] More information about East Ontario Bulk Planning Initiatives is available on the IESO website (link).
[17] More information about the East Ontario Electricity Network is available on the IESO website (link).

recommendation so that the final recommendation meets Ontario's future electricity needs and priorities. Section 7 of the report includes the analysis of alternatives.

The bulk planning process is continuing to evolve. The IESO will work to increase transparency and cost discovery around transmission versus generation decision making as resource acquisition mechanisms continue to mature. Outcomes of this engagement will also be incorporated in other related electricity planning work and regional planning processes, such as the next GTA East regional planning cycle.

All background information, including engagement meeting presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's East Ontario Bulk Planning Initiatives engagement webpage.

9.3 Bringing Communities to the Table

The IESO held meetings with communities to seek input on local planning priorities and initiatives that should be taken into consideration in the development of this bulk plan. At major milestones in the study development process, targeted discussions were held with the upper- and lower-tier municipalities both in the East Ontario planning regions as well as in the adjacent GTA East planning area to discuss study recommendations. These meetings helped to inform electricity needs at the municipal/community-level, develop options and recommended solutions, and further build and strengthen local relationships for ongoing dialogue beyond this bulk process.

9.4 Engaging with Indigenous Communities

As part of the engagement process, the IESO reached out to Indigenous communities in and near the Eastern Ontario planning area throughout the development of the plan. Those invited to participate included: Alderville; Algonquins of Ontario (AOO Consultation Office); Algonquins of Pikwakanagan; Association of Iroquois and Allied Indians; Beausoleil; Chippewas of Georgina Island; Chippewas of Rama; Curve Lake; Haudenosaunee Confederacy Chiefs Council; Haudenosaunee Development Institute; Hiawatha; Huron-Wendat Nation; Mississaugas of Scugog Island; Mohawk Council of Akwesasne; Mohawks of the Bay of Quinte; Ogemawahj Tribal Council; MNO High Land Waters Métis Council; MNO Oshawa and Durham Region Métis Council; MNO Ottawa Region Métis Council; and MNO Peterborough and District Wapiti Métis Council.

A webinar for Indigenous communities was held on April 13, 2022. To ensure the invited communities had ample opportunity to participate, after the webinar concluded the presentation deck was emailed to them along with an invitation and registration information for a general webinar that was held on April 14, 2022. Feedback was received from the Haudenosaunee Development Institute which was posted along with the other received feedback on the IESO's engagement page for Bulk Electricity Planning - East Ontario under the entry for May 5, 2022. A general webinar was held on August 11, 2022, an invitation email was sent to the communities on July 19. A link to the materials for East Ontario planning was included and communities were informed that a feedback/comment period would be open until September 1, 2022.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions in Ontario.

10. Conclusions and Recommendations

To minimize cost, minimize land-use impacts, mitigate forecast risk, preserve options to increase system capability in the future and due to lack of cost effective stand-alone resource or energy efficiency alternatives, the solution package #1 from Table 4 is recommended to address the transmission equipment EOL needs and accommodate the demand forecast for the Ottawa and the Peterborough to Quinte West areas over the long-term. Solution package #1 includes:

- Refurbish all 800 km of 230 kV circuits on the Gatineau Corridor identified as nearing EOL
- Build a new double circuit 230 kV transmission line into Dobbin TS (in Peterborough) from either Cherrywood TS (in Pickering) or Clarington TS (in Oshawa) with a planned in-service of 2029
- Pursue up to 230 MW of additional system cost-effective energy efficiency in the Ottawa area over the 20 year planning horizon, while monitoring demand growth and resource acquisition activities in the Ottawa zone
- Update and expand the use of remedial action schemes (RAS) in the Peterborough and Ottawa areas to meet planning standards and further improve both areas' LMCs

This solution package represents the lowest cost option, with transmission reinforcements estimated to cost approximately $650 M. The transmission reinforcements ensure reliability in the Peterborough to Quinte West area is sufficient for the next 20 years and reliability in the Ottawa area is sufficient until 2037. If the 230 MW of additional energy efficiency is implemented, the Ottawa area's reliability would also be sufficient over the long-term. By refurbishing the existing Gatineau transmission lines and maintaining the supply capacity these lines provide Ottawa, this preserves the ability to further expand the LMC of Ottawa in the future with new transmission from Cornwall, when required. While there exists some load forecast uncertainties (high growth scenarios such as electrification of vehicles, heating, etc.) that, if materialized, can result in the need for additional improvements in the Ottawa area, this solution package lays the foundation to build on. Transmission planning in Ottawa will continue with the next cycle of regional planning scheduled to begin in Q4 2022.

Beyond monitoring load growth to trigger future system reinforcements when they are required, there are additional options with shorter lead times which could contribute to meeting Ottawa's supply capacity needs should they arise under a high growth scenario, including use of imports from Quebec, local demand response, BESS, and targeting additional energy efficiency in Ottawa.

Lastly, as presented in this report, the new transmission line into Dobbin TS can originate from either Cherrywood TS in Pickering or Clarington TS in Oshawa. While both routes are comparable in terms of addressing the needs for Peterborough to Quinte West and Ottawa, a new transmission line originating from Cherrywood TS may provide additional benefits for potential load connections in the Pickering and Whitby areas. Regional planning for the GTA East region is currently in-between planning cycles (in-active), however the working group members remain engaged in discussion to help inform the final line routing decision.

Appendix A – Planning Assessment Criteria

In developing this bulk plan, the IESO followed a number of steps including:

- Data gathering, including development of electricity demand forecasts;
- Conducting technical studies to determine electricity needs and the timing of these needs;
- Developing potential options; and
- Preparing a recommended plan including actions for the near and longer term.

Throughout this process, engagement was carried out with stakeholders interested in the area, in the form of public webinars and targeted discussions with the affected communities, local distribution companies and transmitters.

This bulk report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. The report helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

The overall objectives of planning are consistent among both regional and bulk planning, which are the following:

- Ensure reliability and service quality;
- Enable economic efficiency; and
- Support sector policy and decision making.

There are various reliability standards which, as the electricity system planner and operator, the IESO is obliged to meet. NERC and NPCC membership requires the bulk system be planned to consider specific operating conditions, such as peak and light load, and a set of contingencies to ensure the bulk system is planned reliably and meets standards. Additionally, the IESO is required to demonstrate its adherence to these standards through compliance reporting.

Reliability standards require the IESO to define its own performance criteria to meet under the conditions and contingencies specified. The Ontario Resource and Transmission Assessment Criteria (ORTAC) define the planning performance criteria for Ontario which are more specific and/or more stringent standards than NERC/NPCC. The IESO also considers operational issues and solutions that simultaneously consider bulk system reliability needs, regional needs, and assets reaching end of life, as appropriate.

The study used the planning criteria in accordance with events and performance as detailed by:

- NERC TPL-001 "Transmission System Planning Performance Requirements" (TPL-001),
- NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" (Directory #1), and
- IESO Ontario Resource and Transmission Assessment Criteria (ORTAC).

In addition to meeting established criteria and standards, the IESO also seeks to enable economic efficiency and support sector policy. Bulk system planning has a role in ensuring policy objectives can be incorporated with maximum benefit to ratepayers, and in identifying opportunities for improving overall system economics, especially in a competitive environment. This includes seeking economic opportunities, such as reducing losses, congestion, or other service costs, facilitate intertie/trade requirements, and providing timely and relevant information to market participants to enhance their participation and decision making leading to greater market efficiency and competition. It also includes supporting policy implementation affecting the power grid, such as sensitivity analysis of the economic impact of carbon pricing policies on congestion costs, as well as considering community energy plans and goals.

Appendix B – Load Forecast and Supply Need Data

The following datasets are included in this section and are also available in the excel file provided:

- Ottawa peak demand forecasts
  - Table 4 & 5: Total coincident reference and high growth scenarios for summer and winter seasons
- Peterborough to Quinte West peak demand forecasts
  - Table 6: Total coincident reference scenario for summer season

Refer to the excel file provided for the following datasets:

- Table 7: Forecast Ottawa Hourly Load (2022 to 2042)
- Table 8: Forecast Peterborough to Quinte West Hourly Load (2019 to 2037)
- Table 9: Forecast Ottawa Hourly Capacity Need (2022 to 2042)
- Table 10: Forecast Peterborough to Quinte West Hourly Capacity Need (2019 to 2037)

Notes:

The planning forecast for the Ottawa area is aligned with the Ottawa Zone demand forecast from the 2021 Annual Planning Outlook (Ottawa planning area aligns with definition of the Ottawa Zone)[18]

The planning forecast for the Peterborough to Quinte West area is aligned with the Peterborough to Kingston Integrated Regional Resource Plan demand forecast (Peterborough to Quinte West need is more local in nature comprising of a small number of stations)[19]

[18] The 2021 Annual Planning Outlook is available on the IESO website (link).
[19] The 2021 Peterborough to Kingston IRRP is available on the IESO website (link).

Table 5 | Total Coincident Winter Ottawa Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference Scenario	1505	1529	1552	1575	1601	1618	1644	1668	1696	1714	1729	1760	1788	1824	1857	1892	1931	1969	2020	2076
High Growth Scenario	1,505	1,533	1,562	1,591	1,625	1,651	1,686	1,720	1,758	1,790	1,817	1,857	1,893	1,930	1,963	2,008	2,054	2,101	2,142	2,184

Table 6| Total Coincident Summer Ottawa Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference Scenario	1627	1650	1697	1722	1720	1713	1748	1788	1777	1828	1811	1824	1846	1905	1902	1961	1992	2027	2095	2170
High Growth Scenario	1,627	1,656	1,709	1,742	1,750	1,754	1,801	1,839	1,827	1,891	1,896	1,909	1,952	2,018	2,082	2,142	2,171	2,202	2,264	2,331

Table 7 | Total Coincident Summer Peterborough to Quinte West Peak Demand Forecast (MW)

Forecast Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reference Scenario	317	324	330	330	331	333	335	337	340	343	347	350	354	358	361	365	367	371

Appendix C – Assessment of Supply

The IESO assessed supply capacity requirements for Peterborough to Quinte West and Ottawa areas based on the details in the following sections.

Capacity Assessment

A deterministic approach was used to evaluate the need to improve the load meeting capability of the Peterborough to Quinte West and Ottawa areas. A need was identified where the annual coincident load forecast exceeded the total installed capacity of transmission-connected gas generation in winter or summer (discounted by seasonal derates) and the transmission interface transfer limits (FIDS and FIO).

For example, in the Ottawa supply capacity need is identified when the Ottawa demand is larger than the internal generation resources (70 MW, less derates and contract expiry) plus the transmission capacity into the Ottawa area (i.e., on the FIO interface).

The assessment considered the installed capacity of transmission-connected gas generation in winter or summer (discounted by seasonal derates). To be conservative, imports were not considered as part of this assessment (nor exports). The capability of hydro-electric generation is impacted by water levels which varies based on rainfall and snowmelt. The assessment considered the hydro-electric generation at output levels available during 98% of the time historically (i.e. dry conditions).

Appendix D – Economic Assessment Assumptions

The following is a list of the assumptions made in the economic analysis:

1. The NPV of the cash flows is expressed in 2021$ CAD.
2. The USD/CAD exchange rate was assumed to be 0.76.
3. Natural gas price forecast is as per Sproule Outlook @ Dawn used in the 2021 Annual Planning Outlook (APO).
4. The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 6% and 8% were performed. An annual inflation rate of 2% is assumed.
5. The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the generators and BESS was assumed to be 30 years and 15 years respectively. The life of the BESS was based on 3600 cycles, which is assumed to be used to serve the local need first, and then global energy and ancillary services for the rest of the year. Cost of asset replacement were included where necessary to ensure the same NPV study period.
6. Development timelines for transmission was assumed to be 7 years; development timelines for generation and BESS were assumed to be 3 years.
7. A SCGT and CCGT were identified as one of the lowest-cost gas generation resource alternatives, based on escalating values from a previous study independently conducted for the IESO.[20] A sensitivity of +/- 25% was assessed.
8. A BESS was identified as one of the lowest-cost resource alternatives. Total energy storage system costs are composed of capacity and energy costs (i.e. energy storage devices are constrained by their energy reservoir). Costs were based on escalating values from the 2022 NREL Electricity Annual Technology Baseline (ATB)[21]. A sensitivity of +/- 25% was assessed.
9. Sizing of the storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing gas resources to sufficiently charge to meet the hours of unserved energy.
10. System capacity value was $570/MW-day (2021$ CAD) based on the estimated Net Cost of New Entry (Net CONE) of the anticipated lowest cost marginal resource that would be developed in Ontario when new generation is required. A sensitivity of +/- 25% assessed.
11. Production costs were determined based on energy requirements to serve the local reliability need, assuming the fixed and variable operating & maintenance costs for the resource.

[20] New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the lowest option of new generation.

[21] https://data.openei.org/submissions/4129

12. Carbon pricing assumptions are based on the Ontario Emissions Performance Standards (EPS) program, from $50/t in 2022 to $170/t by 2030, and applied to a new facility's production. A sensitivity of +100% was assessed.
13. The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.
14. Planning estimates for the various transmission facilities assessed were constructed based on similar past projects with assistance from Hydro One. Transmission line refurbishment for a single circuit transmission line costs were assumed at $500k/km and new transmission line costs were assumed at roughly $3-4M/km.

Appendix E – Sizing Battery Energy Storage Systems

To determine the size requirements of BESS that could serve this local need, the dynamics of the need were investigated in detail to ensure that the potential BESS is able to sequentially charge/inject within the local limitations. The system was sized such that the reservoir would have enough storage capability to charge enough energy (MWh) overnight and inject it the next day, with enough capacity (MW) to shave the peak such that it never exceeds the transmission limit.

To accomplish this, a methodology was derived to size BESS for local needs. In general, the model inputs are the local load profile, local transmission limits to avoid, and local energy available for charging the BESS. These inputs are at the hourly granularity, and typically projected for many future years. The first step of the algorithm is to determine the largest peak power capacity requirement (i.e. the single hour where the local load is highest above the transmission limit) and the largest peak energy requirement (i.e. the largest amount of energy required to shave the biggest peak) for the year.

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Integrated Regional Resource Plan

Parry Sound/Muskoka
May 2022

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List of Acronyms

BKF	Breaker Failure
CEP	Community Energy Plan
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
DG	Distributed Generation
GS	Generating Station
ERP	Enabling Resources Program
HONI	Hydro One Networks Inc.
ICECAP	Integrated Community Energy and Climate Action Plans
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LAP	Local Achievable Potential
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NWA	Non-Wires Alternatives
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
SGBM	South Georgian Bay Muskoka

SSS	Sustainable Severn Sound
TS	Transformer Station
TTC	Total Transfer Capability

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

This IRRP was prepared on behalf of the Technical Working Group of the Parry Sound/Muskoka sub-region which included the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Alectra Utilities
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.

The Technical Working Group assessed the reliability of electricity supply to customers in the Parry Sound/Muskoka sub-region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Parry Sound/Muskoka Technical Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community engagement and consultations. The Parry Sounds/Muskoka Technical Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This IRRP addresses the electricity needs of the Parry Sound/Muskoka sub-region over the next 20 years from 2021 to 2040. The Parry Sound/Muskoka sub-region is located in the South Georgian Bay Muskoka region and it encompasses the Districts of Muskoka and Parry Sounds and the northern part of Simcoe County.

The Parry Sound/Muskoka sub-region is winter peaking. Electrical supply to the sub-region is provided through the autotransformers at Essa TS (near Barrie) and Minden TS and the 230 kV transmission lines and step-down transformers as shown in Figure 1. Generation in the area includes the Des Joachims Hydroelectric Generating Station (GS) and the Henvey Inlet Wind Inlet GS.

The electricity within the sub-region is supplied by six local distribution companies (LDCs): Hydro One Networks, Alectra Utilities, Elexicon Energy, Lakeland Power, EPCOR Electricity Distribution Ontario Inc. and Newmarket-Tay Power Distribution Ltd. The transmission asset owner is Hydro One Networks. This IRRP report was prepared by the IESO on behalf of the Technical Working Group composed of the six LDCs and transmitter.

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

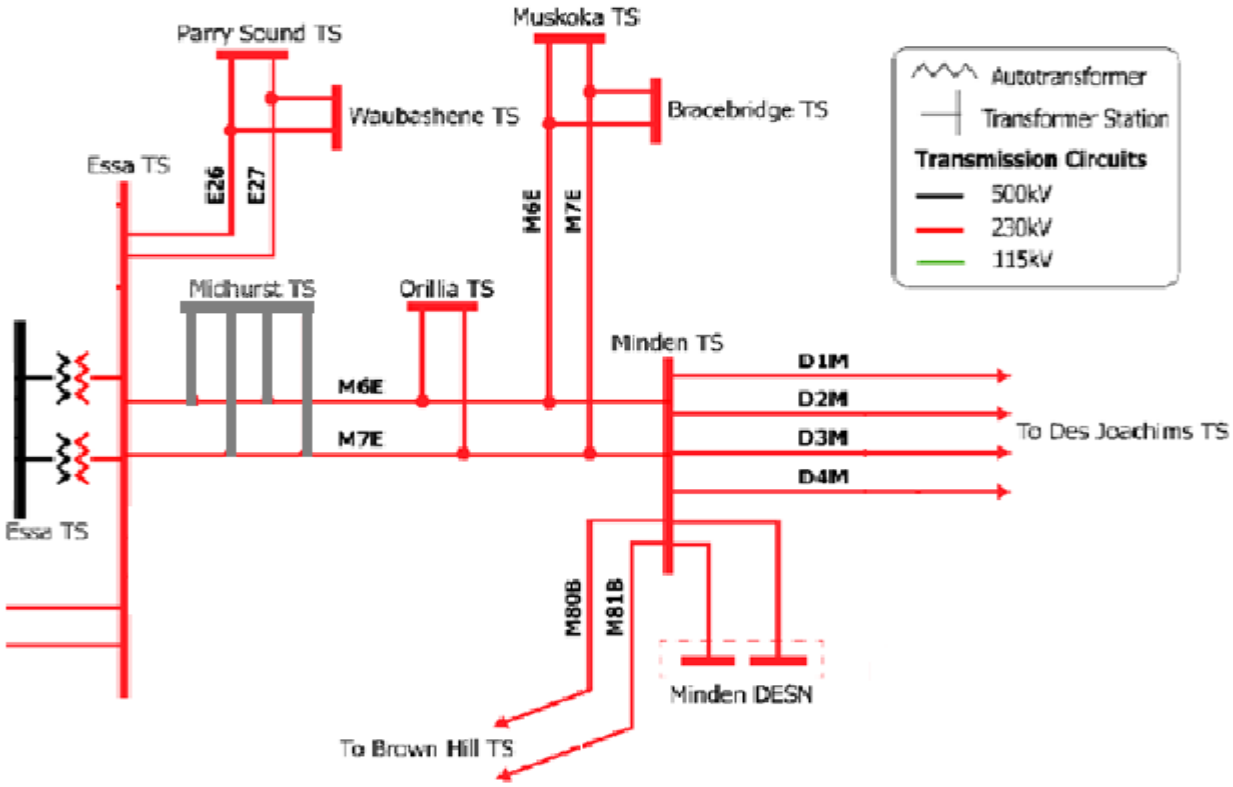
This is the second cycle of regional planning for the Parry Sound/Muskoka sub-region. This cycle began in 2020 with the publication of the South Georgian Bay Muskoka Needs Assessment Report. This was followed by a Scoping Assessment which identified needs that should be addressed through the IRRP process and recommended two IRRPs; one for Parry Sound/Muskoka sub-region and another for Barrie/Innisfil sub-region. A Technical Working Group was then formed to gather data, identify electricity needs in the region and developed recommendations included in this Parry Sound/Muskoka IRRP.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Parry Sound/Muskoka sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Parry Sound/Muskoka sub-region and the study scope are discussed in Section 4;
- The demand forecast and conservation and demand management (CDM) and distributed generation (DG) assumptions are described in section 5;
- Electricity needs in the Parry Sound/Muskoka sub-region are presented in Section 6;
- Alternatives and recommendations to address electricity needs are addressed in Section 7;

- A summary of engagement activities is provided in section 8; and
- The plan conclusion is provided in Section 9.

Figure 1| Parry Sound/ Muskoka Electricity System



2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Parry Sound/Muskoka sub-region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that considers: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The following sections provide details of the needs identified and the recommendations to address these needs. The needs were identified over two main planning horizons, i) 7 to 10 years as near to medium-term and ii) beyond 10 years as longer-term. These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons.

2.1 Needs in the Near to Medium-Term Horizon and Recommendations

The summary of recommendations for the needs in the near to medium-term horizon is listed in the table below.

Table 1 | Summary of Near/Medium-term Plan for Parry Sound/Muskoka IRRP

Need Description	Recommendation	Lead Responsibility	Required by
Waubaushene TS over its summer 10-day Limited Time Rating (LTR)	Consider incremental, cost-effective CDM to defer the need arising in 2027 until the transformers are replaced for end-of-life. If by 2024 there are no commitments for incremental, cost-effective CDM, implement alternative solution such as advancing the end-of-life replacement of the transformers. The Regional Infrastructure Plan (RIP) will further explore this backstop solution	Technical Working Group Hydro One	2024 2027
Sections of M6E/M7E circuits to reach end-of-life	Like for like replacement	Hydro One	2024

Need Description	Recommendation	Lead Responsibility	Required by
Sections of D1M/D2M circuits to reach end-of-life	Like for like replacement	Hydro One	2028

2.1.1 Consider Incremental Cost Effective CDM at Waubaushene TS

Waubaushene TS peak demand forecast will exceed its 10-day LTR rating by 2027 and the existing transformers are reaching end-of-life in 2030. Assessments as part of this IRRP indicate that incremental, cost-effective CDM is a good candidate for deferring this need until the transformers can be replaced as part of their planned sustainment and is the recommended action. However, no provincial framework for CDM programs in 2027 currently exists, and, therefore, the TWG will continue to monitor these developments following plan completion and explore various pathways for incremental cost-effective CDM. If this CDM cannot be committed by 2024[1], the TWG recommends that a backstop solution be implemented, such as advancement of the end-of-life transformers. The backstop solution will be further explored in the Hydro One led RIP.

2.1.2 Like for Like Replacement for sections of 230 kV circuits M6E/M7E and D1M/D2M

Sections of 230 kV circuits M6E/M7E and D1M/D2M will reach end-of-life by 2024 and 2028 respectively. A like-for-like approach is recommended for the replacement of these assets.

2.2 Needs in Longer-Term Horizon and Recommendations

In the longer-term horizon, minor station capacity needs have been identified at Minden TS starting in 2038. A longer-term supply capacity need has also been identified on 230 kV circuit M6E for a Minden HL7 Breaker Failure (BKF).

While this need is expected to arise in the longer-term, potential options were contemplated to inform future plans. The analysis showed that incremental, cost-effective CDM is potentially a good candidate to defer this need, when considering the need characteristics. Given the time of the need, no firm recommendation is required at this time; however, it is recommended to continue to consider incremental, cost-effective CDM as an option in between planning cycles and bring these insights into the next cycle of regional planning for the region.

2.2.1 Supporting Community Energy Plans and Monitoring Energy Efficiency and Electrification Trends

Three main plans in the sub-region have been identified when pertaining to energy and climate change in communities. These include:

[1] This year has been selected on the basis of the lead-time for the backstop solution, i.e., to advance the end-of-life transformers.

- The Integrated Community Energy Climate Action Plans (ICECAP) for the townships for the Archipelago, Carling, Georgian Bay, McKellar, Seguin, Georgian Bay; the Town Parry Sound; Municipality of McDougall; Chimnissing/Beausoleil, Dokis, Henvey Inlet, Magnetawan, Moose Deer Point, Sawanaga, Wahta Mohawk and Wasauksing First Nations; and Wiikwemkoong Unceded Territory
- Sustainable Seven Sound (SSS) supported by seven municipalities in the County of Simcoe and the district Municipality of Muskoka including the Towns of Midland and Penetanguishene and the Township of Georgian Bay, Severn, Oro-Medonte, Tiny and Tay
- Energy Management Plan for Village of Sundridge and Township of Joly and Strong

The scope varies by municipality and plan but the general aim is to improve energy efficiency, building greater resiliency, lower greenhouse gas emissions, and invest in the local economy.

While the IRRP seeks to align with these plans where possible, not all of the objectives fall within the scope of the regional planning nor the IESO's mandate. For example, absent of provincial government policy, the IESO is technology agnostic and will generally choose the most economic option that adequately resolves the need and meets applicable reliability standards. Greenhouse gas emissions are considered in the IRRP's options analysis by accounting for the carbon price associated with emitting resources, but the IESO does not have emission reduction targets unless directed by government policy. Furthermore, while regional planning is responsible for ensuring electricity ratepayer value and minimizing electricity costs, the IESO relies on government policy for broader socioeconomic considerations.

There are three climate energy plan (CEP) objectives that the IESO and regional planning can play a role in supporting. First, the IESO recognizes that distributed energy resources (DER) are becoming increasingly prevalent and features prominently in many CEPs. DERs can provide benefits to both customers as well as the distribution and transmission systems. By enabling DERs to provide wholesale services, system costs can be reduced and opportunities for customers and investors can be increased. The IESO's Enabling Resources Program (ERP) will produce a 5-10 year plan to enable resources to provide services they cannot or cannot fully currently provide. The ERP has identified storage, hybrids, and DERs as high-priority opportunities. The IESO developed a DER roadmap in the fall of 2021 to provide clarity on IESO objectives, initiatives, and timing for DER integration and is completing a DER Potential Study by June 2022. More information can be found on the Distributed Energy Resource Roadmap engagement page.

Second, the Technical Working Group will continue to support and monitor energy efficiency uptake. Conservation expected to be achieved through codes, standards, and program delivery has already been included in the planning forecast as described in Section 5.4. On September 30, 2020, the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensures energy efficiency can continue to play a role in meeting the region's needs. The Technical Working Group will monitor uptake of the CDM framework as well as energy efficiency initiatives in CEPs and assess the impact of these additional savings on the timing of local reliability needs.

Finally, the Technical Working Group will monitor electrification trends and their impact on the demand forecast. The Technical Working Group recognizes that many CEPs are calling for ambitious electrification targets as a means to achieve carbon emission reductions. It is not yet clear how impactful electrification will be to the load forecast in the near-term but it could drive significantly higher demand in the long term that will necessitate new electricity supply into the area. While it is still difficult to establish when firm investments or infrastructure reinforcements will be needed, it is prudent to prepare for a future where electricity demand could potentially be significantly higher than forecast.

3. Development of the IRRP

3.1 The Regional Planning Process

In 2013, the OEB created a formal process for regional planning which is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The regional planning formal process sets out 21 different electricity planning regions for the province. Regional planning assesses the interrelated needs of a region over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the largest transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;

3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Further details on the components of the regional planning process in Ontario and the IESO's approach to regional planning can be found in Appendix A.

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues whereas distribution network planning considers the supply of electricity within an LDC's system. Regional planning is the intersection of those two.

A review of the regional planning process was finalized in 2021 following the completion of the first cycle of regional planning for all 21 regions. The Regional Planning Process Review Final Report is published on the IESO's website.

3.2 Parry Sound/Muskoka and IRRP Development

The process to develop the Parry Sound/Muskoka IRRP was initiated following the publication of Hydro One's South Georgian Bay Muskoka Needs Assessment report in April 2020 and the IESO's Scoping Assessment report in November 2020. The Scoping Assessment report recommended that the needs identified for the Parry Sound/Muskoka sub-region be considered through an IRRP in a coordinated regional approach. The Technical Working Group was then formed to develop the terms

of reference for this IRRP, gather data, identify needs, develop options and recommend solutions in the sub-region.

4. Background and Study Scope

This is the second cycle of regional planning for the Parry Sound/Muskoka sub-region. During the first cycle of regional planning, a Needs Assessment was conducted for the South Georgian Bay Muskoka Region in March 2015 that was led by Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination should be considered and a Scoping Assessment was published in June 2015 which recommended coordinated planning through an IRRP. Subsequently, the IRRP for Parry Sound/Muskoka was published in December 2016 and the RIP was published in August 2017.

This cycle of regional planning started with a Needs Assessment published by Hydro One in April 2020 which identified a number of needs requiring further regional coordination. This was followed by a Scoping Assessment which was published in November 2020. This report recommended an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2021.

4.1 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the Parry Sound/Muskoka sub region for the study period with a focus on providing an adequate, reliable supply to support community growth. The plan includes consideration of forecast electricity demand growth, conservation and demand management (CDM), distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

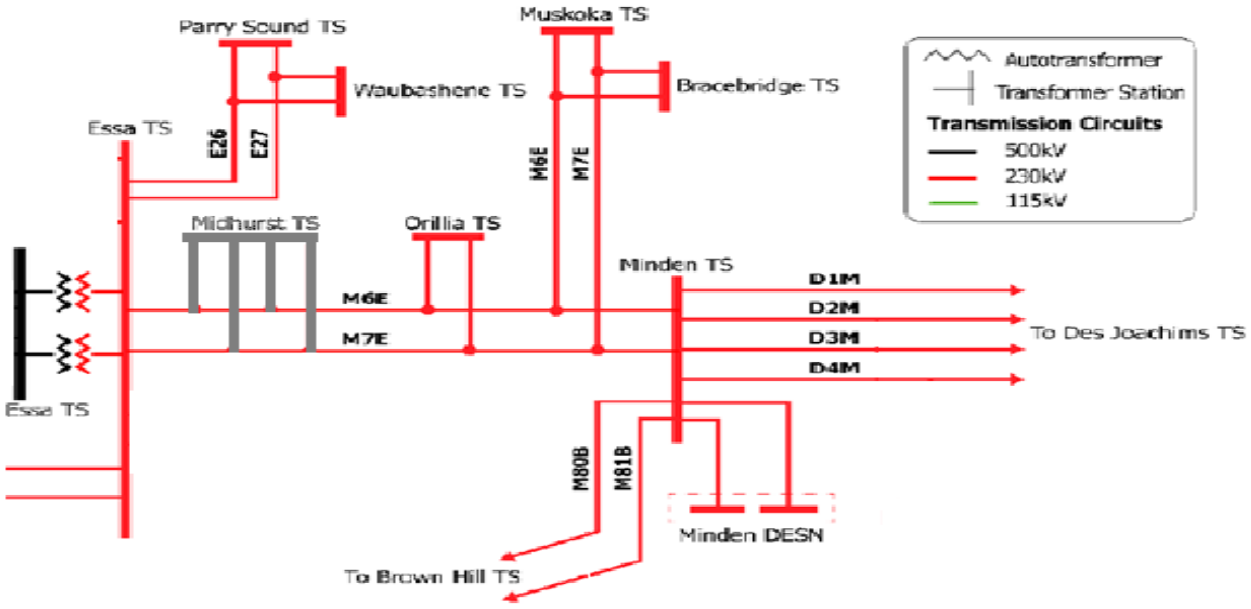
The following transmission facilities were included in the scope of this study:

Step-down transformer stations: Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS and Minden TS.

Transmission lines: D1M, D2M, D3M, D4M, E26, E27, M6E, M7E, M80B, M81B

The single line diagram of the Parry Sound Muskoka sub-region is shown in Figure 2 below. Note that Midhurst and Essa are not within the scope of the this IRRP.

Figure 2 | Single Line Diagram of Parry Sound/ Muskoka Sub-Region



The Parry Sound/ Muskoka IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the Load Meeting Capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC planning criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO controlled grid as described in section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

5. Electricity Demand Forecast

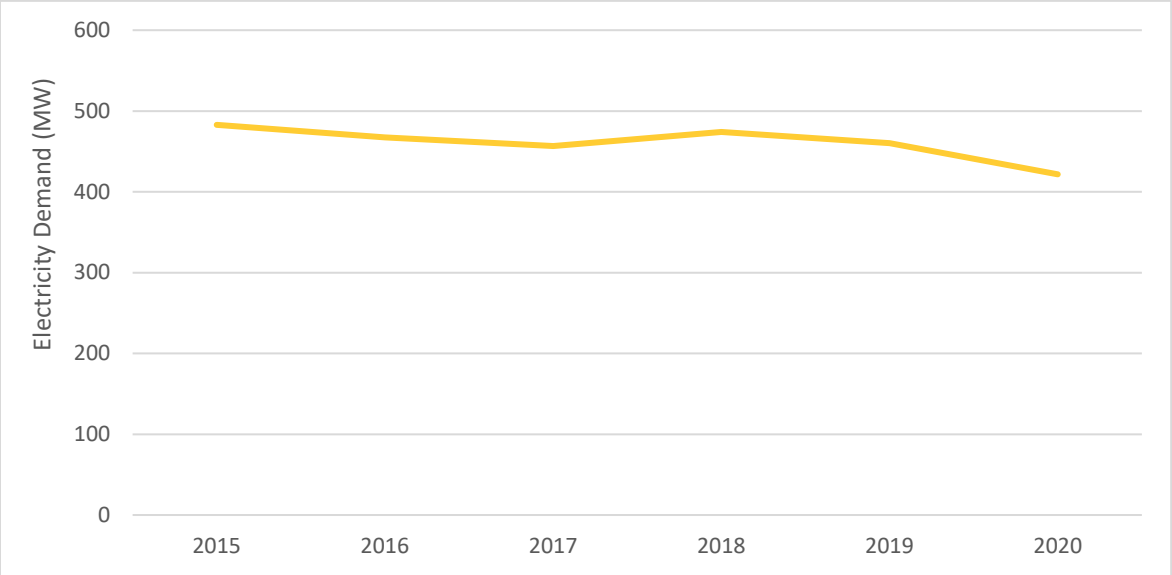
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the Parry Sound/Muskoka sub-region. It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Parry Sound/Muskoka sub-region, the peak loading hour for each year occurs in the winter.

5.1 Historical Electricity Demand

Electricity demand in the Parry Sound/Muskoka sub-region is primarily driven by residential and commercial customers and demand typically peaks during the winter months. However, station capacity needs arise in the summer as the ratings are lower then. The historical demand is shown below in Figure 3. The technical Working Group determined 2020 to be the base year to be used for developing the planning load forecast. The historical peak demand has decreased from 480 MW in 2015 to 420 in 2020.

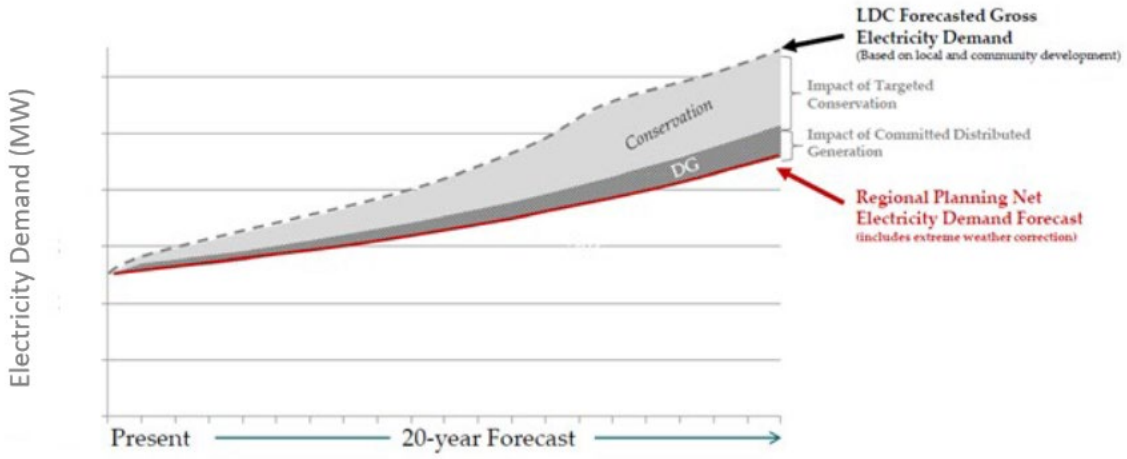
Figure 3 | Historical Winter Peak Demand – Parry Sound/ Muskoka Sub-Region



5.2 Demand Forecast Methodology

A 20-year regional peak demand forecast was developed to assess reliability needs for the Parry Sound/Muskoka sub-region; Figure 4 shows the steps taken to develop this. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions i.e., normal weather, were provided by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation savings and DG contracted through previous provincial programs such as FIT and microFIT. The forecasts were then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix B.

Figure 4 | Illustrative Development of the Demand Forecast



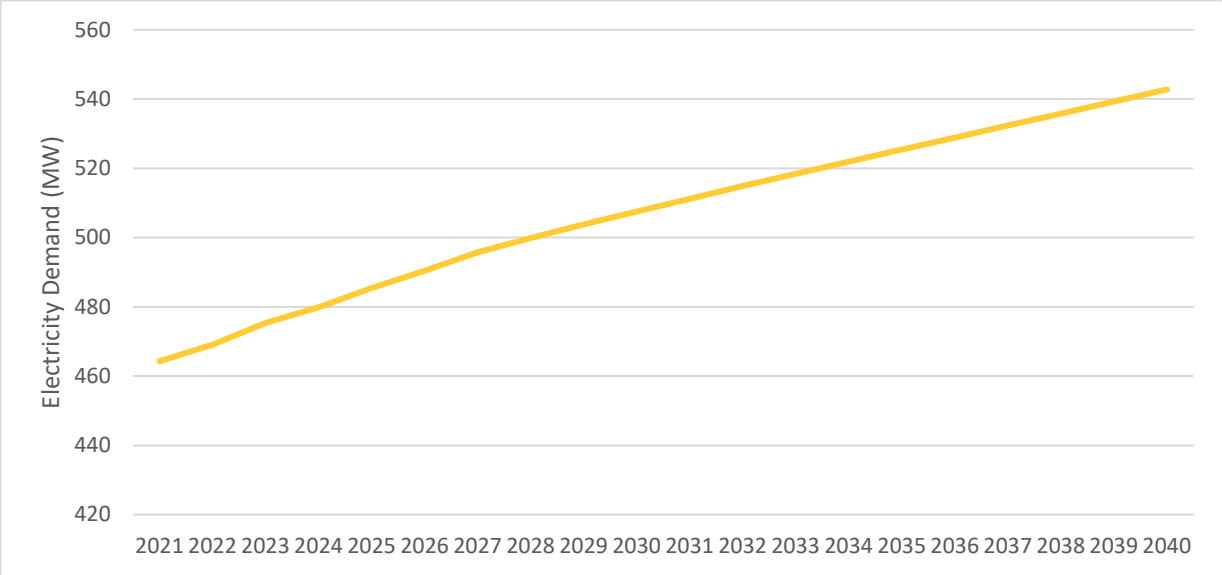
5.3 Gross Demand Forecast

Gross demand forecasts were submitted by each participating LDC in the Parry Sound/Muskoka sub-region. This is because LDCs have better insights of future local demand growth and drivers due to their direct involvement with their customers. This insight includes future connection applications and knowledge regarding typical electrical demand for different types of customer groups. Through engagement for the Parry Sound/Muskoka sub-region, it was communicated that Seguin Township submitted a Minister Zoning Order (MZO) in January 2022 to rezone land along the southern border of the town of Parry Sound for future housing development. The municipality of Parry Sound opposed the MZO application and listed four studies Seguin need to provide before the municipality of Parry Sound can partner with Seguin Township on the project. Also mentioned as part of engagement, was growth of a Parry Sound industrial park. Since these developments had not been committed yet, they were not considered in the gross demand forecasts submitted by the LDCs. These developments will be monitored in between regional planning cycles.

The LDC gross demand forecasts account for increases in demand due to new or intensified development, economic growth, population growth, changes in consumer behaviour, etc. Most LDCs cited alignment with municipal and regional official plans and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for by the IESO as discussed in Section 5.4 below. The gross LDC forecast assumes median on-peak weather conditions.

More details on the LDCs' load forecast methodology can be found in Appendix B. Figure 5 below shows the total gross coincident LDC forecast for both summer and winter weather.

Figure 5 | LDC Coincident Gross Winter Demand Forecast – Median Weather



5.4 Contribution of Conservation to the Demand Forecast

CDM helps in meeting Ontario's electricity needs by reducing demand. This is achieved through a mix of codes and equipment standards amendments as well as CDM program-related activities.

Demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers. Program-related activities include Save on Energy programs, as well as those that are being implemented as part of the 2021-2024 CDM framework.

CDM savings have been applied for the Parry Sound/Muskoka sub-region gross peak demand forecast for median weather, along with DG (as described in section 5.5) to determine the net peak demand for the sub-region. This takes into account both policy-driven conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

The final estimated conservation peak demand reductions applied to the gross demand forecast is shown in Table 2 for a selection of the forecast years. Additional details are provided on Appendix B.

Table 2 | MW Savings from Conservation and Demand Management

Year	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040
Winter Savings (MW)	7	14	17	19	22	24	24	24	24	24

5.5 Contribution of Distributed Generation to Demand Forecast

Distributed Generation is also factored in to offset the Parry Sound/Muskoka sub-region gross peak demand forecast for median weather. No assumptions were made regarding DG growth as in the long-term, the contribution of DG is expected to diminish as contracts expire. The resources that were included in the DG forecast were comprised of a mix of solar and hydroelectric projects. Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output.

The DGs included in this IRRP are distributed connected from the following sites:

- Minden TS
- Muskoka TS
- Orillia TS
- Parry Sound TS
- Waubaushene TS

Effective winter capacity totaled 29 MW in 2022. The expected annual peak demand contribution of contracted DG in the Parry Sound/Muskoka sub-region and capacity contribution factors can be found in Appendix B.

5.6 Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the sub-region and is used to carry out system studies for identifying potential needs in the Parry Sound/Muskoka sub-region. This forecast is created in three steps:

1. The gross median weather forecast, provided by the LDCs, is adjusted to extreme weather conditions, according to the methodology described in Appendix B. The result is the gross extreme weather forecast.
2. The impacts of forecast CDM savings and DGs output are added to the gross extreme weather forecast which results in a net extreme weather forecast, or planning forecast.

3. A coincidence factor is applied to convert the forecast to non-coincident. The coincidence factor is based on the contribution of each station to the group's coincident peak over the past five years. Non-coincident station forecasts are utilized for assessing the capacity adequacy of each transformer station in the sub-region.

The net extreme weather forecasts for the Parry Sound/Muskoka sub-region are shown in Figure 6 and Figure 7 below for summer and winter. For comparison, the figures also show the median gross weather forecast and the extreme gross forecast.

Figure 6 | Summer Net Extreme Weather Demand Forecast

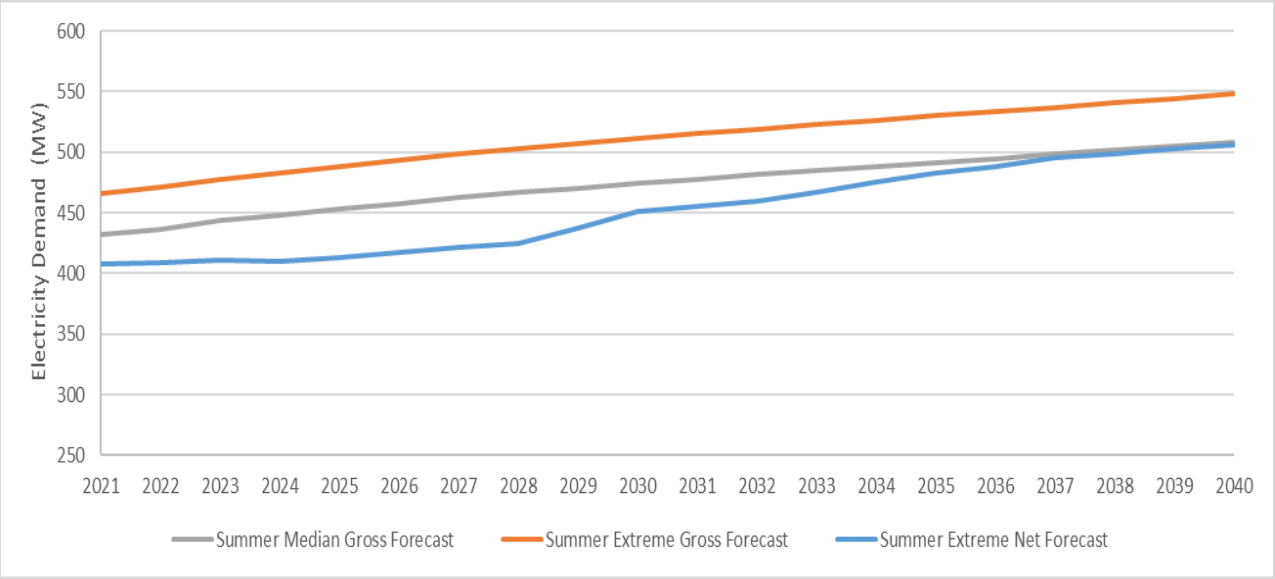
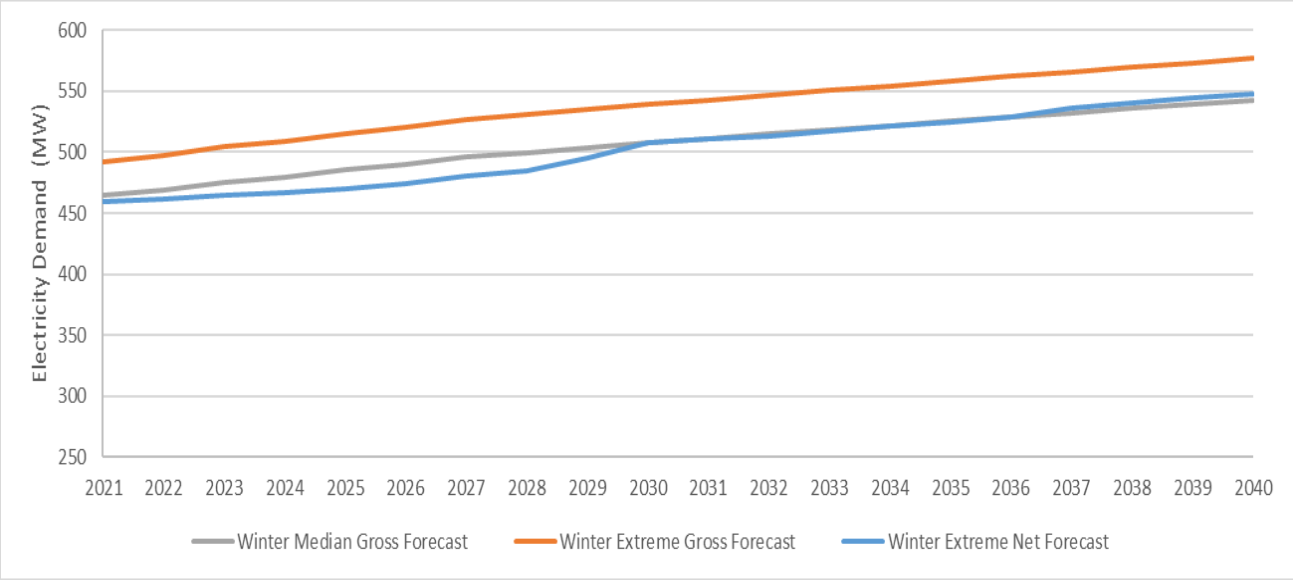


Figure 7 | Winter Net Extreme Weather Demand Forecast



5.7 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over 20 year forecast horizon) for a number of stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of Non-Wires Alternatives (NWA) options.

Additional load profile details including summary tables and hourly heat maps for each need can be found in Appendix B.

5.8 Sensitivity Scenario

A sensitivity scenario was performed for higher demand. This higher demand scenario is to take into account a variety of factors that could drive demand higher; these include but are not limited electric vehicles charging infrastructure and electrified space heating installations in the sub-region. For this, a growth factor of 5% was applied equally to each LDC's station in the sub-region to determine the impact this would have on the need dates identified in system studies.

The higher demand scenario will not be used to drive any firm recommendations for this IRRP; however, it will help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can be useful for communities conducting Community Energy Plans, for the TWG in determining areas to monitor in future cycles of regional planning, and for communities and stakeholders as they think about various projects in the sub-region.

6. Electricity System Needs

6.1 Needs Assessment Methodology

Based on the net extreme weather planning demand forecast, the transmitter's identified end-of-life asset replacement plans and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Technical Working Group identified electricity needs for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results can be found in Appendix D. The needs identified are discussed in the section below.

6.2 Needs Identified

Table 3 below summarizes the needs identified by the Parry Sound/Muskoka IRRP.

Table 3 | Summary of Needs for Parry Sound/Muskoka IRRP

No.	Need	Need Description	Need Date
1	Waubaushene Station Capacity	Waubaushene TS demand forecast is over its summer 10-day LTR	2027
2	End-of-Life refurbishment	M6E/M7E section[2]	2024
3	End-of-Life refurbishment	D1M/D2M section	2028
4	M6E/M7E Supply Capacity	After a loss of either M6E or M7E, the remaining circuit will exceed its Long Term Emergency (LTE) rating	2034
5	Minden Station Capacity	Minden TS demand forecast will exceed its summer 10-day LTR	2038

The summary of the location of the needs identified in the Parry Sound/Muskoka sub-region are shown in Figure 8.

Figure 8 | Summary of Location of Needs



[2] Note that the sections of M6E and M7E that are at end-of-life are different than the thermally limited sections

6.2.1 Station Capacity Needs

Table 4 below shows that there are station capacity needs for the Parry Sound/Muskoka sub-region according to the planning forecast. In the near to medium-term, there are station capacity needs at Waubaushene TS. The summer demand forecast for Waubaushene TS exceeds its 10-day LTR by 2027 as seen in Figure 9. In the longer-term, there are capacity needs for Minden TS arising in 2038 as its summer demand forecast exceeds Minden TS 10-day LTR as seen in Figure 10.

Table 4 | Step-down Station Summer Capacity Needs

Station	10-day LTR Rating (MW)	2022 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Minden TS	52	44.3	44.2	45.8	52.8
Waubaushene TS	94	89.9	91.5	98.6	116.4

Figure 9 | Waubaushene TS Capacity Needs

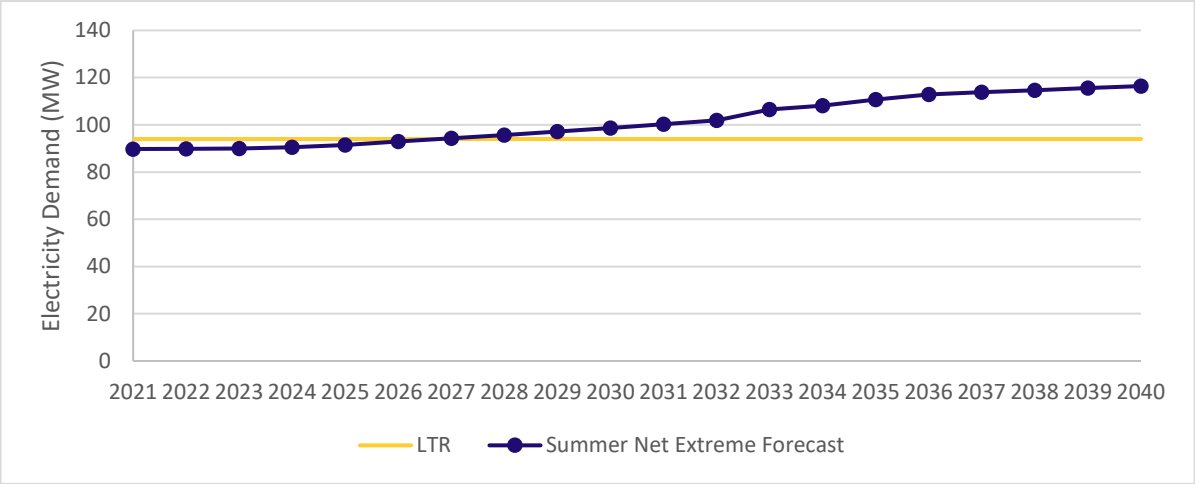
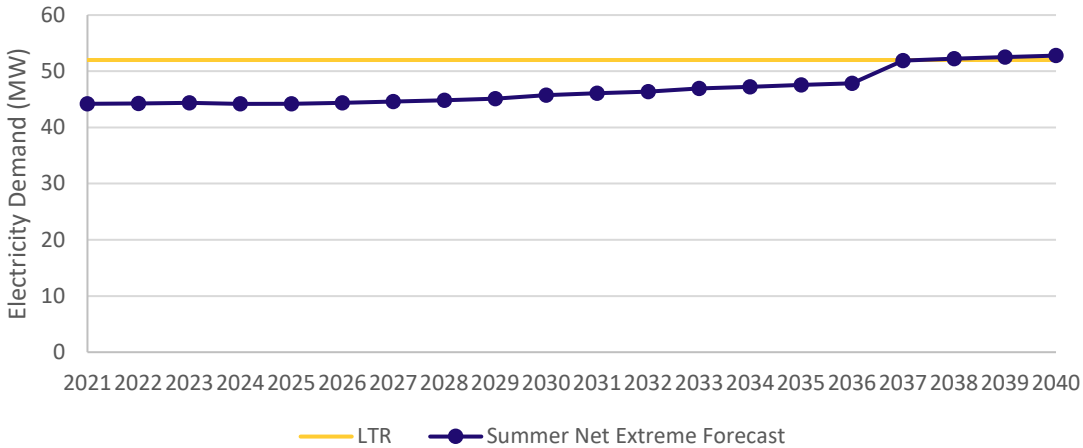


Figure 10 | Minden TS Capacity Needs



In the higher demand sensitivity scenario, the station capacity need is advanced to 2022 for Waubaushene TS and to 2037 for Minden TS.

Besides the station capacity needs identified above, Hydro One's Needs Assessment also identified station capacity need at Parry Sound TS which was identified in the previous cycle of regional planning. The transformers were also assessed at being end-of-life. In order to address the station capacity and end-of-life needs, Hydro One is installing new 230/44 kV 83 MVA transformers which are scheduled to be in service by 2024. The LTRs of the new transformers were applied in the IRRP's assessment of station capacity needs and no further station capacity needs were identified.

6.2.2 Supply Capacity Needs

The circuits M6E and M7E form a 230 kV double circuit from Essa TS to Minden TS. These circuits provide supply to Midhurst, Orillia, Bracebridge and Muskoka. This need occurs for section Minden TS to Cooper Falls JCT (51 km in length) which belongs to the Parry Sound/Muskoka sub-region. M6E section Minden TS to Cooper Falls JCT TS will exceed its LTE rating for a failure of breaker HL7 at Minden HL7 starting in 2038. Also, with M7E already out of service, for loss of Essa T3, M6E is at 133% of its LTE in 2040. Note that in the higher demand sensitivity scenario, this supply capacity need is advanced by two years.

6.2.3 End-of-Life Refurbishment Needs

As per information provided by Hydro One, sections of 230 kV circuits M6E/M7E and D1M/D3M are reaching end-of-life. The in service dates will be 2024 for M6E/M7E and 2028 for D1M/D3M. The end-of-life section includes 25 km from Orillia TS to Cooper Falls JCT for M6E/M7E and 62 km from Minden TS to Otter Creek TS for D1M/D3M.

6.2.4 Load Security and Restoration Needs

There are no load security or restoration needs identified for Parry Sound/Muskoka sub-region for the time frame.

7. Plan Options and Recommendations

In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or to mitigate certain reliability concerns.

2. Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as NWA and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need.

The screening process resulted in NWA being considered for all of the near/medium-term needs to be addressed by the IRRP, except the end-of-life needs. Needs characterization was completed for the Waubaushene TS station capacity need. While the supply capacity need arising on the M6E/M7E circuits is in the longer-term, needs characterization was completed for this need to inform future options.

7.1 Options and Recommendations for Meeting Near/Medium-Term Needs

7.1.1 Waubaushene TS Station Capacity Need

Waubaushene TS will reach end-of-life (EOL) in 2030 and was planned for replacement at this time; however, current needs show an earlier replacement is required. Waubaushene will be over its 10-day summer LTR in 2027.

In terms of non-wires options, the Technical Working Group first reviewed the findings of the Local Achievable Potential (LAP) Study for the Parry Sound and Waubaushene TS service area that was recommended in the last Parry Sound/Muskoka IRRP, and subsequently completed between cycles.

The LAP study was to determine the cost and feasibility of using distributed energy resources (DER) and CDM options to defer needs requiring major capital investments. The LAP explored needs at Parry Sound and Waubaushene and determined that:

1. Dispatchable DERs are required to meet the characteristics of the needs; and
2. There are limited opportunities for dispatchable DER in the area

As part of the development of this IRRP, the Technical Working Group updated the analysis of NWA to ensure it captures the latest information related to option screening, informed by the needs characterization, and options costs. Based on the characteristics of the need, the non-wires alternatives assessment for Waubaushene indicated incremental CDM to be a good candidate for a non-wires solution.

In terms of wires options, the transformers replacement can be advanced and upgraded to larger units to meet the need. However, this requires a lead time of 2-3 years. Another non-wires option considered was energy storage as it is the least cost of the distributed resource options and serves as a benchmark that can be compared with the transformers replacement option.

The table below summarizes the options considered and the net present value of their levelized cost for the Waubaushene station capacity needs.

Table 5 | Options for Waubaushene TS Station Capacity Needs and Costs

	Option	Cost NPV
Wires	Station replacement/upgrade. Transformers are scheduled for replacement in 2030 but this can be advanced and upgraded to larger units. There is an opportunity to align the station capacity needs with EOL replacement; however, a 2-3 year lead time is required	$5 M
Non-wires - Storage	29 MW of storage	$30 M
Non-wires- CDM	Incremental cost effective CDM in the area served by the station	-

It is recommended to consider incremental, cost-effective CDM to defer the need arising in 2027 until the transformers are replaced for end-of-life. If by 2024 there are no commitments for incremental, cost-effective CDM, implement alternative solution such as advancing the end-of-life replacement of the transformers. The RIP will further explore this backstop solution.

7.1.2 D1M/D2M & M6E/M7E (Orillia x Copper) End-of-Life Needs

When equipment reaches the end of its life and requires replacement, a number of options can be considered.

- Replacement of the equipment with "like-for-like" or closest available standard;
- Reconfiguration of existing equipment to "right-size" the replacement option based on:
    - Demand forecast,
    - Changes to the use of the equipment since it was originally installed,
    - Reliability or other system benefits that an alternate configuration may provide; and
- Retirement of equipment, considering the impact on load supply and reliability.

Since no violations were identified for the identified circuits in system studies, a like-for-like replacement with the closest available standard is appropriate and can best address the end-of-life needs at sections of D1M/D2M and M6E/M7E.

7.2 Options and Recommendations for Meeting Longer-Term Needs

For needs appearing in the long term, there is an opportunity to develop and explore options, as specific projects do not need to be committed immediately. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential conservation measures in the study area; test emerging technologies; engage with communities and stakeholders; and lay the foundation for informed decisions in the future.

Additionally; the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast, it may be necessary to initiate the next iteration of the regional planning process earlier.

7.2.1 Minden Station Capacity Needs

Minden TS is expected to have station capacity needs by 2038. Given the timing of the need, no firm recommendation is required at this time. It is advised to monitor the load growth in the areas and provide enough lead time to capture changes into the next cycle of regional planning where these needs can be revisited.

7.2.2 M6E/M7E (Minden x Copper) System Capacity Need

The IRRP considered a number of options including incremental cost-effective CDM and storage, even though this is a longer-term need. This analysis showed that incremental cost-effective CDM is a potentially well-suited for deferring this need. As such, the Technical Working Group should continue to consider incremental, cost-effective CDM in between cycles and in the next cycle of regional planning in the region.

7.3 Summary of Recommended Actions and Next Steps

Table 6, below, summarizes the specific recommendations that should be implemented to address the electricity supply needs in the Parry Sound/Muskoka sub-region.

Table 6 | Summary of Parry Sound/Muskoka IRRP Recommendations

Need Description	Recommendation	Lead Responsibility	Timeline
Minden TS to reach its summer 10-day LTR	Monitor load growth to ensure load supplying capability is maintained; consider in the next cycle of regional planning	Technical Working Group	2038
Waubaushene TS to reach its summer 10-day LTR	Consider incremental, cost-effective CDM to defer the need arising in 2027 until the transformers are replaced for end-of-life. If by 2024 there are no commitments for incremental, cost-effective CDM, implement alternative solution such as advancing the end-of-life replacement of the transformers. The RIP will further explore this backstop solution	Hydro One	2024/2027
M6E/M7E (Minden TS x Cooper Fls JCT) supply capacity	Monitor demand growth in the area; consider CDM option on next cycle of regional planning as a means of deferring transmission upgrade	Hydro One	2034
Sections of D1M/D2M circuits to reach end-of-life	Like-for-like replacement approach	Hydro One	2028
Sections of M6E/M7E Orillia to Cooper to reach end-of-life	Like-for-like replacement approach	Hydro One	2024

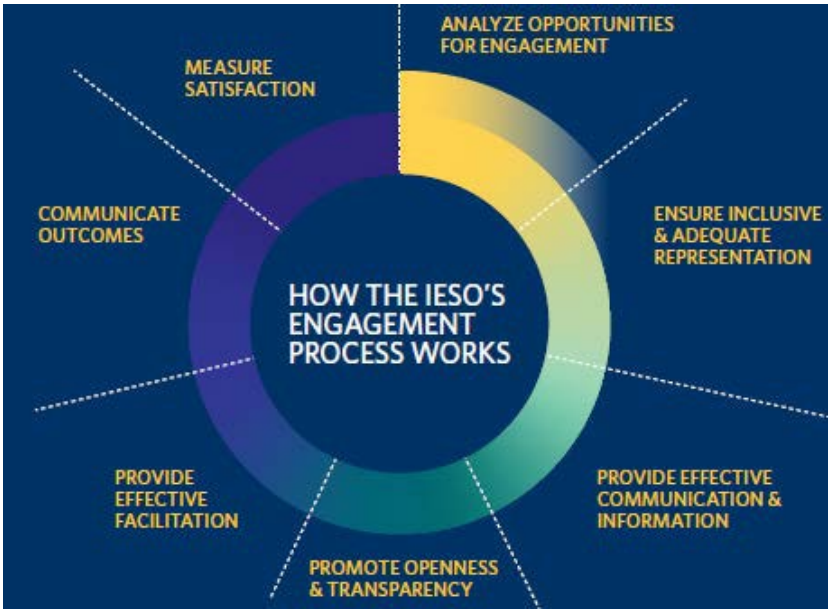
8. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for the IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 11 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Parry Sound/Muskoka

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;

- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Targeted individual and small group meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region.

An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft South Georgian Bay/Muskoka Scoping Assessment Outcome Greater before it was finalized. Feedback received encouraged the IESO to consider renewable technologies to help reduce local demand.

Following a written comment window, the final Scoping Assessment Outcome Report was published in November 2020 that identified the need for a coordinated planning approach done through two sub-regional IRRP: Barrie/Innisfil and Parry Sound/Muskoka.

Following these initial discussions and finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the South Georgian Bay/Muskoka region to ensure that all interested parties were made aware of this opportunity for input.

Three public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. The webinars received cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.
2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

All interested parties were kept informed throughout this engagement initiative via email to South Georgian Bay/Muskoka region subscribers, municipalities and communities as well as the members of the GTA/Central Regional Electricity Network.

Based on the discussions both through the Parry Sound/Muskoka IRRP outreach activities and broader network dialogue, there appears to be significant community growth planned in more rural area requiring new infrastructure, and broad interest in electrification, renewable energy solutions, net-zero development, and decarbonisation of electricity supply. To that end, ongoing discussions will continue through the IESO's GTA Central Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the dedicated IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Southern Huron-Perth electricity planning sub-region or that may have interests in the sub-region throughout the development of the plan. This includes the First Nation communities of Alderville, Beausoleil, Chippewas of Georgina Island, Chippewas of Rama, Curve Lake, Henvey Inlet, Hiawatha, Huron-Wendat Nation, Magnetawan, Mississaugas of Scugog Island, Moose Deer Point, Shawanaga, Wahta Mohawks and Wasauksing as well as the Métis Nation Ontario communities of Barrie South-Simcoe Métis Council, Georgian Bay Métis Council and Moon River Métis Council

9. Conclusion

The Parry Sound/Muskoka IRRP identifies electricity needs in the sub-region and opportunities to preserve or enhance system reliability for the next 20 years. This report makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth and efficiency achievements. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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South Georgian Bay-Muskoka

REGIONAL INFRASTRUCTURE PLAN

December 16, 2022

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Prepared by:
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With support from:

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Elexicon Energy
Lakeland Power
Epcor Electricity Distribution Ontario Inc
Newmarket-Tay Power Distribution Ltd
Wasaga Distribution Inc.

Disclaimer

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

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

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EXECUTIVE SUMMARY

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

The participants of the South Georgian Bay-Muskoka Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangevile Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

This RIP is the final phase of the second cycle of the South Georgian Bay-Muskoka Regional Planning (RP) process. It follows the completion of the South Georgian Bay-Muskoka Integrated Regional Resource Plan ("IRRP") which was subdivided into two sub-regions; Barrie Innisfil and Parry Sound/Muskoka both completed in May 2022. This also follows completion of the South Georgian Bay-Muskoka Needs Assessment ("NA") and Scoping Assessment ("SA") in April 2020 and November 2020, respectively.

The South Georgian Bay-Muskoka RIP provides a consolidated summary of needs and recommended plans for the region over a 10-year planning horizon (2022-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer term needs and trend. All needs for this long-term horizon will be reviewed again and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in August 2017 with the publication of the South Georgian Bay-Muskoka RIP report, which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

I. Update on the needs identified during the previous regional planning cycle

The following needs and projects identified in the previous regional planning cycle have been completed:

- Orillia TS M6E/M7E Switches (2021) - Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS (2021) – Replacement of end-of-life (EOL) 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units.

The following needs and projects identified in the previous regional planning cycle are currently underway:

- Parry Sound TS (2023) - Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment.

- Barrie TS (2023) Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

- Orangeville TS (2023)- Replace existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Also replace and upgrade T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate additional capacity.

II. Newly Identified needs:

The major infrastructure investments in this 2nd cycle recommended by the TWG in the South Georgian Bay-Muskoka Region over the near and medium-term (2022-2032) period are given in Table 1 below, along with their planned in-service date and budgetary estimate for planning purposes.

Table 1. South Georgian Bay-Muskoka Region - Recommended Plans over the 2022-2032 Study Period

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[1]	Cost ($M)[2]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal - Transmission Line	M6E / M7E (Orillia TS x Coopers Fls)	Replace end- f-life (EOL) transmission line conductor (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace EOL transmission line conductor and associated assets (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace EOL transmission line conductor and associated assets (62 km)	HONI	2028	70
Asset Renewal - Transmission Station	Wallace TS	Replace existing EOL 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units	HONI	2025	25
	Midhurst TS	Replace existing 230/44kV 125MVA EOL transformer (T4) with a new 230/44kV 125MVA unit	HONI	2026	12
	Orillia TS	Replace existing EOL 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing EOL 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing EOL 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

The South Georgian Bay-Muskoka TWG recommends that Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 1 while keeping the TWG apprised of project status.

[1] Planned in-service dates are tentative and subject to change

[2] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The next regional planning cycle for the South Georgian Bay-Muskoka Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will start in Q2 2025. However, the next regional planning cycle can be started earlier if required to address any emerging needs.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
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- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders. Figure 1-1 represents the South Georgian Bay-Muskoka Region Map.

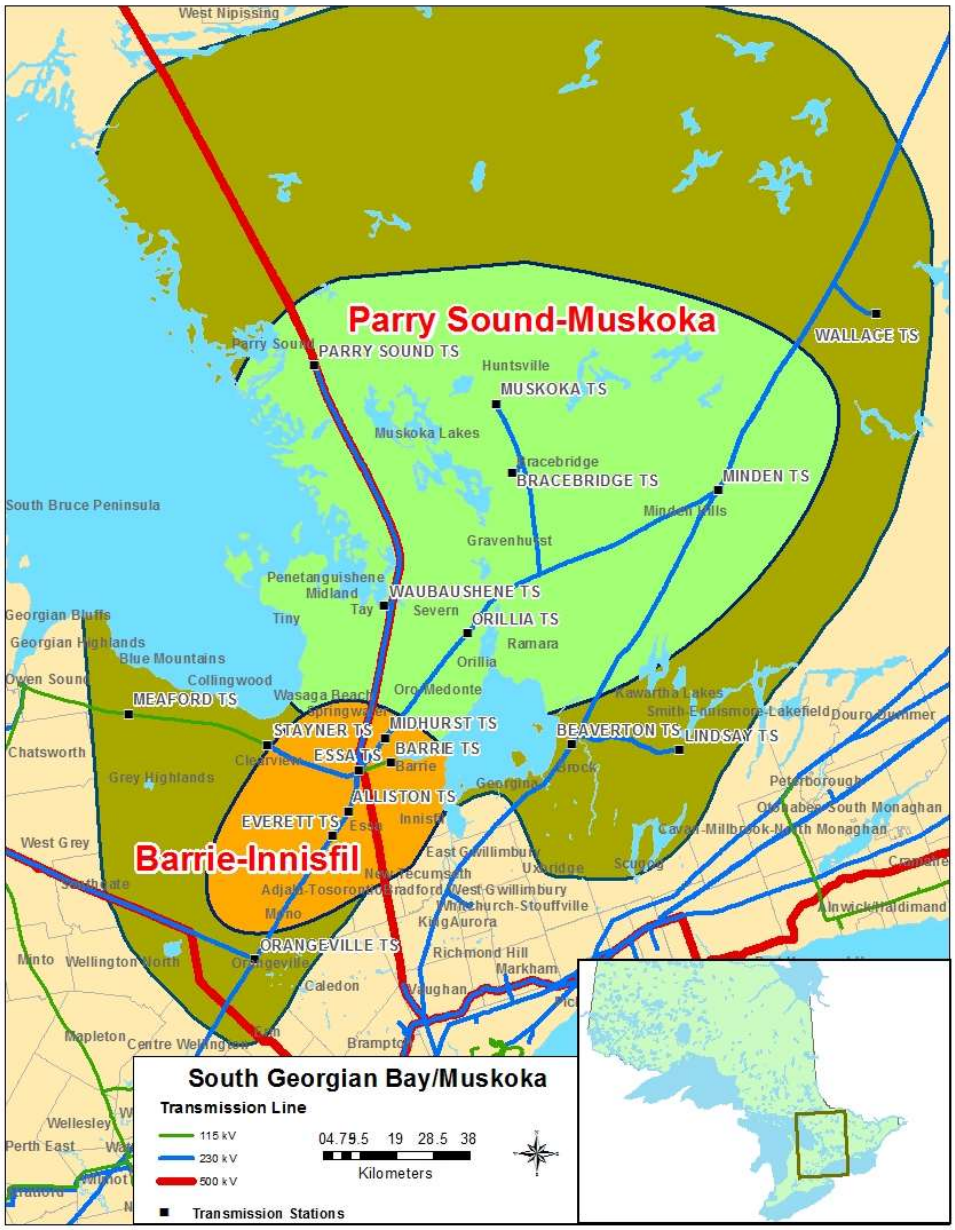


Figure 1-1 South Georgian Bay-Muskoka Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the South Georgian Bay-Muskoka Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2022-2032) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2022-2032 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the South Georgian Bay-Muskoka IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) determines whether further regional coordination is necessary to address them. If no further regional coordination is required to address the need(s), further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer to develop a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straightforward wires solution. The TWG considers various factors in determining that a LP is the appropriate planning approach.

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

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

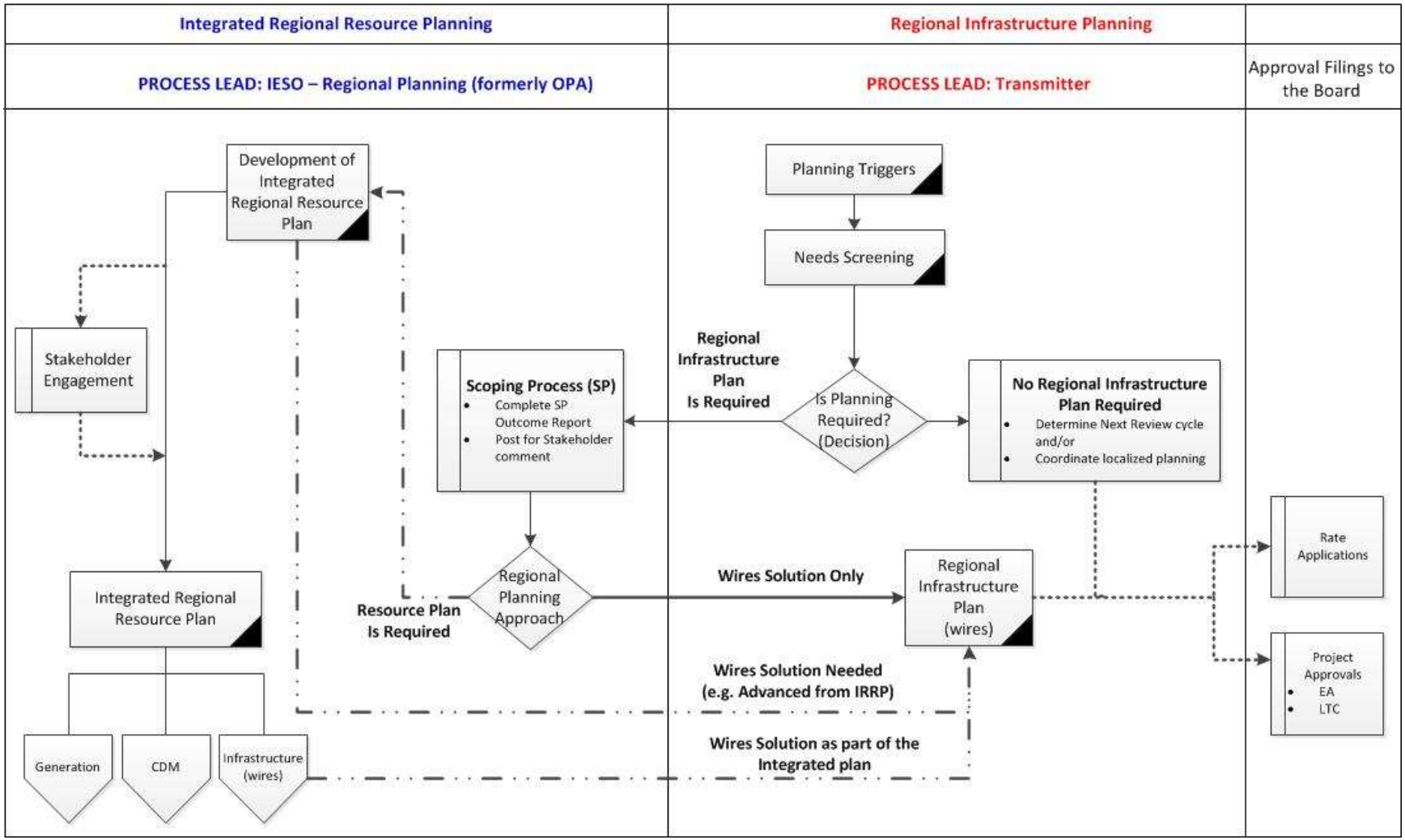


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

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

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

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

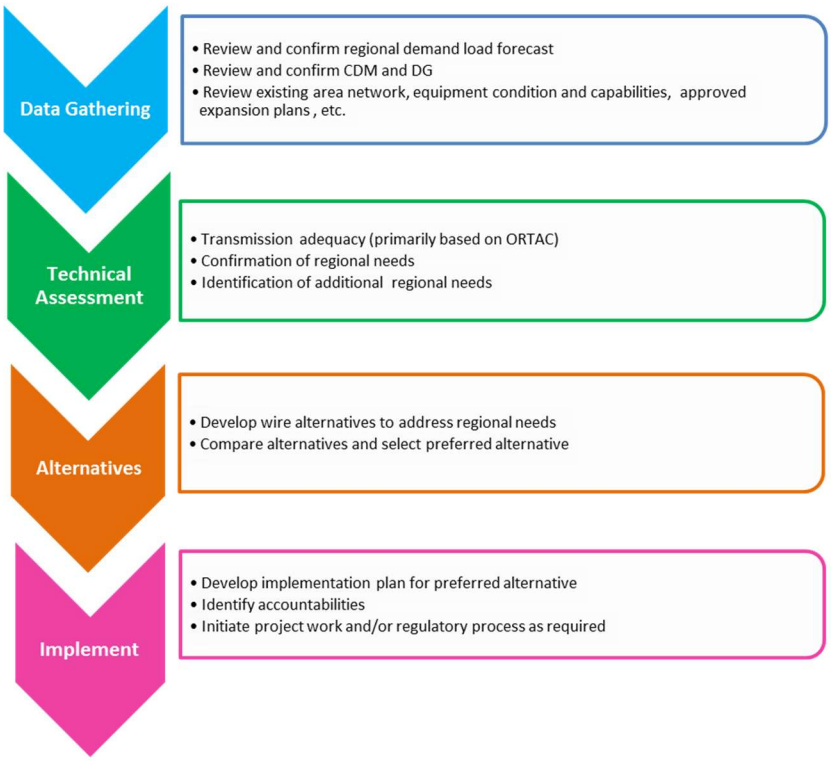


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230KV CIRCUITS E8V AND E9V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this report.

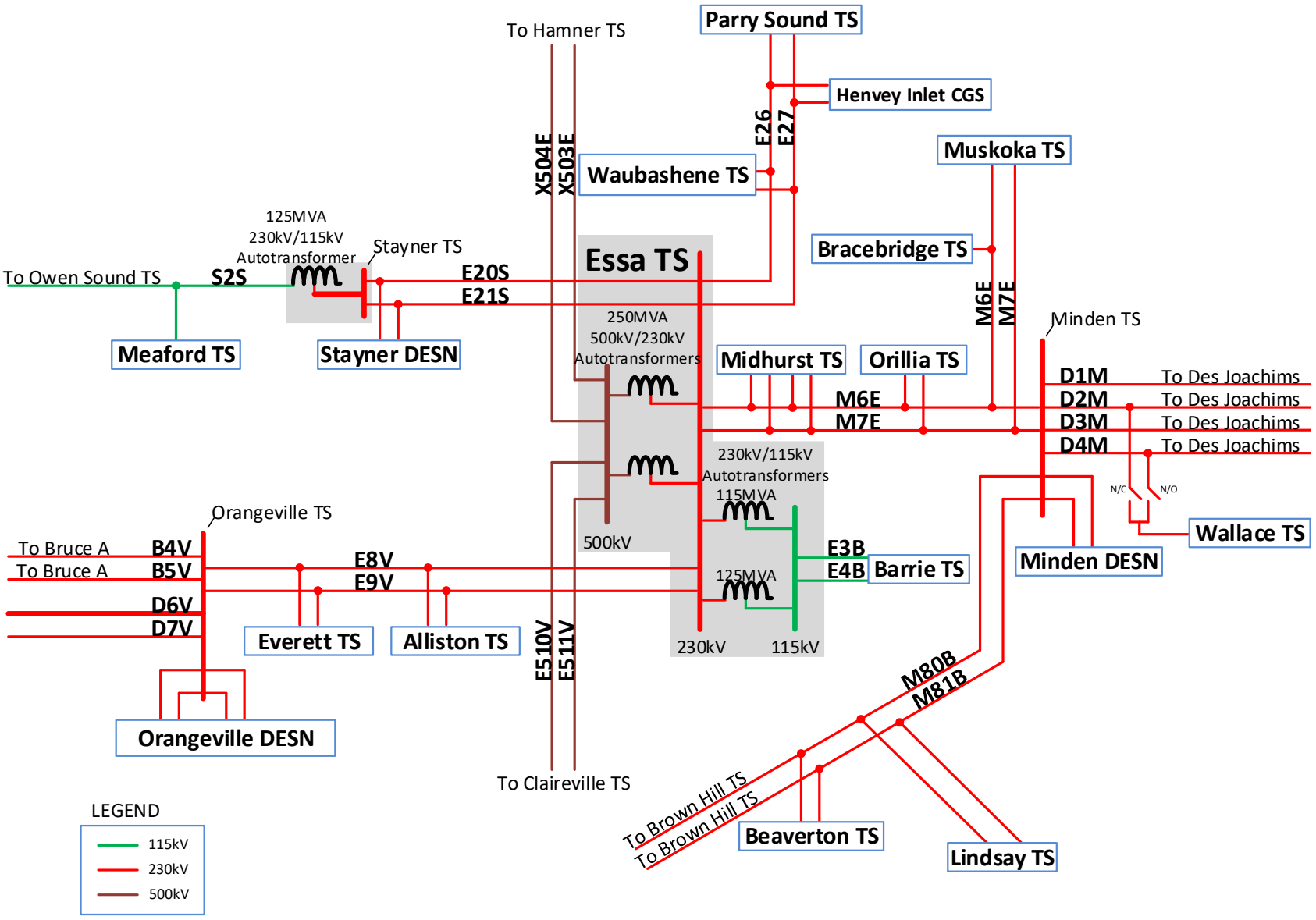
There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The April 2020 South Georgian Bay/Muskoka Region second cycle NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region.

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

This Parry Sound/Muskoka sub-region roughly encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS, and transmission circuits M6E/M7E and E26/E27.
The following circuits are not included in the South Georgian Bay/Muskoka Region:

- The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
- The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.



Note: BATU project will convert E3B/E4B to 230kV and connect Barrie TS directly to Essa TS 230kV bus (In-Service 2023)

Figure 3-1 South Georgian Bay-Muskoka Region Single Line Diagram

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

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

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

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44kV, 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (two banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and defer the overload on circuit M6E.

  Meaford TS Transformer Replacement (2015) – The 115/44 kV, 25/42 MVA T1/T2 transformers were at end-of-life (EOL) and replaced like-for-like.

- Orillia TS M6E/M7E Switches (2021) – Loss of M6E and M7E resulted in violation of ORTAC load restoration criteria based on the peak load forecast. Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS Transformer Replacement (2021) – The 230/44kV, 42MVA T1/T2 transformers were at EOL and replaced with new 230/44kV 83MVA units.

The following projects are underway:

- Barrie TS (2023) – This investment will convert the existing 115kV E3B/E4B circuits to 230kV and connect directly to the Essa 230kV bus. Barrie TS will be rebuilt with new 230/44kV 75/125MVA transformers and connect to the new 230kV E28/E29B circuits. The 230/115kV autotransformers at Essa TS will also be removed as part of this investment.

- Orangeville (2023) – Based on asset condition assessment the existing T3/T4 230/44kV 83MVA transformers will be replaced with new 125MVA units and also, the existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) be replaced with new dual winding 230/27.6, 83MVA units. This investment also involves reconfiguration of low voltage equipment and transfering existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

- Parry Sound TS (2023) - Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to their asset conditions. Hydro One will be installing new 230/44kV 83MVA transformers units to address both end of life and capacity needs at this station.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

During the study period, the load in the South Georgian Bay-Muskoka Region is expected to grow at an average annual rate of approximately 2% (summer) and 1.8% (winter) from 2022 to 2032.

Figure 5-1 shows the South Georgian Bay-Muskoka Region extreme summer weather net load forecast from 2022 to 2042. The load forecasts from the Barrie Innisfil sub-region IRRP and Parry Sound/Muskoka sub-region IRRP were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.
Non-coincident forecast for the individual stations in the region is available in Appendix D and is used to determine any need for station capacity relief.

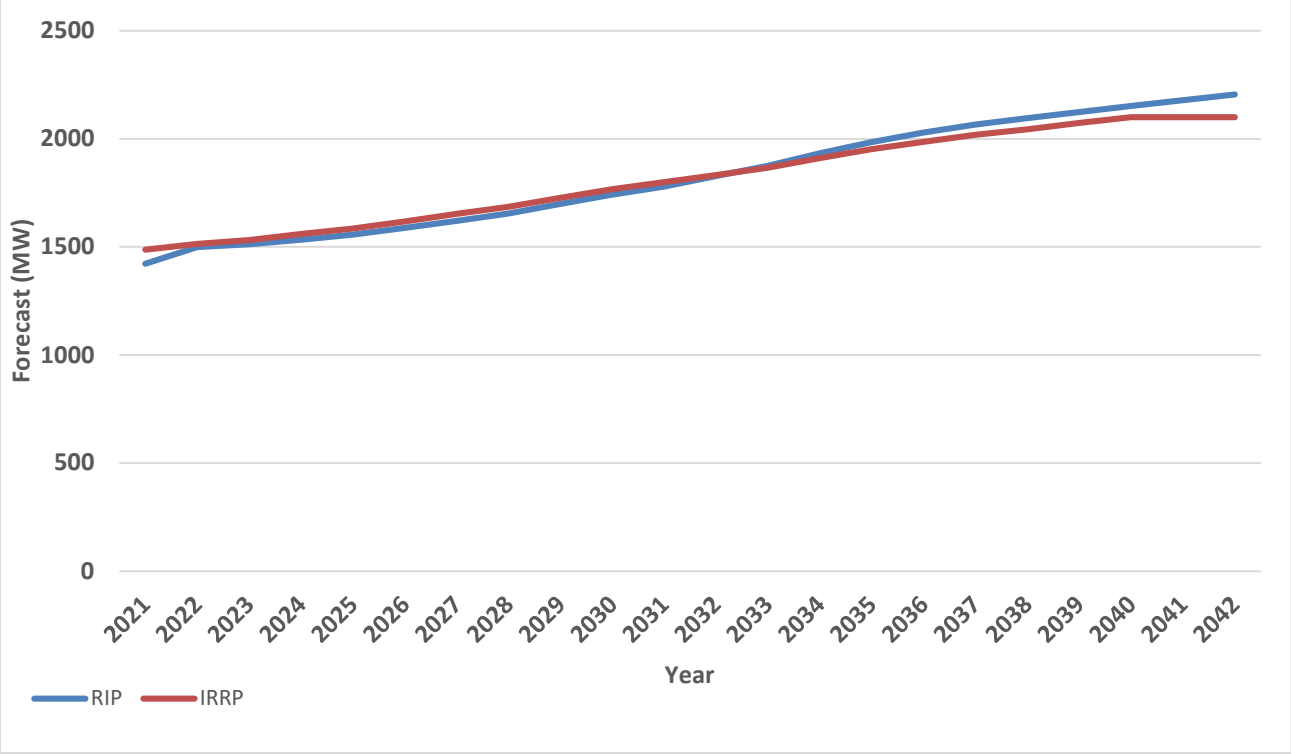


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

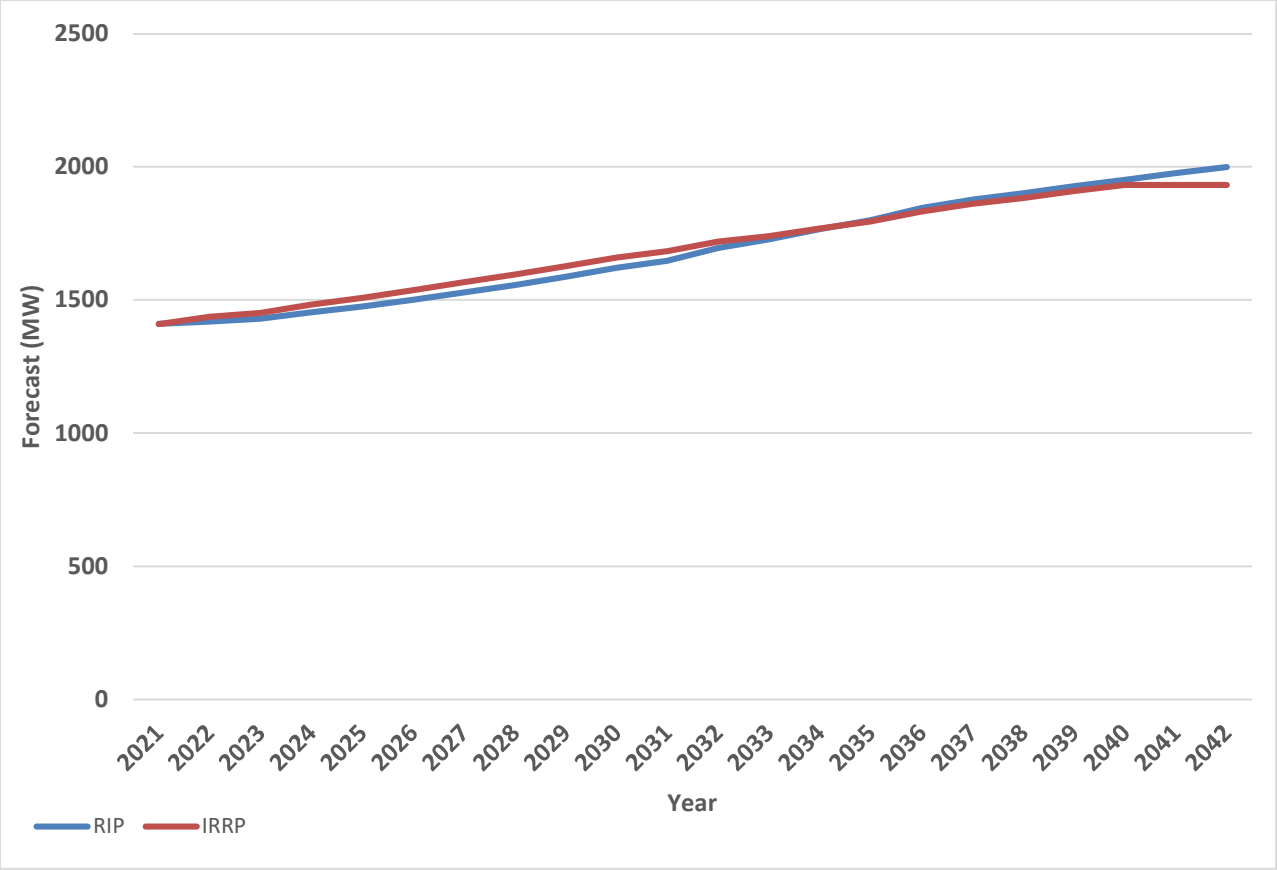


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the IESO's Barrie Innisfil sub-region and Parry Sound/Muskoka sub-region IRRPs.
- LDCs reconfirmed load forecasts up to 2040. The additional two years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Both summer and winter loads were considered to assess line and transformer loadings.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY-MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the South Georgian Bay-Muskoka Region. The findings of these assessments are inputs to this RIP. These assessments are:

1) South Georgian Bay-Muskoka Region second cycle Needs Assessment (NA) Report, April 2020
2) South Georgian Bay/Muskoka second cycle Scoping Assessment Outcome Report, November 2020
3) Barrie/Innisfil sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022
4) Parry Sound/Muskoka sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near to mid-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the South Georgian Bay/Muskoka Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service and specifically, the Barrie Area Transmission Reinforcement project and Orangeville/Parry Sound transformer replacements are in-service by 2023.

Sections 6.1- 6.3 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the South Georgian Bay-Muskoka Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system. The 230 kV circuits also serve local area stations within the region and the power flow on these circuits vary depending on the bulk system transfers as well as the local area loads.

6.1.1 500/230 kV Transformation Facilities

Bulk power supply to the South Georgian Bay-Muskoka Region is provided by 500/230 kV autotransformers at Essa TS which serves as a hub for major power flows between Hanmer TS (Sudbury) and Clairville TS (Toronto). Additional support for the region is provided from the 230 kV generation facilities (Des Joachims GS, Henvey Inlet CGS)

6.1.2 230 & 115 kV Transmission Circuits

The 230kV circuits in the region are as follows;

- E20S/E21S (Essa TS x Stayner TS)
- E26/E27 (Essa TS x Parry Sound TS)
- M6E/M7E (Essa TS x Minden TS)
- D1M/D2M/D3M/D4M (Minden TS x Des Joachims)
- 115 kV - S2S (Stayner TS x Owen Sound TS)

Table 6-1 below highlights the line section(s) and violations identified in the IRRP and reaffirmed in this RIP.

Table 6-1 South Georgian Bay-Muskoka Region - Lines Sections Exceeding ratings

No.	Line	Section	Contingency	Year Line Rating exceeded
1	M6E/M7E	Essa TS x Midhurst TS	N-1[1]	2034
2	M6E	Minden x Coopers Fls JCT	N-1[2]	2038
3	M6E	Minden x Coopers Fls JCT	N-1-1[3]	2040

[1] Loss of one of either M6E or M7E will result in overload of the companion circuit.
[2] Minden TS HL7 breaker fail.
[3] M7E O/S followed by loss of Essa TS T3

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Step-Down Transformation Facilities

There are sixteen (16) step-down transformer stations in the South Georgian Bay-Muskoka Region as listed in Table 6-2.

Table 6-2 South Georgian Bay-Muskoka Region - Step-Down Transformer Stations

Alliston TS	Everett TS	Minden TS	Parry Sound TS
Barrie TS	Lindsay TS	Muskoka TS	Stayner TS
Beaverton TS	Meaford TS	Orangeville TS	Wallace TS
Bracebridge TS	Midhurst TS	Orillia TS	Waubaushene TS

This RIP reviewed the step-down transformation capacity for the stations within the South Georgian Bay-Muskoka Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the 2022-2032 study period are shown in Table 6-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) 10-day LTR.

Table 6-3 South Georgian Bay-Muskoka Region - Stations Requiring Relief in the study period (2022-2032)

Station	Capacity (MW)	2022 Loading (MW)	Need Date
Everett TS	86	85	Immediate
Barrie TS	162[3]	98	2027
Waubaushene TS	94	90	2027

Further, based on the load forecast, the stations requiring relief beyond the study period are listed below:

- Midhurst TS (T1/T2) – 2033
- Midhurst TS (T3/T4) – 2034

6.3 Asset Renewal for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period as listed in Table 6-4 below.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as (but not limited to):

- Equipment deterioration;
- Technical obsolescence due to outdated design;
- Lack of spare parts availability or manufacturer support; and/or,
- Potential health and safety hazards, etc.

The major high voltage equipment considered includes the following:

1. 230/115kV autotransformers;
2. 230 and 115kV load serving step-down transformers;
3. 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
4. 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
5. 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

[3] After completion of the BATU project

Table 6-4 South Georgian Bay-Muskoka Region - Planned Replacement Work

No.	Station / Line Section	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS (T1/T2)	2023
2	Orangeville TS (T1/T2 & T3/T4)	2023
3	Parry Sound TS (T1/T2)	2023
	In Development	
4	Wallace TS (T3/T4)	2025
5	Midhurst TS (T4)	2026
6	Orillia TS (T2)	2025
7	Bracebridge TS (T1)	2026
8	Waubaushene TS T5/T6	2027
9	Alliston TS (T3/T4)	2030
10	M6E/M7E – Cooper Falls Jct x Orillia TS	2026
11	E8V/E9V – Orangeville TS x Essa Jct	2027
12	D1M/D2M – Otter Creek Jct x Minden TS	2028

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[4] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interruped in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

[4] These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The electrical infrastructure needs for the South Georgian Bay-Muskoka Region are summarized in Table 7-1. These needs include those previously identified in the NA for the South Georgian Bay-Muskoka Region and IRRPs for the Barrie/Innisfil and the Parry Sound/Muskoka Sub-Regions as well as any new needs identified during the RIP phase. All estimated costs included in the altnerative analysis are considered as planning budgetary estimates and are used for comparative purposes only.

Table 7-1 South Georgian Bay-Muskoka Region – Near, Medium and Long Term Needs

Type	Section	Needs	Timing
Station Capacity	7.1	Everett TS	2023
		Barrie TS	2027
		Waubaushene	2027
		Midhurst TS	2033/2034
		Minden TS	2036
Supply Capacity	7.2	M6E/M7E (Essa x Midhurst)	2034
		M6E/M7E (Minden x Coopers Fls)	2038
Asset Renewal for Major HV Transmission Equipment	7.3.1	M6E/M7E (Orillia x Coopers Fls)	2026
		E8V/E9V (Orangeville TS x Essa Jct)	2027
		D1M/D2M (Otter Creek Jct x Minden TS)	2028
	7.3.2	Wallace TS (T3/T4)	2025
		Midhurst TS (T4)	2026
		Orillia TS (T2)	2025
		Bracebridge TS (T1)	2026
		Waubaushene TS (T5/T6)	2027
		Alliston TS (T3/T4)	2030
Load Security/Restoration	7.4	None Identified in this planning cycle	-

7.1 Station Capacity Needs

7.1.1 Everett TS

Everett TS is 230/44kV 50/83MVA transformer station with a summer and winter 10-Day LTR of 86MW. Load at this station is forecasted to increase up to 105MW by the end of 2032. Supply capacity is presently limited by a current transformer (CT) ratio setting on the transformer breaker bushing, thereby restricting the ability to utilize the full supply capability of the transformers.

Table 7-2 Everett TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Everett TS	86	85	86	87	88	90	92	93	95	97	100	105

The following alternatives were considered to address Everett TS capacity need:

Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.

Alternative 2 – Replace and upgrade T1/T2 with new 75/125MVA units: Under this alternative the existing T1/T2 transformers will be replaced with new 75/125MVA transformers. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire the T1/T2 transformers. These transformers remain in acceptable condition are not scheduled to be replaced by Hydro One within the study period.

Alternative 3 – Modify the CT Ratio: This alternative would require modifying the CT ratio of the low voltage transformer breaker CTs to realize the full supply capacity of the transformers.

The TWG recommends Alternative 3 as the preferred and cost effective alternative for addressing the need. CT ratios are established based on expected loading at a station and typically lower when transformer stations are initially constructed. As the load increases these ratios must be adjusted to ensure protection, control and metering continue to operate as intended. This solution utilizes existing assets without incurring additional high capital expenditures and will allow the station LTR to increase to 108MW (summer) and 177MW (winter) once completed. The budgetary cost for this alternative is expected to be $0.5M

7.1.2 Barrie TS

The Barrie Area Transmission Upgrade (BATU) project is presently underway and scheduled to be in-service in 2023. Barrie TS will be upgraded to a new 230/44kV 125MVA transformer station with 8 feeder positions (six for Alectra Utilities and two for Hydro One Distribution with InnPower as an embedded customer).

Barrie TS will have a 10-Day LTR of 162MW and the forecasted load will exceed its normal supply capacity in 2028 based on the summer demand forecast (see Table 7-3 below). Coincident with the station capacity violation, Hydro One distribution and its embedded LDC (InnPower) will also see a supply capacity constraint on their two 44kV feeders in 2028. Minor capacity increases can be accommodated on the 44kV system, but only on an emergency basis and cannot be used as a permanent supply solution for increased load growth. InnPower will

need new supply capacity into the Innisfil service territory to service its load growth beyond the 2-feeder capacity that Barrie TS can supply.

An Innisfil supply study was completed to evaluate supply options for InnPower and consequently help to offload demand from Barrie TS. Results of this study are described in the alternatives below.

Table 7-3 Barrie TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Barrie TS	162	98	119	128	141	154	161	163	164	167	170	174

Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address future station capacity restrictions at Barrie TS, nor does it provide InnPower with the mid-term supply capacity required for load growth in their service territory.

Alternative 2 – Inn Power to connect to existing Alectra Feeder as embedded customer:

This solution was initially discussed by the TWG in the first planning cycle to provide increased supply to InnPower without additional station work at Barrie TS. Spare feeder capacity is not available and thus, this alternative fails to meet the full supply needs within the study period and will need to be combined with alternate solutions. This alternative was rejected on this basis, and thus costs have not been explored further.

Alternative 3 – Install an Additional 44kV feeder position from Barrie TS:

This solution was discussed with the TWG and closely relates to Alternative 2. A new dedicated feeder position for InnPower will provide up to 25MW supply capacity, however this solution would still fail to meet the full supply needs of InnPower within the study period, and the increased load will still be seen at Barrie TS triggering a capacity need in 2028. This solution will need to be combined with alternate solutions to relieve Barrie TS.
The combined transmission and distribution costs to install and construct a new distribution line from Barrie TS is estimated to cost $20M, however this alternative is rejected as it does address capacity needs at Barrie TS.

Alternative 4 – Load existing 44kV supply feeders beyond normal capacity

This alternative was explored by the TWG to increase supply on the two 44kV feeders from Barrie TS beyond the normal supply capacity. This solution requires increased voltage support on the distribution system along the feeders and will provide up to 20MW increased supply capacity (10MW/feeder). Distribution costs to facilitate increased feeder loading is estimated to cost $8M, however this alternative is rejected as it still does address Capacity needs at Barrie TS.

Alternative 5 – Provide 230kV tap connection to Innisfil service territory for new transformer station

This alternative involves construction of a 230/27.6kV 50/83MVA transformer station in Innisfil to supply the increased load demand forecast. This station will connect directly to the 230kV E28B/E29B circuits which will be completed in 2023 as part of the Barrie Area Transmission Upgrade project. A new 9km double circuit 230kV transmission line will be constructed to connect this new transformer station.

This alternative will provide increased supply capacity for InnPower within the study period and allow for load growth in the future. This alternative can be utilized as a standalone solution to meet the needs without additional interim investments or in conjunction with other alternatives presented above. This solution also allows InnPower to transfer load to this station which would otherwise be connected to Alliston TS. This transfer of load helps to mitigate a capacity need during the study period which would see an additional expenditure to increase supply capacity on the T3/T4 DESN at Alliston TS.
The estimated cost for this investment is expected to be $44M which is comprised of $14M for transmission line construction and $30M for a new transformer station.

The TWG recommends proceeding with Alternative 5. This alternative provides a robust transmission solution to meet InnPower's demand forecast and will also allow for future load growth beyond the study period. This solution will also help to relieve Barrie TS which will see a capacity need in 2028. Based on findings in the Needs Assessment and IRRP, Hydro One and InnPower have commenced development work on this alternative to meet the 2028 need date and TWG recommends continuing with this work.

7.1.3 Waubaushene TS

Waubaushene TS presently has 230/44 83MVA transformers (T5/T6) with a summer LTR of 94MW. This station will exceed its normal supply capacity in 2028 (see Table 7-4 below).

Summer overloading at this station continues to be of concern and the TWG agrees that a solution is required to address this need. Hydro One Distribution has permanently transferred 10MW of load from Waubaushene TS to Midhurst TS to help with recent summer loading concerns, however a solution is required to further address the upcoming supply capacity need.

Table 7-4 Waubaushene TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Waubaushene TS	94	90	90	91	92	93	94	96	97	99	100	102

Alternative 1 - Maintain Status Quo: This solution is not recommended as it does not address the supply capacity need at the station. This solution will prevent load growth at this station beyond 2027.

Alternative 2 – Load Transfer to neighboring stations

This solution was explored during the NA and IRRP phase. Hydro One distribution assessed transfer capability to other stations and determined that a maximum of 10MW of load could be transferred, and this was completed in Q1 2022. Further transfers are not feasible without significant distribution construction costs and regulators on the low voltage network estimated to be $ 5-10 M depending on feeder construction and voltage regulation.

Alternative 3 – Replace End-of-Life Waubaushene TS T5/T6 transformers with upgraded 125MVA units.

Replace and upgrade existing T5/T6 transformers with larger 75/125MVA units. This solution will increase supply capacity to allow load to continue to grow as per the demand forecast.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative for addressing the need. The existing T5/T6 transformers at Waubaushene TS have been identified by Hydro One as requiring replacement based on their asset condition and is planned for replacement in 2027. This date coincides with the supply capacity need timing as shown in Table 7.4 and thus the TWG agrees this is the ideal scenario to address the capacity need and right size the transformers. The budgetary cost for the replacement and upgrade of the transformers is expected to be $20M. Hydro One will follow Ontario Energy Board (OEB) approved procedures to determine appropriate cost allocation as this project addresses both a sustainment and capacity upgrade need.

7.1.4 Midhurst TS and Minden TS

As identified in Table 7-1, the stations listed below will require capacity relief beyond 2032. Based on the long-term horizon of these needs the load at these stations will be reviewed in the next regional planning cycle. The timing for capacity relief of these stations is shown below:

- Midhurst TS T1/T2: 2033 and Midhurst TS T3/T4: 2034
- Minden TS T3/T4: 2036

7.2 Supply Capacity Needs

The M6E/M7E circuits are a 230kV double circuit transmission line forming a critical path between Essa TS and Minden TS. These circuits are approximately 120 km long and serve to provide connection to load serving stations and provide a path for network flows. Based on the coincident load forecast of the stations in the region, sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The two circuit sections are described below:

1. Essa TS x Midhurst TS (10km) – For the loss of M6E or M7E, the companion circuit will exceed its Long-Term Emergency (LTE) rating as early as 2034 based on theload forecast.

2. Minden TS x Coopers Falls JCT (51km) – This section of transmission line will experience Long-Term Emergency (LTE) rating violations as early as 2038 for a Minden TS HL7 breaker failure, and Essa T3 contingency with M7E out of service.

Based on the long-term horizon of these needs solutions to address them will be further explored in the next regional planning cycle. Flows on this line and its violations are heavily influenced by area resource assumptions and demand forecast of the transformer stations connected to this circuits. IESO has also identified that incremental cost effective CDM, storage and other non-wires alternatives will be explored to address this need. The TWG will review this need in the next regionalplanning cycle and initiate an investment should this violation be advanced due to changing system conditions.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

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

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

7.3.1 Transmission Line Refurbishment

The following transmission line sections were identified by Hydro One as requiring refurbishment over the study period based on asset condition assessment:

1. M6E/M7E Orillia x Coopers Fls – This is a 50km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2026.

2. E8V / E9V Orangeville TS X Essa JCT – This is a 112km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2027.

3. D1M / D2M Otter Creek JCT x Minden TS – This is a 124km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2028.

7.3.2 Transmission Station Refurbishment

Hydro One identified a number of step-down transformers as requiring replacement over the study period based on asset condition assessment. Details of the planned work as recommended by the TWG are given in Table 7-5 below.

Table 7-5 Asset Renewal Plan-Transmission Stations

No.	Station	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV. This investment is also known as Barrie Area Transmission Upgrade (BATU) and will include replacement of end of life equipment at Essa TS, in addition to increasing both station and supply capacity to the area.	2023
2	Orangeville TS Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 230/44kV 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. This replacement plan will decrease the risk of equipment failure and contribute to maintaining supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	2023
3	Parry Sound TS Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment. Replacement of these power transformers will help to maintain the reliability of supply and provide increased supply capacity to customers in the area by right sizing to 83MVA units.	2024
	In Development	
4	Wallace TS Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units. Replacement of Oil circuit breakers will also be part of this investment. This investment will help maintaining reliability of supply to Hydro One Distribution customers and reduce the risk of interruptions caused by station equipment failure.	2025

5	Midhurst TS Replace existing 230/44kV 125MVA T4 transformer with a new like-for-like unit. The T3/T4 DESN presently supplies load to Alectra though 8 x 44kV feeders. T4 is the sole unit that has been identified as requiring replacement due to poor asset condition. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure. Load growth in the area will be reviewed in the next regional planning cycle. The TWG will ensure solutions to increase supply capacity in the region are explored in advance of the need date.	2026
6	Orillia TS Replace existing 230/44kV 125MVA T2 transformer with a new like-for-like 230/44kV 125MVA unit. The T1 transformer was replaced in 2015 after failure and does not require replacement during this study period. This investment will help maintain reliability of supply to Hydro One Distribution customersand decrease the risk of interruptions caused by failure of transformer T2.	2025
7	Bracebridge TS Replace existing 230/44kV 83MVA transformer (T1) with new like-for-like 230/44kV 83MVA unit. Bracebridge TS presently has one transformer (T1) and is used to supply 2 x 44kV feeders and a backup for industrial pipeline operation. The load at this station is not expected to trigger installation of a second transformer and thus like-for-like replacement of T1 will be sufficient during the study period. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2026
8	Waubaushene TS Replace existing 230/44 83MVA transformers (T5/T6) with new 125MVA units. This investment will help to maintain reliability of supply to area customers and provide increased supply capacity to meet demand forecast.	2027
9	Alliston TS Replace existing 230/44kV 83MVA transformers (T3/T4) with new like-for-like 230/44kV 83MVA units.	2030

	This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure and removal of legacy obsolete equipment.	

*The planned in-service year is tentative and is subject to change.

The above asset replacement plans have taken "right sizing" into consideration. All transformer replacements in the development phase are planned to be replacewith like-for-like units based on the load forecast in the study period and Hydro One standard equipment. The TWG recommends that Hydro One proceed with the above station sustainment work to ensure system reliability is maintained.

7.4 Load Security / Restoration

As indicated in section 6.4 there are no load security or restoration violations in the SGB-Muskoka region over the study period. The TWG will continue to monitor and take corrective action as needed.

7.5 Long Term Considerations

Like many other regions in Ontario, load growth in the SGB-Muskoka region will be directly impacted by new energy programs specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near and medium-term planning horizon (2022-2032) are provided in Table 8-1 below, along with their planned in-service dates and budgetary estimates for planning purposes.

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

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[5]	Cost ($M)[6]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and extend and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing end-of-life 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal Needs for Major HV Transmission Equipment	M6E / M7E (Orillia TS x Coopers Fls)	Replace transmission line conductor and associated assets. (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace transmission line conductor and associated assets. (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace transmission line conductor and associated assets. (62km)	HONI	2028	70
	Wallace TS	Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units.	HONI	2030	25
	Midhurst TS	Replace existing 230/44kV 125MVA transformer (T4) with a new 230/44kV 125MVA unit.	HONI	2026	12
	Orillia TS	Replace existing 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

[5] The planned in-service dates are tentative and subject to change.

[6] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The South Georgian Bay-Muskoka TWG recommends Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 8-1. All the other identified needs/options in the long-term will be further reviewed by the TWG in the next regional planning cycle.

9. REFERENCES

[1] Independent Electricity System Operator, Barrie/Innisfil IRRP (2022)

[2] Independent Electricity System Operator, Parry Sound Muskoka IRRP (2022)

[3] Hydro One, South Georgian Bay/Muskoka Needs Assessment (2020)

[4] Hydro One, South Georgian Bay/Muskoka RIP (2017)

[5] Independent Electricity System Operator, Barrie/Innisfil IRRP (2016)

[6] Independent Electricity System Operator, Parry Sound/Muskoka IRRP (2016)

[7] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 August 07, 2007

[8] Ontario Energy Board, Transmission System Code (2018)

[9] Ontario Energy Board, Distribution system Code (2022)

APPENDIX A. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS

No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubaushene TS	230/44

APPENDIX B. SOUTH GEORGIAN BAY-MUSKOKA REGION - TRANSMISSION LINES

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

APPENDIX C. SOUTH GEORGIAN BAY-MUSKOKA REGION - DISTRIBUTORS

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd.	DX
9.	Wasaga Distribution Inc.	DX

APPENDIX D. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	74.7	44	44	44	44	45	45	45	45	46	46	47	48	48	49	50	51	51	52	53	54	55
Alliston TS	T3/T4	112	100.8	76	80	83	86	90	93	91	91	91	92	92	93	93	93	93	93	94	94	94	94	94
Barrie TS	T1/T2	170	162.0	98	119	128	141	154	161	163	164	167	170	174	178	183	189	195	203	213	222	232	233	233
Beaverton TS	T3/T4	204	193.8	69	69	69	69	70	70	71	71	71	72	73	75	78	82	82	83	83	86	87	87	87
Bracebridge TS	T1	83	74.7	27	27	27	27	27	27	27	27	28	28	28	28	28	29	29	29	29	29	29	30	30
Everett TS	T1/T2	86	77.4	85	86	87	88	90	92	93	95	97	100	105	111	119	130	140	149	156	164	171	171	172
Lindsay TS	T1/T2	169	160.6	84	85	85	85	86	87	88	89	89	90	92	94	97	100	101	101	102	103	104	105	105
Meaford TS	T1/T2	55	52.3	33	33	33	33	33	34	34	34	34	35	37	38	38	38	38	38	39	39	39	40	40
Midhurst TS	T1/T2	171	163	150	151	153	154	156	157	159	160	162	162	163	166	167	169	170	171	173	174	175	176	176
Midhurst TS	T3/T4	166	149.4	123	107	111	115	118	122	125	129	133	136	140	144	151	156	160	163	167	171	175	176	176
Minden TS	T1/T2	58	52	44	44	44	44	44	45	45	45	46	46	46	47	47	48	48	52	52	53	53	53	53
Muskoka TS	T1/T2	179	170.1	113	114	113	113	114	115	116	117	125	125	126	127	130	132	133	134	135	136	137	137	137
Orangeville TS	T1/T2	113	101.7	49	49	52	53	53	54	55	55	56	57	59	60	62	62	63	64	65	65	66	67	67
Orangeville TS	T3/T4	170	161.5	90	91	97	98	99	100	102	103	104	106	110	111	114	116	117	119	120	122	123	124	124
Orillia TS	T1/T2	162	153.9	105	106	106	107	107	108	109	119	120	121	122	123	128	130	131	132	133	134	135	135	135
Parry Sound TS	T1/T2	113	101.7	45	46	45	47	48	50	50	51	54	54	55	55	56	56	56	57	57	58	58	58	59
Stayner TS	T3/T4	191	181.5	129	130	130	131	133	135	136	138	140	143	145	147	150	152	159	161	163	166	168	170	171
Wallace TS	T3/T4	54	48.6	36	36	36	36	36	36	36	36	36	37	37	37	37	38	38	38	38	38	38	39	40
Waubaushene TS	T5/T6	99	94.1	90	90	91	92	93	94	96	97	99	100	102	107	108	111	113	114	115	116	117	117	117

Winter Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LV Cap	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	N	74.7	32	32	32	32	32	33	33	33	34	34	35	35	36	36	37	37	38	38	39	40	40
Alliston TS	T3/T4	128	N	115.2	80	69	74	78	81	85	88	87	86	87	87	87	88	88	88	88	88	89	89	89	88
Barrie TS	T1/T2	200	Y	190.0	74	88	97	109	119	127	127	129	131	133	136	140	144	149	153	160	168	176	184	185	186
Beaverton TS	T3/T4	224	Y	212.8	77	78	78	78	79	79	80	80	81	81	81	82	82	83	84	84	85	88	88	89	90
Bracebridge TS	T1	83	N	74.7	34	34	34	34	34	34	34	35	35	35	35	35	35	35	36	36	36	36	36	37	38
Everett TS	T1/T2	95	N	85.5	60	61	62	63	64	65	66	67	69	71	75	81	88	99	109	118	125	132	139	139	140
Lindsay TS	T1/T2	192	Y	182.4	92	93	94	94	95	96	97	98	98	99	100	101	102	102	103	104	105	105	107	106	107
Meaford TS	T1/T2	62	Y	58.9	43	44	44	44	44	44	44	45	45	45	52	52	53	53	53	54	54	54	54	55	56
Midhurst TS	T1/T2	194	Y	184.3	116	116	117	118	119	120	121	122	123	124	125	126	127	128	128	129	130	131	132	132	133
Midhurst TS	T3/T4	191	N	171.9	96	85	88	90	93	95	98	101	103	106	108	111	114	117	119	122	125	127	130	131	132
Minden TS	T1/T2	64	N	58	55	55	55	55	55	56	56	56	57	57	57	58	58	58	59	63	63	63	64	64	65
Muskoka TS	T1/T2	209	Y	198.6	146	146	146	147	148	150	151	151	158	159	160	161	162	163	164	165	166	167	168	168	169
Orangeville TS	T1/T2	133	N	119.7	42	42	45	46	46	46	47	47	47	48	52	52	55	55	56	56	56	57	57	58	58
Orangeville TS	T3/T4	200	Y	190.0	78	78	84	85	86	86	87	87	88	89	97	97	102	103	103	104	104	105	106	107	107
Orillia TS	T1/T2	184	Y	174.8	108	109	110	111	112	112	113	123	123	124	125	126	127	128	129	130	131	132	133	133	134
Parry Sound TS	T1/T2	133	N	119.7	59	60	60	62	64	65	66	66	69	69	70	70	71	71	72	73	73	74	74	75	76
Stayner TS	T3/T4	213	Y	202.4	135	136	137	138	139	141	142	144	145	147	148	150	152	154	167	169	171	173	175	176	178
Wallace TS	T3/T4	60	N	54.0	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40	40	41	41	41	42	42
Waubaushene TS	T5/T6	109	Y	103.6	74	75	76	76	77	78	79	80	80	81	82	83	84	85	86	86	87	88	89	89	90

APPENDIX E. LIST OF ACRONYMS

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



NEEDS ASSESSMENT REPORT

South Georgian Bay - Muskoka

Date: August 27, 2025

Needs Assessment Report

South Georgian Bay - Muskoka

August 27, 2025

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Prepared by: South Georgian Bay-Muskoka Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the South Georgian Bay - Muskoka and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region. Updates may be made based on the best available information throughout the planning process.

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

Executive Summary

REGION	**South Georgian Bay - Muskoka** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: April 29, 2025 **END DATE:** August 27, 2025

The second Regional Planning cycle for the **South Georgian Bay - Muskoka** Region was completed December 6, 2022 with the publication of the Regional Infrastructure Plan ("RIP") report - South Georgian Bay-Muskoka Regional Infrastructure Plan (RIP).

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in **April 2025** for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. A 20-year planning assessment is undertaken in the next phase of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

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

The Technical Working Group (TWG) comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and operational concerns.
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Needs that require further regional coordination.

#	Need Location	Need Description
1	M6E/M7E (Supply Capacity)	Supply Capacity need identified on (Essa x Midhurst, Minden x Coopers Fls JCT). Further coordination is required to reaffirm need, solution and timing.
2	Alliston T3/T4 (Supply Capacity)	Alliston TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
3	Everett T1/T2 (Supply Capacity)	Everett TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
4	Midhurst T1/T2, T3/T4 (Supply Capacity)	Midhurst TS (T1/T2) and (T3/T4) are 230-44kV 125MVA transformer stations and will both exceed their normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
5	Claireville Area North and Flow North	Operational issues identified, will be studied in Bulk System Plan

Needs that do not require further regional coordination.

#	Need Location	Need Description
6	E8V/E9V (Asset Renewal + Supply Capacity)	Essa TS x Orangeville TS line section will be upgraded as per Ministry of Energy's – Energy for Generations report. This upgrade planned for 2029 will resolve supply capacity needs identified on section (Essa x Alliston JCT) and asset renewal needs. Further coordination is not required.

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities Corporation (Alectra)
- Hydro One Distribution
- InnPower
- Orangeville Hydro
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc
- NT Power Distribution
- Wasaga Distribution Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- n/a

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1. INTRODUCTION

The second cycle of the Regional Planning process for the South Georgian Bay - Muskoka Region was completed in December 2022 with the publication of the South Georgian Bay-Muskoka Regional Infrastructure Plan (RIP). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the South Georgian Bay - Muskoka Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

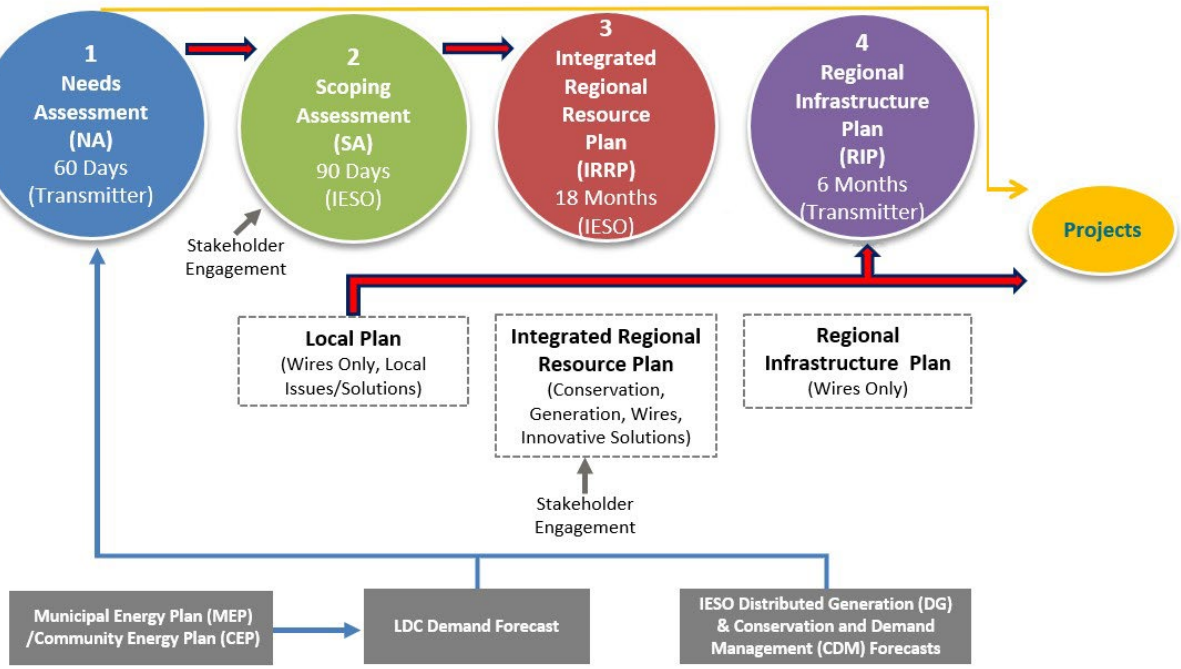


Figure 1: Regional Planning Process

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

Table 1: South Georgian Bay - Muskoka Region TWG Participants

Sr. no.	Name of TWG Participants
1	Independent Electricity System Operator (IESO)
2	Alectra Utilities Corporation (Alectra)
3	Hydro One Networks Inc. (Transmission & Distribution)
4	InnPower
5	Orangeville Hydro
6	Elexicon Energy
7	Lakeland Power
8	EPCOR Electricity Distribution Ontario Inc
9	NT Power Distribution
10	Wasaga Distribution Inc.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the South Georgian Bay - Muskoka region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the South Georgian Bay - Muskoka region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phase of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The geographical boundaries of the South Georgian Bay - Muskoka region is shown in Figure 2 below.

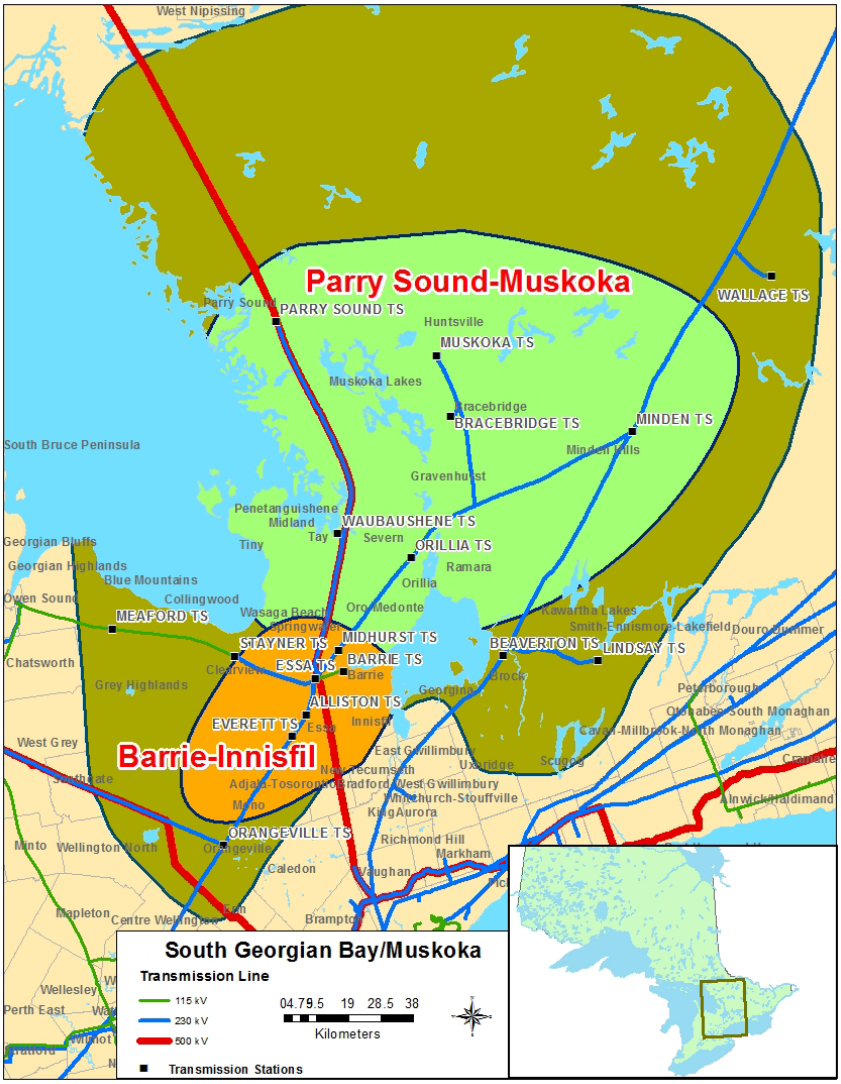


Figure 2: Map of South Georgian Bay - Muskoka Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the South Georgian Bay - Muskoka Region

115kV circuits	230kV circuits	Hydro One Transformer Stations		Generation Stations
S2S	D1M / D2M D3M / D4M E8V / E9V E20S / E21S E26 / E27 E28 / E29 M6E / M7E M80B / M81B	Alliston TS Barrie TS Beaverton TS Bracebridge TS Essa TS * Everett TS Lindsay TS Meaford TS Midhurst TS	Minden TS Muskoka TS Orangeville TS Orillia TS Parry Sound TS Stayner TS* Wallace TS Waubaushene TS	Henvey Inlet North /South) 700MW

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of South Georgian Bay - Muskoka region is shown in Figure 3 below.

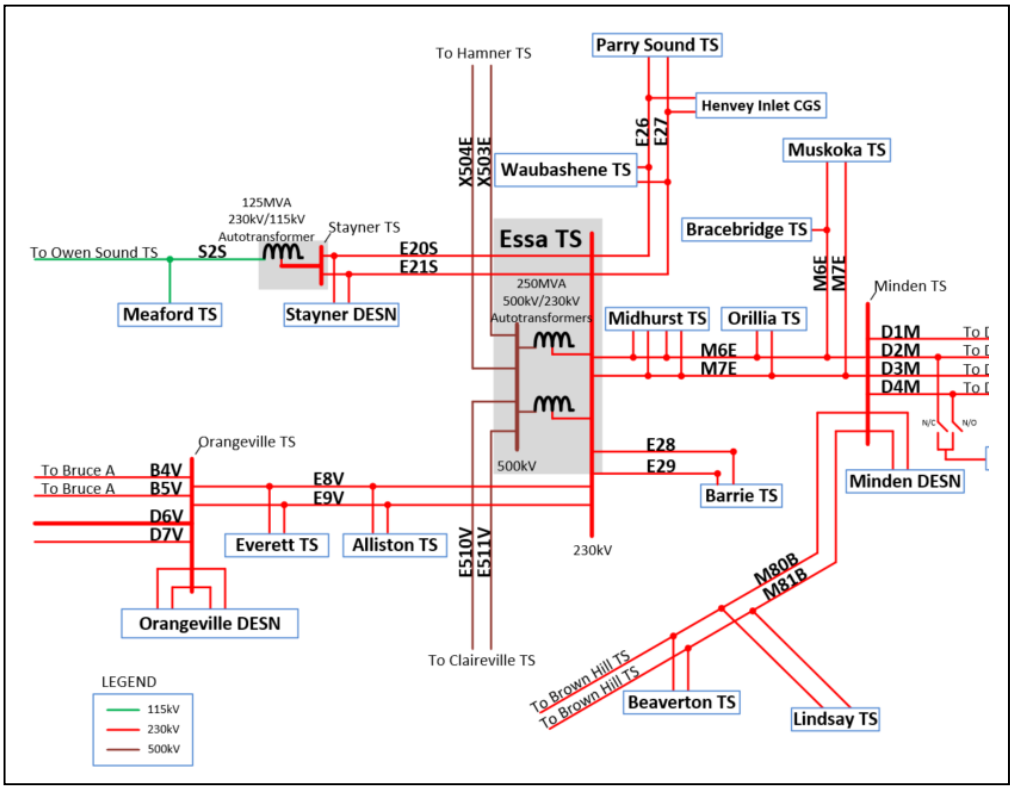


Figure 3: South Georgian Bay - Muskoka Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the **South Georgian Bay - Muskoka** NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- **South Georgian Bay - Muskoka** 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs).
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the **South Georgian Bay - Muskoka**.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on both summer and winter peak loads. Three load forecasts were developed i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenario was developed to conduct a sensitivity analysis to cover unforeseen

developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

- Consideration of existing or planned distributed energy resources

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2034.
- The Region is marginally winter peaking; however, the assessment was done on both summer and winter peak loads due to summer equipment ratings being lower.
- Network line and auto-transformation capacity adequacy is assessed by using coincidence peak loads in the area.
- Load-serving station and radial line capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for Hydro One transformer stations is determined by the seasonal 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Normal planning supply capacity for LDC transformer stations is in accordance with LDC methodology.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Transmission-connected Resources (e.g. Generators) were set to historical generation output of 98% and 85% availability for the seasons under study, information provided by the IESO.

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the South Georgian Bay - Muskoka region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the South Georgian Bay - Muskoka region. The region's extreme summer/winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2024 summer peak extreme weather corrected loads. The extreme summer/winter weather correction factors were provided by Hydro One. The net extreme summer weather forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This

extreme summer/winter weather corrected net load forecast for the individual stations in the South Georgian Bay - Muskoka region is given in Appendix A.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather these scenarios are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

Relevant information regarding system reliability and operational issues in the region as feedback provided by the IESO and Hydro One operation teams during the NA phase.

7. NEEDS

This section describes emerging new needs identified in the South Georgian Bay - Muskoka Region and/or updates on previously identified needs since the completion of Previous Regional Planning (RP) cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. **Everett TS Station Capacity** - CT ratio of the low voltage transformer breaker CTs were modified in 2024. However, additional capacity needs are identified and will be studied in this cycle.
2. **Barrie TS Station Capacity** - Construct new 230/27.6kV 83MVA Innpower MTS and extend 230kV E28B/E29B circuits to connect. The planned in-service year is 2029.
3. **Waubaushene TS Station Capacity** – Replacing and upgrading existing 230/44kV 83MVA T5/T6 transformers with 125MVA units. The planned in-service year is 2028.
4. **M6E/M7E (Orillia TS x Coopers FLS JCT) Asset Replacement** – Updated condition assessments have confirmed that the conductor and key components remain in acceptable asset condition, as a result, this need has been postponed beyond the study period of this RP cycle. A new capacity need, however, has been identified and will be studied in this RP cycle.
5. **E8V/E9V (Orangeville TS x Essa JCT) Asset Replacement** – Updated condition assessments have confirmed that the conductor and key components remain in acceptable asset condition, as a result, this need was postponed to 2035 i.e., beyond the study period of this RP cycle. However, IESO has identified a capacity need via the Central & South Bulk study and System Impact Assessments, which will be discussed in this RP cycle.
6. **D1M/D2M (Minden TS x Otter Creek JCT)** – Updated condition assessments have confirmed that the conductor and key components remain in acceptable asset condition, as a result, this need has been postponed beyond the study period of this RP cycle.
7. **Wallace TS Asset Replacement** – T3/T4 transformers will be replaced with like for like 230/44kV 42MVA standard step-down transformer. The planned in-service year is in 2034.
8. **Midhurst TS Asset Replacement** – T4 transformer will be replaced with like for like 230/44kV 125MVA standard step-down transformer. The planned in-service year is in 2034.
9. **Orillia TS Asset Replacement** – T2 transformer will be replaced with like for like 230/44kV 125MVA standard step-down transformer. The planned in-service year is in 2026.
10. **Bracebridge TS Asset Replacement** – T1 transformer will be replaced with like for like 230/44kV 83MVA standard step-down transformer. The planned in-service year is in 2026.
11. **Alliston TS Asset Replacement** – T3/T4 transformers will be replaced with like for like 230/44kV 83MVA standard step-down transformers. The planned in-service year is in 2040. However, a new capacity need has been identified and will be studied in this RP cycle.

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

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update	NA Report Section
Asset Renewal Needs		
No new Asset Renewal needs identified in this Regional Planning Cycle.		
Station Capacity Needs		
Alliston TS (T3/T4)	Projected to reach capacity in 2032	7.2.1
Everett TS (T1/T2)	Projected to reach capacity in 2030	7.2.2
Midhurst TS (T1/T2)	Projected to reach capacity in 2030	7.2.3
Midhurst TS (T3/T4)	Projected to reach capacity in 2029	7.2.4
Transmission Line Capacity Needs		
230kV M6E/M7E	Projected to reach capacity in mid-term	7.3.1
230kV E8V/E9V	Need identified by IESO in Central & South Bulk study and System Impact Assessments	7.3.2
System Reliability, Operation and Load restoration Needs		
Claireville Area North and Flow North	Operational issues identified, will be studied in the area Bulk System Plan	7.4

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and the TWG identified new asset renewal needs for major HV transmission equipment over the next 10 years in the **South Georgian Bay - Muskoka** Region. They are listed in Table 4 below. Hydro One is the only Transmission Asset Owner (TAO) in the Region

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

Table 4: Major HV Transmission Assets Requiring Replacement in the SGB Muskoka Region

Station/Circuit	Need Description	Planned ISD
Orillia TS	T2 transformer will be replaced with new like for like 230/44kV 125MVA standard step-down transformers	2026
Bracebridge TS	T1 transformer will be replaced with new like for like 230/44kV 83MVA standard step-down transformers	2026
Wallace TS	T3/T4 transformers will be replaced with new like for like 230/44kV 42MVA standard step-down transformers	2034
Midhurst TS	T4 transformer will be replaced with new like for like 230/44kV 125MVA standard step-down transformers	2034

7.1.1 E8V/E9V (Orangeville TS x Essa JCT)

This double circuit 230kV transmission line was in-serviced in 1950. Based on asset condition assessment, this line section requires conductor refurbishment at the end of the study period (2035) to ensure supply reliability and safety is maintained. In conjunction with the existing asset renewal need, these circuits were identified to have a capacity need via the Central & South Bulk study and System Impact Assessments by IESO and recently announced in the *Energy For Generations*[1] report issued by the Ministry of Energy and Mines (June 2025) as a key investment to facilitate growth in the province and strengthen the north-south electricity corridor (more information in section 7.3.2). The in-service date requested in the report precedes the asset renewal upgrade timeline and the upgrade will naturally replace existing components installed on the line. It is recommended this need requires further coordination. The expected in-service date is 2029.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2034 for the 230kV and 115kV Transforming stations in the **South Georgian Bay - Muskoka** Region using the summer and winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Alliston TS (T3/T4)

Alliston TS (T3/T4) is a 230-44kV 50-83MVA Step Down transformer station supplied by the E8V/E9V circuits. This station presently has a summer 10-day LTR of 100MW and will exceed its normal supply capacity in 2032 based on the summer demand forecast.

Previous regional planning cycle identified these transformers would be replaced in 2030, however Hydro One has since revised its assessment on the condition of these units and delayed the replacement outside of the study period to 2040.

It is recommended the capacity need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.2.2 Everett TS (T1/T2)

Everett TS (T1/T2) is a 230-44kV 50-83MVA Step Down transformer station supplied by the E8V/E9V circuits. This station presently has a 10-day LTR of 107MW (sum) and 115MW (win) and will exceed its normal supply capacity in 2030 and 2033 respectively.

As a result of the findings in the previous cycle RIP, Hydro One modified the CT ratio of the low voltage transformer breaker CTs to increase the station capacity. This was completed in 2024 and helped to defer

[1] https://www.ontario.ca/page/energy-generations

a capacity need identified in the previous cycle. Everett TS load forecast continues to grow and irrespective of the recent modifications, station capacity needs continue to exist within the study period.

It is recommended this need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.2.3 Midhurst TS (T1/T2)

Midhurst TS (T1/T2) is a 230-44kV 75-125MVA Step Down transformer station supplied by the M6E/M7E circuits. This station presently has a 10-day LTR of 162MW (sum) and will exceed its normal supply capacity in 2030 based on the summer demand forecast.

It is recommended this need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.2.4 Midhurst TS (T3/T4)

Midhurst TS (T3/T4) is a 230-44kV 75-125MVA Step Down transformer station supplied by the M6E/M7E circuits. This station presently has a 10-day LTR of 149MW (sum) and will exceed its normal supply capacity in 2029 based on the summer demand forecast.

It is recommended this need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2025-2034 for the 230kV and 115kV Transmission line circuits in the South Georgian Bay - Muskoka Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified during the study period:

7.3.1 230kV - M6E/M7E

The M6E/M7E circuits are 230kV transmission lines forming a critical path between Essa TS and Minden TS. Two sections of this circuit (Essa x Midhurst) and (Coopers Fls JCT x Minden) both exceed their Long Term Emergency (LTE) supply capacity during the study period and will require mitigating solutions to allow for increased flow. These needs were also documented in the previous cycle of regional planning and the TWG recommended to continue to monitor loading. Flows on this path are heavily influenced by area load and generation both within and outside of the SGB-Muskoka region.

It is recommended this need to be further explored in the next phase of this regional planning cycle.

7.3.2 230 kV - E8V/E9V

E8V/E9V circuits are 230kV transmission lines forming a critical path between Essa TS and Orangeville TS. These circuits supply customer transformer stations, carry system flows, and are incorporated into the FETT (Flow East Toward Toronto) interface limits. Based on the coincident load forecast, the Essa TS x Alliston JCT line section will exceed its supply capacity during the study period and will require mitigating solutions to allow for increased flows. This finding incorporates a higher growth scenario with the prospect of large industrial connected loads to be connected on the circuits.

In conjunction with the identified capacity need, these circuits were recently announced in the *Energy For Generations*[2] report issued by the Ministry of Energy and Mines (June 2025) as a key investment to facilitate growth in the province and strengthen the north-south electricity corridor. Also based on asset condition assessment, this line section requires conductor refurbishment at the end of the study period (2035) to ensure supply reliability and safety is maintained.

This investment to upgrade these circuits is presently underway with an in-service date planned for 2029. This investment will address the supply capacity needs identified above, including asset replacement. No further regional coordination is required.

7.3.3 115kV Circuits

No Supply capacity needs on 115kV circuit were identified during the study period.

[2] https://www.ontario.ca/page/energy-generations

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service.

Operational needs presented to the TWG consisted of two legacy concerns: Load restoration (M6E/M7E) and Long Term Emergency (LTE) overloading (M6E/M7E)

Load Restoration criteria continue to be respected in the region and were recently addressed by the installation of 230kV motorized in-line switches on the M6E/M7E circuits. Thermal overloading has also been reaffirmed in this Needs Assessment and will be further studied in future stages of regional planning.

Additional operational concerns on area interface limits on the CLAN (Claireville Area North) and FN (Flow North) limits were identified. The TWG acknowledges that increased flows in the overall area impact operational limits, however this will be further assessed in bulk area studies outside of regional planning.

Given the above needs have either already been identified or will be studied outside of this process, no other new significant system reliability, operating and restoring issues have been identified for this Region.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the South Georgian Bay - Muskoka region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

Table 5: Impact of Sensitivity Analysis on Station/Line capacity Needs in the Region

		Summer Growth Scenario			Winter Growth Scenario		
Sr.no.	Need Identified	Low	Normal	High	Low	Normal	High
1	Alliston (T3/T4)	-	2032	2028	-	-	2033
2	Alliston (T2)	-	-	-	-	-	-
3	Barrie (T3/T4)	-	2031	2028	-	-	-
4	Beaverton (T3/T4)	-	-	-	-	-	-
5	Bracebridge (T1)	-	-	-	-	-	-
6	Everett (T1/T2)	-	2030	2027	-	2033	2029
7	Lindsay (T1/T2)	-	-	2034	-	-	2032
8	Meaford (T1/T2)	-	-	-	-	-	
9	Midhurst (T1/T2)	-	2030	2028	-	-	2032
10	Midhurst (T3/T4)	-	2029	2027	-	-	-
11	Minden (T1/T2)	-	-	-	-	-	-
12	Muskoka (T1/T2)	-	-	2030	-	-	2031
13	Orangeville (T1/T2)	-	-	2030	-	-	2034
14	Orangeville (T3/T4)	-	-	-	-	-	-
15	Orillia (T1/T2)	-	-	-	-	-	-
16	Parry Sound (T1/T2)	-	-	-	-	-	-
17	Stayner (T3/T4)	-	-	-	-	-	-
18	Wallace (T3/T4)	-	-	2029	-	-	2030
19	Waubashene (T5/T6)	2030	2028	2026	2034	2028	2028

The sensitivity analysis identified the additional capacity needs at the end of the study period. High growth scenario forecasts introduce additional supply capacity needs at Lindsay TS, Midhurst TS, Muskoka TS, and Wallace TS. These needs will be assessed again during the next phase of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 6: Needs that Require Further Regional Coordination

#	Need Location	Need Description
1	M6E/M7E (Supply Capacity)	Supply Capacity need identified on (Essa x Midhurst, Minden x Coopers Fls JCT). Further coordination is required to reaffirm need, solution and timing.
2	Alliston T3/T4 (Supply Capacity)	Alliston TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
3	Everett T1/T2 (Supply Capacity)	Everett TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
4	Midhurst T1/T2, T3/T4 (Supply Capacity)	Midhurst TS (T1/T2) and (T3/T4) are 230-44kV 125MVA transformer stations and will both exceed their normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
5	Claireville Area North and Flow North	Operational issues identified, will be studied in Bulk System Plan

Table 7: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
6	E8V/E9V (Asset Renewal + Supply Capacity)	Essa TS x Orangeville TS line section will be upgraded as per Ministry of Energy's – Energy for Generations report. This upgrade planned for 2029 will resolve supply capacity need identified on section (Essa x Alliston JCT) and asset renewal needs. Further coordination is not required.

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities Corporation (Alectra)
- Hydro One Distribution
- InnPower
- Orangeville Hydro
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc
- NT Power Distribution
- Wasaga Distribution Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- n/a

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. August 14, 2025)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Hydro One Networks Inc, South Georgian Bay-Muskoka Regional Infrastructure Plan (RIP) (issue December 22, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1:

South Georgian Bay - Muskoka Non-Coincident- Normal Growth Net Load Forecast (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	40	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	75	78	81	84	88	91	95	99	103	107	111
Barrie TS	T3/T4	179	170	87	110	120	131	138	146	162	177	189	200	210
Beaverton TS	T3/T4	203	193	72	59	60	61	63	64	68	70	71	73	75
Bracebridge TS	T1	83	75	35	38	39	39	39	40	40	41	41	42	42
Everett TS	T1/T2	119	107	82	85	90	95	100	106	113	120	127	134	142
Lindsay TS	T1/T2	169	161	76	68	71	74	77	80	89	93	97	101	106
Meaford TS	T1/T2	55	52	33	33	33	33	34	34	34	34	35	35	35
Midhurst TS	T1/T2	171	162	124	125	132	137	132	144	163	165	166	175	177
Midhurst TS	T3/T4	166	149	114	114	116	131	135	150	154	157	161	166	170
Minden TS	T1/T2	138	124	48	44	44	44	44	44	47	47	47	47	48
Muskoka TS	T1/T2	178	169	128	131	135	138	141	145	148	152	156	159	163
Orangeville TS	T1/T2	128	115	74	76	78	81	84	87	91	94	97	101	105
Orangeville TS	T3/T4	180	171	93	93	95	97	98	100	103	105	107	109	111
Orillia TS	T1/T2	162	154	102	87	88	90	91	93	109	111	112	114	116
Parry Sound TS	T1/T2	128	115	51	52	54	55	56	58	59	61	62	63	65
Stayner TS	T3/T4	191	181	128	126	126	126	126	127	128	128	129	129	130
Wallace TS	T3/T4	54	49	42	42	42	43	43	44	44	45	46	46	47
Waubaushene TS	T5/T6	99	94	97	89	92	94	96	98	105	108	110	113	116

Table A.2:

South Georgian Bay - Muskoka – Coincident – Normal Growth Net Load Forecast – (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	22	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	72	75	78	81	84	87	91	95	99	103	107
Barrie TS	T3/T4	179	170	65	67	70	73	77	80	84	88	92	96	101
Beaverton TS	T3/T4	203	193	70	57	58	59	61	62	66	67	69	71	73
Bracebridge TS	T1	83	75	29	29	29	29	30	30	30	31	31	31	32
Everett TS	T1/T2	119	107	77	80	85	89	94	100	106	112	119	126	134
Lindsay TS	T1/T2	169	161	66	57	60	63	66	69	77	80	84	87	91
Meaford TS	T1/T2	55	52	31	30	30	30	30	30	30	30	30	30	30
Midhurst TS	T1/T2	171	162	113	109	113	116	121	125	134	139	144	149	155
Midhurst TS	T3/T4	166	149	105	72	74	76	79	81	83	86	89	91	94
Minden TS	T1/T2	138	124	37	33	33	33	33	33	36	37	37	37	37
Muskoka TS	T1/T2	178	169	120	104	105	108	110	111	119	121	123	125	128
Orangeville TS	T1/T2	128	115	37	37	38	40	41	42	44	46	48	49	51
Orangeville TS	T3/T4	180	171	88	88	89	91	92	94	97	99	101	103	105
Orillia TS	T1/T2	162	154	95	79	81	82	84	85	101	103	104	106	108
Parry Sound TS	T1/T2	128	115	47	43	44	45	47	47	49	50	51	51	52
Stayner TS	T3/T4	191	181	125	123	123	123	123	123	125	125	125	126	127
Wallace TS	T3/T4	54	49	31	31	31	32	32	32	33	33	34	34	35
Waubaushene TS	T5/T6	99	94	96	88	90	92	94	97	104	106	109	112	114

Table A.3:

South Georgian Bay - Muskoka Region Non-Coincident–High Growth Net Load Forecast (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	40	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	75	81	87	94	102	110	118	128	138	149	161
Barrie TS	T3/T4	179	170	87	110	128	148	172	199	231	268	311	361	419
Beaverton TS	T3/T4	203	193	72	65	74	83	94	105	121	135	151	170	190
Bracebridge TS	T1	83	75	35	38	39	41	42	43	44	46	47	48	50
Everett TS	T1/T2	119	107	82	91	102	115	130	147	166	187	211	239	270
Lindsay TS	T1/T2	169	161	76	71	79	87	95	105	120	131	144	157	172
Meaford TS	T1/T2	55	52	33	33	34	35	35	36	37	37	38	39	40
Midhurst TS	T1/T2	171	162	124	134	145	156	169	182	197	212	229	248	268
Midhurst TS	T3/T4	166	149	114	125	138	151	167	183	202	222	244	268	295
Minden TS	T1/T2	138	124	48	44	45	45	45	46	50	50	51	51	52
Muskoka TS	T1/T2	178	169	128	135	141	148	155	162	170	178	187	196	205
Orangeville TS	T1/T2	128	115	74	79	85	92	99	107	115	125	134	145	157
Orangeville TS	T3/T4	180	171	93	96	101	105	110	116	122	128	135	141	148
Orillia TS	T1/T2	162	154	102	89	93	97	102	106	126	131	136	142	148
Parry Sound TS	T1/T2	128	115	51	54	57	59	62	65	69	72	76	80	83
Stayner TS	T3/T4	191	181	128	128	130	132	135	137	141	144	147	150	153
Wallace TS	T3/T4	54	49	42	43	44	46	47	49	51	52	54	56	58
Waubaushene TS	T5/T6	99	94	98	90	96	101	107	114	121	128	136	144	152

Table A.4:

South Georgian Bay – Muskoka Coincident High Growth Net Load Forecast (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	22	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	72	76	80	85	90	96	102	108	114	121	128
Barrie TS	T3/T4	179	170	65	69	75	81	87	94	101	109	118	128	138
Beaverton TS	T3/T4	203	193	70	58	61	64	67	70	76	79	83	87	91
Bracebridge TS	T1	83	75	29	29	30	30	31	31	32	33	33	34	35
Everett TS	T1/T2	119	107	77	82	90	97	106	115	126	137	149	162	177
Lindsay TS	T1/T2	169	161	66	59	63	67	72	77	87	92	98	105	112
Meaford TS	T1/T2	55	52	31	31	31	31	31	32	32	33	33	33	34
Midhurst TS	T1/T2	171	162	113	110	116	122	129	135	147	155	163	171	180
Midhurst TS	T3/T4	166	149	105	74	77	81	85	89	94	99	104	109	114
Minden TS	T1/T2	138	124	37	33	34	34	34	35	38	39	39	40	40
Muskoka TS	T1/T2	178	169	120	104	107	110	113	115	124	127	129	132	136
Orangeville TS	T1/T2	128	115	37	38	40	42	45	47	51	54	57	60	64
Orangeville TS	T3/T4	180	171	88	89	93	96	100	104	108	113	117	122	127
Orillia TS	T1/T2	162	154	95	81	84	86	89	92	110	113	117	121	125
Parry Sound TS	T1/T2	128	115	47	44	46	47	50	51	54	56	57	59	61
Stayner TS	T3/T4	191	181	125	125	127	129	131	134	137	140	143	146	149
Wallace TS	T3/T4	54	49	31	31	32	33	34	35	36	37	39	40	41
Waubaushene TS	T5/T6	99	94	96	90	94	97	102	106	115	120	125	131	136

Table A.5:

South Georgian Bay - Muskoka Non-Coincident- Normal Growth Net Load Forecast (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	34	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	59	61	64	66	69	71	74	77	80	84	87
Barrie TS	T3/T4	190	181	93	93	97	102	107	112	124	135	144	152	159
Beaverton TS	T3/T4	224	213	82	82	84	86	88	90	92	94	97	99	101
Bracebridge TS	T1	83	75	40	40	41	41	42	42	43	43	44	44	45
Everett TS	T1/T2	128	115	68	72	77	81	86	92	98	104	110	118	125
Lindsay TS	T1/T2	192	182	100	102	107	111	115	120	125	129	134	140	145
Meaford TS	T1/T2	61	58	42	44	44	43	44	44	47	47	46	46	46
Midhurst TS	T1/T2	193	183	126	125	131	136	130	141	153	153	153	160	161
Midhurst TS	T3/T4	191	172	94	90	92	93	95	97	99	100	102	104	106
Minden TS	T1/T2	146	131	57	53	53	53	53	54	58	58	58	58	59
Muskoka TS	T1/T2	209	199	157	147	150	154	157	159	164	167	170	173	176
Orangeville TS	T1/T2	145	131	60	59	62	66	69	73	77	81	84	88	92
Orangeville TS	T3/T4	198	188	104	102	104	108	110	113	118	121	123	126	129
Orillia TS	T1/T2	184	175	107	99	101	103	105	107	118	120	123	125	128
Parry Sound TS	T1/T2	135	122	64	62	64	65	68	68	71	72	73	74	75
Stayner TS	T3/T4	213	202	153	149	149	150	151	151	157	158	159	160	161
Wallace TS	T3/T4	60	54	44	45	45	46	47	48	49	49	50	51	52
Waubaushene TS	T5/T6	109	104	88	93	94	94	107	108	108	108	109	109	110

Table A.6:

South Georgian Bay - Muskoka – Coincident – Normal Growth Net Load Forecast – (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	11	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	51	53	55	57	59	61	64	66	69	72	75
Barrie TS	T3/T4	190	181	51	53	54	56	57	59	60	62	64	65	67
Beaverton TS	T3/T4	224	213	81	81	83	85	87	89	91	93	95	97	100
Bracebridge TS	T1	83	75	32	33	33	34	34	34	35	35	35	36	36
Everett TS	T1/T2	128	115	65	68	73	77	82	87	93	99	105	112	119
Lindsay TS	T1/T2	192	182	90	92	95	99	103	107	111	116	120	125	130
Meaford TS	T1/T2	61	58	38	35	35	35	35	35	38	37	37	37	37
Midhurst TS	T1/T2	193	183	114	118	121	125	129	132	135	139	143	147	152
Midhurst TS	T3/T4	191	172	94	96	98	99	101	103	105	106	108	110	113
Minden TS	T1/T2	146	131	56	52	52	53	53	53	57	57	58	58	58
Muskoka TS	T1/T2	209	199	136	126	128	132	135	137	141	144	146	149	152
Orangeville TS	T1/T2	145	131	34	32	34	37	39	41	44	46	48	50	52
Orangeville TS	T3/T4	198	188	99	96	99	102	104	107	112	115	117	120	123
Orillia TS	T1/T2	184	175	107	98	100	102	105	106	118	120	122	124	127
Parry Sound TS	T1/T2	135	122	58	56	57	58	61	62	63	64	65	67	68
Stayner TS	T3/T4	213	202	153	149	149	150	151	151	157	158	159	160	161
Wallace TS	T3/T4	60	54	38	38	39	40	40	41	42	42	43	44	45
Waubaushene TS	T5/T6	109	104	86	88	90	91	93	95	96	98	100	102	104

Table A.7:

South Georgian Bay - Muskoka Region Non-Coincident – High Growth Net Load Forecast (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	34	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	59	64	69	74	80	87	94	102	110	119	129
Barrie TS	T3/T4	190	181	93	99	104	111	117	124	132	140	148	157	167
Beaverton TS	T3/T4	224	213	82	85	89	94	99	104	109	115	121	128	135
Bracebridge TS	T1	83	75	40	41	43	44	45	47	48	50	51	53	55
Everett TS	T1/T2	128	115	68	77	87	98	111	125	141	160	181	205	232
Lindsay TS	T1/T2	192	182	100	107	116	125	136	147	159	172	186	202	219
Meaford TS	T1/T2	61	58	42	43	44	45	46	46	47	48	49	50	51
Midhurst TS	T1/T2	193	183	126	135	133	141	150	158	168	178	189	201	214
Midhurst TS	T3/T4	191	172	94	100	106	112	119	126	133	141	150	159	168
Minden TS	T1/T2	146	131	57	53	54	54	55	56	60	61	62	63	63
Muskoka TS	T1/T2	209	199	157	151	158	166	174	181	191	199	208	217	227
Orangeville TS	T1/T2	145	131	60	62	68	76	83	90	100	109	119	130	142
Orangeville TS	T3/T4	198	188	104	105	110	117	123	130	139	147	154	162	171
Orillia TS	T1/T2	184	175	107	101	106	111	116	121	136	142	148	154	161
Parry Sound TS	T1/T2	135	122	64	64	67	70	75	78	82	85	89	93	97
Stayner TS	T3/T4	213	202	153	151	154	157	161	165	173	177	180	185	189
Wallace TS	T3/T4	60	54	44	46	48	50	52	54	56	58	61	64	66
Waubaushene TS	T5/T6	109	104	88	92	97	101	106	112	117	123	129	136	143

Table A.8:

South Georgian Bay – Muskoka Coincident High Growth Net Load Forecast (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	11	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	51	54	57	60	64	68	72	77	81	86	92
Barrie TS	T3/T4	190	181	51	54	57	60	63	66	69	73	77	81	85
Beaverton TS	T3/T4	224	213	81	82	86	90	94	97	101	106	110	115	120
Bracebridge TS	T1	83	75	32	33	34	35	35	36	37	38	38	39	40
Everett TS	T1/T2	128	115	65	70	77	83	91	99	108	118	129	141	154
Lindsay TS	T1/T2	192	182	90	94	100	106	113	120	127	135	144	153	163
Meaford TS	T1/T2	61	58	38	35	36	36	37	37	40	41	41	42	42
Midhurst TS	T1/T2	193	183	114	120	127	134	141	147	155	163	171	180	190
Midhurst TS	T3/T4	191	172	94	98	102	107	111	115	120	125	130	136	142
Minden TS	T1/T2	146	131	56	53	54	56	57	58	64	65	66	68	70
Muskoka TS	T1/T2	209	199	136	129	135	143	150	156	165	172	179	188	196
Orangeville TS	T1/T2	145	131	34	33	35	39	41	44	48	51	54	58	61
Orangeville TS	T3/T4	198	188	99	98	102	108	113	117	125	130	136	142	148
Orillia TS	T1/T2	184	175	107	100	103	107	111	115	128	132	136	140	145
Parry Sound TS	T1/T2	135	122	58	56	58	59	62	63	66	67	69	70	72
Stayner TS	T3/T4	213	202	153	151	154	157	161	165	173	177	180	185	189
Wallace TS	T3/T4	60	54	38	39	40	41	43	44	45	47	48	50	52
Waubaushene TS	T5/T6	109	104	86	89	92	95	98	101	104	107	111	115	118

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Alliston TS	230/44	E8V/E9V
2	Barrie TS	230/44	E28/E29
3	Beaverton TS	230/44	M80B/M81B
4	Bracebridge TS	230/44	M6E
5	Everett TS	230/44	E8V/E9V
6	Lindsay TS	230/44	M80B/M81B
7	Meaford TS	230/44	S2S
8	Midhurst TS	230/44	M6E/M7E
9	Minden TS	230/44	Minden TS
10	Muskoka TS	230/44	M6E/M7E
11	Orangeville TS	230/44/27.6	Orangeville TS
12	Orillia TS	230/44	M6E/M7E
13	Parry Sound TS	230/44	E26/E27
14	Stayner TS	230/115/44	E20S/E21S
15	Wallace TS	230/44	D2M/D4M
16	Waubaushene TS	230/44	E26/E27

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations		Circuit ID	Voltage (kV)
1.	Essa TS	Stayner TS	E20/E21S	230
2.	Essa TS	Parry Sound TS	E26/E27	230
3.	Essa TS	Minden TS	M6E/M7E	230
4.	Minden TS	Des Joachims TS	D1M/D2M	230
5.	Minden TS	Des Joachims TS	D3M/D4M	230
6.	Minden TS	Brown Hill TS	M80B/M81B	230
7.	Essa TS	Barrie TS	E28/E29	230
8.	Stayner TS	Owen Sound TS	S2S	115

Appendix D: List of LDC's

No.	Name of LDC
1	Hydro One Distribution
2	Alectra Utilities
3	InnPower
4	Orangeville Hydro
5	Elexicon Energy
6	Lakeland Power
7	EPCOR Electricity Dist. Ontario Inc.
8	NT Power Distribution Ltd.
9	Wasaga Distribution Inc.

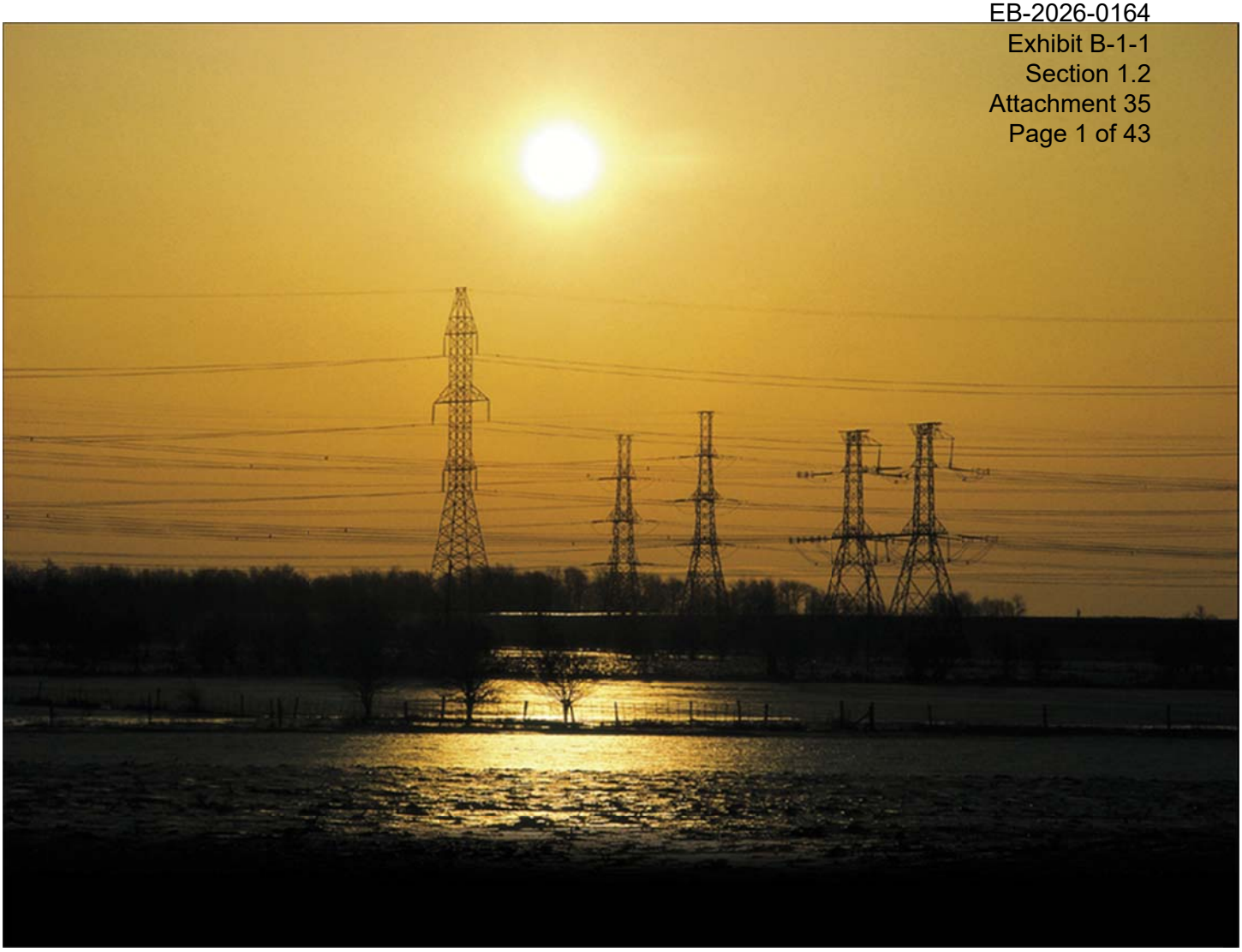
Appendix E: List of Municipalities in the South Georgian Bay - Muskoka Region

	Name of Municipality				
1	City of Barrie	19	Town of Kearney	37	Township of McKellar
2	City of Kawartha Lakes	20	Town of Midland	38	Township of McMurich
3	City of Orillia	21	Town of Midland	39	Township of Mulmur
4	County of Haliburton	22	Town of Mono	40	Township of Muskoka Lakes
5	Grey Highlands	23	Town of New Tecumseth	41	Township of Nipissing
6	Municipality of Callander	24	Town of Orangeville	42	Township of Perry
7	Municipality of Magnetawan	25	Town of Parry Sound	43	Township of Ryerson
8	Municipality of Meaford	26	Town of Penetanguishene	44	Township of Seguin
9	Municipality of Powassan	27	Town of Shelburne	45	Township of Severn
10	Municipality of Whitestone	28	Town of Wasaga Beach	46	Township of Southgate
11	Owen Sound	29	Township of Armour	47	Township of Springwater
12	South Gate	30	Township of Carling	48	Township of Strong
13	Town of Bracebridge	31	Township of Clearwater	49	Township of The Archipelago
14	Town of Collingwood	32	Township of Essa	50	Township of Tiny
15	Town of Gravenhurst	33	Township of Georgian Bay	51	Village of Burk Falls
16	Town of Huntsville	34	Township of Georgian Bluffs	52	Village of South River
17	Town of Innisfil	35	Township of Lake of Bays	53	Village of Sundridge
18	Town of Joly	36	Township of McDougall		

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage

Acronym	Description
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station



Sudbury/Algoma

2020 REGIONAL INFRASTRUCTURE PLAN
DECEMBER 16, 2020

hydro one

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Prepared and supported by:

Company
Greater Sudbury Hydro Inc.
Hydro One Networks Inc. (Distribution)
North Bay Hydro (Embedded LDC)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Transmission)







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Disclaimer

This Regional Infrastructure Plan (RIP) report is an electricity infrastructure plan that identifies and addresses near and mid-term needs based on information provided and/or collected by the Study Team.

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE SUDBURY/ALGOMA REGION.

The participants of the Regional Planning activities for the Sudbury/Algoma region ('the Study Team')included members from the following organizations:

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- North Bay Hydro (Embedded LDC)
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the Sudbury/Algoma region was completed in June 2016 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle Sudbury/Algoma region's Needs Assessment (NA) completed in August 2020. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, this RIP is based on the data collected during the NA phase and the findings and recommendations of the NA report. A new Energy Efficiency framework was announced by the Ontario Government since the completion of the NA of the Sudbury/Algoma region. Resulting impacts of the newly announced framework are not reflected in the present RIP.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the Sudbury/Algoma region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the NA report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the initiation of the previous regional planning cycle, the following project has been completed:

- **Espanola TS**: Replace 115/44 kV 15MVA (T1) and 42MVA (T2) transformers with new 115/44 kV 42 MVA units. These transformers were assessed at being at their end-of-life and in need of replacement due to the assets'condition. This project was successfully carried out and in serviced in Q4 2016.

- **Larchwood TS** – Replace 110/44 kV 20 MVA (T2) transformer with a new 115/44kV 42MVA unit. This project was successfully completed and in serviced in Q4 2015.

The major infrastructure investments identified and supported by the Study Team over the near- and mid-term planning horizon are provided in Table 1 below, along with their planned in service dates and budgetary allowances for planning purpose.

Table 1: Recommended Plans in Sudbury/Algoma region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Allowance ($M)
1	Manitoulin TS Capacity Constraint	Change limiting CT ratio	2021	0.02
2	Under peak load conditions, the loss of two Martindale 230/115kV transformers may result in the overload of the third Martindale transformer	Martindale autotransformers T21/T23 Replacement project	2022[1]	76
3	With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable limits set out in the Ontario Ressources and Transmission Assessement Criteria(ORTAC) document	Unbundle X25S/X26S	2023	8
4	Elliot Lake TS end-of-life (EOL) Power Transformer Replacement	Right-sizing that station by replacing 115/44 kV 42 MVA (T1) power transformer with new 115/44kV 42 MVA unit. Remove 115/44 kV 19 MVA (T2) 8autotransformer. Upon completion of this project, the station will remain with 2 – 115/44kV 42 MVA (T1/T3) power transformers.	2025	23
5	Algoma TS end-of-life (EOL) autotransformer replacement	Replace 230/115kV 195 MVA and 115 MVA autotransformers (respectively T5 and T6) with new 230/115kV 125 MVA transformers.	2025	23
6	Clarabelle TS end-of-llife (EOL) Power transformer Replacement	Replace 230/44kV 125 MVA (T1/T2) power transformers with new 230/44kV 125 MVA units.	2027	19
7	Martindale TS end-of-life (EOL) Power Transformer Replacement	Replace 230/44 kV 125 MVA (T1/T2) power transformers with new 230/44 kV 125 MVA units.	2028	19
8	Martindale TS Supply Capacity Constraint	Maintain the status quo and reassess station supply needs during the next Regional Planning Cycle	2028	N/A

The Study Team recommends the continuation of the investments listed in Table 1. Hydro One transmission will coordinate with affected LDCs to implement these undertakings.

[1] Earlier Regional Planning documents indicate 2020 as the planned in service date for this project. Needs reprioritization as well as current pandemic conditions resulted in pushing the targeted completion date for this undertaking to 2022.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SUDBURY/ALGOMA REGION BETWEEN 2020 AND 2029.

The report was prepared by Hydro One Networks Inc. (HONI) with input from Study Team members during the Needs Assessement (NA) phase and documents the results of the NA and recommended plan. The Study Team included representative from Greater Sudbury Hydro Inc, North Bay Hydro, HONI(Transmission and Distribution) and the Independent Electricity System Operator (IESO) in accordance with the Regional Planning process established by the Ontario Energy Board (OEB) in 2013.

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden. The boundaries of the Sudbury to Algoma Region are shown below in Figure 1.

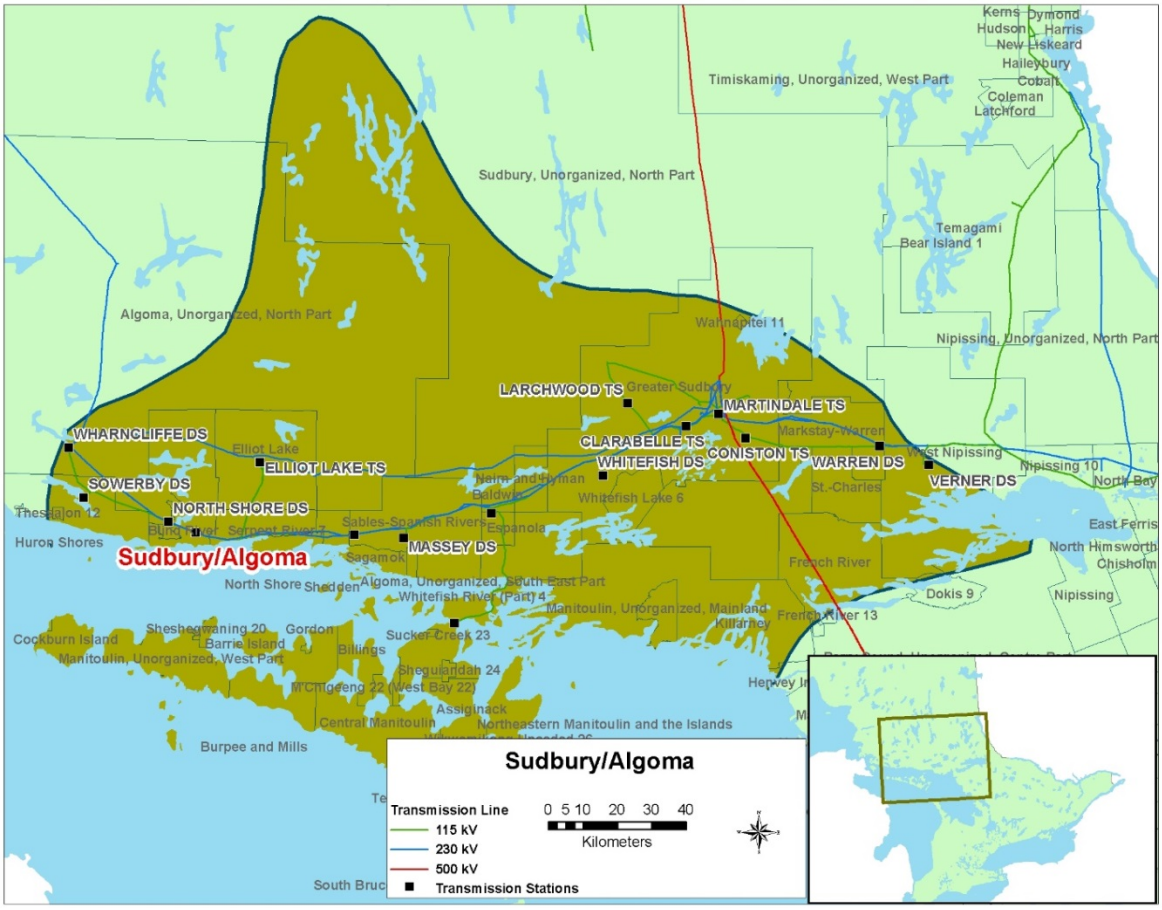


Figure 1-1: Sudbury/Algoma region

Electrical supply to the Sudbury/Algoma region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS

(Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to northwest Ontario through Mississagi TS

1.1 Objective and Scope

The RIP report examines the needs in the Sudbury/Algoma region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., NA and/or Integrated Regional Resource Plan(IRRP);
- Assess and develop a wires plan to address these new needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid and long-term, transmission and distribution system capability along with any updates with respect to local plans, Conservation and Demand Management (CDM), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration. A new Energy Efficiency framework was announced by the Ontario Government since the completion of the NA of the Sudbury/Algoma region. This RIP does not take into account the resulting impact of the newly announced CDM framework.

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

As mentioned this particular RIP is based on the information collected and recommendations from the NA phase of regional planning because no further regional coordination or assessments were required.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board (OEB) in 2013 through amendments to the Transmission System Code (TSC) and Distribution System Code (DSC). The process consists of four phases: the Needs Assessment [2] (NA), the Scoping Assessment (SA), the Integrated Regional Resource Plan (IRRP), and the Regional Infrastructure Plan (RIP).

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company (LDC) or customer and develops a Local Plan (LP) to address them.

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

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

[2] Also referred to as Needs Screening

further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion and reconfirmation of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, SA, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

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

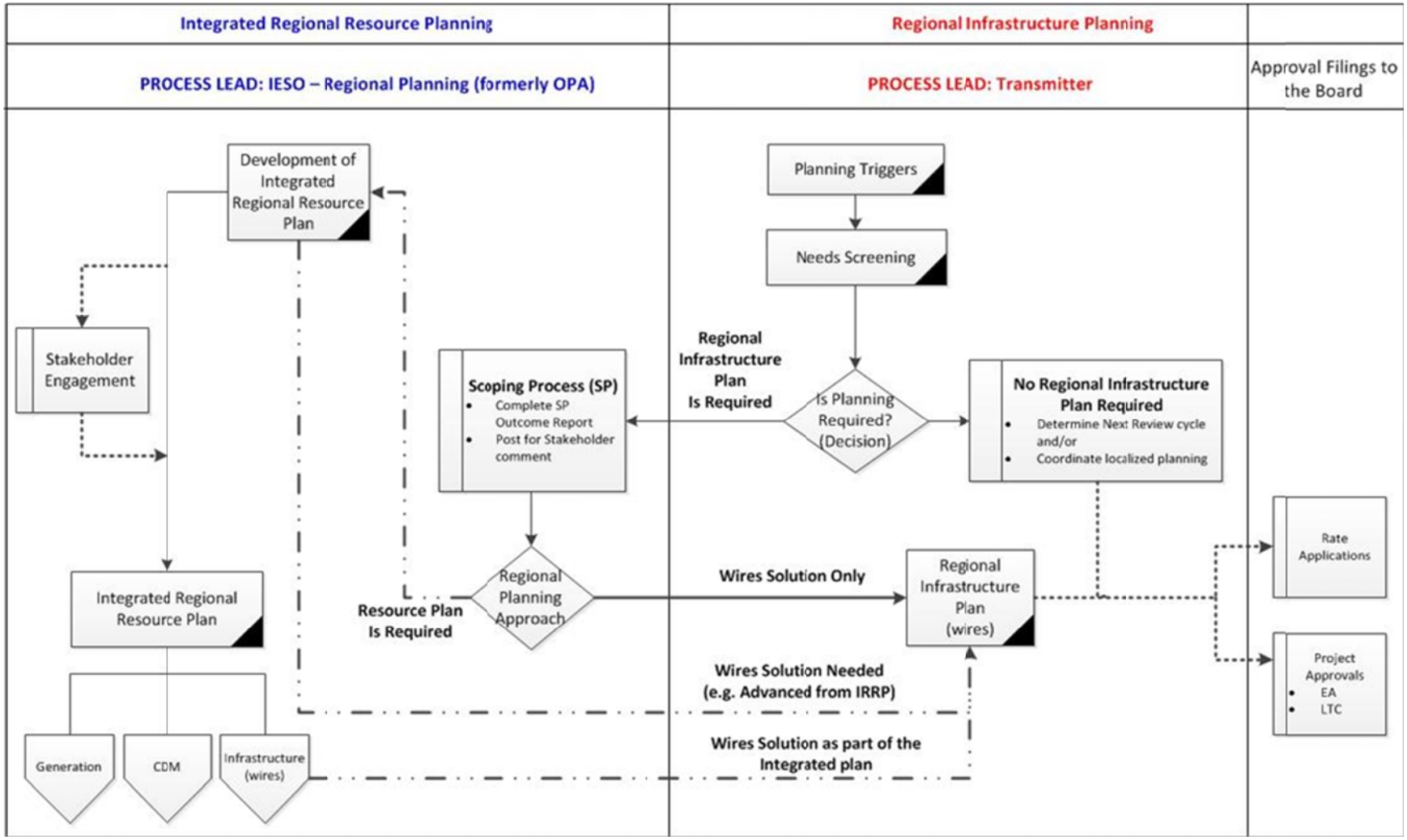


Figure 2-1: Regional Planning Process Flowchart

For the Sudbury/Algoma region, no need was identified that requires regional coordination. Hence,the Regional Planning process for the region moved directly to its RIP phase following the completion of the NA phase.

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

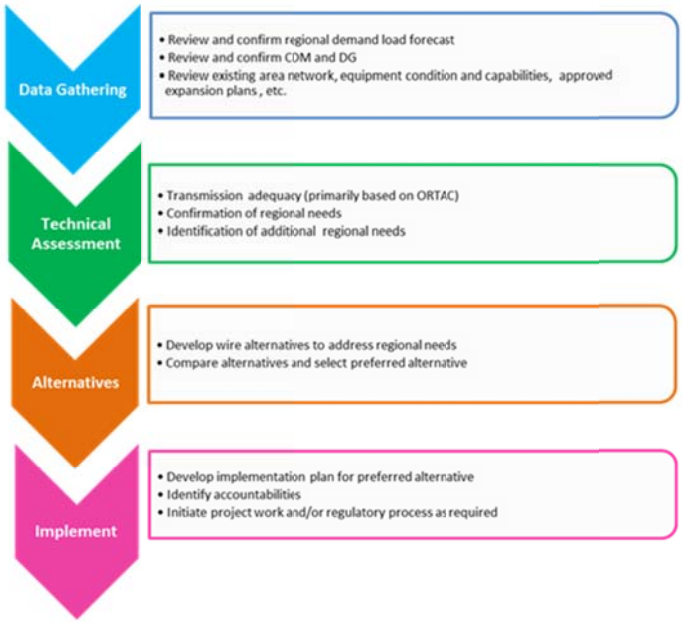


Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SUDBURY/ALGOMA REGION IS COMPRISED OF THE GREATER SUBDURY AREA, MANITOULIN ISLAND AND THE TOWNSHIPS OF VERNER, WARREN, ELLIOT LAKE AND WALDEN. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED THROUGH A NETWORK OF 230KV AND 115KV CIRCUITS SUPPLIED FROM AUTOTRANSFORMERS AT HANMER TS, ALGOMA TS AND MARTINDALE TS.

Bulk electrical supply to the Sudbury/Algoma region is currently provided through Hanmer TS, Algoma TS and Martindale TS, three (3) major autotransformers station in the region. This area is further reinforced through the 500 kV circuits (P502X and X503/504E) connecting Hanmer TS (in Sudbury) to Porcupine TS (in Timmins) and Essa TS (in Barrie). The area is also connected to the north western Ontario through Mississagi TS.

This region has the following two transmission-connected local distribution companies (LDC):

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)

North Bay Hydro is a third LDC in this region embedded into the Hydro One Disribution system. Although invited to participate directly in the NA process, the data related to this LDC as well as their operational concerns was communicated through their host LDC Hydro One Distribution.

Tranmission connected industrial/commercial loads in the Sudbury to Algoma region form a large percentage (approximately 50%) of the overall demand. Although these customers are not explicitly participating in the regional planning process, Hydro One will consider their impact in the RIP of this region.

Below is a description of the major assets in the region:

- Hanmer TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Algoma TS (230 kV) and Martindale TS (230 kV) are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Eight (8) step-down transformer stations supply the Sudbury/Algoma load Algoma TS (115 kV), Martindale TS (115 kV), Coniston TS[3], Larchwood TS, Manitoulin TS, Espanola TS, Clarabelle TS, Elliot Lake TS. There are also nine HVDS that supply load in the Region: Sowerby DS, Wharncliffe DS, North Shore DS, Striker DS, Spanish DS, Massey DS, Whitefish DS, Warren DS and Verner DS.

[3] Coniston TS in its entirety is being decommissioned and removed.The load previously supplied from Coniston TS will be transferred onto Martindale TS DESN. The targeted completion date falls between now and the next Regional Planning Cycle for this region.

- Nine (9) Customer Transformer Stations (CTS) are supplied in the Region: Carmeuse Lime CTS, Sudbury Smelter CTS, Falconbridge CTS, Nickel Rim CTS, Eacom Nairn CTS, Onaping Area M&M CTS, Milman Foundry CTS, Vale Copper #4 CTS and Vale Frood Stbe #2 CTS.
- There are four (4) existing transmission connected generating stations (GS) in the region as follows:
    - Red Rock GS is a 40 MW hydro electric generation plant connected to circuit T1B
    - Rayner GS is a 42MW hydro electric generation plant connected to circuit T1B
    - McLean's Mountain Wind is a 60 MW wind farm connected to circuit S2B. It is located at the North end of the Manitoulin Island.
    - Aux Sables GS is a 5 MW hydro electric generation plant connected to 115kV circuit S2B
    - Serpent GS is a 8 MW hydro electric generation facility connected to 115kV circuit S2B

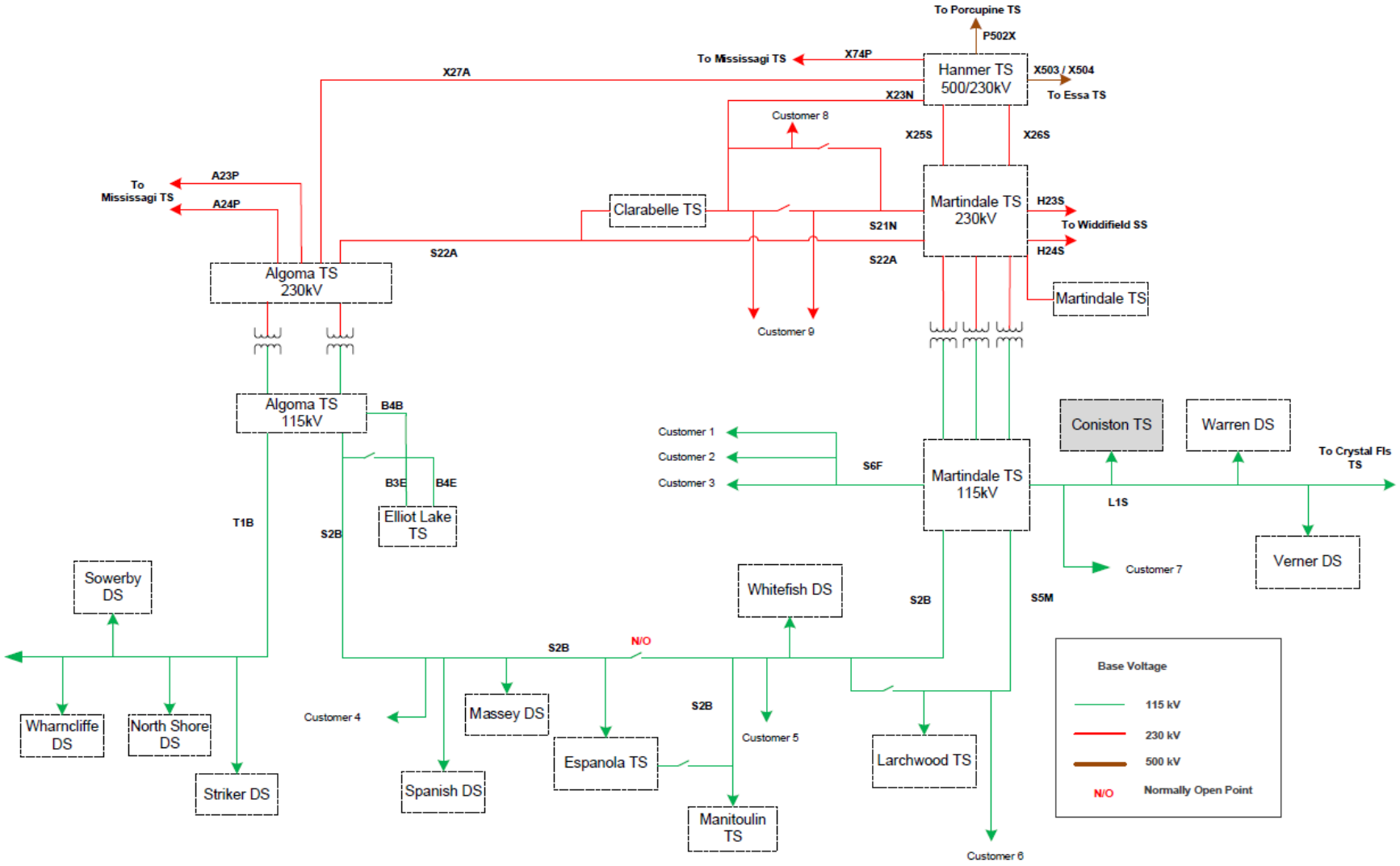


Figure 3-3: Single Line Diagram of Sudbury/Algoma Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE SUDBURY/ALGOMA REGION.

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

i. **Espanola TS**: Replace 115/44 kV 15MVA (T1) and 42MVA (T2) transformers with new 115/44 kV 42 MVA units. These transformers were assessed at being at their end-of-life and in need of replacement due to the assets'condition. This project was successfully carried out and in serviced in Q4 2016.

ii. **Larchwood TS** – Replace 110/44 kV 20 MVA (T2) transformer with a new 115/44kV 42MVA unit. This project was successfully completed and in serviced in Q4 2015.

iii. **Coniston TS** - The previous Regional Planning cycle Needs Assessment makes mention of the removal of the Coniston TS and its load being transferred to a newly built Hanmer TS DESN. Due to customers's changing system needs, this plan was reviewed and it evolved into the removal of the station in concurrence with the conversion of the legacy 22kV loads to 27.6kV and their transfer onto one of the feeders originating from Martindale TS. Current pandemic conditions have slowed down the progression of this project. The project is currently planned to be completed in Q3 2021.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The LDCs provided load forecasts for all the stations supplying their loads in the Sudbury/Algoma region for the 10 year study period. The IESO provided a CDM and Distributed Generation (DG) forecast for the Sudbury/Algoma region. The region's extreme winter non-coincident peak gross load forecast for each station was prepared by applying the LDC gross load forecast growth rates to the actual 2019/20 winter peak load corrected for extreme weather. The extreme weather correction factors were provided by Hydro One. The net extreme weather corrected winter load forecast was produced by reducing the gross load forecast for each station by the percentage CDM and by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and thus an increase in net demand. These load forecasts for the individual stations in region are given in Appendix A. While the non-coincident load forecast was used to determine the need for station capacity, the coincident load forecast was used to assess the need for autotransformation and transmission line capacity in the region.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2020-2029.
- All transmission facilities listed in Section 3 are in service.
- Where forecasts were not available, industrial loads were assumed based on historical information.
- Winter is the critical period with respect to line and transformer loadings. The assessment is therefore based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads.
- Autotransformers capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per the Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE SUDBURY/ALGOMA REGION OVER THE 2020-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the Sudbury/Algoma region. The study is presented below:

The NA report principally identified two (2) needs within the study period and reaffirmed existing needs arising from EOL asset issues. A review of the loading on the transmission lines and stations in the Sudbury/Algoma region was also carried out as part of this RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the identified needs in the first cycle of the Regional Planning of the Sudbury/Algoma have been addressed. The low voltage at Manitoulin TS stems from the station being at the end of a long radial circuit under normal operating conditions. The power transformers at Manitoulin TS are equipped with under load tap changers with wide regulation bands (+/-20%) to maintain the LV side voltage within acceptable voltage limits. As such, Hydro One and the affected LDC are assured that the low voltage incidence at the Manitoulin TS high side connection point has no material impact on the system or its connected customers. Hydro One will continue to monitor the voltage performance at the Manitoulin TS high side connection point and will take the appropriate remedial actions if and when this low voltage incidence is deemed adversely impactive to customers and system reliability.

6.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Algoma TS and Martindale TS) supplying the Region are within their thermal limits and within the voltage range as per Ontario Resource and Transmission Assessment Criteria (ORTAC) over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.2 230 kV Transmission Lines

The 230 kV circuits supplying the Region are within their thermal limits as per ORTAC over the study period for the loss of a single 230 kV circuit in the Region.

6.3 115kV Transmission Lines

The 115 kV circuits supplying the Region are within the thermal limits of the circuits as per ORTAC over the study period adequate over the study period for the loss of a single 115 kV circuit in the Region.

6.4 230 kV and 115 kV Connection Facilities

A station capacity and voltage assessment was performed over the study period for the 230 kV and 115 kV TS's in the Region using the winter station peak load forecasts that were provided by the study team. The results are as follows:

6.4.1 Clarabelle TS

The 2019 actual non-coincident winter peak load at Clarabelle TS was 121 MW which is below the its 10-day winter LTR of 184 MW. Based on demand forecast Clarabelle TS will not be loaded above its 10-day LTR during the assessed planning horizon.

6.4.2 Elliot Lake TS

The 2019 actual non-coincident winter peak load on Elliot Lake TS was 20 MW which is below its 10-day winter LTR of 66 MW. Based on demand forecast, Elliot Lake TS will not be loaded above its 10-day LTR during the assessed planning horizon.

6.4.3 Espanola TS

The 2019 actual non-coincident winter peak for Espanola TS was 13 MW which is below the station 10-day winter LTR of 61 MW. As per the demand forecast, the loading at Espanola TS will not exceed the station 10-day winter LTR within the assessed planning horizon.

6.4.4 Larchwood TS

The 2019 actual non-coincident winter peak for Larchwood TS was 13 MW which is below the station 10-day winter LTR of 37 MW. Based on the submitted load forecast, the loading on Larchwoord TS will not exceed the station 10-day winter LTR within the assessed planning horizon.

6.4.5 Manitoulin TS

Manitoulin TS has a summer and winter 10-day LTR of 37 MW. The station loading - the weather adjusted winter peak loading of 37.8 MW - is already above the station LTR. The station supply capability is limited by a Current Transformer (CT) ratio setting on the low voltage bus of the station, thereby restricting the ability to utilize the full supply capability of the transformers. It should be noted

that the station low voltage bus configuration is such that the loss of one of the transformers will remove half of the load by configuration[4]. Therefore, the loss of one of the transformers during station peaking conditions will not result in a thermal overload of the remaining transformer. That being said, adequate supply capability at the station should be maintained to pick up the dropped load in the occurrence of such an event. Given its geographical location, this station cannot rely on any other nearby station for capacity relief via load transfer. Plans are already in place to address this need. These plans are further detailed in section 7 of this report.

IESO has expressed concerns on the voltage performance at the 115kV connection point of circuit S2B at Manitoulin TS. During system conditions where the nearby McCleans Mountain wind farm is unavailable, voltages on the 115kV side of the station can be as low as 108 kV which is below ORTAC voltage limit of 113kV. This low voltage incidence has previously been well documented and studied and was further reiterated in 2015 during the first cycle of the Sudbury/Algoma Needs Assessment. Circuit S2B is normally operated open, leaving Manitoulin TS, McCleans Mountain wind farm, one industrial customer and Whitefish DS on the Martindale TS side of the circuit. The low voltage at Manitoulin TS stems from the station being at the end of a long radial circuit under normal operating conditions. The power transformers at Manitoulin TS are equipped with under load tap changers with wide regulation bands (+/- 20%) to maintain the LV side voltage within acceptable voltage limits. As such, Hydro One is assured that the low voltage incidence at the Manitoulin TS high side connection point has no material impact on the system or its connected customers. Hydro One will continue to monitor the voltage performance at the Manitoulin TS high side connection point and will take the appropriate remedial actions if and when this low voltage incidence is deemed adversely impactive to customers and system reliability.

6.5 End-of-life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

[4] Discussion between the Transmitter and the LDC have confirmed that the existing configuration continues to provide an acceptable level of reliability.

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. “right sizing” opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, from Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Accordingly, major high voltage equipment has been identified as approaching its end-of-life over the next 10 years and assessed for right sizing opportunity in section 7. At this time, end-of-life driven sustainement needs have been identified at the following stations in the region:

- Algoma TS,
- Clarabelle TS,
- Elliot Lake TS and
- Martindale TS

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within 8 hours.
b. Load interrupted in excess of 150 MW must be restored within 4 hours.
c. Load interrupted in excess of 250 MW must be restored within 30 minutes.

No new significant system reliability and operating issues were identified for the Sudbury/Algoma region.

The IESO has expressed the need for additional voltage control flexibility at Algoma TS and this is being addressed as part of the autotransformer replacement project planned at the station. The new autotransformers being procured are equipped with Under Load Tap Changers that will provide the required voltage control flexibility.

Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW as per ORTAC. The maximum load interrupted by configuration due to the loss of two elements is below the ORTAC limit of 600MW by the end of the 10-year study period.

6.7 Longer Term Outlook (2029-2040)

Consistent with the NA, the RIP is based on on the 2020-2029 period, a further looking assessment was conducted and looked into the loading between 2029 and 2039. Appendix E presents the winter load forecast used for this assessement. The long-term load forecast was obtained from extrapolation of the near and medium term load forecast into 2039 using the station specific load growth factors.

No long-term needs for the Sudbury/Algoma region was identified beyond the already identified additional capacity needs at Manitoulin TS (starting 2020) and Martindale TS (starting 2028). Recommendations have been made and agreed upon by the Study Team on how to best address these needs. The study group recommend an on-going monitoring of additional load connection requests as they materialize themselves.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in service facilities to address these needs.

Current development and sustainment plans are further discussed below.

7.1 Martindale TS Supply Capacity

Martindale TS has a winter 10-day LTR of 164 MW. Based on current load growth projections at the station and considering expiration of generating contracts, the station net load will surpass the station winter 10-day LTR starting in 2028. This is the first iteration of the NA that shows a potential supply capacity need at the station. Given the anticipated timing of the need, there is time to re-evaluate this need in the next cycle of regional planning and once there is additional information on the IESO's resource adequacy framework, scheduled to take place no later than in 2025. Should the need materialize sooner than anticipated at Martindale TS, a station specific needs assessment can be carried out at that time so as to determine the best course of action for meeting the station supply capacity needs.

The following alternatives were considered to address the Martindale TS Supply Capacity need:

1. **Alternative 1 - Maintain Status Quo (Recommended)**: Martindale TS will exceed supply capacity in 2028 based on the load forecasts provided by area customers. The next cycle of regional planning will commence no later than in 2025 and will allow the working group to reevaluate this need and confirm whether or not the occurrence of the supply capacity congestion at Martindale still holds true in 2028. Should this be the case, the study group at that moment will decide the best course of actions to fill this need.

2. **Alternative 2– Add a low voltage capacitor bank for power factor correction:** Studies show that an additional 10 MW of supply capacity can be enabled by the the addition of a capacitor bank on the low voltage bus of this station. The addition of the capacitor bank will improve the station load power factor and draw less reactive power through the power transformers, enabling more active power flow on the units. This solution will provide capacity relief at Martindale TS beyond the study period and defer the need for additional transformation capacity. This alternative was considered but rejected due to how far in the future the need is ought to materialize itself. The next Regional Planning cycle of the region is to reevalute the station supply capacity needs and decide the optimal approach to address the need should it still exist.

7.2 Manitoulin TS Supply Capacity

Manitoulin TS has a summer and winter 10-day LTR of 37 MW. The station loading – the extreme weather adjusted winter peak loading of 37.8 MW - is already above the station LTR .The station supply capability is limited by a Current Transformer(CT) ratio setting on the low voltage bus of the station, thereby restricting the ability to utilize the full supply capability of the transformers. It should be noted that the station low voltage bus configuration is such that the loss of one of the transformers will remove half of the load by configuration[5]. That being said, adequate supply capability at the station should be maintained to pick up the dropped load in the occurrence of such an event. Given its geographical location, this station cannot rely on any other nearby station for capacity relief via load transfer. This need must be adressed as soon as practically feasible to allow full utilization of the station transformers capacity.

The following alternatives were considered to address the Manitoulin TS Supply Capacity need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected due to the fact that the station winter peak load is already above the station LTR. The absence of neighboring load supply stations that can provide capacity relief to Manitoulin TS should one of the power transformer be unavailable makes this alternative even more unacceptable.

2. **Alternative 2 - Change the CT ratio(Recommended):** A Preliminary assessement has identified that the existing limitation can be removed by changing the CT ratio. Hydro One Networks Inc. is coordinating the implementation of this alternative with the affected LDC. This alternative is currently planned to be implemented in 2021.

7.3 Martindale TS – Hanmer TS Corridor Unbundling

With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC. The scope of this project aims to decouple one of the two circuits (X25S or X26S) into its own position at both Hanmer TS and Martindale TS. Hydro One Networks initiated this project as per the IESO's recommendation provided via a letter dated October 19th, 2018 addressed to Hydro One Transmission Planning Division. The targeted in service date is in year 2023.

7.4 Martindale TS EOL Autotransformer Replacement

Martindale TS is a 230/115kV BES classified station which also includes a 230kV/44kV Dual Element Spot Network (DESN) station located in Sudbury. The station is comprised of two (2) – 230/115 kV 125 MVA autotransformers (T21, T22) and one (1) 230/115 kV 115 MVA autotransformer (T23).

[5] Discussion between the Transmitter and the LDC have confirmed that the existing configuration continues to provide an acceptable level of reliability.

Autotransformers T21 and T23 as well as five (5) – 230kV breakers and select disconnect switches have been identified as EOL based on asset condition. Under peak load conditions, the loss of the two 125 MVA Martindale 230/115kV autransformers may result in the overload of the third smaller autransformer. The completion of this project will see the station equipped with three (3) 125MVA 230/115kV autotransformers.

The following alternatives where considered to remedie the T23 thermal overload and address EOL assets needs at Martindale TS:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment (Recommended):** Proceed with like for like replacement of the identifield EOL equipment within the station except for T23 where a larger unit matching the other two autotransformers is to be procured to replace the existing smaller unit. This alternative would address the end-of-life assets need and would alleviate the risk of overloading T23 should the other two larger transformer become simulatenously unavailable. This project is ongoing and planned to be in serviced in 2022.

7.5 Martindale TS EOL Power Transformer Replacement

Martindale TS, as mentioned above, also features a DESN station that supply both LDCs identified in the Sudbury/Algoma region. The DESN station is comprised of two(2) – 125 MVA 230/44kV power transformers. These power transformers as well as select 44 kV equipment are scheduled to be replaced in 2028 to address end-of-life needs. The identified EOL equipment will be replaced with Hydro One standard equipement of similar size and capabilities. These are the largest standard 230/44kV transformers Hydro One uses. The scope of this project as presently planned does not aim at increasing the Martindale TS supply capacity beyond what exists today nor does it deviate from Hydro One's standard transformer size and procurement practices.

The following alternatives were considered to address Martindale TS DESN station EOL assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment (Recommended):** Proceed with these end-of-life asset replacement as per the existing refurbishment plan for the EOL equipment at Martindale TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

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7.6 Algoma TS EOL Autotransformer Replacement

Algoma TS is a BES autotransformation station located west of Sudbury in the Algoma area. The station serves at termination point to four (4) circuits – X27A, S22A and A23/24P – and features two 230/115kV autotransformers that supply the underlying 115kV transmission system. The autotransformer are respectively 195MVA (T5) and 115MVA (T6). The autotransformers are scheduled to be replaced with two 230/115kV 125 MVA units by the end of 2022. The new units are being procured with Under Load Tap Changers (ULTC) as a mean to provide better operational flexibility.

The following alternatives were considered to address Algoma TS station EOL assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 – Like-for-Like replacement with similar equipment**: This alternative was considered and rejected. The station supply need has been assessed and as a result, standard 125 MVA units are sufficient to adequately supply the forecasted region electricity need. Pursueing with this alternative will involve the procurement of two(2) non standard sized transformers and will continue to deviate Hydro One asset fleet with its standard equipement procurement standards.

3. **Alternative 3 – Like for like replacement with similar equipement and right sizing of T5 and T6 autotransformers (Recommended)**: Proceed with the end-of-life asset replacement and transformer right sizing plans as per the existing plans at Algoma TS. This alternative would address the end-of-life assets need, maintain reliable and adequate supply to the customers in the area while better aligning Hydro One asset fleet with its standard equipment procurement practices.

7.7 Clarabelle TS EOL Power Transformer Replacement

Clarabelle TS is a 230/44kV transformer station located in the Sudbury/Algoma region. The station features two 230/44kV 125 MVA step down transformers that supply both identified LDCs in the Sudbury/Algoma region. The power transformer at Clarabelle TS are scheduled to be replaced in 2027 alongside select station equipment to address EOL needs.
The following alternatives were considered to address Clarabelle TS station EOL assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment (Recommended):** Proceed with these end-of-life asset replacement as per the existing refurbishment plan for the power

transformers and identified EOL equipment at Clarabelle TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.8 Elliot Lake TS EOL Power Transformer Replacement

Elliot Lake TS is a Hydro One transformer station located west of Sudbury. The station consists of two(2) 115/44kV 42 MVA transformers (T1 and T3) alongside one 115kv/44kV 19 MVA transformer (T2). A station asset assessement has identified T1 and T2 as candidate for replacement within the mid-term horizon. Concurently, recent supply need assessement at the station has deemed T2 no longer necessary to maintain supply reliability and adequacy at the station. The LDC supplied from Elliot Lake TS further concurred that T2 can be removed from Elliot Lake TS without impacting their supply reliability and adequacy . As such, this project will see the like-for-like replacement of T1 transformer, the removal of T2 transformer and the reconfiguration of the station to a near standard Jones DESN design.

The following alternatives were considered to address Elliot Lake TS station EOL assets need:

4. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

5. **Alternative 2 – Like-for-Like replacement with similar equipment**: This alternative was considered and rejected. The station supply need has been assessed and as a result, T2 transformer was deemed no longer necessary. Pursueing with this alternative will involve the procurement of an additional transformer that is no longer needed in addition of continueing to maintain non standard station configuration.

6. **Alternative 3 - Like for like replacement with similar equipement and removal of T2(Recommended)**: Proceed with the end-of-life asset replacement and station reconfiguration plans as per the existing station refurbishement and reconfiguration plans at Elliot Lake TS. This alternative would address the end-of-life assets need, maintain reliable supply to the customers in the area while avoiding the need to procure and maintain an asset that is deemed no longer necessary.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SUDBURY/ALGOMA REGION.

The Study Team reaffirms the recommendations from NA to the continue with infrastructure investments presented in section 7. Hydro One and the affected LDCs are to jointly coordinate the implementation of these undertakings while keeping the Study Team apprised of project status. Below is a summary of the near and mid-term planned projects along with their respective planned in service dates and planning allowances:

1. Hanmner TS to Martindale TS corridor Unbundling – Estimated at $8M and planned to be in service in 2023,
2. Martindale TS autotransformer replacement - Estimated at $76M and planned to be in service in 2022
3. Martindale TS EOL Power transformer replacement – Estimated at $19M and planned to be in service in 2028
4. Manitoulin TS supply capacity – Estimated at $20,000 and planned to be in serviced in 2021
5. Algoma TS EOL autotransformer replacement – Estimated at $23M and planned to be in service in 2023
6. Clarabelle TS EOL Power transformer replacement – Estimated at $19M and planned to be in service in 2027
7. Elliot Lake TS EOL Power transformer replacement – Estimated at $23M and planned to be in service in 2025

9. REFERENCES

[1]. Hydro One, “Needs Assessment Report, Sudbury/Algoma region”, 6 August 2020

[2]. Regional Infrastructure Planning Report 2016 – Sudbury/Algoma - June 2016

[3]. Needs Assessment Report Sudbury/Algoma – March 2015

[4]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[5]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: Transmission Lines in the Sudbury/Algoma Region

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	X74P	Hanmer TS	Mississagi TS	230
2.	X27A	Hanmer TS	Algoma TS	230
3.	A23P, A24P	Algoma TS	Mississagi TS	230
4.	X23N	Hamner TS	-	230
5.	S21N	Martindale TS	-	230
6.	X25S, X26S	Hanmer TS	Martindale TS	230
7.	S22A	Martindale TS	Algoma TS	230
8.	S6F	Martindale TS	-	115
8.	S5M	Martindale TS	Larchwood TS	115
9.	S2B	Martindale TS	Algoma TS	115
10.	B4B	Algoma TS	B3E Tap	115
11.	T1B	Algoma TS	-	115
12.	B3E	B4B Tap	Elliot Lake TS	115
13.	B4E	B4B Tap	Elliot Lake TS	115
14.	L1S	Martindale TS	Crystal Falls TS	115

Appendix B: Lists of Autotransformer and Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Algoma TS	230/115
2.	Coniston TS	115/22
3.	Clarabelle TS	230/44
4.	Elliot Lake TS	115/44
5.	Espanola TS	115/44
6.	Hamner TS	500/230
7.	Larchwood TS	115/44
8.	Manitoulin TS	115/44
9.	Martindale TS	230/115 230/44

Appendix D: Lists of LDCs in the Sudbury/Algoma region

Sr. No.	Company	Connection Type (TX/DX)
1.	Greater Sudbury Hydro	TX / DX
2.	Hydro One Distribution	TX
3.	North Bay Hydro	DX

Appendix D: Extreme Weather Adjusted Non-Coincident Winter Load Forecast

Table D.1: Sudbury/Algoma region Winter Non-Coincident Load Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LTR (MW)	LV Cap Bank	Historical Data (MW)				Load Growth Factor	Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment									
						2019	WAN	WAE		Near Term Forecast (MW)					Medium Term Forecast (MW)				
					Customer Data	1	1.0158	1.0758		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Clarabelle TS	*T1/T2*	204.8	184.32	N	H1Dx Gross Peak				1.07%	47.19	47.64	48.08	48.53	48.98	49.43	49.88	50.32	50.77	51.22
					GSH Gross Peak				0.81%	83.67	84.28	84.89	85.50	86.11	86.72	87.33	87.94	88.55	89.16
					Station Gross Peak					130.86	131.92	132.97	134.03	135.09	136.15	137.20	138.26	139.32	140.38
					DG					6.70	6.70	6.70	6.70	6.70	6.70	0.00	0.00	0.00	0.00
					CDM					0.48	0.50	0.51	0.53	0.55	0.56	0.58	0.60	0.62	0.63
					Station Net Peak	121.19	123.10	130.37		123.68	124.72	125.76	126.80	127.84	128.88	136.62	137.66	138.70	139.74
Elliot Lake TS	*T1/T2/T3*	73.8	66.42	N	Gross Peak				0.67%	20.02	20.15	20.27	20.40	20.52	20.65	20.77	20.90	21.02	21.15
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
					Station Net Peak	19.59	19.90	21.07		19.94	20.23	20.35	20.48	20.61	20.74	20.86	20.99	21.12	21.25
Espanola TS	*T1/T2/T3*	64.4	61.18	Y	Gross Peak				0.65%	13.06	13.14	13.21	13.29	13.37	13.45	13.53	13.61	13.69	13.77
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06
					Station Net Peak	12.78	12.98	13.74		13.01	13.08	13.16	13.24	13.32	13.39	13.47	13.55	13.63	13.70
Larchwood TS	*T2*	41.7	37.53	N	Gross Peak				1.02%	13.11	13.24	13.37	13.49	13.62	13.74	13.87	13.99	14.12	14.25
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.07
					Station Net Peak	12.79	12.99	13.76		13.06	13.19	13.31	13.44	13.56	13.68	13.81	13.93	14.05	14.18
Manitoulin TS	*T3/T4*	41.7	37.53	N	Gross Peak				1.08%	40.21	40.59	40.98	41.37	41.75	42.14	42.52	42.91	43.30	43.68
					DG					2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01
					CDM					0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.19	0.19	0.20
					Station Net Peak	37.22	37.81	40.04		38.05	38.43	38.81	39.19	39.58	39.96	40.34	40.72	41.10	41.48

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LTR (MW)	LV Cap Bank	Historical Data (MW)				Load Growth Factor	Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment									
						2019	WAN	WAE		Near Term Forecast (MW)					Medium Term Forecast (MW)				
					Customer Data	1	1.0158	1.0758		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Martindale TS	*T25/T26*	182.6	164.34	N	H1Dx Gross Peak				0.06%	53.33	53.36	53.38	53.41	53.44	53.47	53.50	53.52	53.55	53.58
					GSH Gross Peak				2.15%	97.54	99.49	101.44	103.39	105.34	107.29	109.25	111.20	113.15	115.10
					Station Gross Peak					150.86	152.84	154.82	156.80	158.78	160.76	162.74	164.72	166.70	168.68
					DG					7.49	7.49	7.49	7.49	7.49	2.49	2.49	0.89	0.89	0.89
					CDM					0.57	0.58	0.61	0.64	0.68	0.70	0.72	0.73	0.75	0.77
					Station Net Peak	139.19	141.39	149.75		142.80	144.77	146.73	148.67	150.62	157.58	159.53	163.10	165.06	167.02
Massey DS	*T1*	N/A	N/A	N/A	Gross Peak	6.81	6.92	7.33	0.57%	6.95	6.99	7.03	7.07	7.10	7.14	7.18	7.22	7.25	7.29
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	6.81	6.92	7.33		6.93	6.96	7.00	7.04	7.07	7.11	7.15	7.18	7.22	7.26
North Shore DS	*T1*	N/A	N/A	N/A	Gross Peak				1.06%	5.75	5.81	5.87	5.93	5.98	6.04	6.10	6.15	6.21	6.27
					DG					2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59
					CDM					0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	5.61	5.70	6.03		3.14	3.20	3.25	3.31	3.36	3.42	3.48	3.53	3.59	3.65
Sowerby DS	*T1*	N/A	N/A	N/A	Gross Peak				0.81%	4.96	5.00	5.04	5.08	5.12	5.15	5.19	5.23	5.27	5.31
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03
					Station Net Peak	4.85	4.93	5.22		4.95	4.98	5.02	5.06	5.09	5.13	5.17	5.21	5.24	5.28
Spanish DS	*T1*	N/A	N/A	N/A	Gross Peak				0.88%	3.94	3.97	4.00	4.03	4.07	4.10	4.13	4.17	4.20	4.23
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
					Station Net Peak	3.84	3.90	4.13		3.92	3.95	3.99	4.02	4.05	4.08	4.11	4.15	4.18	4.21
Striker DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				0.79%	7.83	7.89	7.95	8.01	8.06	8.12	8.18	8.24	8.29	8.35
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
					Station Net Peak	7.65	7.77	8.23		7.80	7.86	7.92	7.97	8.03	8.09	8.14	8.20	8.26	8.31

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LTR (MW)	LV Cap Bank	Historical Data (MW)				Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment											
						2019	WAN	WAE	Load Growth Factor	Near Term Forecast (MW)					Medium Term Forecast (MW)					
					Customer Data	1	1.0158	1.0758		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Verner DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				0.69%	6.10	6.14	6.18	6.22	6.26	6.30	6.34	6.38	6.42	6.46
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	5.97	6.06	6.42		6.08	6.12	6.16	6.20	6.24	6.27	6.31	6.35	6.39	6.43
Warren DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				0.78%	7.61	7.67	7.72	7.78	7.83	7.89	7.95	8.00	8.06	8.11
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
					Station Net Peak	7.44	7.55	8.00		7.58	7.64	7.69	7.75	7.80	7.86	7.91	7.97	8.02	8.08
Wharncliffe DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				1.30%	5.52	5.59	5.66	5.72	5.79	5.86	5.93	5.99	6.06	6.13
					DG					0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
					CDM					0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	5.37	5.45	5.78		5.08	5.15	5.22	5.28	5.35	5.42	5.48	5.55	5.62	5.68
Whitefish DS	*T1*	N/A	N/A	N/A	Gross Peak				0.67%	6.65	6.69	6.74	6.78	6.82	6.86	6.90	6.94	6.99	7.03
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	6.51	6.61	7.00		6.6	6.67	6.71	6.75	6.79	6.83	6.87	6.91	6.95	6.99

Appendix E: Long-term Winter Load Forecast

Table E.1: Sudbury/Algoma region Winter Non-Coincident Load Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	Station winter LTR (MVA)	Station Winter LTR (MW)	Winter Peak Load - Linearized Load Forecast - Extended to Long-term Forecast											
				Near Term Forecast (MW)					Medium Term Forecast (MW)					Long-term Forecast	
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034	2039
Clarabelle TS	T1/T2	204.8	184.32	123.68	124.72	125.76	126.80	127.84	128.88	136.62	137.66	138.70	139.74	146.68	151.50
Elliot Lake TS	T1/T2/T3	73.8	66.42	19.94	20.23	20.35	20.48	20.61	20.74	20.86	20.99	21.12	21.25	22.11	22.70
Espanola TS	T1/T2/T3	64.4	61.18	13.01	13.08	13.16	13.24	13.32	13.39	13.47	13.55	13.63	13.70	14.24	14.61
Larchwood TS	T2	41.7	37.53	13.06	13.19	13.31	13.44	13.56	13.68	13.81	13.93	14.05	14.18	15.07	15.70
Manitoulin TS	T3/T4	41.7	37.53	38.05	38.43	38.81	39.19	39.58	39.96	40.34	40.72	41.10	41.48	44.23	46.17
Martindale TS	T25/T26	182.6	164.34	142.80	144.77	146.73	148.67	150.62	157.58	159.53	163.10	165.06	167.02	180.71	190.46
Massey DS	T1	N/A	N/A	6.93	6.96	7.00	7.04	7.07	7.11	7.15	7.18	7.22	7.26	7.51	7.68
North Shore DS	T1	N/A	N/A	3.14	3.20	3.25	3.31	3.36	3.42	3.48	3.53	3.59	3.65	3.88	4.05
Sowerby DS	T1	N/A	N/A	4.95	4.98	5.02	5.06	5.09	5.13	5.17	5.21	5.24	5.28	5.54	5.72
Spanish DS	T1	N/A	N/A	3.92	3.95	3.99	4.02	4.05	4.08	4.11	4.15	4.18	4.21	4.44	4.60
Striker DS	T1/T2	N/A	N/A	7.80	7.86	7.92	7.97	8.03	8.09	8.14	8.20	8.26	8.31	8.71	8.99
Verner DS	T1/T2	N/A	N/A	6.08	6.12	6.16	6.20	6.24	6.27	6.31	6.35	6.39	6.43	6.70	6.89
Warren DS	T1/T2	N/A	N/A	7.58	7.64	7.69	7.75	7.80	7.86	7.91	7.97	8.02	8.08	8.46	8.73
Wharncliffe DS	T1/T2	N/A	N/A	5.08	5.15	5.22	5.28	5.35	5.42	5.48	5.55	5.62	5.68	6.14	6.46
Whitefish DS	T1	N/A	N/A	6.63	6.67	6.71	6.75	6.79	6.83	6.87	6.91	6.95	6.99	7.28	7.48
			Region Total	402.65	406.95	411.07	415.19	419.30	428.44	439.26	444.99	449.13	453.25	481.71	501.74

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long-term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



NEEDS ASSESSMENT REPORT

Sudbury Algoma Region

October 24, 2025

Needs Assessment Report

Sudbury Algoma Region

October 24, 2025

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: Sudbury Algoma Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Sudbury Algoma region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region. Updates may be made based on the best available information throughout the planning process.

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

Executive Summary

REGION	**Sudbury Algoma** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: June 27, 2025 **END DATE:** October 24, 2025

The second Regional Planning cycle for the Sudbury Algoma Region was completed in December 2020 with the publication of the Regional Infrastructure Plan ("RIP") report – Sudbury Algoma Regional Infrastructure Plan (RIP).

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in **June 2025** for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

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

The Technical Working Group (TWG) comprises representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and operational concerns.
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Needs that require further regional coordination.

#	Need Location	Need Description
1	**Martindale TS 230/44 kV step-down transformers (T25 & T26)**	Capacity Need: The load exceeds the 10-day LTR of the step-down transformers, T25 and T26, based on winter demand forecast at the station by 2034.
2	**Martindale TS 230/115 kV Autotransformers (T21, T22, & T23)**	Capacity Need: With one autotransformer out-of-service and subsequent failure of another unit, the third autotransformer will exceed its winter 10-day LTR. The Martindale TS autotransformers supply the local 115 kV system serving LDCs and industrial customers. Based on the winter coincident forecast, this need is expected to materialize in 2030.
3	**Manitoulin TS 115 kV Voltage**	Voltage violation: The 115 kV bus at Manitoulin TS experiences low voltage under peak demand conditions at the station.

Needs that do not require further regional coordination.

#	Need Location	Need Description
1	**Martindale TS 230/44 kV step-down transformers (T25 & T26)**	Asset Renewal Need: T25 and T26 are approaching End of Life (EOL) based on their condition assessment. The transformers are planned for like-for-like replacement in 2032.

List of LDC(s) to be involved in further regional planning phases:

- Greater Sudbury Hydro
- North Bay Hydro (Embedded LDC)
- Hydro One Distribution

List of LDC(s) which are not required to be involved in further regional planning phases:

- N/A

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Sudbury Algoma Region was completed in December 2020 with the publication of the Sudbury Algoma Regional Infrastructure Plan (RIP). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the Sudbury Algoma Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

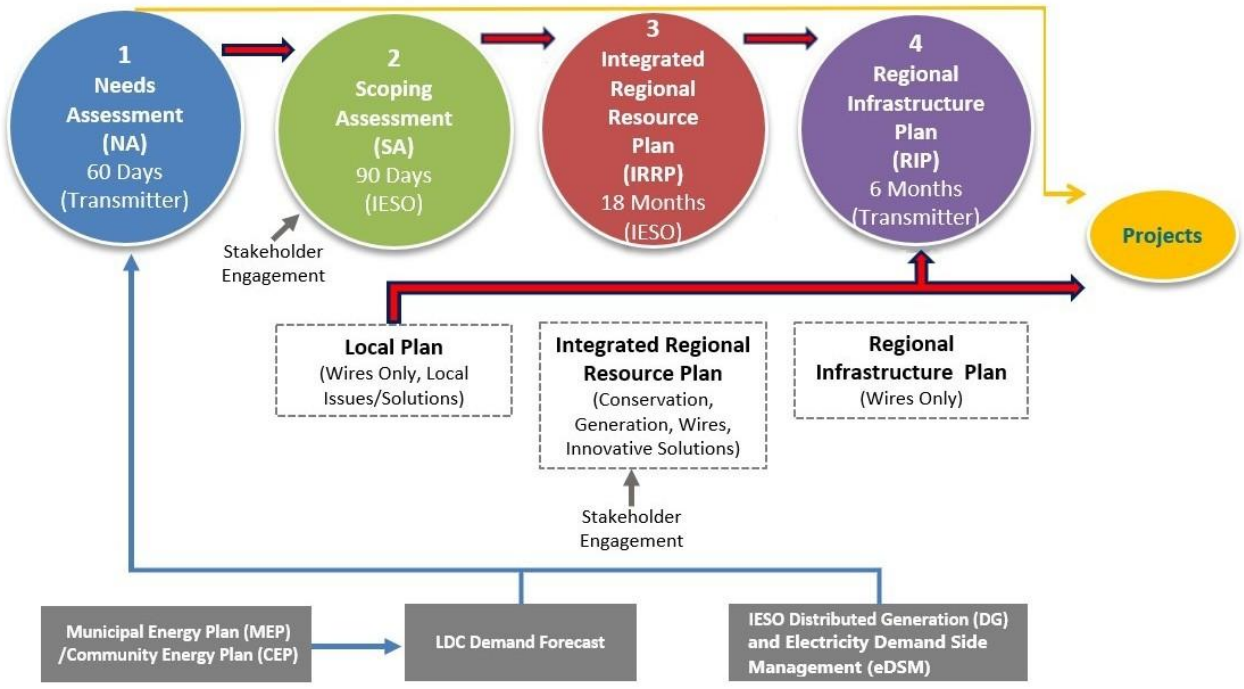


Figure 1: Regional Planning Process

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

Table 1: Sudbury Algoma Region TWG Participants

Sr. no.	Name of TWG Participants
1	Independent Electricity System Operator (IESO)
2	Hydro One Networks Inc. (Transmission & Distribution)
3	Greater Sudbury Hydro
4	North Bay Hydro (Embedded LDC)

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the Sudbury Algoma region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Sudbury Algoma region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Electrical supply to the Sudbury Algoma Region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS (Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to Northwest Ontario through Mississagi TS.

The geographical boundaries of the Sudbury Algoma region are shown in Figure 2 below.

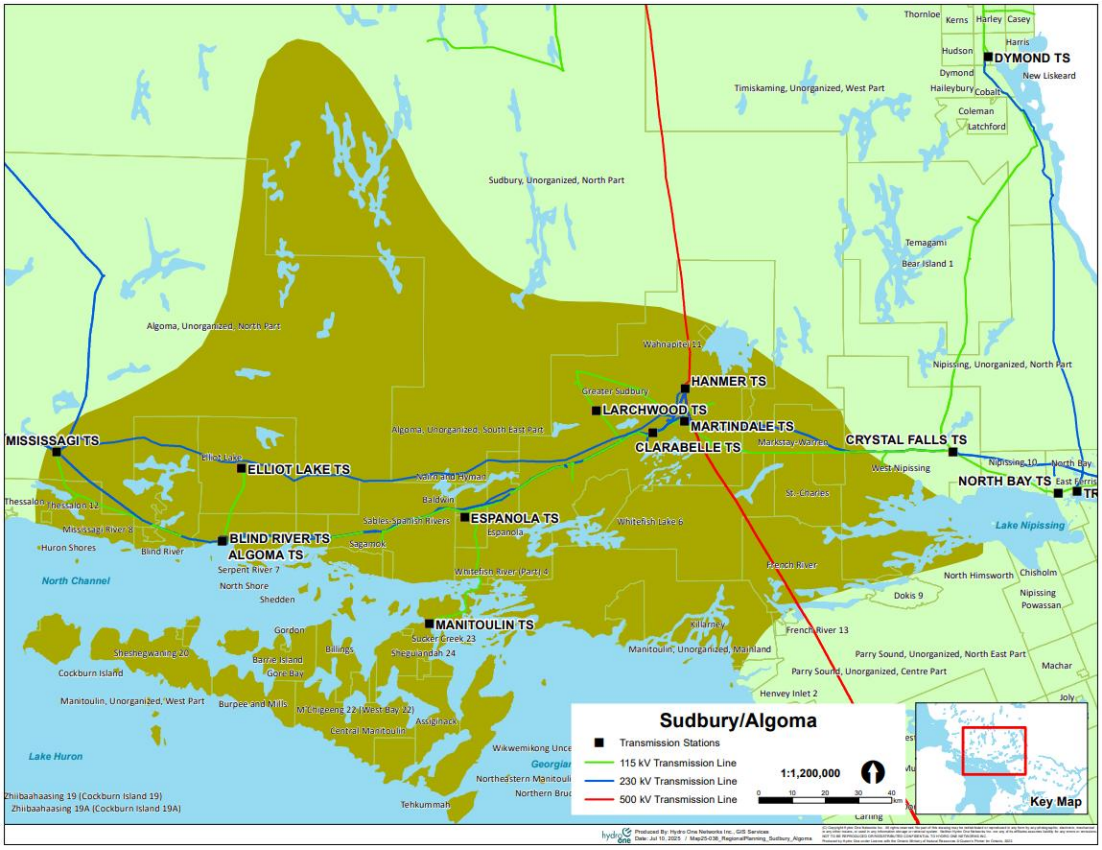


Figure 2: Map of Sudbury Algoma Regional Planning Area

The circuits and stations of the area are summarized in Table 2 below:

Table 2: Transmission Stations and Circuits in the Sudbury Algoma Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
• S6F • S5M • S2B • B4B • T1B • B3E • B4E • L1S	• X74P • X27A • A23P • A24P • X23N • S21N • X25S • X26S • X29S • S22A	• Algoma TS* • Martindale TS* • Hanmer TS* • Clarabelle TS • Elliot Lake TS • Espanola TS • Larchwood TS • Manitoulin TS • Mississagi TS	• Red Rock GS • Rayner GS • McLean Mountain WGS • Aux Sable GS • Serpent River CGS

*Stations with autotransformers installed

The single line diagram of the Transmission Network of Sudbury Algoma region is shown in Figure 3 below.

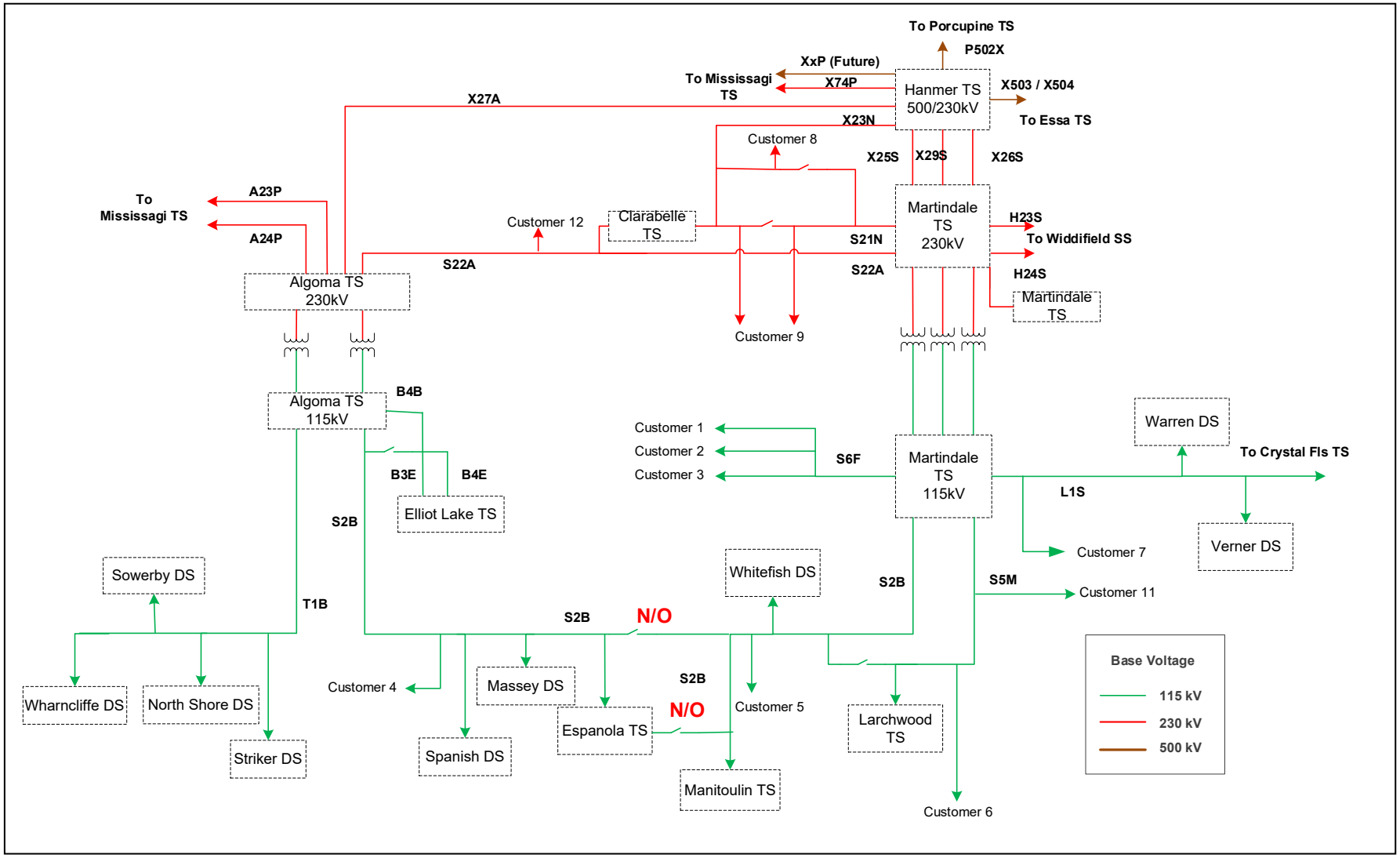


Figure 3: Sudbury Algoma Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the **Sudbury Algoma NA**. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. The list of all the Municipalities falling under the geographical boundaries of the region is given in Appendix-E.

The information provided includes the following:

- **Sudbury Algoma** 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs).
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment.
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the **Sudbury Algoma region**.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing".
- Load forecast data requested from industrial customers in the region.
- This assessment is based on both summer and winter peak loads. Three load forecasts were developed, i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.
- Consideration of existing or planned distributed energy resources.

The following other assumptions are made in this report.

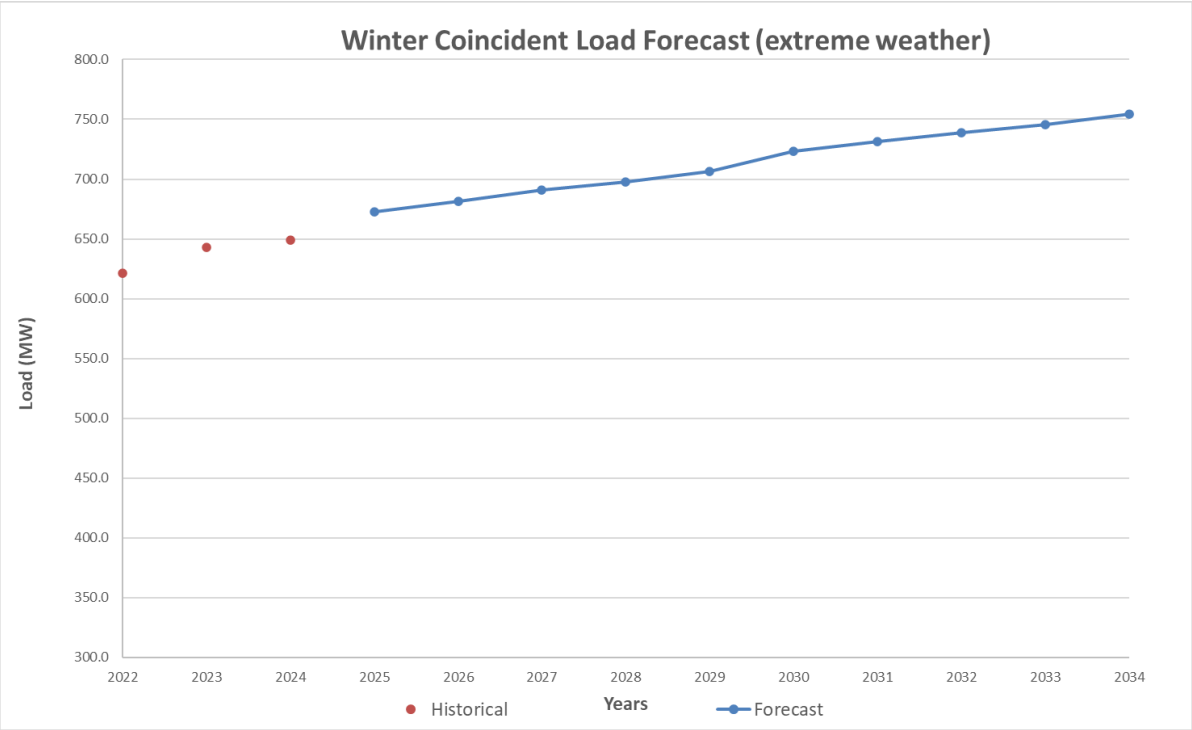
- The study period for this Needs Assessment is 2025-2034.
- While the Region is currently winter peaking, this assessment covers both summer and winter peak loads in the area.
- Line capacity adequacy is assessed by using coincidence peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer and winter 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

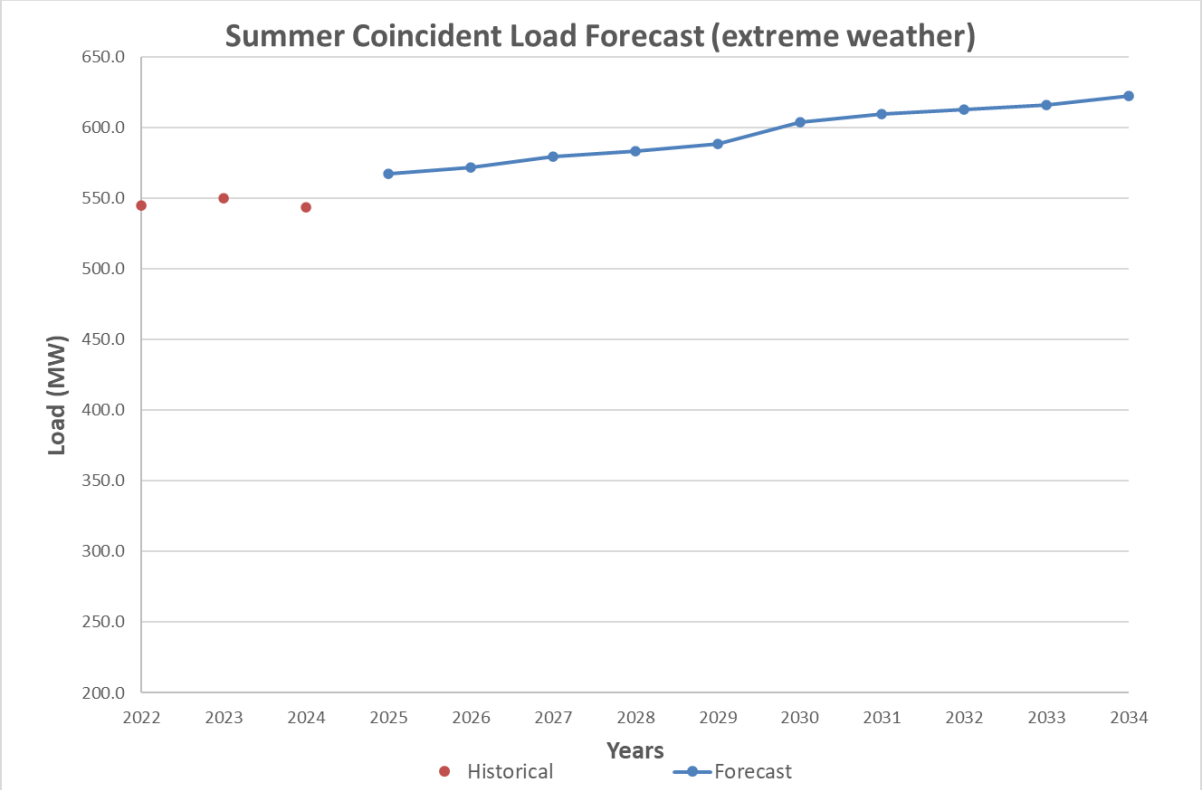
6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the Sudbury Algoma region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided an Electricity Demand Side Management ("eDSM"), and Distributed Generation ("DG") forecast for the Sudbury Algoma region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2024 summer peak extreme weather corrected loads. The extreme summer and winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer and winter weather corrected net load forecast for the individual stations in the Sudbury Algoma region is given in Appendix A. Note, the industrial loads have not been shown in the tables in Appendix A. The winter and summer coincident load forecast are shown in graphs below, which include industrial loads in the region. The Sudbury Algoma region is winter peaking and the winter coincident load is expected to grow from 650 MW in 2024 to 755 MW by 2034. The summer coincident peak load is expected to grow from 543 MW in 2024 to 623 MW by 2034. Graphs 1 and 2 show the winter and summer coincident load forecasts over the study period.

Graph 1: Winter Coincident Forecast in Sudbury Algoma Region



Graph 2: Summer Coincident Forecast in Sudbury Algoma Region



6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis on the high growth scenarios is provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

Relevant information regarding system reliability and operational issues in the region as feedback provided by the IESO and Hydro One Operation teams during the NA phase.

7. NEEDS

This section describes emerging needs identified in the Sudbury Algoma Region and/or updates on previously identified needs since the completion of the previous Regional Planning cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. **Algoma TS - 230/115kV Autotransformer Replacement:** Replaced T5 and T6 autotransformers with new 230/115kV, 125 MVA transformers. The new replacement units have Under Load Tap Changer (ULTCs) for better operational flexibility. New T5 was placed in-service in 2021 and updated nomenclature to T7. New T6 was placed in-service in 2025 and updated nomenclature to T8.
2. **Clarabelle TS - 230/44kV Step-down transformer replacement:** The replacement of 230/44kV, 125 MVA step-down transformers T1 and T2 has been deferred to late 2030s based on their recent condition assessment.
3. **Coniston TS – Station Decommissioning:** The decommissioning of Coniston TS was completed in 2021.
4. **Elliot Lake TS – Station Refurbishment:** Right sizing the station by replacing EOL 115/44 kV, 42 MVA (T1) autotransformer with new 115/44kV 42 MVA unit and removal of autotransformer T2. Upon completion of this project, the station will remain with 2 – 115/44kV 42 MVA (T1/T3) auto transformers and a DESN. The project is expected to be completed in 2026.
5. **Hanmer TS to Martindale TS corridor unbundling:** Circuit X25S was unbundled and new circuit X29S was connected to the terminal stations. The project was completed in 2023.

6. **Martindale TS – 230/115kV Autotransformer Replacement:** Autotransformers T21 and T23 were replaced with 125 MVA unit in 2018.
7. **Martindale TS – 230/44kV Step-down transformer Replacement:** Transformers T25 and T26 were also identified for replacement in the previous regional planning cycle based on asset condition with planned completion in 2028. However, based on recent condition assessment the replacement of the transformers has been deferred to 2032.

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

All near and mid-term needs that are discussed as part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update
Asset Renewal Needs	
Martindale TS 230/44 kV step-down transformers (T25 & T26)	Transformers T25 and T26 are approaching EOL based on their condition assessment. The transformers are planned for like-for-like replacement in 2032.
Station Capacity Needs	
Martindale TS 230/44 kV step-down transformers (T25 & T26)	The load exceeds the 10-day LTR rating of the transformers based on winter demand forecast at the station by 2034.
Martindale TS 230/115 kV Autotransformers (T21, T22, & T23)	With one autotransformer out-of-service and subsequent failure of another unit, the third autotransformer will exceed its winter 10-day LTR. The Martindale TS autotransformers supply the local 115 kV system serving LDCs and industrial customers. Based on the winter coincident forecast, this need is expected to materialize in 2030.
Transmission Line Capacity Needs	
None Identified	None Identified
Voltage Performance	
Manitoulin TS 115 kV voltage	The 115 kV bus at Manitoulin TS experiences low voltage under peak demand conditions at the station.
System Reliability, Operation and Load restoration Needs	
None Identified	None Identified

7.1 Asset Renewal Needs for Major HV Transmission Equipment

Apart from the asset renewal needs identified during the second regional planning cycle, Hydro One and the TWG did not identify any new asset renewal requirements for major high-voltage transmission equipment over the next 10 years in the **Sudbury Algoma Region**. Hydro One remains the sole Transmission Asset Owner (TAO) in the Region.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One’s perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

Table 4: Major HV Transmission Assets Requiring Replacement in Sudbury Algoma Region

Station/Circuit	Need Description	Planned ISD
Martindale TS	Existing T25 and T26 are 230/44 kV, 125 MVA step-down transformers at Martindale TS. These are the largest standard 230/44 kV units in Hydro One fleet. As per recent condition assessment, the units are approaching EOL. and need replacement. The transformers are currently planned for like-for-like replacement.	**2032**

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2025-2034 for the 230kV and 115kV Transforming stations in the **Sudbury Algoma** Region using the summer and winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Martindale TS (T25/T26)

T25 and T26 are 230/44 kV, 125 MVA step-down transformers supplying the DESN load at Martindale TS. For each season, the supply capacity of the DESN is determined by the winter and summer 10-day LTR of the most limiting transformer. The load at the DESN was expected to exceed its winter 10-day LTR of 164 MW by 2028 in the previous regional planning cycle. However, based on the latest load forecast developed in this Needs Assessment, the peak winter load is expected to exceed the winter 10-day LTR by 2034. The peak summer load at the station is lower and well within the summer 10-day LTR of the transformers.

It is recommended that the capacity need of the step-down transformers be studied in the next phase of regional planning. Note, the capacity need of T25/T26 may be impacted by the asset renewal need of the same units if the 10-day LTR of the future units is greater than existing values.

7.2.2 Martindale TS (T21/T22/T23)

T21, T22 and T23 are 230/115 kV, 125 MVA autotransformers responsible for supplying the local 115 kV system which serves LDCs and industrial customers via 115 kV circuits. Under peak winter coincident load, the loss of two autotransformers will result in marginally overloading the third autotransformer above its 10-day LTR of 173 MW. This overload is expected to materialize in 2030 for transformer T23 with the least LTR (173 MW). The overload will be experienced on the other two units by 2034.

Similarly, autotransformer T22 reaches its 10-day LTR under a breaker fail contingency at Martindale TS which results in simultaneous loss of autotransformers T21 and T23. The 10-day LTR of T22 is slightly higher at 178 MW and the need is expected to materialize in 2034.

It is recommended that the capacity need of the autotransformers be further studied in the next phase of regional planning.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

A Transmission Lines Capacity Assessment was performed over the study period 2025-2034 for the 230kV and 115kV Transmission line circuits in the **Sudbury Algoma** Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, in the Sudbury Algoma region there are no transmission lines capacity needs.

7.4 Voltage Performance

Voltage performance was assessed for the Sudbury Algoma region for all elements in-service and post system contingencies.

7.4.1 Manitoulin TS

The 115 kV bus experiences low voltage under peak load conditions at Manitoulin TS. Under system conditions when Mclean Mountain wind farm is unavailable and peak load conditions at Manitoulin TS, the 115 kV bus at the station is below the ORTAC limit of 113 kV. The ULTCs of the step-down transformers have a wide range and are able to maintain the 44 kV bus voltage within the ORTAC limits. This need was reaffirmed in the previous regional planning cycle. No mitigation was recommended since there was no material impact to customers connected on the 44 kV bus. Hydro One has monitored and will continue to monitor the performance of the 115 kV and 44 kV buses at the station.

It is recognized that voltage violation at Manitoulin TS 115 kV bus has no material impact to connected customers. Though mitigation is not necessary, the TWG recommends exploring potential wires and non-wires solutions in the next phase of regional planning that can also alleviate other needs in the region.

7.5 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. This section assesses the Load Security and Load Restoration criteria for the region over the study period.

7.5.1 Load Security

As per ORTAC load security criteria:

Criteria 1: With all transmission facilities in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.

Low voltage is observed on the 115 kV bus at Manitoulin TS under peak load conditions as described in the needs above.

An outage of the largest generator in the region, Rayner G1/G2, resulted in all equipment loading to be within continuous rating and voltages to be in normal ranges.

Criteria 2: With any one element out of service, equipment loading must be within applicable long-term emergency ratings, voltages must be within applicable emergency ranges, and transfers must be within applicable normal condition stability limits. Planned load curtailment or load rejection, excluding voluntary demand management, is permissible only to account for local generation outages. Not more than 150 MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management.

For all n-1 contingencies in the Sudbury Algoma region, this criterion is satisfied.

Criteria 3: With any two elements out of service, voltages must be within applicable emergency ranges, equipment loading must be within applicable short-term emergency ratings and transfers must be within applicable emergency condition stability limits. Equipment loading must be reduced to the applicable long-term emergency ratings in the time afforded by the short-time ratings. Planned load curtailment or load rejection exceeding 150 MW is permissible only to account for local generation outages. Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management.

Martindale TS autotransformers:

- If an autotransformer experiences unplanned outage at Martindale TS, the operating practice is to transfer load to another station to prepare for the loss of another autotransformer. This is achieved by transferring Martindale TS supplied section of circuit S2B to Algoma TS. The load transfer will prevent the remaining autotransformer from exceeding its 10-day LTR should a second autotransformer fail.
- Planned outages of autotransformers are scheduled during off peak seasons when the load in the 115 kV subsystem is low. Additionally, Martindale supplied section of circuit S2B is transferred to Algoma, if necessary. The low loading on 115 kV subsystem and/or load transfer will prevent the remaining autotransformer from exceeding its 10-day LTR should an autotransformer fail.
- Under the breaker fail contingency described in section 7.2.2, the breaker in question is equipped with motor operated disconnect switches. Hydro One control room can isolate the breaker by opening the motor operated disconnect switches and re-energizing the autotransformers within the time afforded by the short-term rating of the units.

This criterion is satisfied with any two elements out of service in the Sudbury Algoma region.

7.5.2 Load Restoration

The transmission system is planned with design criteria in a way to ensure that the affected loads can be restored within restoration time provided.

- All loads must be restored within approximately 8 hours.
- Load interruption greater than 150 MW, the excess amount of load greater than 150 MW needs to be restored within approximately 4 hours.
- Load interruption greater than 250 MW, the excess amount of load greater than 250 MW needs to be restored within approximately 30 minutes.

In the Sudbury Algoma region, there are radial circuits and loads that are supplied by single transformers, with limited transfer capability. Planned outages are taken by transferring load (where possible) and in coordination with any impacted customers. Unplanned outages may require investigation by operators and field crews to identify and replace faulted equipment in the system to restore power to impacted customers. Though there can be instances where load may not be restored within 8 hours as per ORTAC, all reasonable efforts are made to achieve the criterion.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Sudbury Algoma region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer and winter load forecast for all LDC serving stations. A 75% additional growth was used for Martindale TS and Clarabelle TS to reflect greater interest in connecting to these stations from proponents. Industrial customer load was not increased. Instead, a fictitious new load of 40 MW was connected to the 115 kV system at Martindale TS, and another 40 MW load was connected to 115 kV circuit S2B emanating from Algoma TS.

No new needs were identified as part of the sensitivity analysis. Table 5 below lists the impact on capacity needs at Martindale TS. Note, it is understood that adding the 40 MW load on section of S2B supplied by Martindale TS would exacerbate the existing voltage concerns at Manitoulin TS 115 kV bus and was not discussed further.

Table 5: Impact of Sensitivity Analysis on Needs in the region

#	Need Identified	Winter Growth Scenario	
		Normal Growth Scenario	High Growth Scenario
1	**Martindale TS 230/44 Step-down Transformer overload**	2034	2030
2	**Martindale TS 230/115 Autotransformer overload**	2030	Imminent

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 7: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
1	**Martindale TS 230/44 kV step-down transformers (T25 & T26)**	Asset Renewal Need: T25 and T26 are approaching End of Life (EOL) based on their condition assessment. The transformers are planned for like-for-like replacement in 2032.

Table 8: Needs that Require Further Regional Coordination

#	Need Location	Need Description
1	**Martindale TS 230/44 kV step-down transformers (T25 & T26)**	Capacity Need: The load exceeds the 10-day LTR of the step-down transformers, T25 and T26, based on winter demand forecast at the station by 2034.
2	**Martindale TS 230/115 kV Autotransformers (T21, T22, & T23)**	Capacity Need: With one autotransformer out-of-service and subsequent failure of another unit, the third autotransformer will exceed its winter 10-day LTR. The Martindale TS autotransformers supply the local 115 kV system serving LDCs and industrial customers. Based on the winter coincident forecast, this need is expected to materialize in 2030.
3	**Manitoulin TS 115 kV Voltage**	Voltage violation: The 115 kV bus at Manitoulin TS experiences low voltage under peak demand conditions at the station.

List of LDC(s) to be involved in further regional planning phases:

- Greater Sudbury Hydro
- North Bay Hydro (Embedded LDC)
- Hydro One Distribution

List of LDC(s) which are not required to be involved in further regional planning phases:

- N/A

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 21, 2025)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1:

Sudbury Algoma Region – Non-Coincident Summer Extreme Weather Net Load Forecast (MW)

Station	DESN ID	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Clarabelle TS	T1/T2	169.8	106.4	107.0	107.5	108.1	108.7	109.2	109.7	110.4	111.0	111.7
Elliot Lake TS	T1/T3	38.2	13.7	13.8	13.8	13.8	13.8	13.8	13.8	13.9	13.9	14.0
Espanola TS	T1/T2	53.3	9.6	9.7	9.7	9.7	9.7	9.8	9.8	9.8	9.8	9.9
Larchwood TS	T2	50.1	10.7	10.8	10.8	10.9	11.0	11.0	11.1	11.2	11.2	11.3
Manitoulin TS	T3/T4	41.1	24.9	25.2	25.3	25.5	25.7	26.1	26.3	26.9	27.1	27.3
Martindale TS	T25/T26	151.8	116.4	118.1	122.0	123.6	125.2	126.6	128.1	129.7	131.2	135.0
Massey DS	T1	6.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.9
North Shore DS	T1	8.4	5.6	5.6	5.6	5.7	5.7	6.4	6.4	6.5	6.5	7.0
Sowerby DS	T1	6.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Spanish DS	T1	8.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Striker DS	T1/T2	8.4	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.2
Verner DS	T1/T2	8.4	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.9
Warren DS	T1/T2	8.4	5.9	5.9	5.9	6.0	6.0	6.0	6.0	6.1	6.1	6.1
Wharncliffe DS	T1/T2	8.4	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.9
Whitefish DS	T1	8.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.6

Table A.2:

Sudbury Algoma Region – Non-Coincident Winter Extreme Weather Net Load Forecast (MW)

Station	DESN ID	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Clarabelle TS	T1/T2	184.3	123.7	125.8	127.7	129.8	131.8	133.8	135.7	137.8	139.8	141.9
Elliot Lake TS	T1/T3	41.4	17.5	17.6	17.7	17.8	17.9	18.0	18.0	18.1	18.2	18.3
Espanola TS	T1/T2	58.0	11.8	11.9	12.0	12.0	12.1	12.2	12.2	12.3	12.4	12.5
Larchwood TS	T2	53.9	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.5	12.7	12.8
Manitoulin TS	T3/T4	50.0	39.3	39.7	40.1	40.6	41.0	42.2	42.6	44.3	44.8	45.3
Martindale TS	T25/T26	164.3	142.6	146.5	149.2	151.4	153.7	155.9	157.9	160.3	162.4	164.7
Massey DS	T1	8.6	6.4	6.4	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.7
North Shore DS	T1	10.8	6.1	6.2	6.3	6.3	6.4	8.5	8.6	8.6	8.7	10.3
Sowerby DS	T1	8.6	4.3	4.3	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5
Spanish DS	T1	10.8	3.9	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.1	4.2
Striker DS	T1/T2	10.8	7.1	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.6	7.7
Verner DS	T1/T2	10.8	6.5	6.5	6.6	6.6	6.7	6.7	6.8	6.9	6.9	7.0
Warren DS	T1/T2	10.8	8.0	8.1	8.1	8.2	8.3	8.3	8.4	8.5	8.6	8.6
Wharncliffe DS	T1/T2	10.8	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0
Whitefish DS	T1	10.8	6.6	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.0

Table A.3:

Sudbury Algoma Region – Coincident Summer Extreme Weather Net Load Forecast (MW)

Station	DESN ID	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Clarabelle TS	T1/T2	169.8	94.7	95.3	95.7	96.3	96.8	97.2	97.7	98.3	98.8	99.5
Elliot Lake TS	T1/T2	38.2	12.2	12.2	12.2	12.3	12.3	12.3	12.3	12.3	12.4	12.4
Espanola TS	T1/T2	53.3	8.7	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	9.0
Larchwood TS	T2	50.1	9.2	9.2	9.3	9.4	9.4	9.5	9.5	9.6	9.6	9.7
Manitoulin TS	T3/T4	41.1	23.0	23.3	23.4	23.6	23.8	23.9	24.1	24.3	24.5	24.7
Martindale TS	T25/T26	151.8	101.7	103.3	106.6	108.1	109.6	110.9	112.2	113.7	115.1	118.3
Massey DS	T1	6.8	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.5	3.5	3.5
North Shore DS	T1	8.4	4.2	4.2	4.3	4.3	4.4	5.0	5.0	5.1	5.1	5.6
Sowerby DS	T1	6.8	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Spanish DS	T1	8.4	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9
Striker DS	T1/T2	8.4	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Verner DS	T1/T2	8.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.6
Warren DS	T1/T2	8.4	5.6	5.6	5.6	5.7	5.7	5.7	5.8	5.8	5.8	5.9
Wharncliffe DS	T1/T2	8.4	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	3.0
Whitefish DS	T1	8.4	5.0	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.2

Table A.4:

Sudbury Algoma Region – Coincident – Winter Extreme Weather Net Load Forecast (MW)

Station	DESN ID	LTR (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Clarabelle TS	T1/T2	184.3	108.1	109.8	111.5	113.2	115.0	116.7	118.3	120.1	121.8	123.5
Elliot Lake TS	T1/T2	41.4	17.3	17.4	17.5	17.6	17.7	17.8	17.8	18.0	18.0	18.2
Espanola TS	T1/T2	58.0	11.9	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.4	12.5
Larchwood TS	T2	53.9	11.6	11.7	11.8	11.9	12.0	12.1	12.2	12.3	12.5	12.6
Manitoulin TS	T3/T4	50.0	37.6	38.0	38.4	38.8	39.2	39.6	40.0	40.5	40.9	41.4
Martindale TS	T25/T26	164.3	129.8	133.3	135.7	137.7	139.8	141.8	143.6	145.7	147.6	149.7
Massey DS	T1	8.6	6.2	6.2	6.2	6.3	6.3	6.3	6.4	6.4	6.4	6.5
North Shore DS	T1	10.8	2.4	2.4	2.5	2.5	2.6	4.6	4.6	4.7	4.7	6.2
Sowerby DS	T1	8.6	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2
Spanish DS	T1	10.8	3.9	3.9	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.1
Striker DS	T1/T2	10.8	7.1	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.6	7.7
Verner DS	T1/T2	10.8	6.3	6.4	6.4	6.5	6.5	6.6	6.6	6.7	6.7	6.8
Warren DS	T1/T2	10.8	8.1	8.2	8.3	8.3	8.4	8.5	8.6	8.6	8.7	8.8
Wharncliffe DS	T1/T2	10.8	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3
Whitefish DS	T1	10.8	6.2	6.3	6.3	6.3	6.4	6.4	6.5	6.5	6.6	6.6

Appendix B: Lists of Autotransformer and Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)
1	Algoma TS	230/115
2	Clarabelle TS	230/44
3	Elliot Lake TS	115/44
4	Espanola TS	115/44
5	Hamner TS	500/230
6	Larchwood TS	115/44
7	Manitoulin TS	115/44
8	Martindale TS	230/115, 230/44

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations		Circuit ID	Voltage (kV)
1	Hanmer TS	Mississagi TS	X74P	230
2	Hanmer TS	Algoma TS	X27A	230
3	Algoma TS	Mississagi TS	A23P, A24P	230
4	Hanmer TS		X23N	230
5	Martindale TS		S21N	230
6	Hanmer TS	Martindale TS	X25S, X26S, X29S	230
7	Martindale TS	Algoma TS	S22A	230
8	Martindale TS		S6F	115
9	Martindale TS	Larchwood TS	S5M	115
10	Martindale TS	Algoma TS	S2B	115
11	Algoma TS	B3E Tap	B4B	115
12	Algoma TS		T1B	115
13	B4B Tap	Elliot Lake TS	B3E	115
14	B4B Tap	Elliot Lake TS	B4E	115
15	Martindale TS	Crystal Falls TS	L1S	115

Appendix D: List of LDC's

No.	Name of Municipality
1	Greater Sudbury Hydro Inc.
2	Hydro One Networks Inc. (Distribution)
3	North Bay Hydro (Embedded LDC)

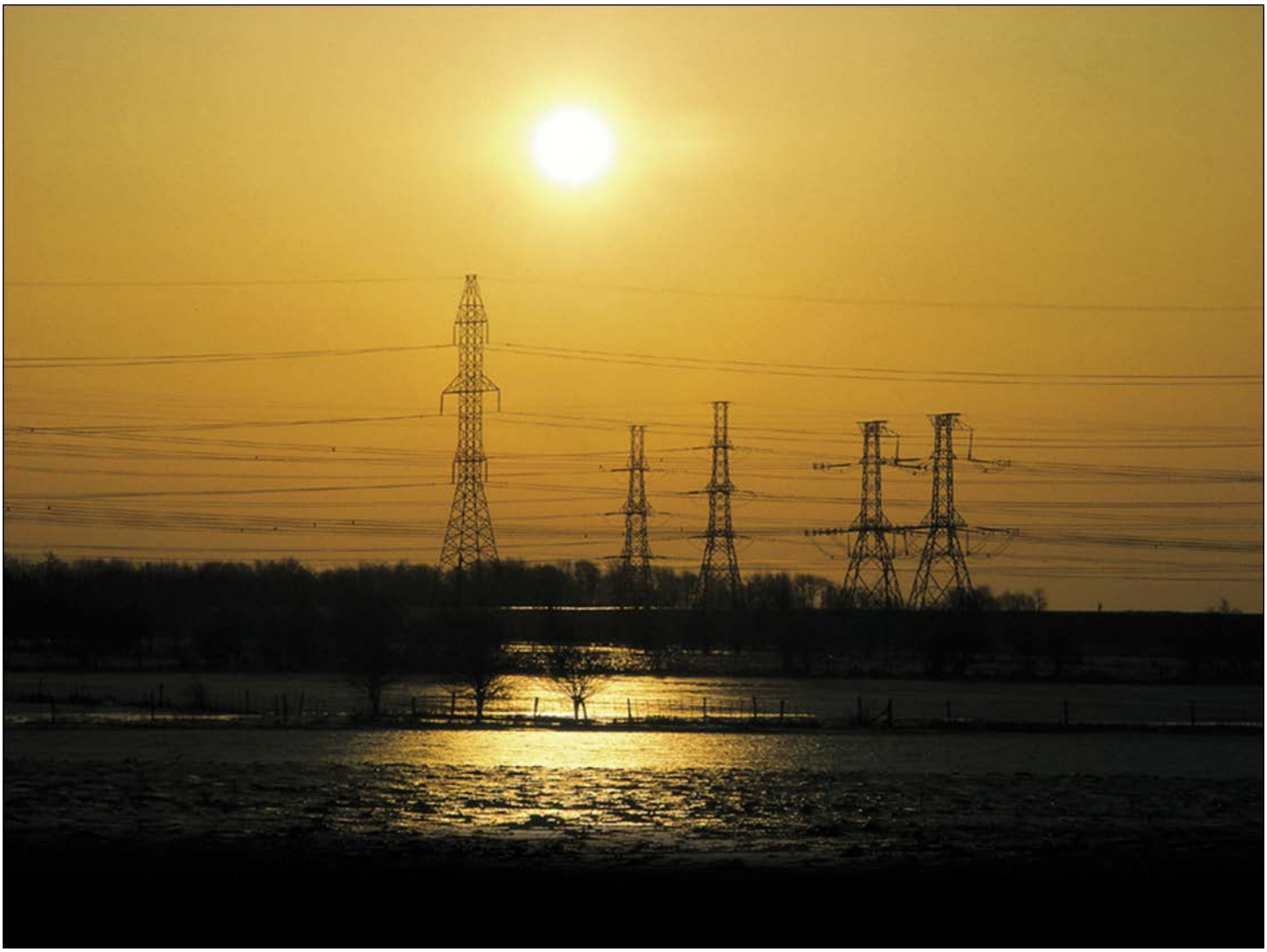
Appendix E: List of Municipalities in the Sudbury Algoma Region

No.	Name of Municipality
1	City of Elliot Lake
2	Municipality of Billings
3	Municipality of Central Manitoulin
4	Municipality of French River
5	Municipality of Gordon/Barrie Island
6	Municipality of Killarney
7	Municipality of Markstay-Warren
8	Municipality of St. Charles
9	Town of Blind River
10	Town of Espanola
11	Town of Gore Bay
12	Town of Northeastern Manitoulin and The Islands
13	Township of Assiginack
14	Township of Baldwin
15	Township of Burpee & Mills
16	Township of Chapleau
17	Township of Cockburn Island
18	Township of Nairn & Hyman
19	Township of Sables Spanish Rivers
20	Township of Tehkummah

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage

Acronym	Description
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station



Chatham-Kent / Lambton / Sarnia Regional Infrastructure Plan

August 13, 2022

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Bluewater Power Distribution Corporation
Entegrus Power Lines Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator

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Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs (2021-2030) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Working Group.

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

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

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Executive Summary

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE CHATHAM-KENT / LAMBTON / SARNIA (CKLS) REGION.

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

- Hydro One Networks Inc. (Lead Transmitter)
- Bluewater Power Distribution Corporation
- Entegrus Power Lines Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator

In the first cycle of the Regional Planning ("RP") process for the CKLS Region, a Needs Assessment ("NA") was published in June 2016 and recommended that an Integrated Regional Resource Plan ("IRRP") was not required. The first cycle of the RP process was completed in August 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This RIP is the final phase of the second cycle of the regional planning process for the CKLS Region, which follows the completion of the Chatham-Kent/Lambton/Sarnia Region Scoping Assessment Outcome Report in December 2021 and the CKLS Needs Assessment in September 2021. This report provides a consolidated summary of needs and recommended plans for the Chatham-Kent/Lambton/Sarnia Region for the near-term (up to 5 years) and mid-term (5 to 10 years).

Investments planned for the CKLS Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Construct new Lambton-by-Chatham double-circuit line (St. Clair Transmission Line)	2028	$210-290M[1]
2	Build new Dresden TS supplied by LxC corridor	2028	$40M
3	St. Andrews TS refurbishment	2025	$40-50M

[1] Letter: IESO Letter to Hydro One re Transmission Line from Lambton to Chatham [4]

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE CHATHAM-KENT / LAMBTON / SARNIA REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the joint study carried out by Hydro One, Entegrus Power Lines Inc., Bluewater Power Distribution Corporation, Hydro One Distribution, and the Independent Electricity System Operator (“IESO”), in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The CKLS Region includes the municipalities of Lambton Shores and Chatham-Kent, as well as the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. The area is bordered by the London area to the east and Windsor-Essex to the southwest. The boundaries of the Region are highlighted in Figure 1-1 below.

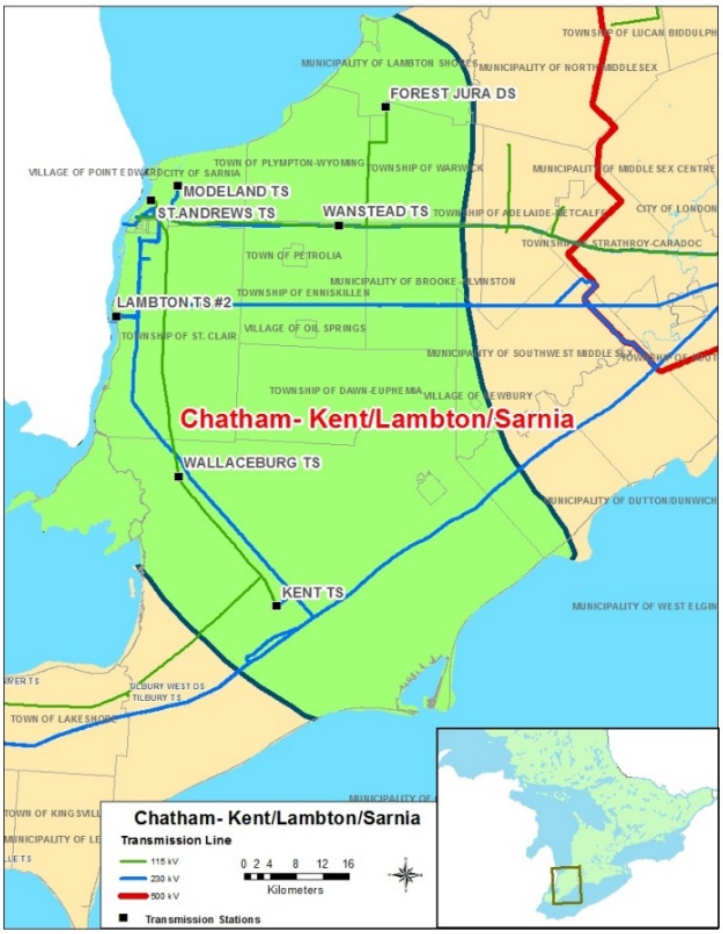


Figure 1-1. Chatham-Kent/Lambton/Sarnia Region

1.1 Objective and Scope

This RIP report examines the needs in the CKLS Region. Its objectives are:

- To develop a wires plan to address needs identified in previous planning phases for which a wires-only alternative was recommended by the Working Group
- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region

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

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2021-2030) identified in previous planning phases (Needs Assessment or Local Plan)
- Identification of any new needs over the 2021-2030 period
- Develop a plan to address any longer term needs identified by the Working Group

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the Region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

The IRRP phase will generally assess infrastructure (wires) versus resource options (e.g. CDM, generation and Distributed Energy Resources ("DER")) at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure

options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

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

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

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, IRRP, and LP phases of regional planning.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers

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

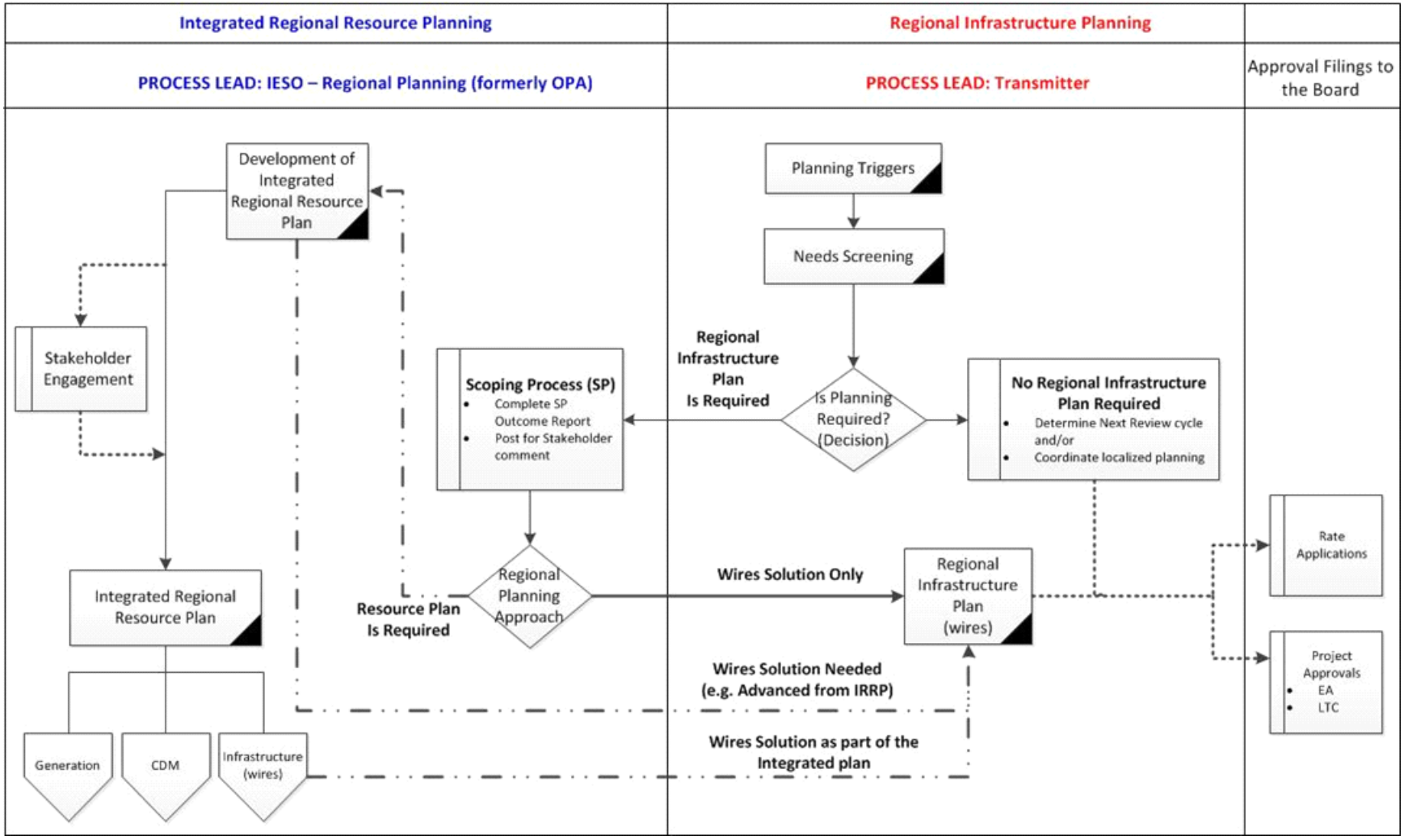


Figure 2-1. Regional Planning Flowchart

2.3 RIP Methodology

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

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

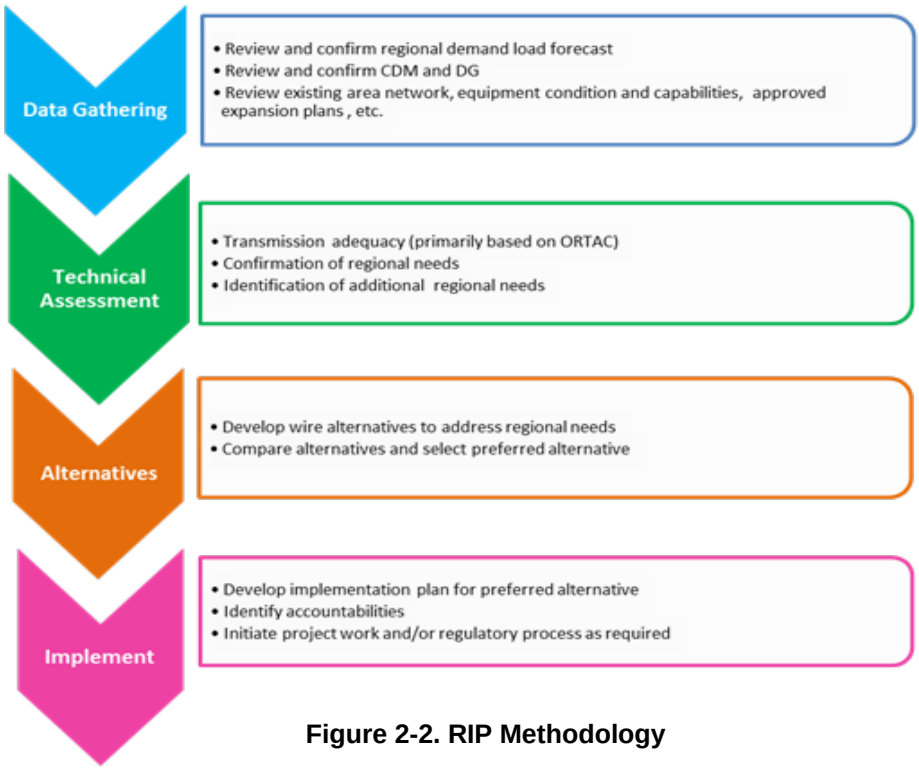


Figure 2-2. RIP Methodology

3. REGIONAL CHARACTERISTICS

THE CHATHAM-KENT / LAMBTON / SARNIA REGION COMPRISES THE MUNICIPALITIES OF LAMBTON SHORES AND CHATHAM-KENT, AS WELL AS THE TOWNSHIPS OF PETROLIA, PLYMPTON-WYOMING, BROOKE-ALVINSTON, DAWN-EUPHEMIA, ENNISKILLEN, ST. CLAIR, WARWICK, AND VILLAGES OF OIL SPRINGS AND POINT EDWARD. THE AREA IS BORDERED BY THE LONDON AREA TO THE EAST AND WINDSOR-ESSEX TO THE SOUTHWEST AS SHOWN IN FIGURE 1-1.

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines. The bulk of the electrical supply is transmitted through 230 kV circuits (N21W, N22W, L24L, L26L, W44LC and W45LS) between Longwood TS and Buchanan TS and Lambton TS/Scott TS/Chatham SS, and 230 kV circuits L28C and L29C towards Chatham SS. This Region also contains a number of interconnections with neighboring Michigan State (B3N, L4D and L51D).

Within the Region, electricity is delivered to the end users of LDCs and direct-connected industrial customers by eight Hydro One step-down transformation stations, as well as nine customer-owned transformer or distribution stations supplied directly from the transmission system. Large gas-fired generators in the region include: Greenfield Energy Centre CGS, TransAlta Sarnia CGS, St. Clair Power CGS, North Kent 1 CGS, and Greenfield South Power Corporation (GSPC) CGS. Appendix A lists all step-down transformer stations in the Region. Appendix B lists all transmission circuits and Appendix C lists LDCs in the Region. The Single Line Diagram for the CKLS Region transmission system facilities is shown below in Figure 3-1.

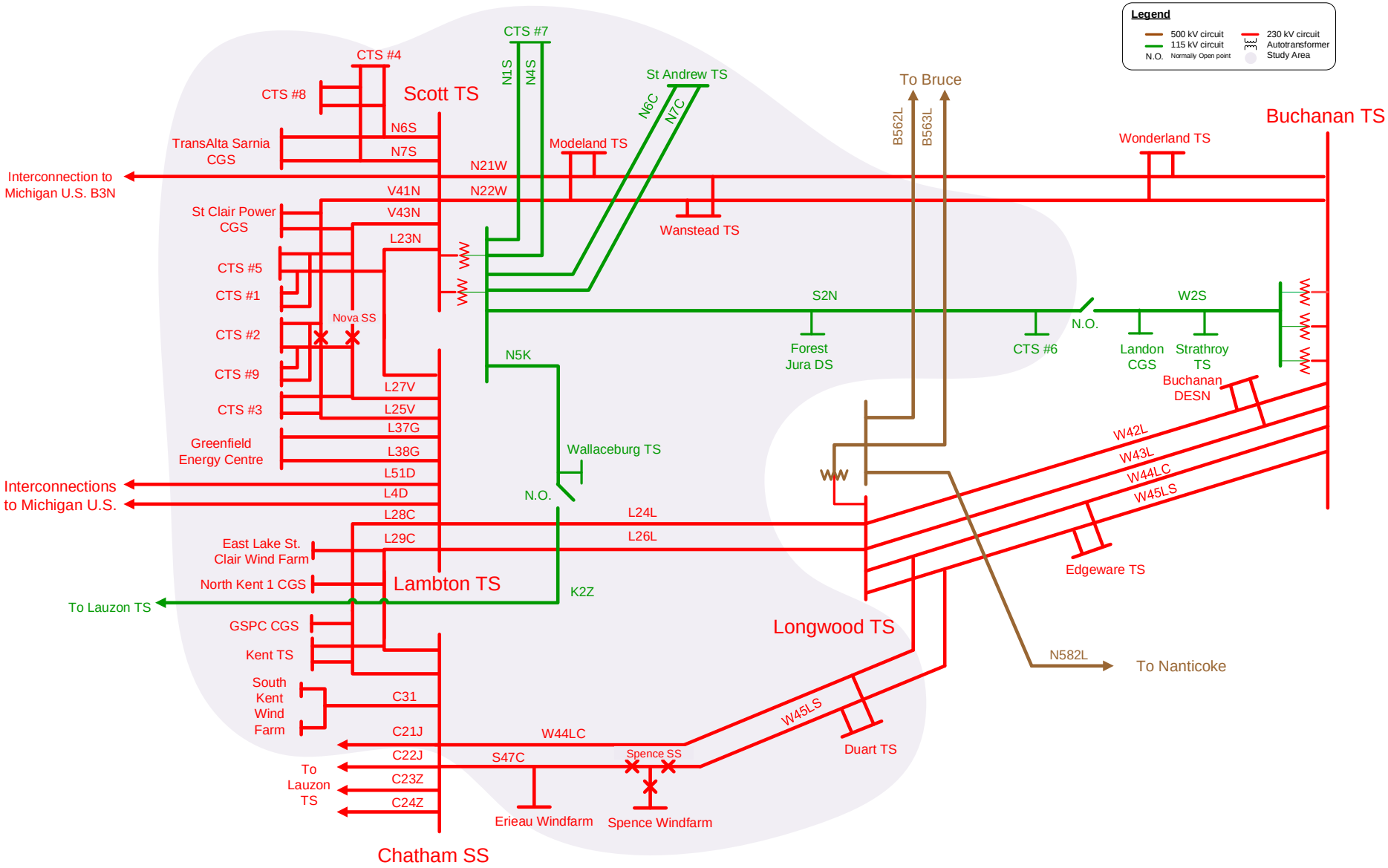


Figure 3-1. Chatham-Kent / Lambton / Sarnia Region Single-Line Diagram

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

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE CHATHAM-KENT / LAMBTON / SARNIA REGION.

In addition to Hydro One's ongoing transmission station and line sustainment programs, specific projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For bulk power system transfer needs:

- 230 kV Capacitor Bank replacement at Chatham SS in 2020

For major station refurbishment needs based on asset condition assessment:

- Wanstead TS in 2018

For renewable generation connection needs:

- 230 kV North Kent 1 Wind Farm onto circuit L29C in 2017
- 230 kV East Lake St. Clair Wind Farm onto L29C in 2012
- 230 kV Erieau Wind Farm onto circuit S47C in 2012

The following projects are underway:

- Lambton TS switchyard is currently undergoing major station refurbishment work with a projected in-servicing by 2023
- Scott TS switchyard is currently undergoing major station refurbishment work with a projected in-servicing by 2024
- New Lambton by Chatham transmission line is currently under development with a projected in-servicing by 2028

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the CKLS Region is forecast to increase annually between 2021 and 2030. The growth rate varies across the Region with most of the growth concentrated in the Municipality of Chatham-Kent and more specifically in the Dresden area. The Region's 2022 RIP load forecasts, including the Dresden Area forecast, are provided in Appendix D and were prepared by the Working Group upon initiation of the RIP phase. The RIP forecasts are identical to the Needs Assessment forecast except as otherwise noted in Appendix D.

As per the load forecasts in Appendix D, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 2.7% annually from 2021-2030 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 2.4% from 2021-2030.

As per the load forecasts in Appendix D, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 2.5% annually from 2021-2030 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 2.2% from 2021-2030.

For both winter and summer coincident load, the strongest growth is expected between 2021 and 2025, tapering off to an average of 1% annual growth over the last 5 years of the study period.

Figure 5-1 shows the Region's gross and net *winter* coincident forecasts while Figure 5-2 shows the Region's gross and net *summer* coincident forecasts. The regional-coincident (at the same time) forecast represents the total peak load of all 18 step-down transformer stations in the Region.

Based on historical load and on the coincident load forecasts, the Region's summer coincident peak load is larger than its winter coincident peak load. Based on historical load and the non-coincident load forecasts, the Region contains most stations that are summer peaking and a few that are winter peaking. Equipment ratings are normally higher in winter than summer due to ambient temperature. Based on these factors, assessment for this Region was conducted for summer peak load.

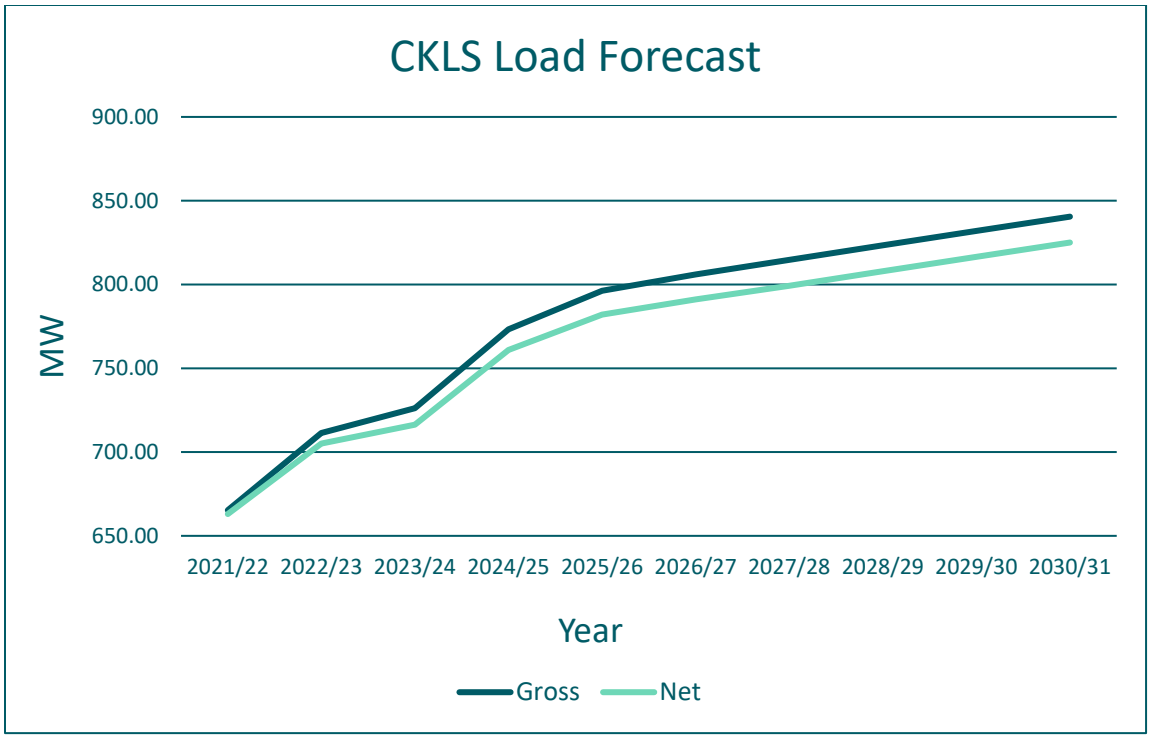


Figure 5-1. Chatham-Kent/Lambton/Sarnia Region Winter Coincident Forecast

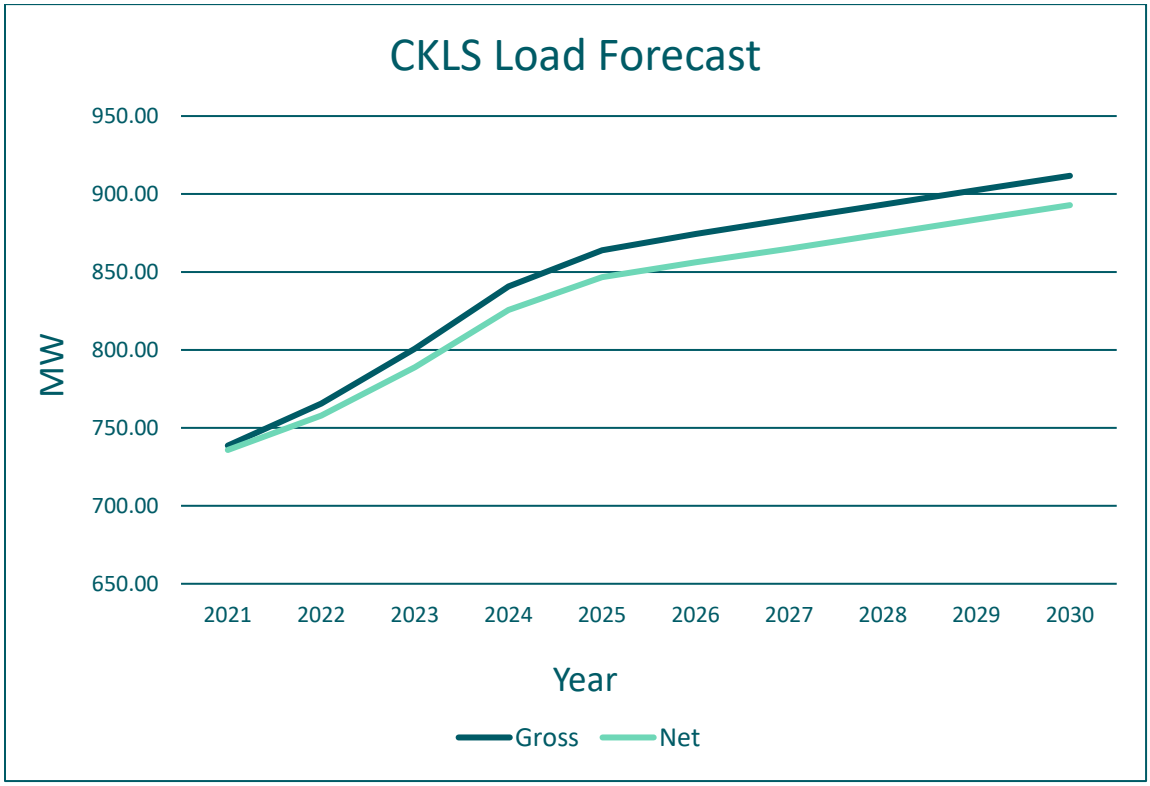


Figure 5-2. Chatham-Kent/Lambton/Sarnia Region Summer Coincident Forecast

5.2 Study Assumptions

The following assumptions are made in this report.

1) The study period for the RIP assessments is 2021-2030.

2) The Region contains most stations that are summer peaking and some that are winter peaking. The assessment is therefore based on summer peak loads.

3) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer and winter 10-Day Limited Time Rating (LTR), as appropriate.

4) Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2021-2030 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STEP-DOWN TRANFORMATION STATION FACILITIES SUPPLYING THE CHATHAM-KENT / LAMBTON / SARNIA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle, two regional assessments have been conducted for the Chatham-Kent/Lambton/Sarnia Region. The findings of these studies are input to the RIP. The studies are:

1) Needs Assessment Report – Chatham-Kent/Lambton/Sarnia Region, September 2021
2) Chatham-Kent/Lambton/Sarnia Region Scoping Assessment Report, December 2021

This RIP reviewed the loading on transmission lines and stations in the Chatham-Kent/Lambton/Sarnia Region based on the RIP load forecast. Sections 6.1-6.5 presents the results of this review and Table 6-1 lists the Region's needs identified in both the Needs Assessment and the SA phases.

In addition, this RIP reviewed an updated list of Hydro One transmission lines and station major sustainment work over the next several years to determine if there are opportunities to consolidate with any emerging development needs within the Region. Section 7.5 presents the results of this review.

Table 6-1: Near and Mid-term Regional Needs

Type	Section	Needs	Timing
Needs and Timing Identified in the Needs Assessment Report and the Scoping Assessment [1]			
Transmission Circuit Capacity	6.2.2	Post-contingency overload and voltage violations on L28C/L29C due to strong load growth in neighbouring Windsor-Essex region	Medium-Term
Transformation Capacity	6.2.3	Transformation capacity need in the Wallaceburg TS and Kent TS area (Dresden area) due to new load connection requests	Short- to Medium-Term
		St. Andrews TS	2024
		Forest Jura HVDS	2030
Voltage Performance	6.3.3	Voltage violations on 115kV N5K circuit in the absence of new Dresden area station due to new load connection requests	Short- to Medium-Term
Bulk System Performance	6.3.4	Bulk system performance need on circuits L28C/L29C due to strong load growth in neighbouring Windsor-Essex region	Medium-Term
End-Of-Life Equipment Needs	6.4	Lambton TS	2023
		Scott TS	2024
		St. Andrews TS	2025
		Kent TS	2027
	SA	N1S/N4S	2027
		N6C/N7C	2027
		S2N	2025
		N5K*	2027

*subject to final routing selection for the Lambton by Chatham (St. Clair) transmission line [5]

6.1 230 kV Transmission Facilities

Half of the 230 kV transmission circuits in the CKLS Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the London and Windsor-Essex areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Scott TS to Buchanan TS 230kV transmission circuits N21W/N22W – supplies Modeland TS, Wanstead TS, and Wonderland TS (London Area)
2) Lambton TS to Longwood TS 230kV transmission circuits L24L/L26L
3) Chatham SS to Buchanan TS 230kV transmission circuits W44LC/W44LS/S47C – supplies Duart TS, and generation connections for Erieau Wind Farm and Spence Wind Farm
4) Lambton TS to Chatham SS 230kV transmission circuits L28C/L29C – supplies Kent TS, and generation connections for East Lake St. Clair Wind Farm, North Kent 1 CGS, and GSPC CGS

The RIP review shows that, based on current forecast station loadings, bulk transfers, and IESO's West of London Bulk Study [3], 230 kV circuits L28C/L29C are expected to exceed their post-contingency thermal limits and experience voltage violations over the study period. Supply capacity of all other 230kV transmission circuits is adequate over the study period.

6.2 230/115 kV Transformation Facilities

Bulk power supply to the CKLS Region is provided by Hydro One's 230 kV to 115 kV and 230kV to 345kV autotransformers. The number and location of these autotransformers are as follows:

1) Two (2) 230/115kV autotransformers at Scott TS
2) Two (2) 230/345kV autotransformers at Lambton TS (interconnection to Michigan)

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period.

6.3 Supply Capacity of the 115 kV Network

The CKLS Region contains two (2) double-circuit and two (2) single circuit 115 kV lines. These 115 kV circuits radially supply local area load. These circuits are as follows (see Figure 3-2):

1) Scott TS TS to CTS #7 115 kV double-circuit transmission line N1S/N4S – radially supplies CTS
2) Scott TS TS to St. Andrews TS 115 kV double-circuit transmission line N6C/N7C – radially supplies St. Andrews TS
3) Scott TS to Adelaide JCT 115 kV transmission circuit S2N – radially supplies Forest Jura HVDS and CTS #6
4) Scott TS to Kent TS TS 115 kV transmission circuit N5K with normally-open point at Wallaceburg TS – radially supplies Wallaceburg TS

The RIP review shows that based on current forecast station loadings, the supply capacity of the 115 kV network is adequate over the study period.

6.4 Step-down Transformer Stations

There are 18 step-down transformer stations within the CKLS Region. Nine supply electricity to LDCs and nine are transmission-connected industrial customer stations. These stations are listed in Appendix C. One of the 18 stations is owned and operated by an LDC.

As part of the Needs Assessment, as well as this RIP, step-down transformation station capacity was reviewed. Since the September 2021 Needs Assessment, the load forecasts at stations in the region remained unchanged; refer to Appendix D for the forecasts. Based on new customer connection requests, there is a potentially strong capacity need in the Dresden area, which is currently supplied by Kent TS and Wallaceburg TS. If the need materializes, additional capacity would be required in the next 3-6 years. The analysis also showed that the net load forecast at St. Andrews will reach the station's summer LTR in 2024, however, the planned like-for-like replacement of the transformers and switchyard (2025) will increase the station capacity and address the capacity need. Likewise, the net load forecast at Forest Jura HVDS is expected to reach the stations summer LTR in 2030 – the station owner, Hydro One Distribution, will continue to monitor the station loading and develop a plan to address the capacity need that is forecasted towards the end of the study period. The gross load forecast at all remaining stations can be accommodated over the study period.

6.5 Other Items Identified During Regional Planning

6.5.1 End-Of-Life Equipment Replacement Needs

Lambton TS – T7/T8, T5/T6 and Component Replacement

Lambton TS has two 230kV/345 kV 600MVA auto-transformers (T7/T8) that facilitate the interconnection to Michigan and two 230kV/27.6kV 56/75/93MVA step-down transformers (T5/T6) that supply Hydro One Distribution via six 27.6 kV feeders.

The current scope of this project is to replace the T7/T8 transformers with a single 1000MVA auto-transformer, the T5/T6 transformers like-for-similar with 50/83MVA capacity, the 27.6kV switchyard and associated equipment.

Based on the load forecast, similar equipment ratings are required for the EOL replacement. The new step-down transformers will increase the capacity of the station by 20 MVA. This project is underway and the planned in-service date for the project is in year 2023.

Scott TS – T5 and 115kV Switchyard Replacement

Scott TS has two 230kV/115kV 150/200/250 MVA auto-transformers (T5/T6) that supply the 115kV system in the CKLS region. Transformer T5 has been in service since 1958 as well as the 115 kV switchyard.

The current scope of this project included the like-for-like replacement of the T5 auto-transformer and the 115kV switchyard including associated equipment.

Based on the load forecast, similar equipment ratings are required for EOL replacement. The planned in-service date for the project is in year 2024.

St. Andrews TS – T3/T4 and Component Replacement

St. Andrews TS is transformer station that was built in 1964. The station consists of two 115kV/27.6 kV 56/74/93 MVA step-down transformers (T3/T4) supplied radially by 115 kV circuits N6C/N7C. The station supplies Bluewater Power Distribution Corporation via six feeders and an industrial customer via two feeders.

The current scope of this project is to replace T3/T4 transformers like-for-similar with 50/83MVA capacity and the 27.6kV switchyard along with associated equipment.

Based on the load forecast for the station, similar equipment ratings are required for EOL replacement of all equipment discussed above. The new transformers will increase the capacity of the station by 20MVA. The planned in-service date for the project is in year 2025.

Kent TS – T2 and Component Replacement

Kent TS consists of two 230kV/27.6 kV, 75/100/125 MVA step-down transformers (T1/T2) supplied by 230 kV circuits L28C/L29C (Lambton x Chatham). The station supplies Hydro One Distribution and Entegrus Powerlines Inc. T1 was replaced on demand due to a transformer failure in 2020.

The scope of this project includes the like-for-like replacement of transformer T2 along with the 27.6kV switchyard and associated equipment.

Based on the load forecast, similar equipment ratings are required for EOL replacement. Once T2 is replaced, the capacity of the station will increase by 35-40MVA. The planned in-service date for the project is in year 2027.

N1S/N4S – Transmission Line Refurbishment

End-of-life refurbishment of 115kV double-circuit transmission line is planned for the section between Scott TS and Vidal JCT and is expected to be completed in 2027.

N6C/N7C – Transmission Line Refurbishment

End-of-life refurbishment of 115kV double-circuit transmission line is planned for the section between Scott TS and St. Andrews TS, and is expected to be completed in 2027.

S2N – Transmission Line Refurbishment

End-of-life refurbishment of 115kV transmission line is planned for the section between Scott TS and Adelaide JCT and is expected to be completed in 2025.

N5K – Transmission Line Refurbishment

End-of-life refurbishment of 115kV transmission line is planned for the section between Scott TS and Kent TS and is expected to be completed in 2027. Depending on the route selection for the new Lambton-by-Chatham transmission line (referred to as the St. Clair Transmission Line project), this refurbishment may not be required as the N5K circuit may be decommissioned.

7. REGIONAL PLANS

THIS SECTION DESCRIBES THE NEEDS FROM TABLE 6-1 AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS.

7.1 Transmission Circuit Capacity

7.1.1 Circuits L28C/L29C

The L28C/L29C double-circuit transmission line will start to experience capacity issues and voltage violations in the medium term due to significant capacity needs in the neighbouring Windsor-Essex region as well as the demand for potential new connections in Dresden Area. The need for reinforcement of this corridor was documented in IESO's West of London Bulk System Study which recommended the construction of a new 230kV double-circuit transmission line between Lambton and Chatham.

Recommended Plan and Current Status

To address the potential need for additional capacity and improved voltage performance along this corridor, Hydro One has agreed with IESO's recommendation to construct the new 230kV double-circuit transmission line which is expected to be in-serviced in 2028. Three of the five routes that are currently under study involve the decommissioning of circuit N5K and a voltage conversion of Wallaceburg TS from 115kV to 230kV. The selection of the preferred route for the new double-circuit line is anticipated in Q2 2023.

7.2 Transformation Capacity

7.2.1 Wallaceburg TS and Kent TS Area (Dresden Area)

There is potentially a strong need for capacity in the Dresden Area which is currently supplied by Wallaceburg TS and Kent TS. The demand for new customer connections in the area has the potential of exceeding 100 MW by 2025 and upwards of 130 MW by the end of the study period – a capacity need that cannot be wholly supplied by the available capacities at Wallaceburg TS and Kent TS. Wallaceburg TS has approximately 5-10 MW of available capacity, whereas the existing Kent TS (T1/T2) has about 30-35 MW of spare capacity which will increase to roughly 65 MW once T2 is replaced in 2027, and the need for new capacity in this area remains in high demand. This need was also documented in IESO's Dresden Load Connection Study (included in Appendix 3 of the CKLS Scoping Assessment Outcome Report [2]) which recommended the construction of a new station supplied by the 230kV Lambton by Chatham corridor. If Wallaceburg TS is converted to 230kV supply as a result of the new Lambton by Chatham transmission line routing, additional transformation capacity of 30-40 MW would become available.

Recommended Plan and Current Status

Subject to the confirmation of the load materializing in the Dresden Area, Hydro One would move forward with IESO's recommendation of constructing a new station (proposed to be named Dresden TS) on the Lambton by Chatham corridor. Due to the existing limitations on the L28C/L29C circuits the construction of the new Dresden TS would be aligned with the construction of the new Lambton by Chatham transmission line with the intention of being ready connect new customers at the same time that the new double-circuit line is complete, in 2028. The immediate capacity needs of new customers can be supplied by the limited capacities available at Kent TS (T1/T2 DESN) and Wallaceburg TS until the proposed Dresden TS is placed in service. The need for Dresden TS may possibly be delayed if the Lambton by Chatham routing results in additional capacity becoming available at Wallaceburg TS.

7.2.2 St. Andrews TS

St. Andrews TS will reach its LTR in 2024, from which point it will continue to grow at an average rate of less than 0.5% towards the end of the study period. As the station is expected to slowly start exceeding its LTR, additional capacity is required.

Recommended Plan and Current Status

To address the capacity need at St. Andrews, it is recommended that Hydro One proceed with the sustainment plan to replace the end-of-life transformers and switchyard which will increase the LTR of the station by 20 MVA and provide sufficient capacity for the long-term. The replacement of the EOL assets is expected to be completed in 2025. Capital contribution from customers is not anticipated at this time as this a like-for-like sustainment project.

Additionally, if more capacity is requested in the local area of St. Andrews TS, the nearby Modeland TS will still have approximately 30MVA of spare capacity by the end of the study period. The existing Modeland TS also has the potential for future expansion should capacity need arise in the area.

7.2.3 Forest Jura HVDS

Forest Jura HVDS, a station owned by Hydro One Distribution, is expected to reach its LTR in 2030, with and average growth rate of 1.2% over the study period. If the forecast materializes as expected, additional capacity will be required in the long-term.

Recommended Plan and Current Status

To address the potential capacity need at Forest Jura HVDS, Hydro One Distribution will monitor the loading and determine a plan to ensure the station can meet the capacity demand.

7.3 Voltage Performance

7.3.1 Circuit N5K

Assuming a large load growth at Wallaceburg TS in the absence of the proposed Dresden TS, there would be voltage violations on the 115kV N5K circuit. This violation is mitigated with the new Dresden TS in place and Wallaceburg loaded within its LTR. Also, if the Lambton by Chatham line routing results in the decommissioning of N5K and Wallaceburg TS being supplied at 230kV, the violation is mitigated.

Recommended Plan and Current Status

It is recommended to maintain loading at Wallaceburg within its capacity limit and wait for the Lambton by Chatham line routing to be established, anticipated in Q2 2023, which will determine if the supply voltage to Wallaceburg TS is increased to 230kV. The line routing selection will also help determine the urgency in constructing the new Dresden TS.

7.4 Bulk System Performance

7.4.1 Circuits L28C/L29C

Based on the study assumptions listed in Section 5.2, and accounting for needs in neighbouring Windsor-Essex Region, there is a bulk system need to reinforce the 230kV corridor between Lambton and Chatham. There are a number of large-scale combined-cycle gas plants in the Sarnia-Lambton area and gas-fired generation output could vary depending on broader system conditions such as expected load growth in the province or availability of other generation resources. Moreover, the Chatham-Kent/Lambton/Sarnia Region is connected to the US market through interconnections in Sarnia and Lambton. Import and export generation levels on the interties have a significant impact on the bulk transmission system. Generation output and import/export levels were parameters considered for the bulk system performance for this Region as well as to serve the growing needs in neighbouring regions (Windsor-Essex region and Chatham-Kent area). The IESO undertook a study to assess the bulk system adequacy for the West of London area, under different system conditions. As a result, the need to reinforce the Lambton-by-Chatham corridor was identified to increase supply capacity into Windsor-Essex region and Chatham-Kent area to meet the mid-term capacity need, and improve the deliverability of resources in Lambton-Sarnia.

Recommended Plan and Current Status

As recommended in IESO's West of London Bulk System Study, Hydro One will proceed with the construction a new double-circuit transmission line between Lambton and Chatham to address bulk system reinforcement needs. The project is expected to be completed in 2028.

7.5 Transmission Sustainment Plans

As part of Hydro One's transmitter requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Table 7-1 lists Hydro One's major transmission sustainment *projects* in the Region that are currently planned or underway. Maintenance *programs* such as insulator, shield wire, structure replacements will continue to be carried out in the Region as required based on equipment/asset condition assessments.

Table 7-1: Hydro One Transmission Major Sustainment Initiatives[2]

Station/Lines	General Description of Work	Planning In-Service Date
Lambton TS	• Replacement of T7/T8 auto-transformers and associated switches • Replacement of T5/T6 DESN transformers and associated switches • Replacement 27.6kV switchyard and associated equipment	2023
Scott TS	• Replacement of T5 auto-transformer • Replacement of 115kV switchyard and associated equipment	2024
St. Andrews TS	• Replacement of T3/T4 DESN transformers and associated switches • Replacement of 27.6kV switchyard and associated equipment	2025
Kent TS	• Replacement of T2 DESN transformers and associated switch • Replacement of 27.6kV switchyard and associated equipment	2027
N1S/N4S	• Refurbishment of circuit section between Scott TS and Vidal JCT	2027
N6C/N7C	• Refurbishment of circuit section between Scott TS and St. Andrews TS	2027
S2N	• Refurbishment of circuit section between Scott TS and Adelaide JCT	2025
N5K	• Refurbishment of circuit section between Scott TS and Kent TS*	2027

*subject to final routing selection for the Lambton by Chatham (St. Clair) transmission line

[2] Scope and dates as of August 2022 and are subject to change

Based on the needs identified in the region thus far and the transmission sustainment plans listed in Table 7-1, consolidation of sustainment and development needs is not necessary at this time.

8. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE CHATHAM-KENT / LAMBTON / SARNIA REGION.

Six near and mid-term needs were identified for the CKLS Region. They are:

I. Transmission Circuit Capacity on Lambton by Chatham Corridor (mid-term)

II. Transformation Capacity in Dresden Area (mid-term)

III. Transformation Capacity at St. Andrews TS (short- to mid-term)

IV. Transformation Capacity at Forest Jura HVDS (mid-term)

V. Voltage Performance on N5K (mid-term)

VI. Bulk System Performance on Lambton by Chatham Corridor (mid-term)

This RIP report addresses six needs and has concluded that regional plans are required. Next Steps, Lead Responsibility, and Timeframes for implementing the regional plans to address needs I through VI are summarized in the Table 8-1 below.

Table 8-1: Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	In-Service Date	Cost	Needs Mitigated
1	Construct new Lambton by Chatham double-circuit line (St. Clair Transmission Line)	Project Under Development	Hydro One Transmission	2028	$210-290M	I,VI
2	Build new Dresden TS supplied by Lambton by Chatham corridor	Initiate project	Hydro One Transmission	2028*	$40M	II,V
3	St. Andrews TS Refurbishment	Detailed Estimate	Hydro One Transmission	2025	$40-50M	III
4	Monitor growth at Forest Jura HVDS	Monitor & Determine Plan	Hydro One Distribution	--	--	IV

*may be delayed if Lambton by Chatham route selection results in additional capacity available at Wallaceburg TS

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Hydro One, “Needs Assessment Report, Chatham-Kent/Lambton/Sarnia Region”, 30 September 2021. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/chathamlambtonsarnia/Documents/ChathamAreaRegion-NeedsAssessmentReport-Final.pdf

[2] IESO, “Chatham-Kent/Lambton/Sarnia Scoping Assessment Outcome Report”, 30 December 2021. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Chatham-Kent-Lambton-Sarnia/CKLS-Scoping-Assessment-Outcome-Dec-2021.ashx

[3] IESO, “Need for Bulk System Reinforcements West of London”, September 2021. https://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/WOL_Bulk_Report_Final_20210923.ashx

[4] IESO, “Letter: IESO Letter to Hydro One re Transmission Line from Lambton to Chatham”, March 2021. https://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/WOL-Stage-1-Handoff-Letter-Final-Signed.ashx

[5] Hydro One, “Hydro One Website: Saint Clair Transmission Line Project Page”. https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/saint-clair/

APPENDIX A: STEP-DOWN TRANSFORMER STATIONS IN THE CHATHAM-KENT / LAMBTON / SARNIA REGION

Station	Voltage (kV)	Supply Circuits
Duart TS	230 kV	W44LC/W45LS
Forest Jura HVDS	115 kV	S2N
Kent TS	115 kV	L28C/L29C
Lambton TS	230 kV	N/A
Modeland TS	230 kV	N21W/N22W
Scott TS	230/115 kV	N/A
St Andrews TS	115 kV	N6C/N7C
Wallaceburg TS	115 kV	N5K
Wanstead TS	230 kV	N21W/N22W
Customer CTS #1	230 kV	V43N/L23N
Customer CTS #2	230 kV	V41N/L27V
Customer CTS #3	230 kV	L25V/L27V
Customer CTS #4	230 kV	N6S/N7S
Customer CTS #5	230 kV	V43N/L23N
Customer CTS #6	115 kV	S2N
Customer CTS #7	115 kV	N1S/N4S
Customer CTS #8	230 kV	N6S/N7S
Customer CTS #9	230 kV	V41N/L27V

APPENDIX B: REGIONAL TRANSMISSION CIRCUITS IN THE CHATHAM-KENT / LAMBTON / SARNIA REGION

Location	Circuit Designation	Voltage (kV)
Scott TS – TransAlta Sarnia CGS	N6S/N7S	230 kV
Scott TS – Nova SS	V41N/V43N	230 kV
Scott TS – Lambton TS	L23N	230 kV
Lambton TS – Nova SS	L25V/L27V	230 kV
Lambton TS – Greenfield Energy Centre CGS	L37G/L38G	230 kV
Lambton TS – Chatham SS	L28C/L29C	230 kV
Chatham SS – South Kent Wind Farm CGS	C31	230 kV
Buchanan TS – Longwood TS – Chatham SS	W44LC	230 kV
Buchanan TS – Longwood TS – Spence SS	W45LS	230 kV
Spence SS – Chatham SS	S47C	230 kV
Lambton TS – Longwood TS	L24L/L26L	230 kV
Scott TS – Buchanan TS	N21W/N22W	230 kV
Scott TS – CTS	N1S/N4S	115 kV
Scott TS – St. Andrews TS	N6C/N7C	115 kV
Scott TS – CTS	S2N	115 kV
Scott TS – Wallaceburg TS	N5K	115 kV
Kent TS – Lauzon TS	K2Z	115 kV

APPENDIX C: DISTRIBUTORS IN THE CHATHAM-KENT / LAMBTON / SARNIA REGION

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc.	Duart TS	Tx
	Forest Jura HVDS	Tx
	Kent TS	Tx
	Lambton TS	Tx
	Wallaceburg TS	Tx
	Wanstead TS	Tx
Bluewater power Distribution Corp.	Modeland TS	Tx
	St. Andrews TS	Tx
	Wanstead TS	Dx
Entegrus Powerlines Inc.	Kent TS	Tx, Dx
	Wallaceburg TS	Dx

APPENDIX D: REGIONAL LOAD FORECAST (2021-2030)

Table D-1. Gross Winter Regional-Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Duart TS	215.2	14.97	15.68	15.88	21.29	21.51	21.72	21.95	22.19	22.44	22.67	22.89
Forest Jura DS	31.25	18.84	19.12	19.40	19.69	19.98	20.28	20.58	20.88	21.19	21.50	21.82
Kent TS (T1/T2)	171.2*	59.51	61.12	68.36	66.17	68.00	72.65	74.54	75.22	75.91	76.58	77.24
Kent TS (T3/T4)	65.8	31.57	31.98	32.39	32.81	33.24	33.67	34.11	34.55	35.00	35.45	35.91
Lambton TS	114.1**	56.80	57.19	57.59	57.99	58.40	58.80	59.21	59.63	60.04	60.46	60.88
Modeland TS	214.8	66.30	70.00	76.91	83.81	90.72	97.63	100.85	104.08	107.30	110.52	113.75
St. Andrews TS	110.9***	62.10	65.97	66.48	66.98	101.49	102.00	102.50	103.01	103.52	104.03	104.53
Wallaceburg TS	63	26.84	27.10	27.37	27.64	27.91	28.19	28.46	28.74	29.03	29.31	29.60
Wanstead TS	128.8	37.39	38.71	39.65	40.37	40.98	48.63	49.35	50.11	50.86	51.59	52.31
CTS #1	N/A	28.20	28.43	28.67	28.91	29.14	29.39	29.63	29.88	30.12	30.37	30.63
CTS #2	N/A	16.42	16.63	16.85	17.07	17.29	17.52	17.75	17.98	18.22	18.45	18.69
CTS #3	N/A	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36
CTS #4	N/A	40.06	40.30	40.55	40.79	41.04	41.29	41.54	41.80	42.05	42.31	42.57
CTS #5	N/A	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47
CTS #6	N/A	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.52	1.53	1.54	1.55
CTS #7	N/A	47.46	47.79	48.12	48.45	48.79	49.13	49.47	49.82	50.16	50.51	50.87
CTS #8	N/A	49.27	98.00	98.88	99.87	100.49	101.05	101.71	102.46	103.16	103.83	104.42
CTS #9	N/A	0.00	3.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 210 MVA after T2 is replaced (2027)

** LTR will increase to approximately 135 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 135 MVA after T1/T2 are replaced (2025)

Table D-2. Gross Summer Regional-Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	15.00	15.65	15.88	20.68	20.89	21.09	21.31	21.55	21.78	22.01	22.22
Forest Jura DS	31.25	19.82	20.12	20.43	20.74	21.06	21.38	21.70	22.03	22.37	22.71	23.06
Kent TS (T1/T2)	155.6*	88.60	90.17	95.73	93.78	94.63	99.41	101.60	102.55	103.51	104.46	105.39
Kent TS (T3/T4)	59.8	41.83	42.36	42.89	43.43	43.97	44.53	45.09	45.65	46.23	46.81	47.40
Lambton TS	103.8**	58.25	58.68	59.11	59.55	59.99	60.44	60.88	61.34	61.79	62.25	62.71
Modeland TS	196.5	98.97	102.99	109.95	116.90	123.86	130.82	134.07	137.32	140.56	143.81	147.06
St. Andrews TS	101.8***	60.67	63.86	64.32	64.78	92.55	93.01	93.47	93.94	94.40	94.86	95.33
Wallaceburg TS	51.8	33.91	34.25	34.74	35.26	35.58	35.88	36.21	36.56	36.92	37.24	37.55
Wanstead TS	118.9	39.25	40.69	41.66	42.65	43.49	51.03	51.97	52.95	53.92	54.87	55.80
CTS #1	N/A	26.67	26.90	27.14	27.37	27.61	27.85	28.10	28.34	28.59	28.84	29.09
CTS #2	N/A	17.80	18.01	18.22	18.43	18.65	18.86	19.09	19.31	19.53	19.76	19.99
CTS #3	N/A	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16
CTS #4	N/A	44.34	44.63	44.92	45.22	45.51	45.81	46.11	46.41	46.71	47.02	47.32
CTS #5	N/A	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53
CTS #6	N/A	2.69	2.71	2.73	2.75	2.77	2.79	2.81	2.83	2.85	2.87	2.89
CTS #7	N/A	53.79	54.19	54.59	54.99	55.40	55.81	56.22	56.64	57.06	57.48	57.90
CTS #8	N/A	29.57	79.73	80.62	81.57	82.08	82.54	83.07	83.68	84.25	84.80	85.27
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 195 MVA after T2 is replaced (2027)

** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table D-3. Gross Winter Non-Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Duart TS	215.2	15.62	16.36	16.57	22.21	22.43	22.65	22.89	23.15	23.40	23.65	23.88
Forest Jura DS	31.25	18.84	19.12	19.40	19.69	19.98	20.28	20.58	20.88	21.19	21.50	21.82
Kent TS (T1/T2)	171.2*	67.94	69.78	78.05	75.54	77.63	82.95	85.10	85.88	86.67	87.43	88.18
Kent TS (T3/T4)	65.8	36.64	37.11	37.59	38.08	38.58	39.08	39.58	40.10	40.62	41.14	41.68
Lambton TS	114.1**	61.93	62.37	62.80	63.24	63.68	64.12	64.57	65.02	65.47	65.93	66.39
Modeland TS	214.8	73.93	78.06	85.76	93.46	101.16	108.87	112.46	116.06	119.65	123.25	126.84
St. Andrews TS	110.9***	64.73	68.76	69.29	69.82	105.78	106.31	106.84	107.37	107.90	108.43	108.96
Wallaceburg TS	63	32.37	32.69	33.01	33.33	33.66	33.99	34.33	34.67	35.01	35.35	35.70
Wanstead TS	128.8	39.16	40.54	41.52	42.28	42.92	50.93	51.69	52.48	53.26	54.03	54.78
CTS #1	N/A	31.78	32.04	32.31	32.58	32.85	33.12	33.39	33.67	33.95	34.23	34.51
CTS #2	N/A	17.04	17.26	17.49	17.72	17.95	18.18	18.42	18.66	18.91	19.15	19.40
CTS #3	N/A	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60
CTS #4	N/A	47.22	47.50	47.79	48.09	48.38	48.67	48.97	49.27	49.57	49.87	50.18
CTS #5	N/A	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64
CTS #6	N/A	3.04	3.06	3.08	3.10	3.12	3.14	3.16	3.18	3.21	3.23	3.25
CTS #7	N/A	53.71	54.08	54.46	54.84	55.22	55.60	55.99	56.38	56.77	57.17	57.57
CTS #8	N/A	51.40	102.23	103.15	104.17	104.82	105.41	106.10	106.88	107.61	108.31	108.92
CTS #9	N/A	0.00	3.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 210 MVA after T2 is replaced (2027)

** LTR will increase to approximately 135 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 135 MVA after T1/T2 are replaced (2025)

Table D-4. Gross Summer Non-Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	17.52	18.28	18.55	24.15	24.39	24.63	24.89	25.17	25.44	25.71	25.96
Forest Jura DS	31.25	26.60	27.00	27.41	27.83	28.26	28.69	29.13	29.57	30.02	30.48	30.95
Kent TS (T1/T2)	155.6*	105.10	106.96	113.55	111.24	112.25	117.92	120.52	121.65	122.78	123.90	125.01
Kent TS (T3/T4)	59.8	46.81	47.40	48.00	48.60	49.21	49.83	50.46	51.09	51.73	52.38	53.04
Lambton TS	103.8**	65.41	65.90	66.39	66.88	67.37	67.87	68.37	68.88	69.39	69.90	70.42
Modeland TS	196.5	114.81	119.46	127.53	135.60	143.68	151.75	155.51	159.28	163.05	166.81	170.58
St. Andrews TS	101.8***	65.06	68.48	68.98	69.47	99.25	99.74	100.24	100.74	101.23	101.73	102.23
Wallaceburg TS	51.8	39.11	39.50	40.07	40.67	41.04	41.39	41.77	42.18	42.58	42.96	43.32
Wanstead TS	118.9	46.42	48.13	49.27	50.45	51.44	60.36	61.47	62.63	63.77	64.90	66.00
CTS #1	N/A	32.20	32.48	32.76	33.05	33.34	33.63	33.92	34.22	34.51	34.82	35.12
CTS #2	N/A	19.35	19.57	19.80	20.03	20.27	20.51	20.75	20.99	21.23	21.48	21.73
CTS #3	N/A	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75
CTS #4	N/A	48.71	49.02	49.34	49.67	49.99	50.32	50.64	50.98	51.31	51.64	51.98
CTS #5	N/A	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96
CTS #6	N/A	2.77	2.79	2.81	2.83	2.85	2.87	2.89	2.91	2.93	2.95	2.97
CTS #7	N/A	56.08	56.50	56.92	57.34	57.76	58.19	58.62	59.05	59.49	59.93	60.37
CTS #8	N/A	112.89	113.74	114.59	115.45	116.32	117.19	118.07	118.96	119.85	120.75	121.66
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 195 MVA after T2 is replaced (2027)

** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table D-5. Net Winter Regional Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Duart TS	215.2	14.97	15.59	15.63	20.90	21.02	21.15	21.35	21.58	21.82	22.05	22.27
Forest Jura DS	31.25	18.84	19.00	19.08	19.19	19.36	19.56	19.83	20.10	20.41	20.73	21.05
Kent TS (T1/T2)	171.2*	59.51	60.76	67.36	64.61	66.03	70.40	72.17	72.77	73.45	74.12	74.78
Kent TS (T3/T4)	65.8	31.57	31.78	31.86	31.99	32.20	32.47	32.85	33.25	33.70	34.15	34.61
Lambton TS	114.1**	56.80	56.84	56.63	56.50	56.52	56.65	56.95	57.28	57.70	58.12	58.54
Modeland TS	214.8	66.30	69.59	75.79	82.08	88.53	95.12	98.21	101.34	104.56	107.79	111.01
St. Andrews TS	110.9***	62.10	65.59	65.43	65.36	99.44	99.64	100.03	100.45	100.96	101.46	101.97
Wallaceburg TS	63	26.84	26.94	26.92	26.94	27.03	27.17	27.40	27.64	27.92	28.21	28.50
Wanstead TS	128.8	37.39	38.48	39.02	39.39	39.75	47.21	47.86	48.57	49.32	50.05	50.76
CTS #1	N/A	28.20	28.43	28.67	28.91	29.14	29.39	29.63	29.88	30.12	30.37	30.63
CTS #2	N/A	16.42	16.63	16.85	17.07	17.29	17.52	17.75	17.98	18.22	18.45	18.69
CTS #3	N/A	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36
CTS #4	N/A	40.06	40.30	40.55	40.79	41.04	41.29	41.54	41.80	42.05	42.31	42.57
CTS #5	N/A	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47
CTS #6	N/A	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.52	1.53	1.54	1.55
CTS #7	N/A	47.46	47.79	48.12	48.45	48.79	49.13	49.47	49.82	50.16	50.51	50.87
CTS #8	N/A	49.27	98.00	98.88	99.87	100.49	101.05	101.71	102.46	103.16	103.83	104.42
CTS #9	N/A	0.00	3.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 210 MVA after T2 is replaced (2027)

** LTR will increase to approximately 135 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 135 MVA after T1/T2 are replaced (2025)

Table D-6. Net Summer Regional Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	15.00	15.56	15.63	20.28	20.39	20.52	20.71	20.93	21.16	21.39	21.61
Forest Jura DS	31.25	19.82	20.00	20.09	20.22	20.40	20.63	20.91	21.22	21.55	21.89	22.24
Kent TS (T1/T2)	155.6**	88.60	89.63	94.23	91.46	91.71	96.05	98.07	98.90	99.85	100.80	101.74
Kent TS (T3/T4)	59.8	41.83	42.10	42.18	42.33	42.59	42.94	43.42	43.93	44.50	45.08	45.67
Lambton TS	103.8***	58.25	58.32	58.13	58.03	58.07	58.23	58.56	58.93	59.39	59.84	60.30
Modeland TS	196.5	98.97	102.38	108.27	114.31	120.60	127.07	130.13	133.23	136.48	139.73	142.97
St. Andrews TS	101.8****	60.67	63.49	63.30	63.19	90.55	90.71	91.06	91.43	91.90	92.36	92.82
Wallaceburg TS	51.8	33.91	34.04	34.16	34.37	34.46	34.59	34.86	35.17	35.52	35.85	36.15
Wanstead TS	118.9	39.25	40.45	40.99	41.62	42.20	49.54	50.41	51.33	52.30	53.25	54.18
CTS #1	N/A	26.67	26.90	27.14	27.37	27.61	27.85	28.10	28.34	28.59	28.84	29.09
CTS #2	N/A	17.80	18.01	18.22	18.43	18.65	18.86	19.09	19.31	19.53	19.76	19.99
CTS #3	N/A	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16
CTS #4	N/A	44.34	44.63	44.92	45.22	45.51	45.81	46.11	46.41	46.71	47.02	47.32
CTS #5	N/A	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53
CTS #6	N/A	2.69	2.71	2.73	2.75	2.77	2.79	2.81	2.83	2.85	2.87	2.89
CTS #7	N/A	53.79	54.19	54.59	54.99	55.40	55.81	56.22	56.64	57.06	57.48	57.90
CTS #8	N/A	29.57	79.73	80.62	81.57	82.08	82.54	83.07	83.68	84.25	84.80	85.27
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 195 MVA after T2 is replaced (2027)

** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table D-7. Net Winter Non-Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Duart TS	215.2	15.62	16.26	16.30	21.80	21.92	22.06	22.27	22.50	22.76	23.00	23.23
Forest Jura DS	31.25	18.84	19.00	19.08	19.19	19.36	19.56	19.83	20.10	20.41	20.73	21.05
Kent TS (T1/T2)	171.2*	67.94	69.37	76.90	73.76	75.39	80.37	82.40	83.08	83.86	84.63	85.38
Kent TS (T3/T4)	65.8	36.64	36.89	36.97	37.12	37.37	37.69	38.12	38.58	39.10	39.63	40.17
Lambton TS	114.1**	61.93	61.99	61.76	61.62	61.64	61.78	62.10	62.47	62.92	63.38	63.84
Modeland TS	214.8	73.93	77.60	84.51	91.52	98.72	106.06	109.52	113.01	116.60	120.19	123.79
St. Andrews TS	110.9***	64.73	68.36	68.19	68.12	103.65	103.86	104.26	104.70	105.23	105.76	106.28
Wallaceburg TS	63	32.37	32.49	32.46	32.49	32.59	32.77	33.04	33.33	33.67	34.02	34.37
Wanstead TS	128.8	39.16	40.30	40.86	41.25	41.63	49.44	50.13	50.86	51.65	52.42	53.16
CTS #1	N/A	31.78	32.04	32.31	32.58	32.85	33.12	33.39	33.67	33.95	34.23	34.51
CTS #2	N/A	17.04	17.26	17.49	17.72	17.95	18.18	18.42	18.66	18.91	19.15	19.40
CTS #3	N/A	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60	36.60
CTS #4	N/A	47.22	47.50	47.79	48.09	48.38	48.67	48.97	49.27	49.57	49.87	50.18
CTS #5	N/A	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64	10.64
CTS #6	N/A	3.04	3.06	3.08	3.10	3.12	3.14	3.16	3.18	3.21	3.23	3.25
CTS #7	N/A	53.71	54.08	54.46	54.84	55.22	55.60	55.99	56.38	56.77	57.17	57.57
CTS #8	N/A	51.40	102.23	103.15	104.17	104.82	105.41	106.10	106.88	107.61	108.31	108.92
CTS #9	N/A	0.00	3.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 210 MVA after T2 is replaced (2027)

** LTR will increase to approximately 135 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 135 MVA after T1/T2 are replaced (2025)

Table D-8. Net Summer Non-Coincident Forecast (MW)

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	17.52	18.17	18.25	23.69	23.81	23.96	24.19	24.44	24.72	24.98	25.23
Forest Jura DS	31.25	26.60	26.84	26.97	27.14	27.38	27.68	28.07	28.47	28.92	29.38	29.85
Kent TS (T1/T2)	155.6**	105.10	106.31	111.78	108.49	108.78	113.94	116.33	117.31	118.45	119.57	120.68
Kent TS (T3/T4)	59.8	46.81	47.11	47.21	47.37	47.67	48.05	48.59	49.16	49.80	50.45	51.11
Lambton TS	103.8***	65.41	65.50	65.28	65.16	65.21	65.39	65.77	66.18	66.69	67.20	67.72
Modeland TS	196.5	114.81	118.76	125.59	132.60	139.89	147.40	150.94	154.54	158.31	162.08	165.84
St. Andrews TS	101.8****	65.06	68.08	67.88	67.77	97.10	97.28	97.65	98.05	98.55	99.04	99.54
Wallaceburg TS	51.8	39.11	39.26	39.41	39.65	39.75	39.91	40.21	40.56	40.97	41.35	41.70
Wanstead TS	118.9	46.42	47.84	48.49	49.23	49.91	58.60	59.63	60.71	61.86	62.98	64.09
CTS #1	N/A	32.20	32.48	32.76	33.05	33.34	33.63	33.92	34.22	34.51	34.82	35.12
CTS #2	N/A	19.35	19.57	19.80	20.03	20.27	20.51	20.75	20.99	21.23	21.48	21.73
CTS #3	N/A	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75
CTS #4	N/A	48.71	49.02	49.34	49.67	49.99	50.32	50.64	50.98	51.31	51.64	51.98
CTS #5	N/A	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96
CTS #6	N/A	2.77	2.79	2.81	2.83	2.85	2.87	2.89	2.91	2.93	2.95	2.97
CTS #7	N/A	56.08	56.50	56.92	57.34	57.76	58.19	58.62	59.05	59.49	59.93	60.37
CTS #8	N/A	112.89	113.74	114.59	115.45	116.32	117.19	118.07	118.96	119.85	120.75	121.66
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* LTR will increase to approximately 195 MVA after T2 is replaced (2027)

** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)

*** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table D-9. Dresden TS Net Summer Non-Coincident Forecast

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load (MW)	33.45	45	43	56.3	59	59	59	59	59

Table D-10. Dresden TS Net Winter Non-Coincident Forecast

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load (MW)	50.6	60.6	80.6	109.6	128.6	128.6	128.6	128.6	128.6

APPENDIX E: LIST OF ACRONYMS

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



Third Cycle

REGIONAL INFRASTRUCTURE PLAN REPORT

Greater Bruce/Huron

April 11, 2025

Regional Infrastructure Plan Report

Greater Bruce/Huron

April 11, 2025

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Greater Bruce/Huron Technical working group

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Disclaimer

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

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

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

Executive Summary

REGION	**Greater Bruce/Huron region** (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: October 20, 2024	**END DATE:** April 11, 2025

1. INTRODUCTION

The Regional Infrastructure Plan ("RIP") is the final step of Regional Planning ("RP") process for the Greater Bruce/Huron ("GBH") region, preceded by, the publication of Needs Assessment ("NA") report in September 2024 by Hydro One. At the end of NA phase, the Technical Working Group ("TWG") decided that there is no need for Scoping Assessment ("SA") and/or Integrated Regional Resource Plan ("IRRP") phases to meet the identified needs in this cycle; therefore, the TWG proceeded directly to the RIP phase.

Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans, and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

2. OBJECTIVES AND SCOPE

Objectives:

- Provide a comprehensive summary of needs and wires plans to address the needs for the GBH region.
- Identify new supply needs that may have emerged since Needs Assessment phase.
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

Scope:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2024-2033 identified in Needs Assessment.
- Identification of any new needs over the 2024-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the GBH as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of the Regional Planning Process and their outcomes and details of the Regional Infrastructure plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the GBH region though a regional planning area map and a Single Line diagram ("SLD").

The GBH region comprises of the counties of Bruce, Huron, and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, and Middlesex counties.

Electricity supply for the GBH region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the region. These circuits connect the region to the adjacent South Georgian Bay/Muskoka region and the adjacent Kitchener-Waterloo-Cambridge-Guelph ("KWCG") region.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

This section provides a summary and brief description of all the projects completed in the past ten (10) years or are currently underway.

I. The following Major projects were completed during the last ten years:

1. Goderich TS – Transformers T1, T2 and T3 Removal, Transformer T5 Installation and station Reconfiguration. This project was completed in 2017.
2. Centralia TS – Transformers T1 and T2 Replacement, Transformer T3 Removal and station Reconfiguration. This project was completed in 2018.
3. Palmerston TS – Transformers T1 and T2 Replacement, Transformer T3 Removal and station Reconfiguration. This project was completed in 2019.
4. Bruce A TS – 230kV ABCB ("Air-Blast Circuit Breaker") Station Refurbishment. This project was completed in 2022.
5. Stratford TS – Transformer T1 Replacement. This project was completed in 2022.
6. Hanover TS – Transformer T2 Replacement. This project was completed in 2022.
7. 115 kV L7S Circuit – Capacity Increase and Clearance Improvement between Seaforth TS and Kirkton JCT. This project was completed between 2022 to 2023.
8. Wingham TS – Transformers T1 and T2 Replacement. This project was completed in 2024.

II. Following Major projects are underway:

1. Seaforth TS – Transformers T1, T2, T5 and T6 Replacement. This project is planned to be completed by Q1 2027.

Note: The planned in-service years for the above projects are tentative and subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the summer *net* and *gross* coincident load in the region is expected to grow at an average rate of approximately 1.4% and the winter *net* and *gross* coincident load in the region is expected to grow at an average rate of approximately 0.8%.

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2024-2033.
- LDCs reconfirmed load forecasts up to 2033 in the area are the same as their load forecasts in NA phase.
- All planned facilities for which work has been initiated and are listed in section 5 are assumed to be in-service.
- Some of the stations in this region are summer peaking and others are winter peaking, so this assessment is based on summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating ("LTR") based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per Ontario Resource and Transmission Assessment Criteria ("ORTAC").

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing transmission systems and transformer station facilities supplying the GBH region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment

- Owen Sound TS – T5 Replacement: Like-for-Like replacement of transformer T5 to maintain supply reliability to the LDCs in the area. This project is planned to be completed by 2032.

b. Station Capacity

- During the study period, no station capacity needs were identified.

c. Transmission Line Capacity

- During the study period, no transmission system capacity needs were identified.

d. System Reliability, Operation and Load restoration

- 115 kV L7S Circuit – System reliability and performance issues due to line galloping and line component failures.
- Operational issue with supply capacity at Hanover TS under outage conditions.
- Operational issue with supply capacity on D10H when load is transferred between Detweiler TS in KWCG region and Hanover TS in the GBH region.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred solutions for the GBH region. The needs include those previously identified in the NA for the GBH region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the Greater Bruce/Huron region are given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Seaforth TS	T1, T2, T5 and T6 Transformer Replacement	Hydro One Transmission	Q1 2027	$76M
Owen Sound TS	T5 Transformer Replacement	Hydro One Transmission	Q2 2032	$25M
System Reliability, Operation and Load restoration Needs				
115 kV L7S Circuit Capacity Increase	Monitoring the performance of this circuit and proceeding with corrective plan as required in the next phase of the Regional Planning cycle	Hydro One Transmission	On Going	N/A
Operational issue with supply capacity at Hanover TS, under outage conditions	Monitor and review in next regional planning cycle	Hydro One Transmission	Next Regional Planning Cycle	N/A
Operational issue with supply capacity on D10H, during load transfer between Detweiler TS and Hanover TS	Monitor and review in next regional planning cycle	Hydro One Transmission	Next Regional Planning Cycle	N/A

Notes:

a) The planned in-service dates are tentative and subject to change.
b) Costs are based on budgetary planning estimates exclude the cost for distribution infrastructure (if required)

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1. INTRODUCTION

The Regional Infrastructure Plan ("RIP") is the final step of Regional Planning Process. Hydro One as the lead transmitter undertake the development of a RIP with input from the Technical Working Group ("TWG") for the region and publishes a RIP report. The third cycle of the Regional Planning process for the Greater Bruce/Huron ("GBH") region was initiated with the publication of Needs Assessment ("NA") and the report was published in September 2024 by Hydro One.

At the end of the NA phase, the TWG decided that there is no need for Scoping Assessment ("SA") and Integrated Regional Resource Plan ("IRRP") phases to meet the identified regional needs, and all identified system operational needs in this cycle will be revisited in the next Regional Planning Cycle. The TWG decided that there is no need for integrated regional planning to meet the identified needs in this cycle and that planning can proceed directly to the RIP.

The RIP report includes a common discussion of all the options and recommended plans, and preferred wire infrastructure investments identified in NA phase to address the near- and medium-term needs.

This report was prepared by the GBH region TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDC"), the Municipalities and the IESO. Participants of the TWG are listed below in Table 1.

Table 1: **GBH** region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Hydro One Networks Inc. (Distribution)
3	Independent Electricity System Operator (IESO)
4	ERTH Power Corporation
5	Festival Hydro
6	Westario Power Inc.
7	Entegrus Powerline Inc.
8	Wellington North Power

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the GBH region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the GBH region.
- Identify new supply needs that may have emerged since the Needs Assessment ("NA") phase.
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and/or distribution facilities that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major High Voltage ("HV") transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, electricity Demand Side Management ("eDSM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration. The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs 2024-2033 identified in previous planning phase, the NA phase in this cycle.
- Identification of any new needs over the 2024-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the GBH region Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels looks at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment which is led by the transmitter to identify, assess, and document which of the needs that,

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;

b) require further regional coordination and identification of Local Distribution Companies ("LDCs") to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., electricity Demand Side Management ("eDSM"), supply resources, etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), IRRP and/or RIP.

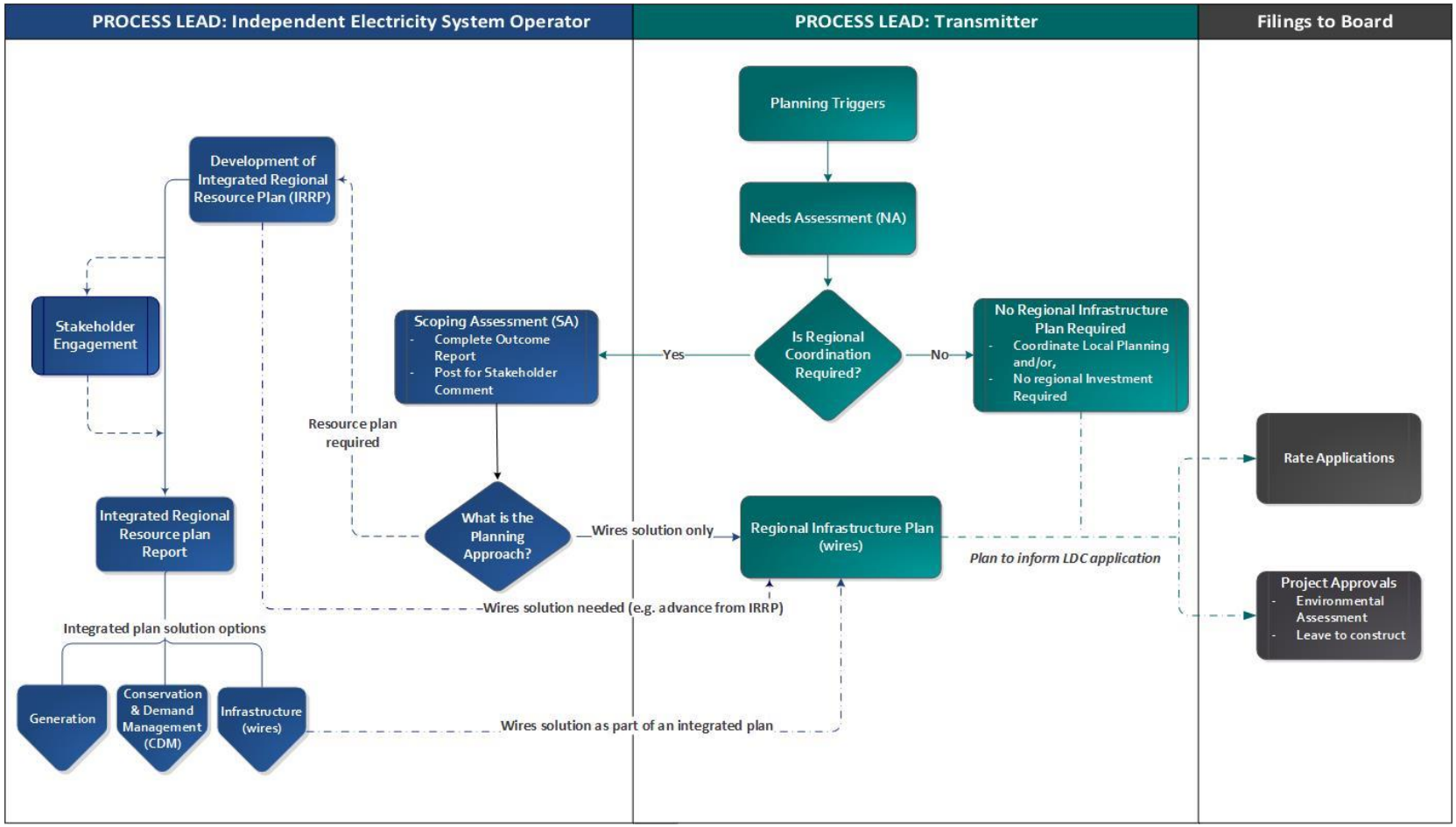
The purpose of the IRRP is to coordinate regional wires and non-wires options to create an integrated plan considering feasibility, cost, reliability, government policy directives, environmental performances, and community preferences to address the need. Worth noting, the LDCs' eDSM targets as well as contracted Supply Resource plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution (planning can be initiated in parallel to IRRP). Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led community and stakeholder engagement with municipalities in the region or sub-region.

The RIP phase is the final phase of the regional planning process and involves discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, the RIP report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure 1.

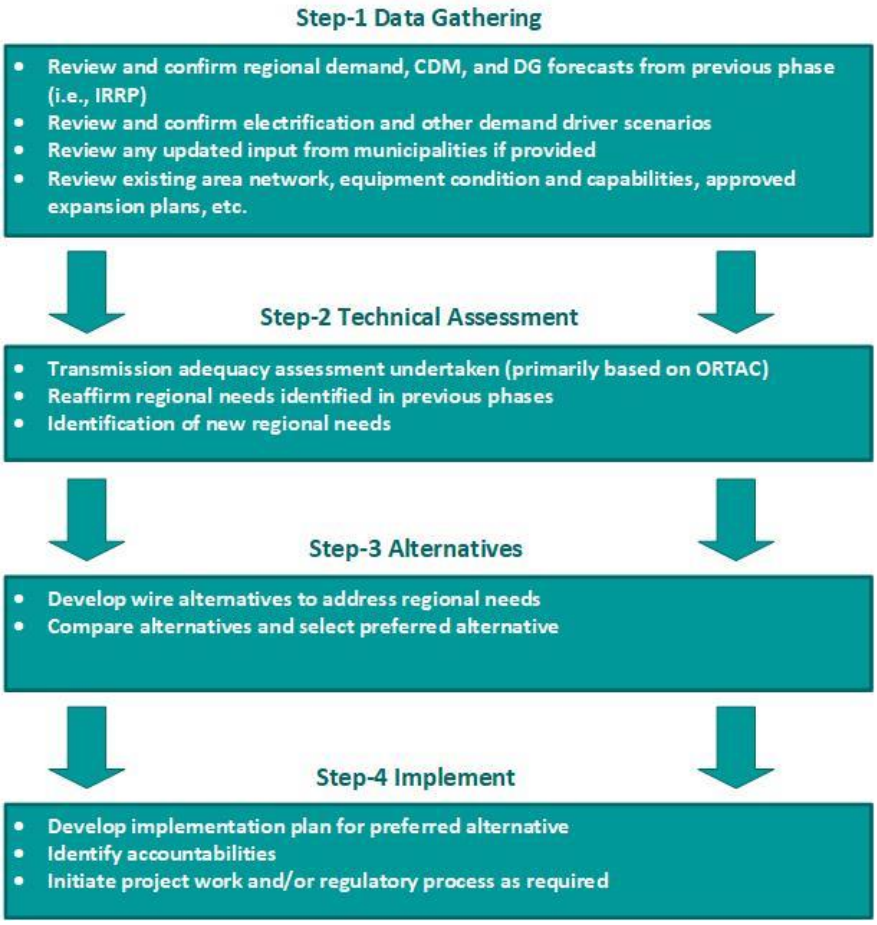
Figure 1: Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Regional Infrastructure Plan phase is a four-step process as shown in Figure 2. These phases are described in the following sub-sections:

Figure 2: Regional Infrastructure Plan Methodology



3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the TWG to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As it was confirmed by the TWG, there was no major change to the NA phase load forecast; therefore, the load forecast from the NA phase was used for this RIP.

- Review and confirm electrification and other growth scenarios which affect the projects recommended in previous stages.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtaining permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GBH region comprises of the counties of Bruce, Huron, and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, and Middlesex counties.

The geographical boundaries of the GBH region is shown in Figure 3 below.

Figure 3: Map of GBH Regional Planning Area



Electricity supply for the GBH region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station ("NGS") and local renewable generation facilities in the Region. Majority of the electrical supply in the region is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS.

These circuits connect the GBH region to the adjacent South Georgian Bay/Muskoka region and the adjacent Kitchener-Waterloo-Cambridge-Guelph ("KWCG") region. Within this region, electricity is delivered to the end users of LDCs and directly connected industrial customers by eleven (11) Hydro One step-down transformation stations, as well as seven (7) customer-owned transformer or distribution

stations supplied directly from the transmission system. Appendix B lists all step-down transformer and distribution stations in the Region. Appendix C lists all transmission circuits and Appendix D lists LDCs in the Region. The circuits and stations of the area are summarized in Table 2 below:

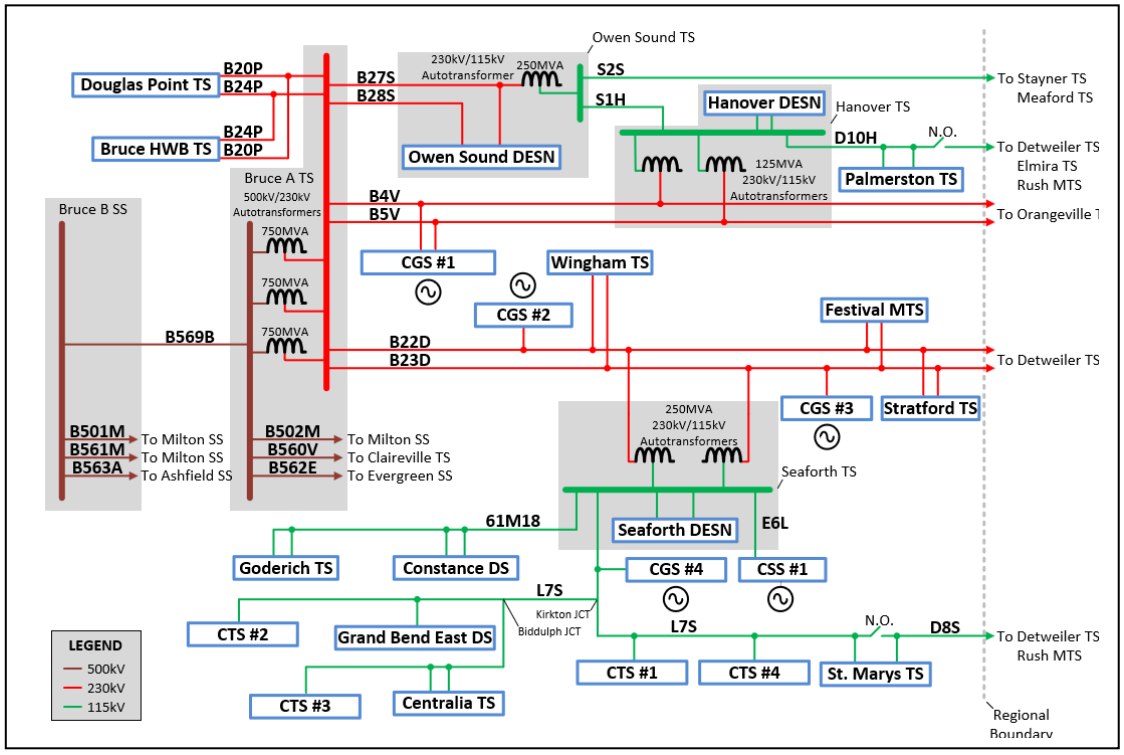
Table 2: Transmission Station and Circuits in the GBH region

115kV circuits	230kV circuits	Hydro One Transformer/Distribution Stations		Generation Stations
S2S	B4V	Bruce A TS *	Goderich TS	Bruce A NGS
S1H	B5V	Bruce B SS	Constance DS	Bruce B NGS
D10H-North	B22D	Bruce HWP B TS	St. Marys TS	CGS #1
61M18	B23D	Douglas Point TS	Centralia TS	CGS #2
L7S	B27S	Hanover TS *	Grand Bend East DS	CGS #3
E6L	B28S	Owen Sound TS *	Stratford TS	CGS #4
	B20P	Seaforth TS *	Customer CTS #1	
	B24P	Wingham TS	Customer CTS #2	
		Festival MTS #1	Customer CTS #3	
		Palmerston TS	Customer CTS #4	

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of GBH region is shown in Figure 4 below.

Figure 4: GBH region Transmission Single Line Diagram



5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that have been completed in the past ten (10) years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the GBH region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner ("TAO") in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. The following Major projects were completed during the last ten years:

1. Goderich TS – T1, T2, T3 Removal, T5 Installation and station Reconfiguration: Removal of 15/20/25MVA 115-27kV T1 transformer, removal of 11/15MVA 115-27kV T2 and T3 transformers, and installation of a new 50/67/83MVA 115-27kV T5 transformer to address thermal capacity issues at this station. Under this project, the station was reconfigured following DESN arrangement standards. This project was completed in 2017.

2. Centralia TS – T1 and T2 Replacement, T3 Removal and station Reconfiguration: Replacement of 11/15/19MVA 115-28kV T1 and T2 transformers with new 25/33.3/41.7MVA 115-28kV units, removal of 11/15/19MVA 115-28kV T3 transformer and reconfiguration of the station as per DESN arrangement standards. This project was completed in 2018.

3. Palmerston TS – T1 and T2 Replacement, T3 Removal and station Reconfiguration: Replacement of 42MVA 115-44kV T1 and T2 transformers with new 50/66.7/83.3MVA units, removal of 42MVA 115-44kV T3 transformer, and reconfiguration of the non-standard three (3) transformer arrangement station to two (2) transformer DESN station arrangement as per the standard. This project was completed in 2019.

4. Bruce A TS – 230kV ABCB Station Refurbishment: Replacement of sixteen (16) 230kV Air-Blast Circuit Breakers ("ABCB") with SF6 type to maintain station supply reliability to the customers in the area. This project was completed in 2022.

5. Stratford TS – T1 and Component Replacement: Replacement of 50/67/83MVA 230-27.6kV T1 transformer and associated equipment to maintain station supply reliability to Festival Hydro Inc., Hydro One Distribution as well as other embedded LDCs in the area. The project was completed in 2022.

6. Hanover TS – T2 and Component Replacement: Replacement of the 115-44kV transformer T2 with a new 50/66.7/83.3MVA 110-44kV unit to maintain station supply reliability to Hydro One Distribution and embedded LDCs in the area. The project was completed in 2022.

7. 115 kV L7S Circuit – Capacity increase and clearance Improvement: Between year 2022 to 2023, sub-standard clearances of the limiting section of L7S were addressed to increase their sag temperature from 83°C to 125°C and improve the capacity of this circuit. Furthermore, Hydro One undertook a complete condition assessment of L7S and identified a variety of deficiencies that have been addressed.

8. Wingham TS – T1 and T2 Replacement: Replacement of 50/83MVA 230-44kV T1 and T2 transformers with new 50/66.7/83MVA 230-44kV units to maintain station reliability to the customers in the area. This project was completed in 2024.

II. Following Major projects are underway:

1. Seaforth TS – T1, T2, T5 and T6 Replacement: Replacement of 25/33.3/41.7MVA 115-28kV T1 and T2 step-down transformers with 25/33.3/41.7MVA 110-28kV units and replacement of 150/200/250MVA 230-115kV T5 and T6 autotransformers with 150/200/250MVA 239-121-13.9kV units. This project will maintain station reliability and ensure continued supply reliability to Hydro One Distribution and embedded LDCs in the area. The project is planned to be completed by Q1 2027.

Note: The planned in-service years for the above projects are tentative and subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

After verification from the TWG participants, as no material changes were identified in the GBH region, NA Load Forecasts were used in the development of this Report. TWG participants, including representatives from LDCs, IESO and Hydro One provided information and input for the load forecast. The municipalities were contacted as part of the stakeholder engagement process to get their insight into the future load growth and was considered during the load forecast development.

As per the load forecasts for the study period from 2024 to 2033, the summer net and gross coincident load in the region is expected to grow at an average rate of approximately 1.4% annually and the winter net and gross coincident load in the region is expected to grow at an average rate of approximately 0.8% annually.

Figures 5 & 6 shows the GBH region summer and winter weather net and gross coincident load forecast from 2024 to 2033. The load forecast from the GBH region was adopted as agreed to by the TWG.

Based on historical load and the non-coincident load forecasts, the Greater Bruce/Huron region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than in winter due to ambient temperature. Based on these factors, assessment for this region was conducted for both summer and winter peak load.

Non-coincident and coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

Figure 5: GBH Region Summer Coincident Net and Gross Load Forecast

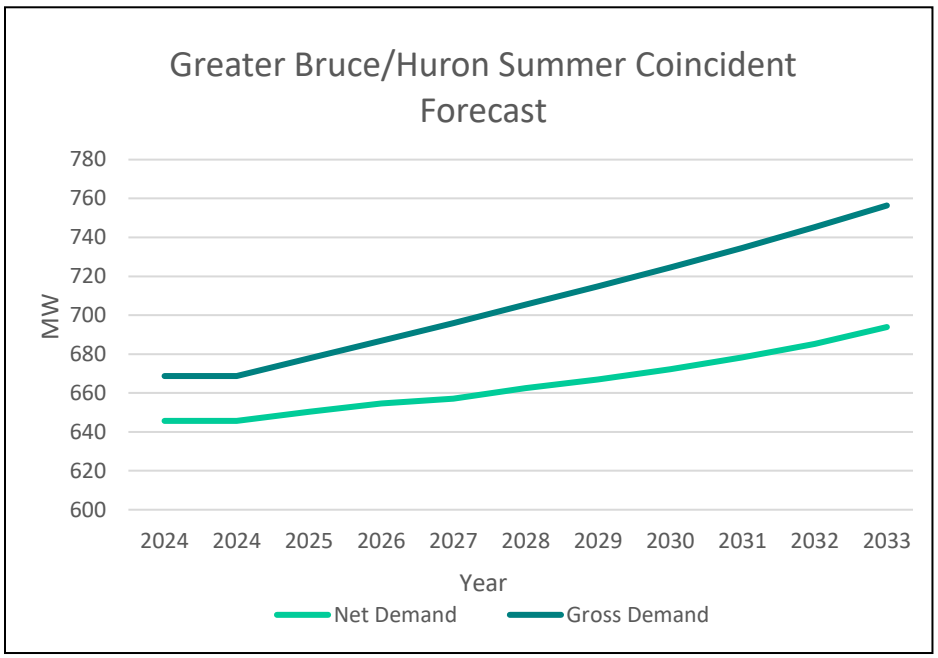
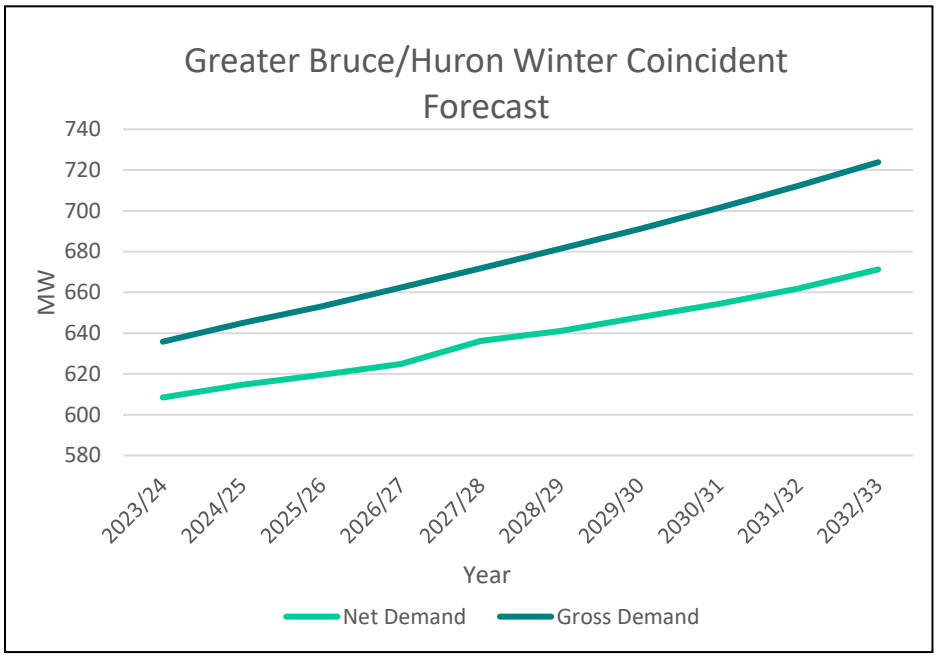


Figure 6: GBH Region Winter Coincident Net and Gross Load Forecast



6.2. Other Study Assumptions

The following other assumptions are made in this report:

- The study period for the RIP assessments is 2024-2033.
- LDCs reconfirmed load forecasts up to 2033 in the area are the same as the NA phase.
- All planned facilities for which work has been initiated and are listed in section 5 are assumed to be in-service.
- Some of the stations in this region are summer peaking and others are winter peaking, so this assessment is based on summer and winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating ("LTR") based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing transmission systems and transformer station facilities supplying the GBH region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in section 5 are completed.

In the current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- GBH region Third cycle Needs Assessment report, Completed in September 2024 by Hydro One

The TWG identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections 7.1 to 7.4 and a detailed description and status of plans to meet these needs are given in section 8 of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG have also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next ten (10) years in the GBH region.
The complete list of major HV transmission equipment requiring replacement in the GBH region is provided in table 3 in this sub-section. Hydro One is the only Transmission Asset Owner (“TAO”) in the GBH region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major HV equipment information shared and discussed as part of this process is listed below:

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

- 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 3 below contains the new asset replacement needs identified during the RIP study period:

Table 3: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Owen Sound TS	T5 Transformer Replacement	Q2 2032

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

7.2. Station Capacity Needs

Over the study period 2024-2033 RIP reviewed the capacity of all the 230kV and 115kV transforming stations within the GBH region. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer and winter) Limited Time ratings.

The NA study previously found no station capacity needs in the GBH region. This RIP, aligned with the latest load forecast, confirms that all stations remain within their LTR limits throughout the study period, with no capacity need identified at this time.

7.3. Transmission Line Capacity Needs

Over the study period 2024-2033 RIP reviewed the capacity of all the 230kV and 115kV transmission lines within the GBH region. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer and winter) Limited Time ratings.

The NA study previously found no transmission line capacity needs in the GBH region. This RIP, aligned with the latest load forecast and assessed contingencies, confirms that all Tx lines remain within their LTR limits throughout the study period, with no capacity need identified at this time.

7.4. System Reliability, Operation and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency. Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

Following the assessment done in GBH region, below system reliability need has been identified:

- 115kV L7S circuit:
  There have been some reports regarding system operation and performance of this circuit. Majority of issues reported were due to line galloping and line component failures.

  To increase the line capacity on this circuit, Hydro One addressed sub-standard clearances on sections on L7S between Seaforth TS and Kirkton JCT in 2022-2023. During the same time, Hydro One replaced deficient line components on various sections of this circuit to improve the delivery point performance. Hydro One will continue monitoring the performance of the remaining sections of this circuit and will proceed with corrective plans as required.

During both NA and RIP phases, TWG identified the following system operational issues in this region:

- Operational difficulties regarding transferring load between Detweiler TS in Kitchener-Waterloo-Cambridge-Guelph Region and Hanover TS in GBH. This is a concern in the operational timeframe when there are autotransformers out of service Detweiler TS and Hanover TS, due to increasing load on the 115kV circuit D10H.

- System operational issues during post-contingency load supply at Hanover TS. This is seen when there is one autotransformer out of service, and operators need to prepare for the loss of the remaining transformers.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the GBH region. These needs include those previously identified in the NA for the GBH region as well as any new needs identified during

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary.

The needs in the region are summarized below in Table 4 below:

Table 4: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Planned ISD	COST ($M)
Asset Renewal Needs			
Seaforth TS	T1, T2, T5, T6 Transformer Replacement	Q1 2027	$76M
Owen Sound TS	T5 Transformer Replacement	Q2 2032	$25M
System Reliability, Operation and Load restoration Needs			
115 kV L7S Circuit Capacity Increase	Monitoring the performance of this circuit and proceeding with corrective plan as required in the next phase of the Regional Planning cycle	On Going	N/A
Operational issue with supply capacity at Hanover TS, under outage conditions	Monitor and review in next regional planning cycle	Next Regional Planning Cycle	N/A
Operational issue with supply capacity on D10H, during load transfer between Detweiler TS and Hanover TS	Monitor and review in next regional planning cycle	Next Regional Planning Cycle	N/A

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

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all the load to other existing facilities;
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
- Replacing equipment with higher ratings and built to current standards.

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

8.1.1. Seaforth TS – T1, T2, T5 and T6 Transformers Replacement

Seaforth TS is a major station and consists of two (2) 150/200/250MVA 115-27.6kV autotransformers supplied by 230kV circuits B22D and B23D (Bruce x Detweiler). The 115kV yard from Seaforth TS supplies nearly 200km of single circuit supply along the circuits L7S,61M18 and E6L. Seaforth TS also consists of two (2) 25/33/42MVA 115-27.6kV step-down transformers and supplies Hydro One Distribution and embedded LDCs via four 27.6kV feeders.

Following the asset condition assessment, the current scope of this project is to replace 230-115kV autotransformers T5 and T6, and step-down transformers T1 and T2 with like-for-like units which will be sufficient units based on the current load forecast.

Operations has identified the need for refined voltage control on the 115kV system. Therefore, the new autotransformers T5 and T6 at Seaforth TS will be equipped with Under Load Tap Changers ("ULTC") to meet this need. The planned in-service date for the project is Q1 2027.

8.1.2. Owen Sound TS – T5 Transformer Replacement

Owen Sound TS is supplied by two (2) 230kV circuits B27S and B28S and consists of two (2) 75/100/125MVA 230-44kV transformers T3 and T4 feeding its 44kV Dual Element Spot Network ("DESN"). This station also consists of a 150/200/250MVA 230-115kV autotransformer T5 which feeds 115kV circuits S2S and S1H.

Based on asset condition assessment, autotransformer T5 is expected to reach its end of life during the study period. It is planned to replace T5 with a like-for-like unit. The planned in-service date for the project is Q2 2032.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV and 115kV transforming stations in the GBH region using the summer and winter peak load forecasts that were provided by the study team. Based on the results, all stations are within their LTR limits and there is no need for station capacity upgrades at this time.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transmission line circuits in the GBH region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater for this need. Based on the results, no new transmission system capacity needs were identified.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2024-2033 to cater to this need**.**

Following the assessment done, below need have been identified for this Region:

- 115kV L7S circuit:
  There have been some reports regarding system reliability and the performance of this circuit. Majority of issues reported were due to line galloping and line component failures.

  To address the line capacity on this circuit, Hydro One increased sub-standard clearances on sections on L7S between Seaforth TS and Kirkton JCT in 2022-2023. During the same time, Hydro One replaced deficient line components on various sections of this circuit to improve the delivery point performance. Hydro One will continue monitoring the performance of the remaining sections of this circuit and will proceed with corrective plans as required.

The TWG has identified below system operational issues related to current load supply concerns under certain operational conditions:

- Operational issue with supply capacity at Hanover TS under outage conditions:
  There have been reports of operational difficulties transferring load between Detweiler TS in KWCG region and Hanover TS in GBH region. This is a concern in the operational timeframe when there are autotransformers out of service at Detweiler TS and Hanover TS, due to increasing load on the 115kV circuit D10H.
- Operational issue with supply capacity on D10H when load is transferred between Detweiler TS in KWCG region and Hanover TS in the GBH region:
  Thia issue is regarding post-contingency load supply concerns at Hanover TS when there is one autotransformer out of service, and operators need to prepare for the loss of the remaining transformer.

The TWG recognizes that the operational conditions experienced in real-time may not always align with the planning timeframe considerations applied in this RIP but are indicative of potential concerns as load continues to grow. Thus, TWG agrees that no further action is required at this time. However, the TWG will monitor these concerns and investigate this need further in the next cycle of regional planning.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan ("RIP") report for GBH region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2024-2033 are provided in Table 5 below, along with their planned in-service dates ("ISD") and budgetary estimates for planning purposes.

Table 5: Recommended Plans over the next 10 Years/Long Term

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Seaforth TS	T1, T2, T5 and T6 Transformer Replacement	Hydro One Transmission	Q1 2027	$76M
Owen Sound TS	T5 Transformer Replacement	Hydro One Transmission	Q2 2032	$27M
System Reliability, Operation and Load restoration Needs				
115 kV L7S Circuit Capacity Increase	Monitoring the performance of this circuit and proceeding with corrective plan as required in the next phase of the Regional Planning cycle	Hydro One Transmission	On Going	N/A
Operational issue with supply capacity at Hanover TS, under outage conditions	Monitor and review in next regional planning cycle	Hydro One Transmission	Next Regional Planning Cycle	N/A
Operational issue with supply capacity on D10H, during load transfer between Detweiler TS and Hanover TS	Monitor and review in next regional planning cycle	Hydro One Transmission	Next Regional Planning Cycle	N/A

Note:

a) The planned in-service dates are tentative and subject to change.
b) Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Greater Bruce/Huron Second Cycle Regional Infrastructure Planning, (issue April 2022)

[6] Greater Bruce/Huron Third Cycle Needs Assessment, (issue September 2024)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: GBH region – Summer Non-Coincident - Net Load Forecast

Station/DESN	Summer LTR (MVA)	Summer LTR (MW)	2023 (Historical) (MW)	Summer Non-Coincident NET Forecast (MW)									
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Douglas Point TS	97.20	87.48	56.18	57.69	58.11	58.51	58.61	61.09	61.47	61.89	62.28	62.72	63.26
Hanover TS	125.90	119.61	84.99	84.88	85.66	86.40	86.42	86.65	87.09	87.63	88.54	89.35	90.70
Owen Sound TS	208.50	198.08	98.17	104.09	105.10	106.08	107.50	108.29	109.33	110.46	111.68	112.88	114.18
Seaforth TS	45.10	42.85	29.87	29.08	29.26	29.43	29.46	29.57	29.75	29.98	30.16	30.44	30.68
Stratford TS	125.10	118.85	80.23	85.22	85.58	85.91	86.12	86.54	87.16	87.88	88.60	89.56	91.45
Wingham TS	97.00	87.30	50.76	51.50	51.88	52.25	52.37	52.63	53.02	53.44	53.85	54.32	54.83
Palmerston TS	132.20	125.59	66.09	70.42	70.85	71.24	71.27	71.68	71.99	72.35	72.78	73.17	73.62
Goderich TS	126.50	120.18	40.68	43.55	43.73	43.89	43.95	44.00	44.14	44.33	44.53	44.84	45.18
Constance DS	28.80	25.92	18.91	20.26	20.45	20.63	20.71	20.84	21.01	21.22	21.45	21.73	22.07
St. Marys TS	52.80	47.52	23.64	25.31	25.41	25.50	25.57	25.70	25.88	26.10	26.37	26.64	26.95
Centralia TS	61.10	58.05	38.10	40.14	40.62	41.09	41.37	41.77	42.28	42.88	43.71	44.86	45.86
Grand Bend East DS	31.25	28.13	19.58	20.39	20.50	20.60	20.60	20.65	20.75	21.02	21.18	21.39	21.71
Bruce HWP B TS	113.20	101.88	8.83	8.83	8.77	8.70	8.59	8.50	8.43	8.37	8.29	8.22	8.16
Festival MTS #1	N/A	N/A	34.47	37.21	37.44	37.61	37.63	37.73	37.91	38.15	38.44	38.83	39.34
Customer CTS #1	N/A	N/A	3.63	3.44	3.46	3.47	3.48	3.49	3.51	3.52	3.53	3.55	3.56
Customer CTS #2	N/A	N/A	5.92	5.96	6.02	6.07	6.12	6.17	6.23	6.28	6.34	6.39	6.45
Customer CTS #3	N/A	N/A	4.54	4.63	4.67	4.72	4.76	4.81	4.85	4.90	4.94	4.99	5.04
Customer CTS #4	N/A	N/A	15.57	15.75	15.94	16.13	16.33	16.52	16.72	16.92	17.13	17.33	17.54

Table A.2: GBH region – Summer Coincident - Net Load Forecast

Station/DESN	Summer LTR (MVA)	Summer LTR (MW)	2023 (Historical) (MW)	Summer Coincident NET Forecast (MW)									
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Douglas Point TS	97.20	87.48	52.73	53.96	54.36	54.72	54.82	57.28	57.64	58.04	58.40	58.82	59.33
Hanover TS	125.90	119.61	84.99	84.88	85.66	86.40	86.42	86.65	87.09	87.63	88.54	89.35	90.70
Owen Sound TS	208.50	198.08	91.35	96.72	97.65	98.56	99.94	100.68	101.65	102.70	103.84	104.97	106.18
Seaforth TS	45.10	42.85	28.55	27.65	27.83	27.99	28.02	28.12	28.29	28.51	28.68	28.96	29.19
Stratford TS	125.10	118.85	78.90	83.79	84.15	84.47	84.67	85.09	85.70	86.40	87.12	88.06	89.94
Wingham TS	97.00	87.30	50.76	45.17	45.51	45.84	45.95	46.18	46.52	46.89	47.26	47.68	48.13
Palmerston TS	132.20	125.59	64.08	68.26	68.68	69.06	69.08	69.48	69.78	70.13	70.55	70.94	71.37
Goderich TS	126.50	120.18	40.68	37.34	37.50	37.63	37.70	37.75	37.87	38.03	38.20	38.48	38.77
Constance DS	28.80	25.92	18.67	19.99	20.18	20.36	20.44	20.57	20.74	20.95	21.18	21.46	21.79
St. Marys TS	52.80	47.52	23.64	25.14	25.24	25.33	25.39	25.52	25.71	25.92	26.19	26.46	26.76
Centralia TS	61.10	58.05	37.53	39.52	39.99	40.46	40.73	41.12	41.62	42.22	43.04	44.18	45.16
Grand Bend East DS	31.25	28.13	17.09	17.69	17.79	17.88	17.88	17.92	18.01	18.26	18.40	18.59	18.88
Bruce HWP B TS	113.20	101.88	5.66	6.03	5.99	5.94	5.87	5.81	5.76	5.71	5.66	5.62	5.57
Festival MTS #1	N/A	N/A	27.53	29.72	29.90	30.04	30.05	30.13	30.27	30.47	30.70	31.01	31.42
Customer CTS #1	N/A	N/A	1.38	1.39	1.39	1.40	1.40	1.41	1.41	1.42	1.42	1.43	1.44
Customer CTS #2	N/A	N/A	3.21	3.24	3.26	3.29	3.32	3.35	3.38	3.41	3.44	3.47	3.50
Customer CTS #3	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Customer CTS #4	N/A	N/A	5.07	5.13	5.19	5.26	5.32	5.38	5.45	5.51	5.58	5.65	5.72

Table A.3: GBH region – Winter Non-Coincident - Net Load Forecast

Station/DESN	Winter LTR (MVA)	Winter LTR (MW)	2022/23 (Historical) (MW)	Winter Non-Coincident Net Forecast (MW)									
				2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Douglas Point TS	109.80	98.82	58.70	55.11	55.71	56.26	56.61	62.80	63.25	63.80	64.33	64.88	65.66
Hanover TS	138.80	131.86	83.83	80.13	81.12	82.04	82.42	82.99	83.55	84.67	85.27	86.57	87.52
Owen Sound TS	232.50	220.88	108.11	112.61	114.06	115.50	117.94	119.29	120.57	122.07	123.62	125.14	126.79
Seaforth TS	55.40	52.63	28.44	25.86	26.07	26.25	26.37	26.57	26.73	26.97	27.22	27.52	27.87
Stratford TS	137.50	130.63	67.97	70.44	70.88	71.30	71.69	72.26	72.77	73.45	74.14	74.90	76.73
Wingham TS	107.90	97.11	55.48	53.56	54.10	54.59	54.89	55.32	55.70	56.23	56.82	57.54	58.42
Palmerston TS	147.20	139.84	67.75	71.04	71.67	72.24	72.58	73.28	73.67	74.20	74.68	75.18	75.75
Goderich TS	132.00	125.40	38.86	40.59	40.85	41.09	41.37	41.57	41.73	41.97	42.22	42.52	42.88
Constance DS	35.00	31.50	17.20	18.15	18.39	18.62	18.79	19.01	19.22	19.46	19.69	19.94	20.20
St. Marys TS	59.00	53.10	21.79	22.92	23.07	23.21	23.35	23.54	23.72	23.96	24.19	24.46	24.76
Centralia TS	65.40	62.13	32.57	34.18	34.80	35.42	35.97	36.63	37.31	38.12	39.24	40.25	41.40
Grand Bend East DS	40.00	36.00	16.92	17.11	17.26	17.39	17.47	17.59	17.70	18.06	18.24	18.46	18.74
Bruce HWP B TS	114.80	103.32	11.37	11.79	11.73	11.67	11.57	11.49	11.40	11.32	11.24	11.17	11.10
Festival MTS #1	N/A	N/A	27.50	28.91	29.15	29.35	29.46	29.63	29.77	29.99	30.26	30.61	31.05
Customer CTS #1	N/A	N/A	3.57	3.46	3.43	3.40	3.37	3.34	3.31	3.28	3.25	3.22	3.19
Customer CTS #2	N/A	N/A	5.54	5.71	5.75	5.80	5.84	5.89	5.93	5.98	6.03	6.07	6.12
Customer CTS #3	N/A	N/A	4.51	4.62	4.66	4.70	4.75	4.79	4.84	4.89	4.93	4.98	5.03
Customer CTS #4	N/A	N/A	15.81	16.00	16.19	16.39	16.59	16.79	16.99	17.19	17.40	17.61	17.82

Table A.4: GBH region – Winter Coincident - Net Load Forecast

Station/DESN	Winter LTR (MVA)	Winter LTR (MW)	2022/23 (Historical) (MW)	Winter Coincident Net Forecast (MW)									
				2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Douglas Point TS	109.80	98.82	56.27	52.55	53.13	53.65	53.99	60.16	60.59	61.12	61.63	62.16	62.91
Hanover TS	138.80	131.86	75.33	71.20	72.09	72.92	73.25	73.77	74.27	75.33	75.87	77.11	77.98
Owen Sound TS	232.50	220.88	93.56	97.26	98.61	99.86	102.16	103.34	104.43	105.72	107.05	108.34	109.73
Seaforth TS	55.40	52.63	26.81	24.15	24.35	24.52	24.64	24.82	24.97	25.20	25.44	25.71	26.05
Stratford TS	137.50	130.63	66.42	68.81	69.25	69.65	70.04	70.59	71.09	71.75	72.42	73.17	74.98
Wingham TS	107.90	97.11	52.88	50.83	51.35	51.05	51.33	51.72	52.08	52.57	53.13	53.80	54.62
Palmerston TS	147.20	139.84	63.28	66.34	66.93	67.47	67.78	68.44	68.81	69.29	69.74	70.22	70.75
Goderich TS	132.00	125.40	36.06	37.65	37.90	38.12	38.39	38.57	38.72	38.95	39.18	39.46	39.79
Constance DS	35.00	31.50	16.72	17.64	17.86	18.05	18.20	18.38	18.56	18.78	19.02	19.30	19.63
St. Marys TS	59.00	53.10	19.79	20.82	20.95	21.08	21.21	21.39	21.55	21.76	21.97	22.21	22.49
Centralia TS	65.40	62.13	31.57	33.11	33.71	34.31	34.85	35.49	36.15	36.93	38.03	39.01	40.12
Grand Bend East DS	40.00	36.00	12.58	12.55	12.66	12.76	12.82	12.91	12.99	13.32	13.45	13.61	13.82
Bruce HWP B TS	114.80	103.32	9.65	10.01	9.96	9.91	9.82	9.75	9.68	9.62	9.55	9.48	9.42
Festival MTS #1	N/A	N/A	24.07	25.31	25.52	25.70	25.79	25.94	26.07	26.26	26.50	26.80	27.18
Customer CTS #1	N/A	N/A	3.32	3.29	3.26	3.23	3.21	3.18	3.15	3.12	3.09	3.06	3.04
Customer CTS #2	N/A	N/A	2.17	2.19	2.20	2.22	2.24	2.26	2.27	2.29	2.31	2.33	2.35
Customer CTS #3	N/A	N/A	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16
Customer CTS #4	N/A	N/A	14.42	14.59	14.77	14.94	15.12	15.31	15.49	15.68	15.86	16.06	16.25

Appendix B: Lists of Step-Down Transformer/Distribution Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Bruce HWP B TS	230 kV	B20P/B24P
2	Douglas Point TS	230 kV	B20P/B24P
3	Hanover TS	115 kV	B4V/B5V
4	Owen Sound TS	230 kV	B27S/B28S
5	Seaforth TS	115 kV	B22D/B23D
6	Stratford TS	230 kV	B22D/B23D
7	Wingham TS	230 kV	B22D/B23D
8	Festival MTS #1	230 kV	B22D/B23D
9	Palmerston TS	115 kV	D10H
10	Goderich TS	115 kV	61M18
11	Constance DS	115 kV	61M18
12	St. Marys TS	115 kV	L7S
13	Customer CTS #1	115 kV	L7S
14	Centralia TS	115 kV	L7S
15	Grand Bend East DS	115 kV	L7S
16	Customer CTS #2	115 kV	L7S
17	Customer CTS #3	115 kV	L7S
18	Customer CTS #4	115 kV	L7S

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Bruce A TS – Orangeville TS	B4V/B5V	230 kV
2	Bruce A TS – Detweiler TS	B22D/ B23D	230 kV
3	Bruce A TS – Owen Sound TS	B27S/B28S	230 kV
4	Bruce A TS – Douglas Point TS	B20P/B24P	230 kV
5	Hanover TS – Palmerston TS	D10H-North	115 kV
6	Seaforth TS – Goderich TS	61M18	115 kV
7	Seaforth TS – St. Marys TS	L7S	115 kV
8	Owen Sound TS – Hanover TS	S1H	115 kV
9	Seaforth TS – Edmondville CSS	E6L	115 kV

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Hydro One Networks Inc. (Distribution)
2	ERTH Power Corporation
3	Festival Hydro
4	Westario Power Inc.
5	Entegrus Powerline Inc.
6	Wellington North Power

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Bruce county
2	Huron county
3	Perth county
4	Portion of Grey county
5	Portion of Wellington county
6	Portion of Waterloo county
7	Portion of Oxford county
8	Portion of Middlesex county

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DS	Distribution Station
eDSM	electricity Demand Side Management
GBH	Greater Bruce/Huron
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
KWCG	Kitchener-Waterloo-Cambridge-Guelph
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station
TWG	Technical Working Group
ULTC	Under Load Tap Changers

Niagara Integrated Regional Resource Plan

December 22, 2022

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List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CNPI	Canadian Niagara Power Inc.
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOTL	Niagara-on-the-Lake
NPCC	Northeast Power Coordinating Council

Acronym	Definition
NPEI	Niagara Peninsula Energy Inc.
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

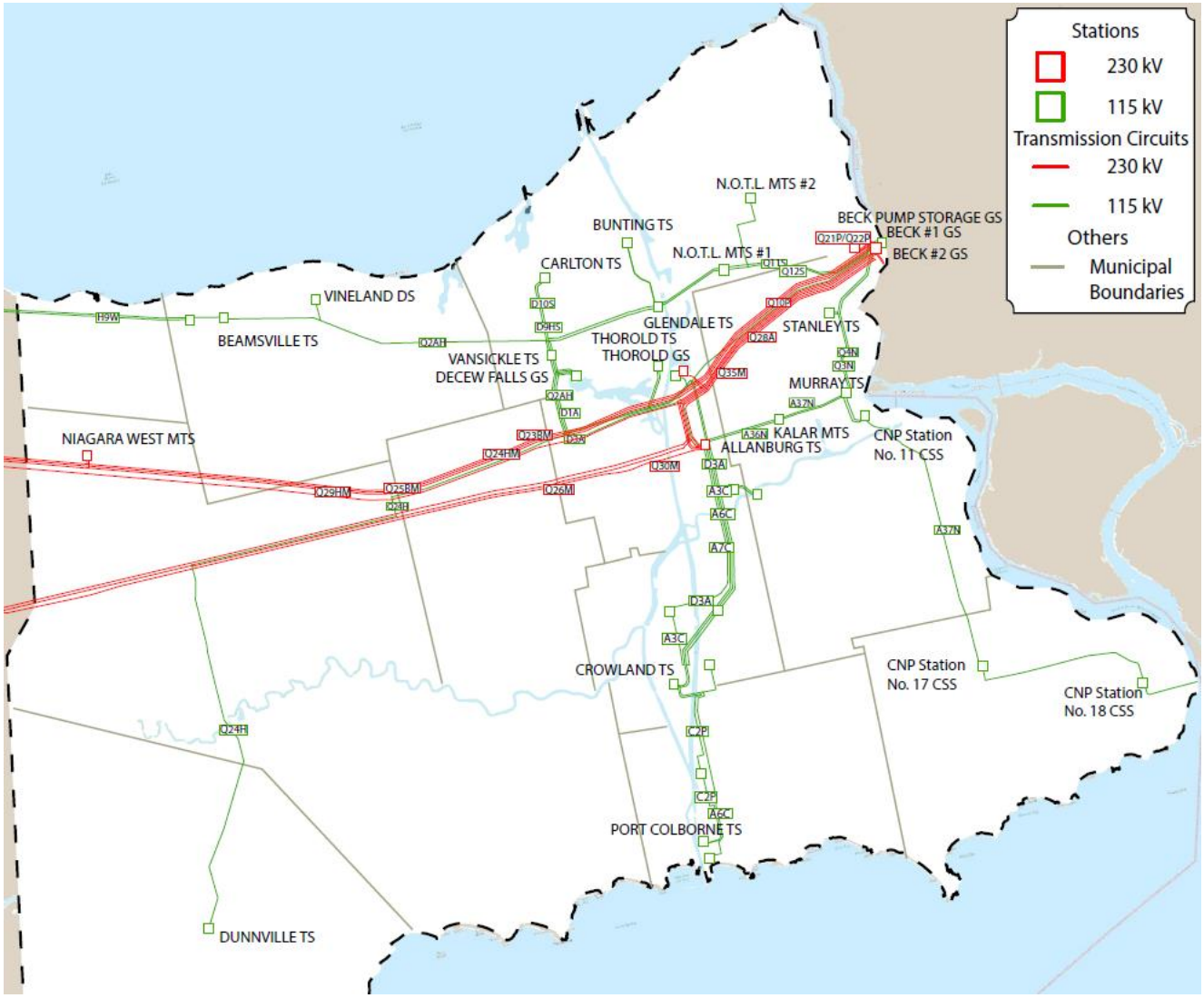
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Niagara Region over the next 20 years, from 2022 to 2041. The Niagara Region is located between Lake Ontario and Lake Erie, and includes one upper-tier municipality (Regional Municipality of Niagara) and 12 lower-tier municipalities: Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln.

This region also includes the following First Nations and Métis Nation of Ontario councils:

- Mississaugas of the New Credit
- Oneida Nation of the Thames
- Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council)
- Métis Nation of Ontario Niagara Region Métis Council

The Niagara Region is summer-peaking and, over the last five years, peak electrical demand has remained steady at an average of 810 MW. Electrical supply is provided primarily through 230/115 kilovolt ("kV") autotransformers at Allanburg Transformer Station ("TS"), and is generally served by 230 kV and 115 kV transmission lines and step-down transformation facilities as shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits that connect Sir Adam Beck Generating Station ("GS") #2 in the east to Burlington TS and Middleport in the west. Other large transmission-connected generating facilities include Sir Adam Beck GS #1 and Decew Falls GS connecting to the 115 kV system, and Thorold GS connecting to the 230 kV system.

Figure 1 | Overview of the Niagara Region



The region's electricity is delivered by six local distribution companies ("LDCs"): Alectra Utilities, Canadian Niagara Power Inc. ("CNPI"), Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara on the Lake Hydro Inc., Niagara Peninsula Energy Inc. ("NPEI"), and Welland Hydro Electric System Corp. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Niagara IRRP was initiated in August 2021, following the publications of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment identified needs for further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;

- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Niagara Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") and reliability standards governed by the North American Electric Reliability Corporation ("NERC"). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Niagara electricity demand forecast, provided by the LDCs, projects sustained growth driven by community area, employment area, and rural settlement expansions. This growth spans multiple municipalities, including (but is not limited to): Lincoln, West Lincoln, Welland, Thorold, and Niagara Falls.

The IRRP recommendations below are organized under a near-/medium-term plan and other ongoing or long-term initiatives. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term, as electrification, energy efficiency, and development plans evolve.

2.1 Near-/Mid-Term Plan

The near- and mid-term plan comprises several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. These recommendations are summarized in Table 1 and further discussed below.

Table 1 | Summary of the Near/Mid-Term Plan for the Niagara IRRP

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West Municipal Transformer Station ("MTS"), and Vineland Distribution System ("DS") station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development of a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental conservation and demand management ("CDM") to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Monitor load growth and transfer load in excess of the station limit to Murray TS transformer 13 and 14 (T13/T14)	• 2023

2.1.1 Load Transfers from Beamsville TS and a New or Expanded 230 kV Station

Stations limits are typically dictated by the lowest rated transformer. Beamsville TS is fully utilized today and there is no remaining capacity for growth. Nearby stations Niagara West MTS and Vineland DS are also forecast to reach their capacity limits by 2026 and 2030, respectively.

The IRRP considered the merits of a portfolio of "non-wires" (non-transmission) options as well as integrated "wires" (transmission) options. Based on planning-level cost estimates and its ability to address capacity shortfalls at the three stations, the Technical Working Group recommends that a new 230 kV station supplied by Q23BM and Q25BM is built. This could be accomplished by expanding the existing Niagara West MTS. Development and implementation for additional capacity should begin as soon as possible for a targeted in-service date of 2026-2027. The next stage of regional planning, the Regional Infrastructure Plan ("RIP") led by Hydro One, should confirm the party who will lead development work (i.e., Grimsby Power, NPEI, or Hydro One).

In the meantime, the IRRP recommends that the local distributors (Grimsby Power, NPEI, Hydro One Distribution), in conjunction with Hydro One Transmission where appropriate, develop a plan to transfer load from Beamsville TS to the other nearby stations (Niagara West MTS, Vineland DS) to manage the urgent Beamsville TS need until the new station is in-service.

2.1.2 Major High Voltage Equipment Replacement of Crowland TS, New 230 kV Transmission Lines, Q28A Upgrade, and Control Actions

The existing T5 and T6 transformers at Crowland TS will require major high voltage ("HV") equipment replacement in 2026, and are forecast to be fully utilized in 2022. Crowland TS, as well as other stations supplied by the A6C/A7C circuits, are also impacted by a load security need that exists today. Moreover, Crowland TS is included in the broader Niagara 115 kV sub-system whose supply capacity need exists today and continues to grow by the end of the planning horizon.

The IRRP developed and evaluated portfolios of non-wires options, standalone generation, and wires alternatives for the multiple needs in this area. Ultimately, the most feasible and cost-effective solution at this time requires wires reinforcements: the upgrade of Q28A, the replacement of 115 kV Crowland TS with a larger 230 kV station supplied by new 230 kV transmission lines from Q24HM and Q29HM, and a new load rejection scheme developed to manage the Niagara 115 kV sub-system load. The IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service dates of 2024, 2024, and 2028 for the load rejection scheme, Q28A upgrade, and new 230 kV station and lines, respectively. Measures to manage the HV equipment replacement infrastructure at Crowland TS should be implemented by Hydro One until the station replacement is in-service.

2.1.3 Load Transfers from Murray TS (T11/T12)

Murray TS (T11/T12) is forecast to be beyond capacity in 2022 during its station peak. Given the small magnitude of this need and the available capacity on the other set of transformers at Murray TS (T13/T14), the IRRP recommends that some load is re-allocated to T13/T14 and growth continues to be monitored.

2.2 Ongoing Initiatives

In addition to the near- and mid-term plan above, two ongoing actions were identified to manage needs expected in the long-term.

2.2.1 Monitor Load Growth

Carlton TS and Kalar MTS are expected to reach capacity in 2028 and 2030, respectively. In the case of Carlton TS, distribution-level load transfers to Bunting TS have been indicated as an option. Given the timing, no firm recommendation is required at this time for either need; the Technical Working Group will continue to monitor load growth and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also keep apprised of and participate in any future Community Energy Plans developed by municipalities of the Niagara Region.

2.2.2 Explore Opportunities for Targeted CDM

In addition to monitoring how the forecast demand materializes, the IRRP recommends continuing to consider opportunities for targeted CDM. During the options analyses, the benefits and potential of incremental, cost-effective CDM were identified – particularly if targeted to manage near-term needs until transmission reinforcements are in-service (as is the case for the Beamsville TS/Vineland DS/Niagara West MTS area, as well as the 115 kV sub-system), or to defer long-term needs (such as at Kalar MTS). The Technical Working Group should continue to support and monitor CDM uptake, and bring these insights into the next cycle of regional planning for the Niagara Region.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report is posted on the IESO's website.

3.2 Niagara and IRRP Development

The process to develop the Niagara IRRP initiated in August 2021, following the publication of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment recommended that the needs identified for the Niagara Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

This is the second cycle of regional planning for the Niagara Region. This region roughly encompasses the municipalities Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln. This region also includes the following First Nations and Métis Nation of Ontario Councils: Mississaugas of the New Credit, Oneida Nation of the Thames, Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council), and the Métis Nation of Ontario Niagara Region Métis Council. Following a Needs Assessment and Scoping Assessment in 2016, a RIP was initiated by Hydro One and subsequently published in 2017, concluding the first planning cycle for the Niagara Region. An IRRP was not developed, as two electricity needs were identified in 2016, but no further regional coordination was required.

The current cycle of regional planning began in 2021 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2021 Niagara Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2022.

This IRRP develops and recommends options to meet the electricity needs of the Niagara Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation ("DG"), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

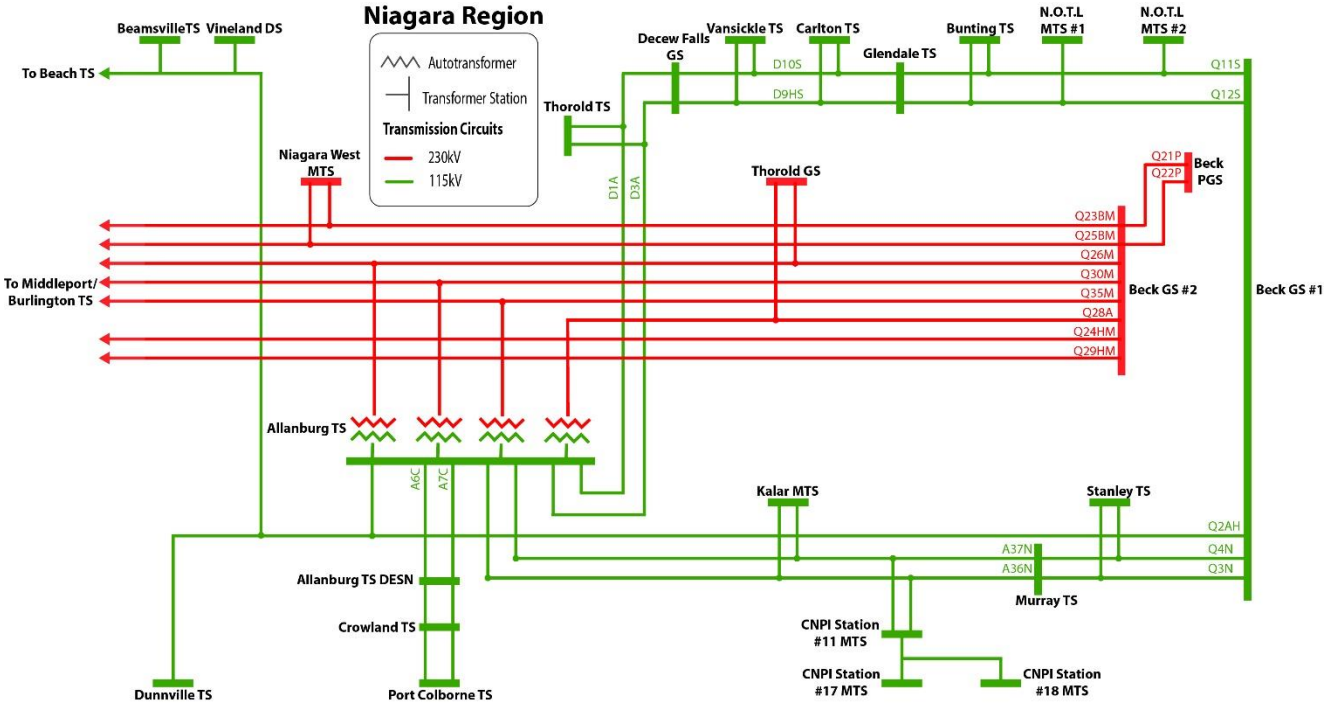
The following transmission facilities were included in the scope of this study:

- Transformer stations: Allanburg TS, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Murray TS, Niagara West MTS, Niagara-on-the-Lake ("NOTL") York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI #11 MTS, CNPI #17 MTS, CNPI #18 MTS. Except for Niagara West MTS, all stations are supplied from 115 kV transmission circuits.
- 115 kV transmission circuits: Q3N/Q4N, Q11S/Q12S, Q2AH, A36N/A37N, A6C/A7C, D1A/D3A, D9HS/D10S.
- 230 kV transmission circuits: Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M.

The single line diagram of the Niagara Region is shown in Figure 2 below. Note that the bulk system transfer capabilities on the Queenston Flow West interface[1] through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[1] Includes flow out at Beck (Q25BM + Q23BM + Q24HM + Q29HM) and flow in at Middleport (Q30M + Q26M + Q35M).

Figure 2 | Single Line Diagram of the Niagara Region



The Niagara IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
  - Examining the load meeting capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
  - Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
  - Confirming identified asset replacement needs and timing with the transmitter and LDCs;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including CDM;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

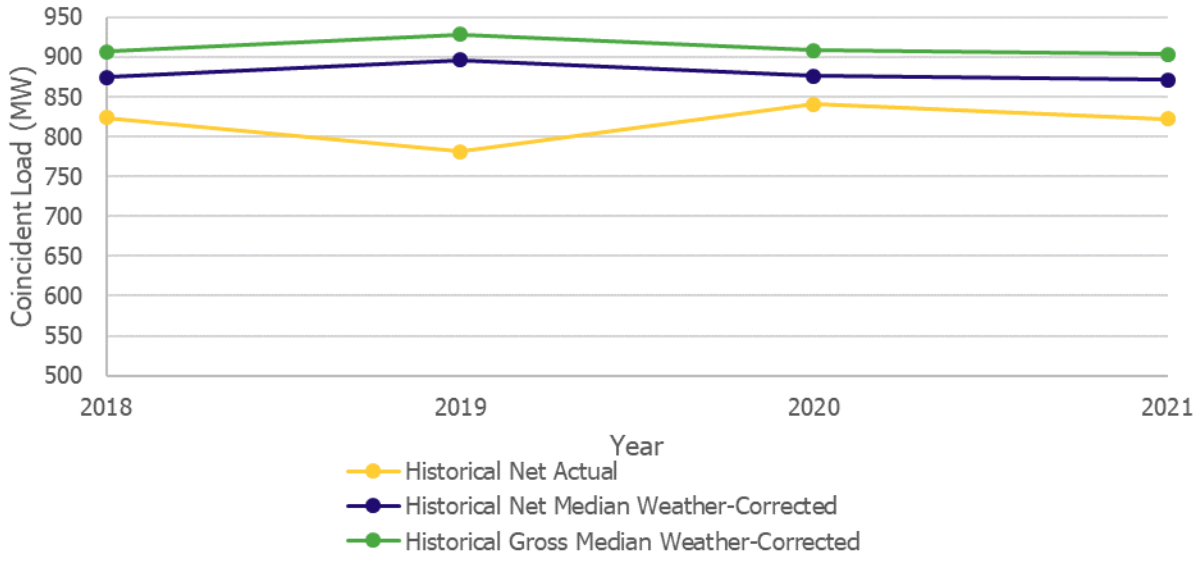
Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Niagara Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of CDM and DG, and the development of a high growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.7.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Niagara Region, the peak loading hour for each year has historically occurred in the summer.

5.1 Historical Demand

Peak electricity demand within the Niagara Region has been steady over the last four years. Figure 3 below shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and gross median weather-corrected (contribution of DG removed) historical demand. The gross median weather-corrected demand has averaged 910 megawatts ("MW") over the past four years, with the peak demand hour for each year occurring consistently in the summer between approximately 4 PM to 7 PM. The 2021 gross median weather-corrected peak at each station in the Niagara Region was used as the starting point for the forecast.

Figure 3 | Historical Demand in the Niagara Region

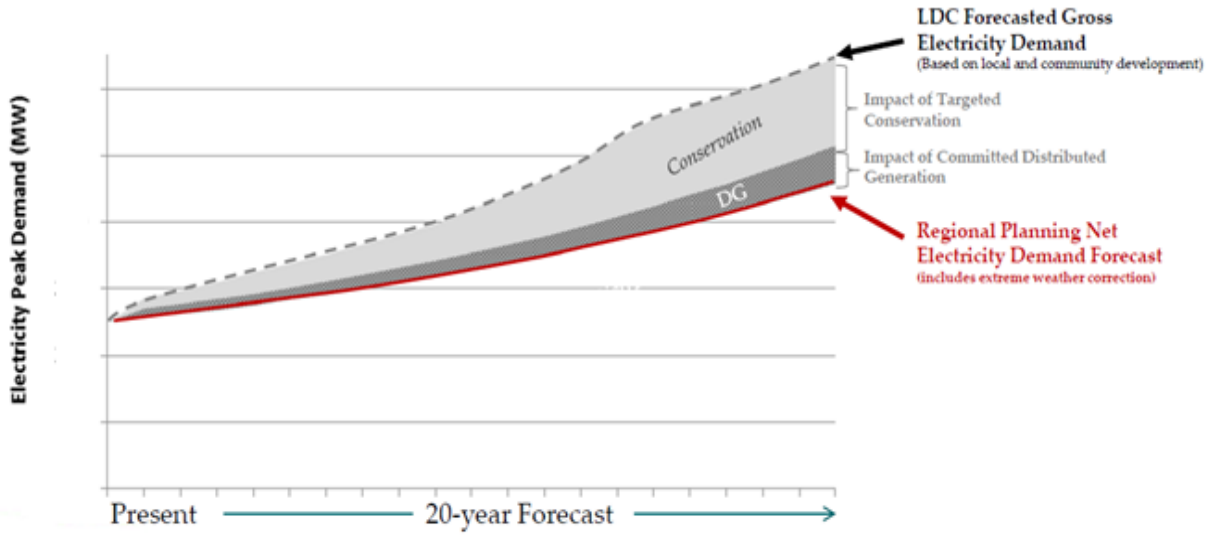


5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 4. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs such as Feed-In Tariff ("FIT") and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Niagara IRRP forecast was created prior to October 2022, the Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 4 | Illustrative Development of Demand Forecast



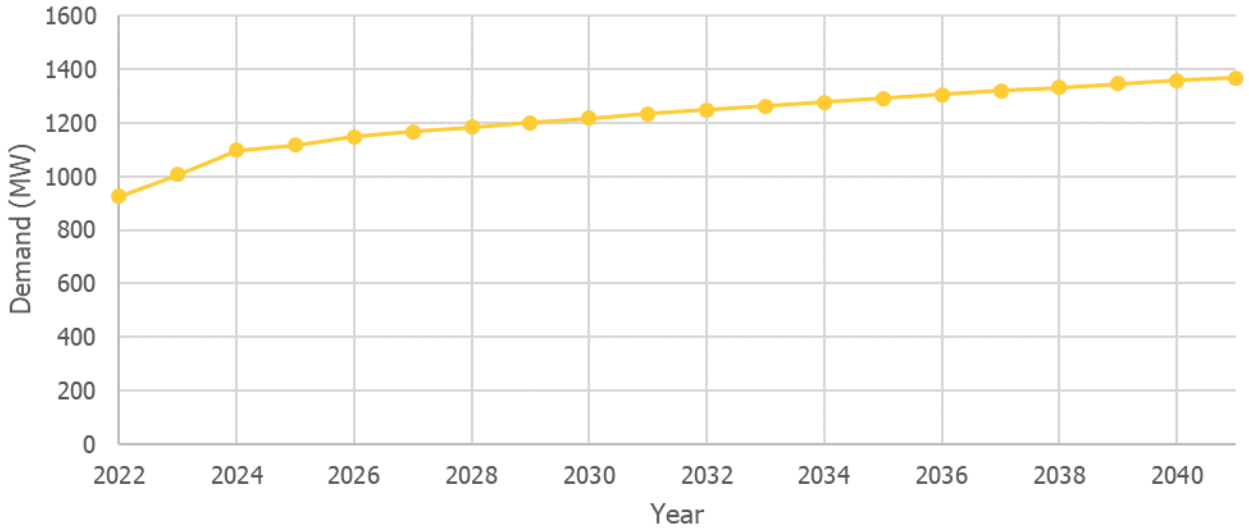
5.3 Gross LDC Forecast

Each participating LDC in the Niagara Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans, and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes median on-peak weather conditions, and station loading that is coincident to the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and municipalities and communities which they serve. The IESO typically carries out demand forecasting at the

provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.8. Figure 5 below shows the total gross demand forecast provided by the LDCs for the Niagara Region.

Figure 5 | Total Gross Demand Forecast Provided by LDCs (Median Weather)[2]



5.4 Contribution of Conservation to the Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

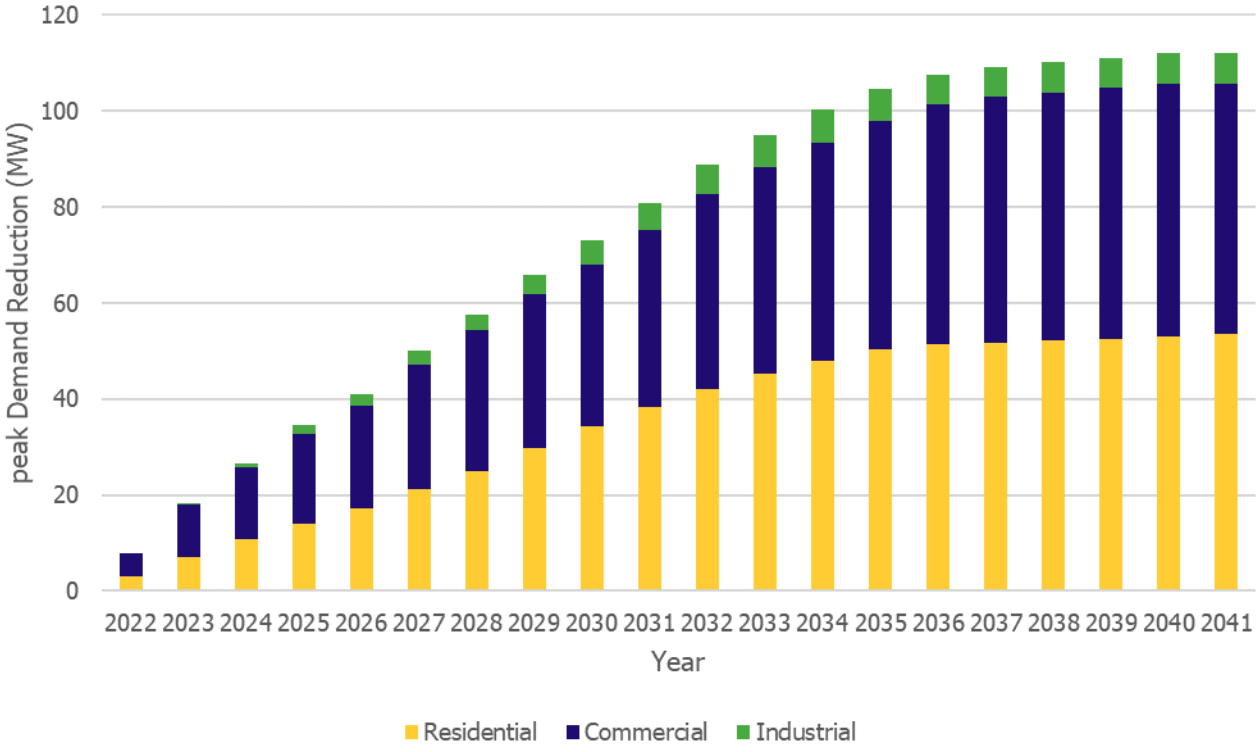
The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. The 2021 – 2024 CDM Framework is the main piece, in which the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

Figure 6 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.9.

[2] Excludes existing transmission-connected industrial customers in the Niagara Region (historically contributing an average of 15 MW to the coincident peak demand).

Figure 6 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

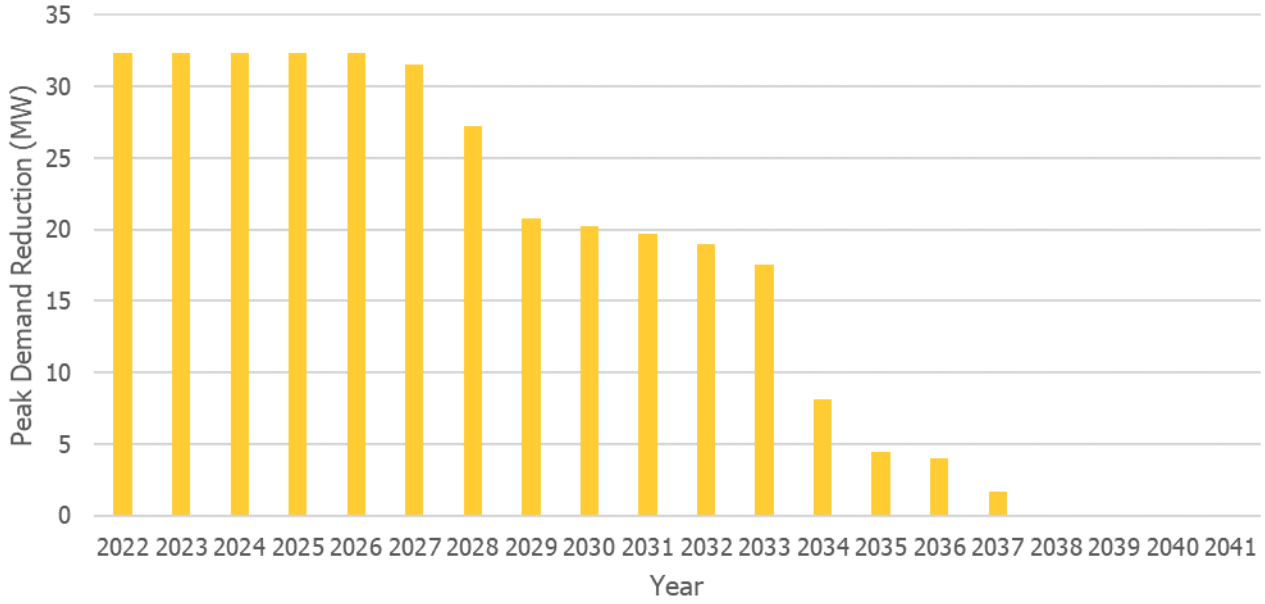


5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Niagara Region is also forecast to offset peak-demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B.10. Most of the total contracted installed DG capacity in the Niagara Region is solar, wind, and waterpower, with some biogas, landfill gas, and natural gas facilities.

After reducing the demand forecast due to conservation, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG. Figure 7 shows the impact of DG on reducing the Niagara Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

Figure 7 | Peak Demand Reduction to Demand Forecast, Due to DG



In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 32 MW of peak contribution is identified for the Niagara Region in 2022, reducing throughout the 2030s to 0 MW by 2038. This reduction is reflected in the high forecast scenario (see Section 5.7 for more details on its development and assumptions), but not the reference forecast. Rather, the reference Niagara IRRP forecast assumes a constant contribution of approximately 32 MW each year for the entire study period. This aligns with the Technical Working Group decision to assume that already-existing DG facilities with expired contracts will continue to offset demand.

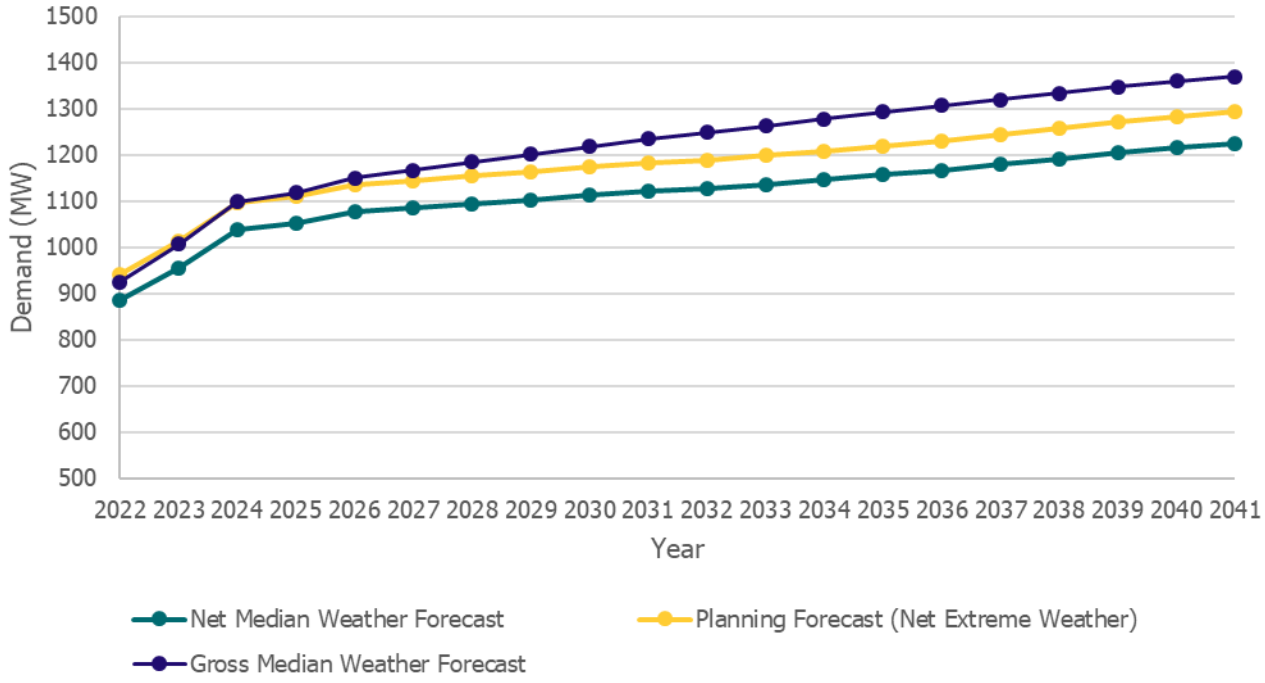
5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and conservation impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past six years.

The coincident net extreme weather forecast for the Niagara Region is shown in Figure 8 below.

Figure 8 | Net Extreme Weather ("Planning") Forecast for the Niagara Region[3]



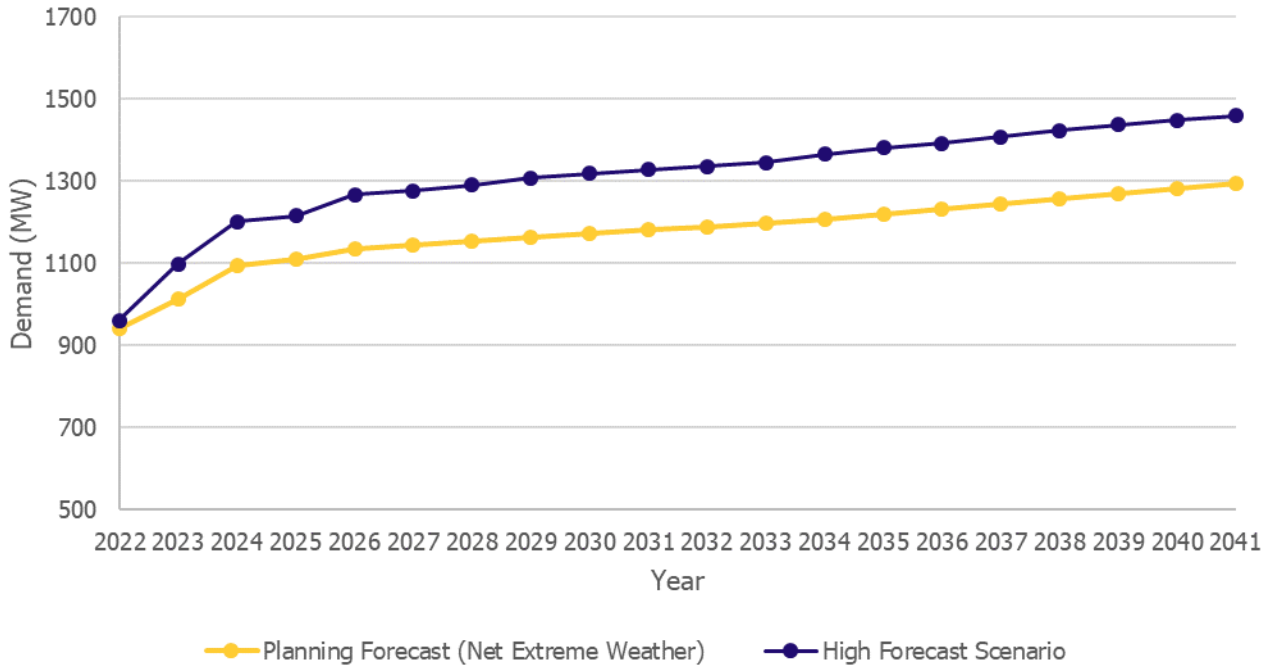
5.7 High Forecast Scenario

The Technical Working Group opted to develop a high forecast sensitivity scenario for the Niagara Region. This higher demand scenario is to take into account a variety of factors that could drive demand higher over the next 20 years, including but not limited to: electric vehicle charging infrastructure, electrified space heating installations, unanticipated new industrial customers, or general higher-than-expected growth. However, the Technical Working Group did not have specific end-use data available to develop the high forecast. Instead, the DG contribution to peak (as described in Section 5.5) was removed according to contract expiries, resulting in approximately 3% higher total regional load by 2041 when compared to the reference planning forecast. The impact on stations with greater contracted DG is higher.

The high forecast also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. These include customers that members of the Technical Working Group were aware of and liaising with, as well as customers that initiated a System Impact Assessment with the IESO during the Niagara IRRP development. In total, another 132 MW was added due to this assumption, when compared to the reference planning forecast. This is shown in Figure 9.

[3] See footnote 2.

Figure 9 | High Forecast Scenario for the Niagara Region[4]



The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain stations with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly

[4] See footnote 2.

estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council ("NPCC") Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating ("LTR") of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment, i.e., breakers, disconnect switches, low-voltage bus or high voltage circuits.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the Niagara IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 – 6.5 below.

6.2 Station Capacity Needs

In the near/mid-term, there are summer station capacity needs at Beamsville TS, Murray TS, Crowland TS, and Niagara West MTS. In the longer term, there are station capacity needs at Carlton TS, Vineland DS, and Kalar MTS. Table 2 below summarizes transformer capacity limitations for the Niagara Region.

Table 2 | Summary of Station Capacity Needs in the Niagara Region

Need	10-day LTR Rating (MW)[5]	Need Date[6]	Size of Need by 2041
Beamsville TS	57	2022	44
Murray TS (T11/T12)	72	2022	14
Crowland TS	96	2022	25
Niagara West MTS	60	2026	22
Carlton TS	94	2028	11
Kalar MTS	68	2030	7
Vineland DS	25	2030	3

6.2.1 Beamsville TS, Niagara West MTS, and Vineland DS

The three stations supplying the Lincoln, West Lincoln, and Grimsby areas (Beamsville TS, Niagara West MTS, and Vineland DS) are forecast to reach their individual station limits, as well as their collective limit (sum of their LTRs). Beamsville TS and Vineland DS each comprise two 115 kV/27.6 kV transformers, with summer LTRs of 57 MW and 25 MW, respectively. The Beamsville TS capacity need exists today (Figure 10), whereas the Vineland DS need is forecast to start in 2030 (Figure 12). Niagara West MTS consists of two 230 kV/27.6 kV transformers, with a summer LTR of 60 MW and a need beginning in 2026 (Figure 11). Cumulatively, the capacity need at these three stations grows to 57 MW by 2041 (Figure 13).

[5] Assuming a 0.9 power factor.
[6] Based on non-coincident station forecasts, as explained in Section 5.6.

Figure 10 | Beamsville TS Capacity Need

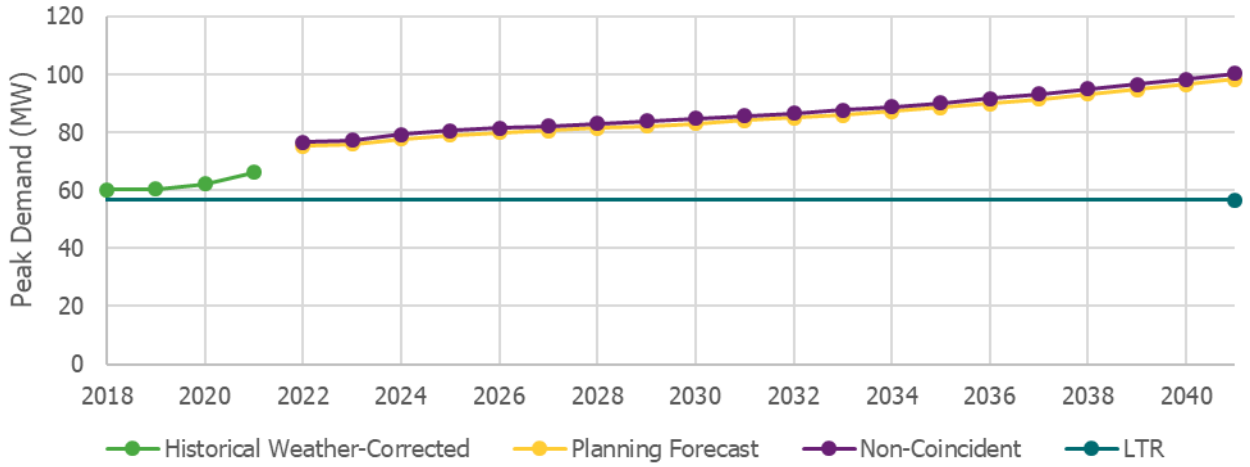


Figure 11 | Niagara West MTS Capacity Need

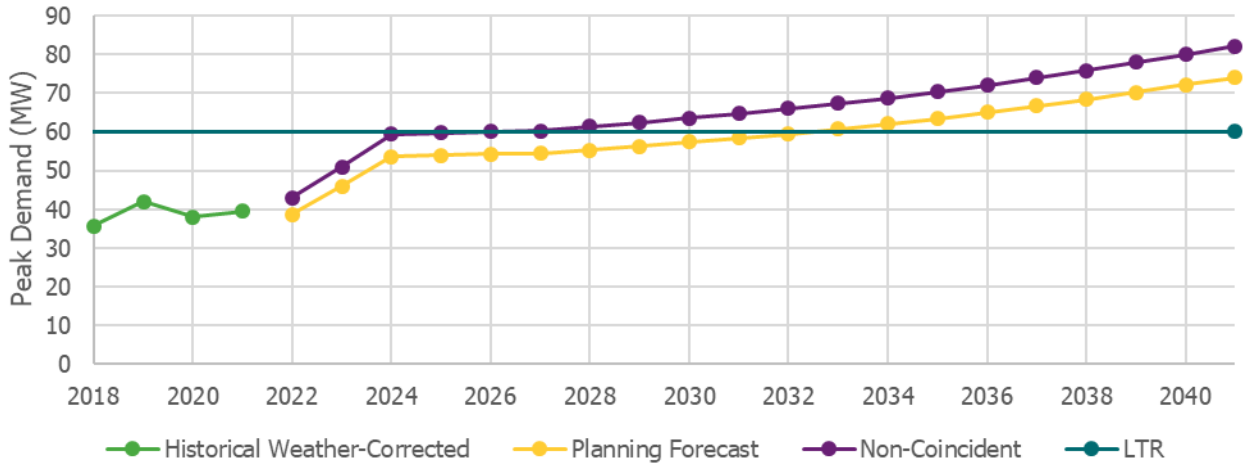


Figure 12 | Vineland DS Capacity Need

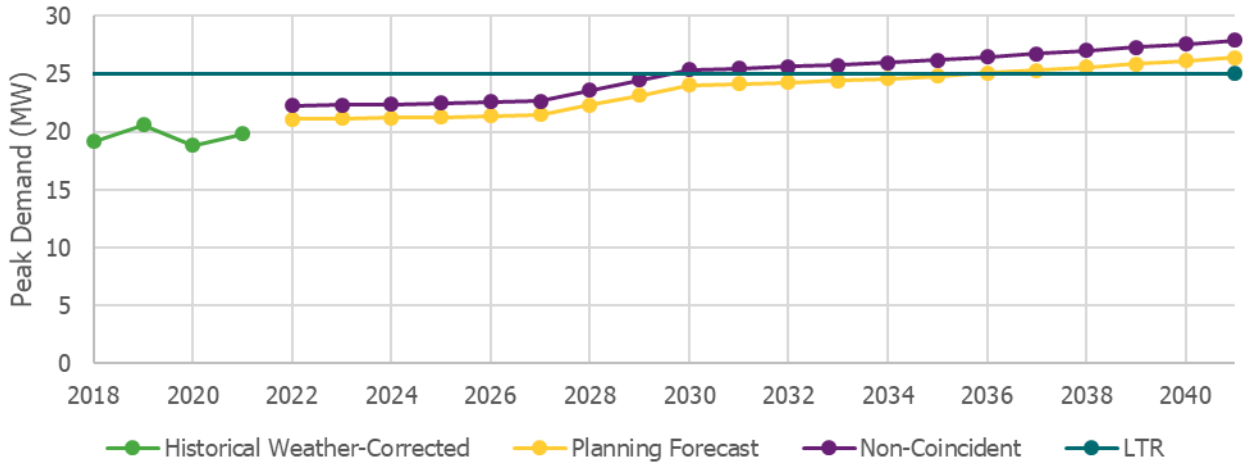
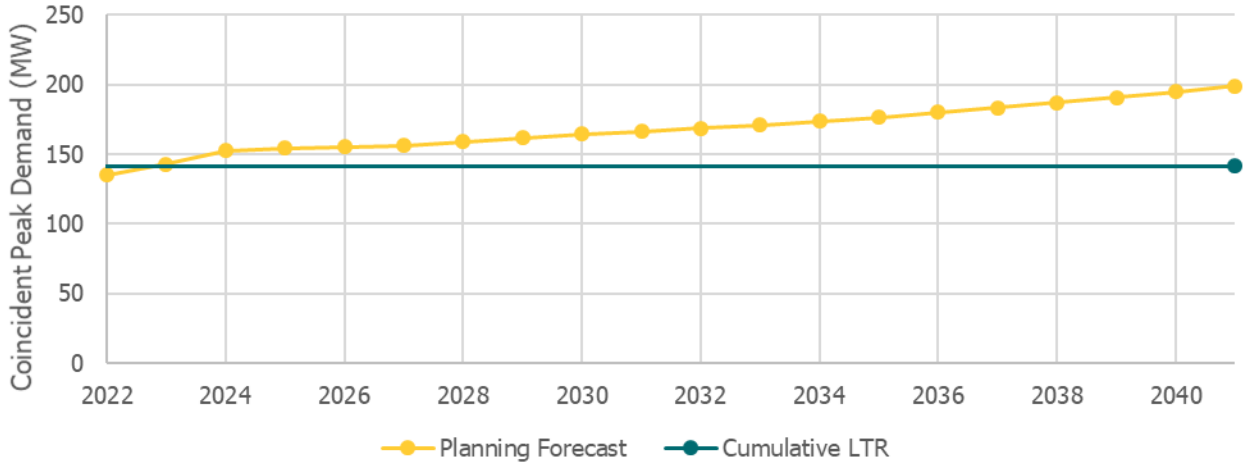


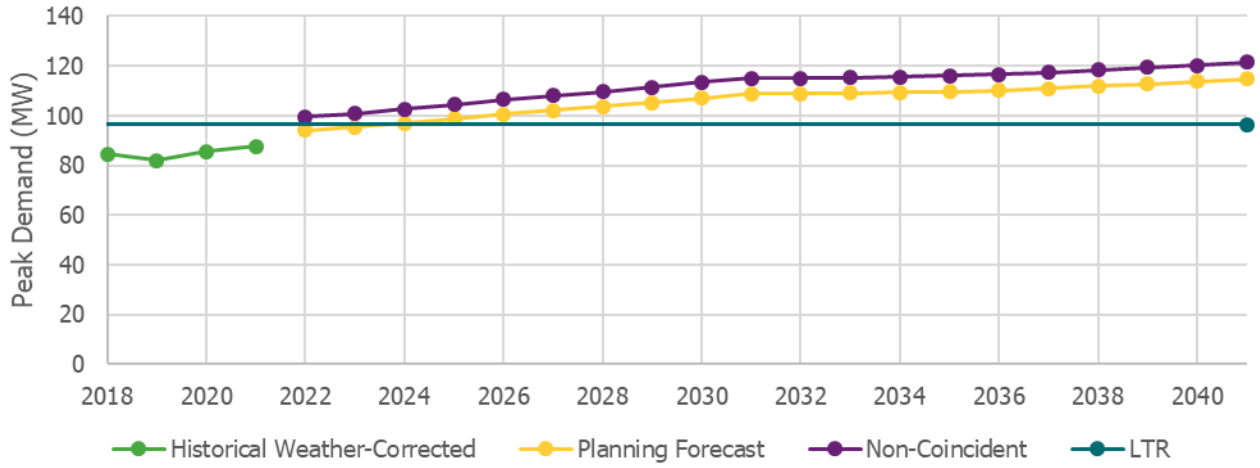
Figure 13 | Beamsville TS, Vineland DS, and Niagara West MTS Cumulative Coincident Capacity Need



6.2.2 Crowland TS

Supplying Welland, Crowland TS is forecast to reach its summer station capacity limit in 2022 and grow to a 25 MW need by 2041. This station comprises two 115 kV/27.6 kV transformers with an LTR of 96 MW.

Figure 14 | Crowland TS Capacity Need



6.2.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

Carlton TS and Kalar MTS each comprise two 115 kV/13.8 kV transformers, with summer LTRs of 94 MW and 68 MW, respectively. Carlton TS is forecast to reach capacity starting in 2028 (Figure 15) while the Kalar MTS need arises in 2030 (Figure 16). Each need will increase to 11 MW and 7 MW, respectively, by 2041. Murray TS consists of four 230 kV/13.8 kV transformers; T11 and T12 have a summer LTR of 72 MW, whereas T13 and T14 are rated to 77 MW. The T11/T12 capacity need exists today, growing to 14 MW by 2041 (Figure 17).

Figure 15 | Carlton TS Capacity Need

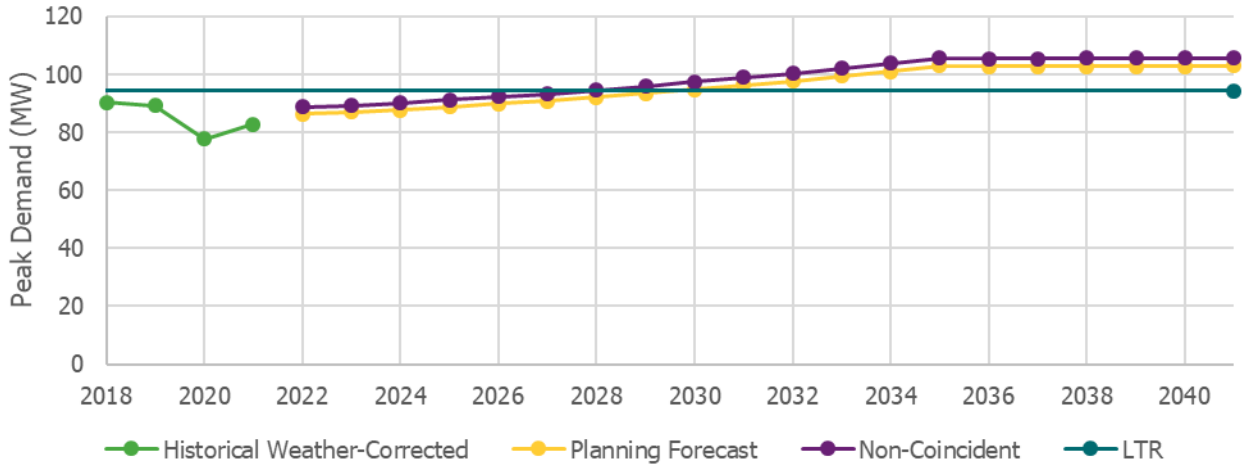


Figure 16 | Kalar MTS Capacity Need

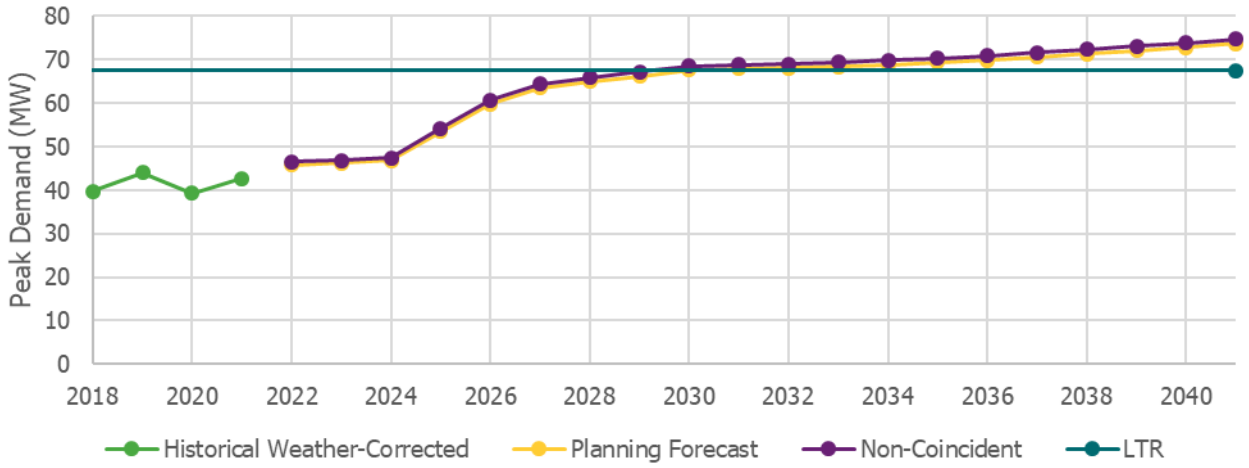


Figure 17 | Murray TS (T11/T12) Capacity Need

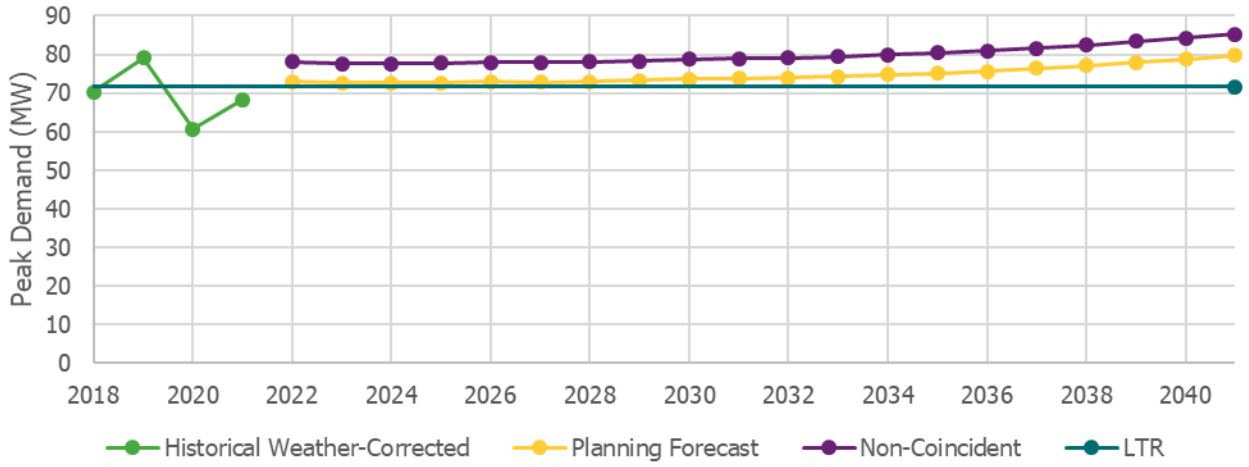


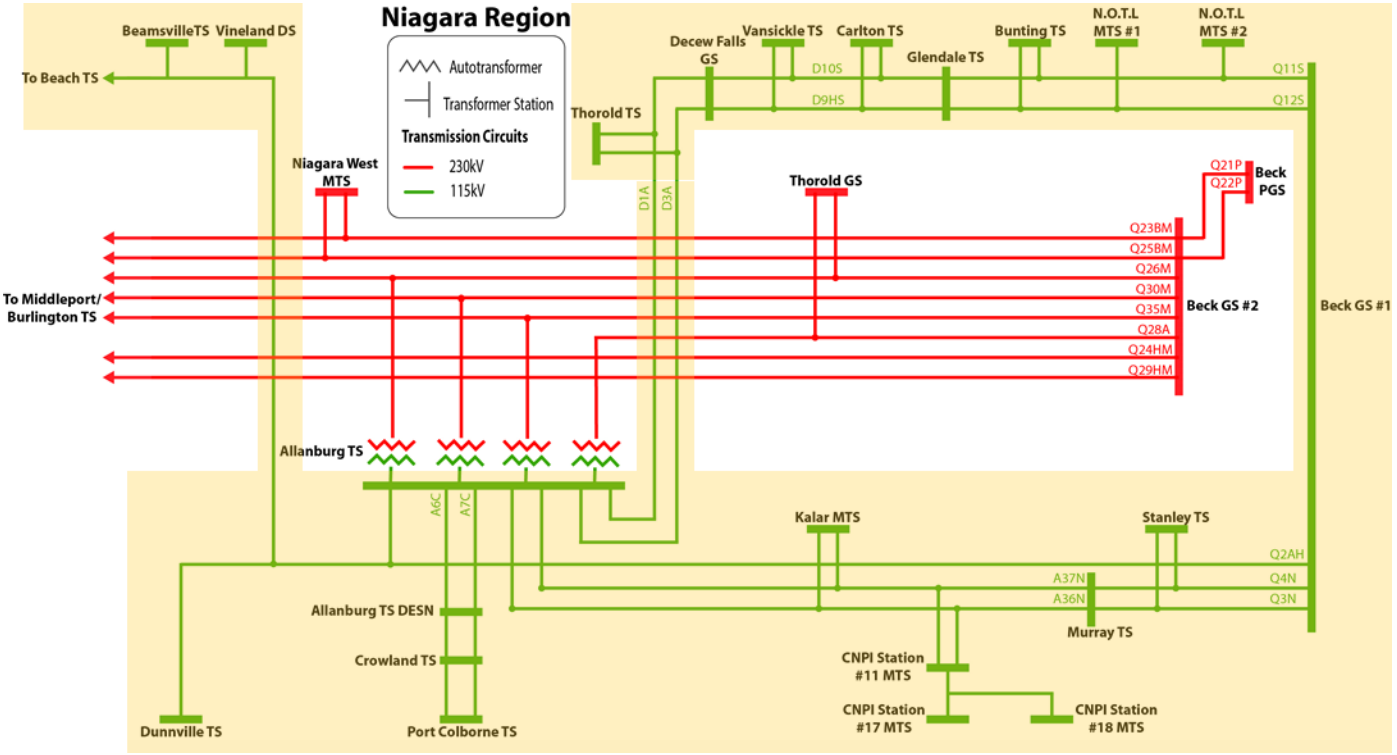
Figure 15 to Figure 17 demonstrate the non-coincident peak demand forecasts at these stations compared to their individual LTRs. Note that these station capacity needs have been presented

together in this sub-section, since this IRRP is not yet recommending infrastructure reinforcements to address them. Section 7.2.1.3 describes this in more detail.

6.3 Supply Capacity Needs

The majority of load in the Niagara Region is supplied through its 115 kV transmission sub-system, which in turn is supplied from the 230/115 kV autotransformers at Allanburg TS, Sir Adam Beck GS #1, and Decew Falls GS. The LMC of the 115 kV sub-system is therefore limited by the capability at Allanburg TS under the various planning scenarios and applicable contingencies. The sub-system is demonstrated in Figure 18.

Figure 18 | Niagara Region's 115 kV Sub-System (Highlighted Yellow)

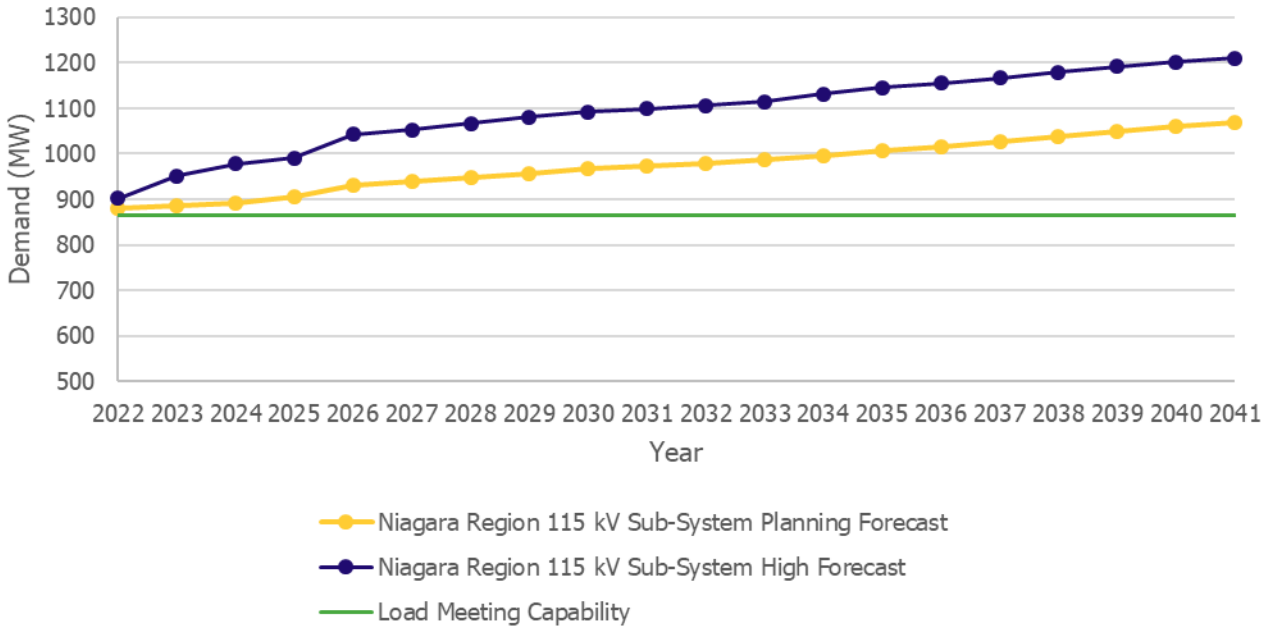


The LMC of the Niagara 115 kV sub-system, presented in Figure 19 against the forecast load, reflects limitations of the existing transmission system. Under certain outage and contingency conditions (such as contingencies impacting two circuits between Beck GS #2 and Middleport/Burlington, or Beck GS #1), the lowest-rated Allanburg autotransformer is overloaded and is the first limiting phenomenon that restricts total reliable supply into the 115 kV sub-system. However, the LMC for this area can also be restricted by other phenomena, including the thermal capability of a section of Q28A during other contingency events and specific generation outage conditions. There are further, more local restrictions within this sub-system too – such as thermal constraints limiting the supply to loads between Allanburg TS and Beck GS #1 through the 115 kV circuits.[7] All of these transmission limits are described in Appendix G.

[7] This particular need, which occurs under outage conditions, could be addressed through permissible operational control actions and would be impacted by a customer's System Impact Assessment that is ongoing at the time of regional planning.

Between 2018 – 2021, the 115 kV sub-system has had a peak coincident weather-corrected load of up to approximately 830 MW. With the reference planning forecast, the 115 kV sub-system load increases such that the supply capacity need grows to approximately 200 MW by 2041; under the high scenario, it is about 340 MW.

Figure 19 | Niagara Region 115 kV Supply Capacity Need



6.4 Asset Replacement Needs

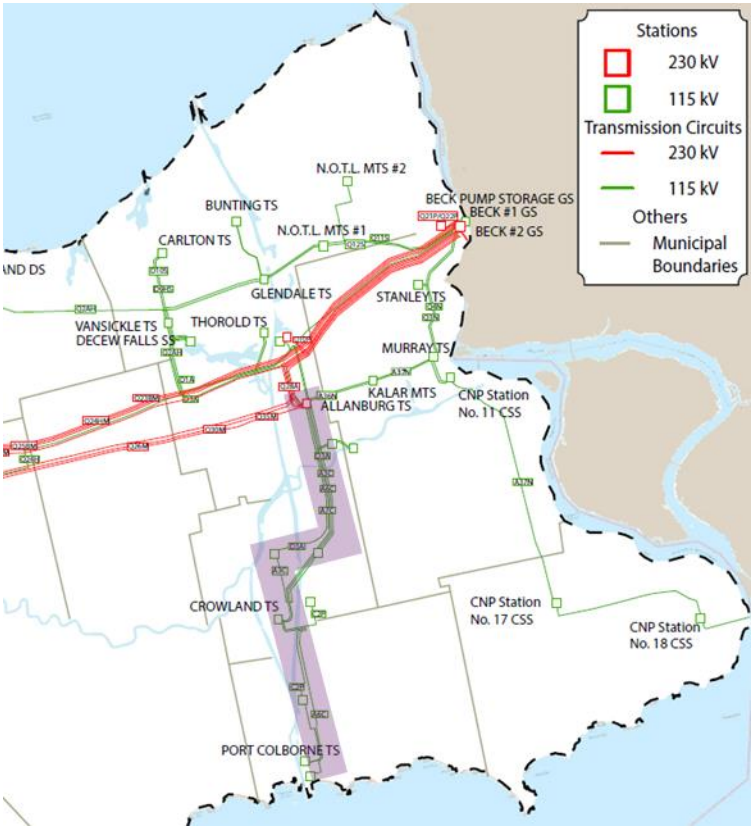
At the time of the Niagara Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. This included Crowland TS, whose transformers were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere ("MVA") units before 2026. As described in the Niagara Region Scoping Assessment, the Technical Working Group agreed that sustainment plans identified by Hydro One would be assumed to proceed as described in the Needs Assessment – unless an opportunity arose for "right-sizing".

Through the development of the IRRP, during which a more comprehensive demand forecast was created and extended to a 20-year planning horizon, and additional needs were identified or refined, the Crowland TS like-for-like replacement plan was reconsidered. This need and its relevance to the other regional needs are described further in Section 7.4.

6.5 Load Security Needs

The circuits designated as A6C/A7C form a 115 kV double-circuit line from Allanburg TS to Crowland TS, before supplying Port Colborne TS as A6C and C2P. These circuits also serve a number of transmission-connected industrial customers that are south of Allanburg TS, primarily east of the Welland Canal. Figure 20 provides an overview of this portion of the transmission system in the Niagara Region.

Figure 20 | Niagara Region Transmission System: A6C/A7C (Highlighted Purple)



The aforementioned stations and transmission-connected customers on the A6C/A7C circuits are included in the Allanburg Load Rejection Scheme; operational actions are taken to disconnect these loads in the event of certain contingencies to prevent voltage decline upon the coincidental loss of Allanburg T1 and T2. At the 2022 expected load levels on the A6C/A7C circuits, a double contingency on the Q26M and Q28A circuits will trigger over 180 MW of load being disconnected from the system. This is a violation of Section 7.1 of the ORTAC, which specifies that only up to 150 MW of planned load curtailment is permissible under these conditions. The load supplied by A6C/A7C is also expected to grow throughout the study period (i.e., up to 2041). By 2041, it is expected that the load security need will grow to approximately 75 MW in excess of the permissible amount. More details regarding this load security need are provided in Appendix G.

6.6 Summary of Identified Needs

Below is an overview of all needs identified in this Niagara IRRP.

Table 3 | Summary of Needs in the Niagara Region

Need	Need Date
Beamsville TS Station Capacity	2022
Murray TS (T11/T12) Station Capacity	2022
A6C/A7C Load Security Need	2022

Need	Need Date
Niagara 115 kV Sub-System Supply Capacity	2022
Crowland TS Station Capacity	2022
Crowland TS Asset Replacement	2026
Niagara West MTS Station Capacity	2026
Carlton TS Station Capacity	2028
Kalar MTS Station Capacity	2030
Vineland DS Station Capacity	2030

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Niagara Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wires" options and can include things like local utility-scale generation, distributed energy resources (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wires options are always considered in regional planning, and are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc) of each need. These are identified through discussions with the Technical Working Group.

While traditional wires infrastructure is always a viable option for regional needs, some non-wires options are more suitable for specific need types and characteristics. Hence, to select and size suitable generation and other non-wires options, additional work is required – including creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile, which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Niagara Region needs.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires options are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective

transmission-connected options for meeting local needs in the Niagara Region are resources with a performance and costs on par with simple cycle gas turbines. New natural gas-fired generation was considered in the economic analysis for illustrative purposes, as it was representative of the lowest cost generation option. Energy storage, such as lithium nickel manganese cobalt oxide batteries, are also becoming cost-competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other energy resources (which are typically distribution-connected) are also considered.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's CDM Guidelines to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[8] Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The non-wires options also include any system capacity benefit that they could contribute to provincial resource adequacy needs, ensuring that they are both sized to address the local need and are comparable to the wires options. The net present value (in 2021 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around costs estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine wires cost estimates before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, in cases where other barriers downstream of the regional planning process (i.e., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options, pilot or demonstration projects can be explored.[9]

The list of assumptions made in the economic analysis can be found in Appendix F.

7.2 Screening Options

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically

[8] More information about the CDM Guidelines is available on the Ontario Energy Board's website.
[9] Barriers to non-wires alternatives and recommendations to address them were a part of the Regional Planning Process Review.

feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 21, and the results of its application to the Niagara IRRP needs are summarized in Table 4 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 21 | IRRP Screening Mechanism

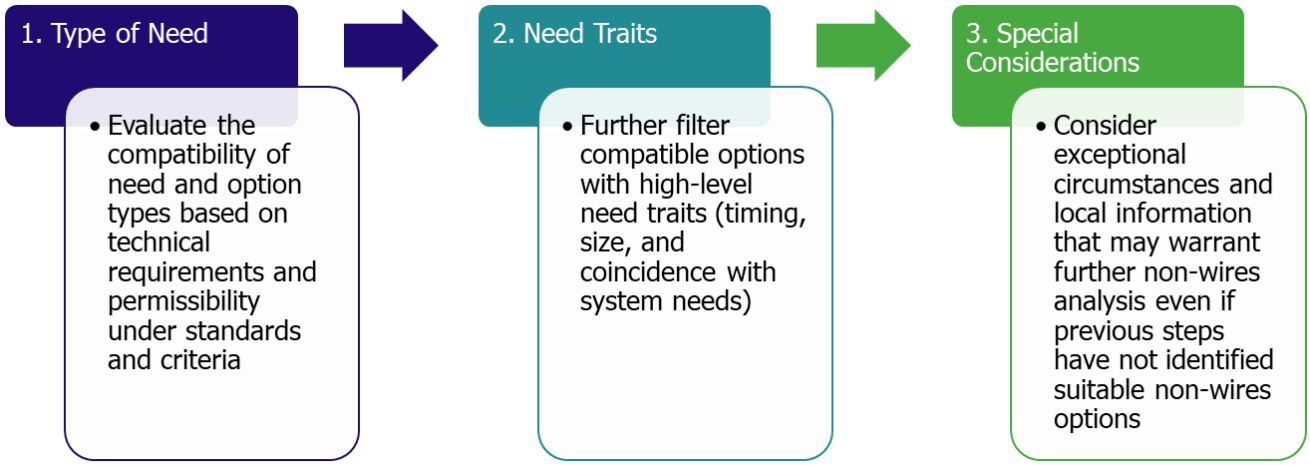


Table 4 | Results of Niagara IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Beamsville TS	Wires, demand response ("DR"), DG, CDM	Transmission-connected generation
Station capacity	Vineland DS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Crowland TS	Wires, DR, DG, CDM	Transmission-connected generation
Station capacity	Kalar MTS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Carlton TS	Wires	All non-wires

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Murray TS (T11/T12)	Wires	All non-wires
Supply capacity	Niagara 115 kV sub-system	Wires, transmission-connected generation, CDM	DR, DG
Asset replacement	Crowland TS	Coordinated with the Crowland TS station capacity need	Coordinated with the Crowland TS station capacity need
Load security	Load supplied by A6C/A7C circuits	Wires	All non-wires

7.2.1 Non-Wires Options for the Capacity Needs

Based on the nature of the need, Step 1 of the screening mechanism identifies that in general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be resources that are connected downstream of the limiting step-down transformer. The following sections outline when Steps 2 and 3 of the screening resulted in further analysis of non-wires options.

7.2.1.1 Beamsville TS, Niagara West MTS, and Vineland DS

As described previously in Section 6.2.1, there are forecast station capacity needs at Beamsville TS, Niagara West MTS, and Vineland DS, as well as a collective capacity shortfall in the area supplied by the three stations. Though eventually considered together given their geographic proximity, Beamsville TS and Vineland DS were screened independently. For Beamsville TS, with its large near-term capacity need, all applicable non-wires options were considered. Conversely, for the small long-term need at Vineland DS, the focus (in terms of a non-wires option) was on incremental CDM.

At the time of screening, the Technical Working Group did not identify a station capacity need at Niagara West MTS; this occurred later in the IRRP development when the forecast was updated by Grimsby Power. Hence, formal screening was not conducted for Niagara West MTS – but this IRRP does ultimately include recommendations that address its need (see Section 7.3).

7.2.1.2 Crowland TS

For Crowland TS, all applicable non-wires options were developed in further detail. Initially, at the time of the screening, the Crowland TS and Kalar MTS station needs were approached together given their perceived geographic proximity. However, recommendations were eventually made for these stations separately after considering factors that made an integrated approach impractical. These factors include distribution voltage level differences, distance to supply forecast growth areas, and misaligned capacity need timing between the two stations.

7.2.1.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

For some needs, further analysis of non-wires is not warranted if there is the high potential for an inexpensive and simple wires alternative that maximizes the use of existing infrastructure. This can include load transfers or control actions that are sufficient to meet the need.

This was the case for the station capacity needs at Carlton TS and Murray TS (T11/T12). At the time of screening, Alectra Utilities indicated plans to reallocate some forecast demand at Carlton TS to a nearby station with additional capacity (Bunting TS). At Murray TS, NPEI is supplied by both T11/T12 and T13/T14. While forecast demand for T11/T12 exceeds its LTR, there is sufficient remaining capacity at T13/T14.[10] Managing the load distribution between the four transformers at Murray TS is expected to address the need at T11/T12.

For the small long-term need at Kalar MTS, incremental CDM was screened in for additional analysis.

7.2.1.4 Niagara 115 kV Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Niagara 115 kV sub-system, the magnitude of the capacity need was large enough that the option development focused on transmission-connected generation or storage, with some consideration for additional locally targeted CDM.

Other non-wires options such as DR and DG were screened out from further analysis for a number of reasons. For instance, the connection of DG (regardless of fuel type) is subject to equipment limitations such as minimum loading, feeder capacity, station thermal capacity, and short circuit requirements. With an approximately 200 MW supply capacity need, the amount of incremental DG required would not be able to connect to a single transformer station in the Niagara Region, and would be unlikely to be accommodated, coordinated, and operated across multiple stations to meet the local supply constraint.[11] Recall that existing contracted DG output at peak was already accounted for during the development of the net demand forecast.

Similarly, DR was screened out due to the magnitude of the Niagara 115 kV supply capacity need. Though DR can be considered as a potential option to the extent that loads in the area can be curtailed during peak hours, the amount of DR that has historically been acquired for system capacity needs can help indicate this option's feasibility. For the 2021 summer obligation period in the capacity auction, approximately 20 MW of total capacity cleared for the Niagara zone. These past auction results provide context as to the scale of demand response that would be required to address the Niagara supply capacity need; this is unlikely to be achievable in the near-term. It is also worth noting that the Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

[10] Approximately 50 MW of remaining capacity is available at Murray TS (T13/T14) according to the IRRP reference planning forecast.
[11] For existing station DG connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

7.2.2 Non-Wires Options for the Asset Replacement Needs

Outcomes of screening non-wires options for the Crowland TS asset replacement need were aligned with the screening outcomes for the Crowland TS incremental station capacity need (i.e., the capacity need that persists even if the station is replaced like-for-like).

7.2.3 Non-Wires Options for the Load Security Needs

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as CDM and DG cannot be applied to load security needs because they usually do not enable uninterruptable power supply to customers in the event of transmission contingencies. While voluntary load loss such as DR could help address the intent of load security planning criteria, it is an option type currently procured through the provincial capacity auction. This implementation mechanism is not the optimal approach, as its current design does not include the monitoring of local adequacy nor permit immediate responses after specific local contingencies. For these reasons, non-wires options are typically screened out for load security needs unless there are exceptional circumstances identified during the IRRP development.

7.3 Options and Recommendations for Meeting the Beamsville TS, Niagara West MTS, and Vineland DS Needs

7.3.1 Transmission Options

Due to the geographic proximity of Beamsville TS, Niagara West MTS, and Vineland DS, integrated transmission options were developed to address the station capacity needs in a coordinated manner. Three options for additional station capacity for the area were considered:

1. The replacement of existing Niagara West MTS with new 2 x 75/125 MVA transformers;
2. The expansion of Niagara West MTS with two new 67 MVA transformer units; or
3. A new, separate 230 kV station supplied from Q23BM and Q25BM.

Option 1 was ruled out, given that there was no indication of asset replacement needs at the existing Niagara West MTS (resulting in stranded asset costs), plus the risk of reduced reliability expected when implementing the replacement. Option 2 was estimated to cost as little as $17M and require three years from the commitment date, whereas Option 3 was estimated to cost up to $40M (depending on the size of the transformers and implementer) and would take three to four years.[12]

Given the immediate need at Beamsville TS, the Technical Working Group also considered load transfer capabilities in the near-term. Beamsville TS and Niagara West MTS both supply Grimsby Power, NPEI, and Hydro One Distribution, while Vineland DS supplies only NPEI. At the time of this IRRP, Grimsby Power estimated the ability to transfer approximately 7 MW of NPEI's forecast load at Beamsville TS to Niagara West MTS. Beyond this amount, the Niagara West MTS station capacity need would arise sooner than already forecast. There is also some remaining capacity (approximately 4 MW) expected at Vineland DS.

[12] All cost estimates, unless otherwise specified, are net present values based on a levelized cash flow analysis rather than capital costs – see Appendix F. In this case, a capital cost estimate of $19M (+/-15%) was provided for Option 2 and $25M - $40M for Option 3.

7.3.2 Non-Wires Options

As explained in Section 7.2.1.1, non-wires options were screened in for additional evaluation for the Beamsville TS and Vineland DS needs.

For Beamsville TS, a number of measures were assessed – such as combinations of incremental targeted CDM with battery storage or gas generation.[13] The most cost-effective non-wires solution portfolio included incremental CDM (approximately 6 MW of additional savings by 2041), plus battery storage assumed to be installed in two phases (2025 and 2038) to match the need profile.[14] For Vineland DS, the incremental CDM potential was also calculated: approximately 2 MW of additional demand savings by 2041.

The net present value ("NPV") of the portfolio of non-wires options for both Beamsville TS and Vineland TS was calculated to be $30M - $57M. The lower cost assumed that the incremental CDM is already system cost-effective based on provincial resource adequacy, whereas the higher cost assumed that the demand savings targeted to these stations would be incremental to the provincial CDM framework. More details on the CDM potential methodology and results are provided in Appendix E.

7.3.3 Recommendation

During the development of the IRRP, the forecasts at Beamsville TS and Niagara West MTS were updated by the impacted LDCs as growth trended higher and new potential customers were identified. By the conclusion of the IRRP, this reinforced the preference for the integrated wires options due to their cost-effectiveness and ability to address the capacity needs at all three stations.

The original scope of the non-wires options that were developed only addressed the Beamsville TS and Vineland DS needs, but were collectively $13M – $40M more expensive than the least expensive wires option. The increased forecast for Niagara West MTS did not impact the wires option of a new 230 kV station in the area – it only increased its cost-effectiveness. Another portfolio of non-wires options sized for Niagara West MTS' final reference forecast capacity need would have increased the non-wires costs further. Reallocating the load forecast on the 115 kV stations to 230 kV supply also helps alleviate the broader Niagara 115 kV sub-system capacity need.

Therefore, due to the cost-effectiveness and ability to meet the multiple needs, the Technical Working Group recommends near-term load transfers to offload Beamsville TS, plus a new 230 kV station supplied from Q23BM and Q25BM. This could be accomplished by expanding the existing Niagara West MTS. The station should be in-service as soon as possible and accommodate at least 57 MW of pre-contingency load in the area by 2041.

It is recommended that after the IRRP, the impacted LDCs coordinate the magnitude and timing of load transfers between the three stations to manage and monitor the Beamsville TS capacity need until the new station is in-service. Moreover, the LDCs and Hydro One should coordinate during the RIP to establish the lead implementer of the new station. Timing, siting, and size of the new

[13] Based on the unserved energy profile forecast at Beamsville TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[14] This included an 18 MW, 144 MWh battery storage facility. The Beamsville TS forecast was updated and increased near the end of the IRRP forecast; cost range estimate would only increase with larger battery storage.

transformers should be factored into the decision – in addition to a comprehensive economic comparison that accounts for both the cost of the transformer station and the distribution-level costs that could incur if the station is sited farther west and away from the service territories that are expected to grow.

7.4 Options and Recommendations for Meeting the Crowland TS, Load Security, and Niagara 115 kV Sub-System Needs

The Crowland station capacity and asset replacement needs, as well as the A6C/A7C load security and Niagara 115 kV sub-system capacity needs, share common transmission elements and impact each other. As such, both wires and non-wires options were developed to address these four needs in an integrated fashion.

7.4.1 Transmission Options

Two sets of transmission options were identified – one that largely involves the continued buildout of the 115 kV system in the Niagara Region, and another that expands the 230 kV supply.

Option Set 1 includes:

- New 115 kV station in Welland, supplied by the existing A6C/A7C circuits (to address the Crowland TS capacity need);
- New 230 kV Allanburg bus (to improve supply to the 115 kV sub-system and mitigate the A6C/A7C load security need); and
- Re-building of 115 kV Crowland TS like-for-like (to address the asset replacement need).

Option Set 2 includes:

- Replacement of sections of 115 kV D3A/A3C circuits with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need).

In terms of preliminary capital costs, Option Set 1 was estimated to be approximately $253M - $353M[15] in total, whereas Option Set 2 may cost $128M.[16] Option Set 1 will require a minimum of three years; Option Set 2 will need six years.

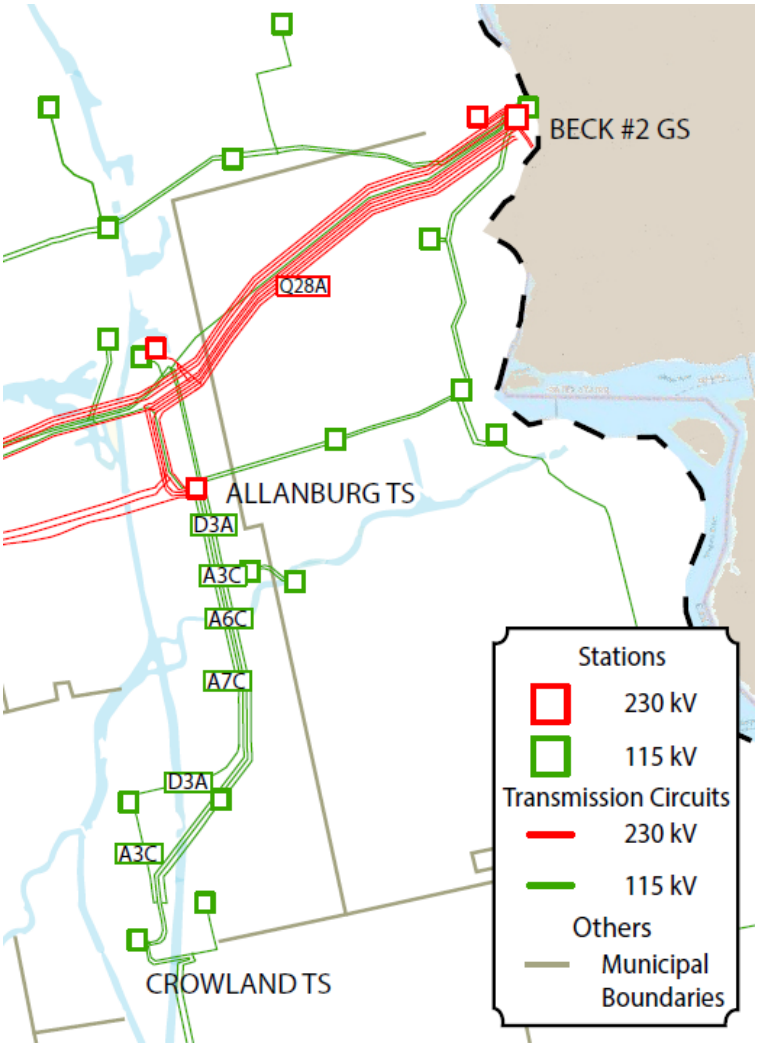
[15] The high end of the cost estimate range for Option Set 1 includes the potential for new 115 kV circuits and other reinforcements if the existing A6C/A7C circuits cannot accommodate the new 115 kV station in Welland.

[16] Capital cost estimates provided by Hydro One during the IRRP were prepared based on preliminary information and intended to provide a ballpark figure to be used strictly for initial options comparison. No engineering or field work was completed as part of the development of these cost allowances and as such, these cost allowances provide no cost guarantee or accuracy range. Costs allocations were derived from previous historical costs/unit costs and were to be used strictly for options comparison; Hydro One may refine and update cost estimates as part of the RIP.

To accommodate the planning forecast, the uprating of an existing 230 kV circuit, Q28A, is also required in addition to either Option Set. The cost and feasibility of this reinforcement is currently being assessed by Hydro One and is estimated to require until at least 2024 to be in-service.

The components of these Option Sets are identified conceptually on the map of Niagara Region's existing transmission system in Figure 22.

Figure 22 | Impacted Areas by the Transmission Options



Under some of the contingencies and conditions expected to limit the 115 kV sub-system LMC, operational measures such as load rejection are permissible according to ORTAC. Therefore, the benefit of a new load rejection scheme was also factored in when assessing the supply capability with each of the wires options described above. It was assumed that this scheme, developed and implemented by Hydro One for the Niagara 115 kV sub-system, could be installed in 2024 or later.[17]

[17] The ultimate in-service date will depend on the complexity of the scheme's design and NPCC approval timelines.

7.4.2 Non-Wires Options

As explained in Section 7.2.1.2 and 7.2.1.4, non-wires options were screened in for additional evaluation for the Crowland TS and 115 kV sub-system supply needs.

For the Crowland TS capacity need alone, incremental targeted CDM, battery storage, and gas generation were all considered either as standalone or integrated options.[18] The most cost-effective non-wires solution portfolio for the Crowland capacity need included incremental CDM (approximately 10 MW of additional savings by 2041), plus a 10 MW/40 MWh battery storage facility installed in two phases (2025 and 2038) to match the need profile. The NPV of this portfolio was calculated to be in the range of $17M - $53M. Similar to what was described for the Beamsville TS non-wires options, this cost range is attributed to the provincial CDM assumptions.[19]

As the Niagara IRRP progressed and the interplay between the Crowland TS needs and the broader Niagara 115 kV supply capability became clearer, a non-wires option was also considered at a high level. An all-generation, 240 MW alternative was sized to compare to the lowest cost transmission option set; 240 MW is the expected increase in the 115 kV sub-system supply capability enabled by Option Set 2 described previously. However, this non-wires option is not a feasible solution due to various factors. While an all-generation option was identified to compare to the wires option on a MW basis, there are significant challenges to implementing and operating a resource to address the multiple, layered, and local needs. For instance, for 240 MW of generation to address both the Crowland TS capacity and replacement needs, as well as the broader 115 kV supply needs, a portion of the generation must be sited on the distribution system to supply customers currently served by Crowland TS and the remaining must be targeted to the region's 115 kV system. There may also be thermal or short circuit limitations to connecting this amount of generation on the distribution system. Moreover, as described in Section 7.2.3, generation is typically not considered a feasible option to solve load security needs.

7.4.3 Recommendation

When comparing the two wires option sets, Option Set 2 is preferred for a number of reasons. It is the more cost-effective option, evaluated at more than $100M less expensive than Option Set 1 (based on capital cost estimates), even though both offer similar 115 kV sub-system supply capability and are sufficient according to the reference planning forecast. Qualitatively, by expanding the 230 kV transmission system, Option Set 2 also offers long-term flexibility to accommodate more load growth in the southern portion of the Niagara Region – particularly along the industrial and commercial hub around the Welland Canal. Option Set 1 provides limited growth options in the area in comparison to Option Set 2, without extensive station expansion at Allanburg TS. Meanwhile, converting the existing 115 kV Crowland TS to 230 kV in Option Set 2 allows the other 115 kV stations in the Niagara Region to accommodate new growth and maximizes the use of existing infrastructure with the available capacity normally utilized by the 115 kV Crowland TS. Triggering the

[18] Based on the unserved energy profile forecast at Crowland TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[19] Another sensitivity was conducted for the battery storage sizing, resulting in a higher cost range of $25M - $61M. See Appendix D.3 for more details.

reconfiguration is also a time-sensitive opportunity, since Crowland TS is expected to require asset replacement in the near term.[20]

Long-term flexibility can also be considered by comparing the options and their ability to accommodate the high IRRP forecast scenario. According to the reference forecast, approximately 200 MW of extra 115 kV supply capability is required by 2041. As shown in Section 6.3, the high scenario increased this requirement to 340 MW. Both Option Sets 1 and 2 enable the increased capability required for the reference forecast, and neither Option Set precludes a further wires or non-wires option in the long-term. These future actions can include new generation resources or additional 230/115 kV auto-transformation. In contrast, a non-wires option sized precisely to meet the reference need would have less flexibility to accommodate growth that exceeds today's expectations.

Regardless, none of the non-wires options described in Section 7.4.2 can sufficiently address the multiple needs at once. Wires Option Set 2 would cost-effectively resolve the Crowland capacity and replacement needs, the A6C/A7C security issue, and enable other load growth on the 115 kV sub-system. For these reasons, the Technical Working Group recommends the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM/Q29HM, as well as the uprating of Q28A. A new load rejection scheme should also be developed to manage the Niagara 115 kV sub-system need. The load forecast should be monitored between regional planning cycles, and there are benefits to targeting incremental CDM to the 115 kV sub-system in order to manage load growth beyond the reference scenario. The technical feasibility and costs of the wires recommendations should be further analyzed in the RIP; the IESO will continue to participate in the RIP Working Group to provide advice and input on this matter.

7.5 Summary of Recommended Actions and Next Steps

The Technical Working Group recommends the actions summarized in Table 5 to meet identified needs in the Niagara IRRP.

Table 5 | Summary of Needs and Recommended Actions

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

[20] All final cost estimates have accounted for the asset replacement value for Crowland TS.

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development for a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Transfer load in excess of the station limit to Murray TS T13/T14	• 2023
• Carlton TS station capacity	• Alectra	• Monitor load growth between regional planning cycles • Transfer load in excess of the station limit to Bunting TS	• 2028
• Kalar MTS station capacity	• NPEI	• Monitor load growth between regional planning cycles and consider future opportunities for incremental CDM	• 2030

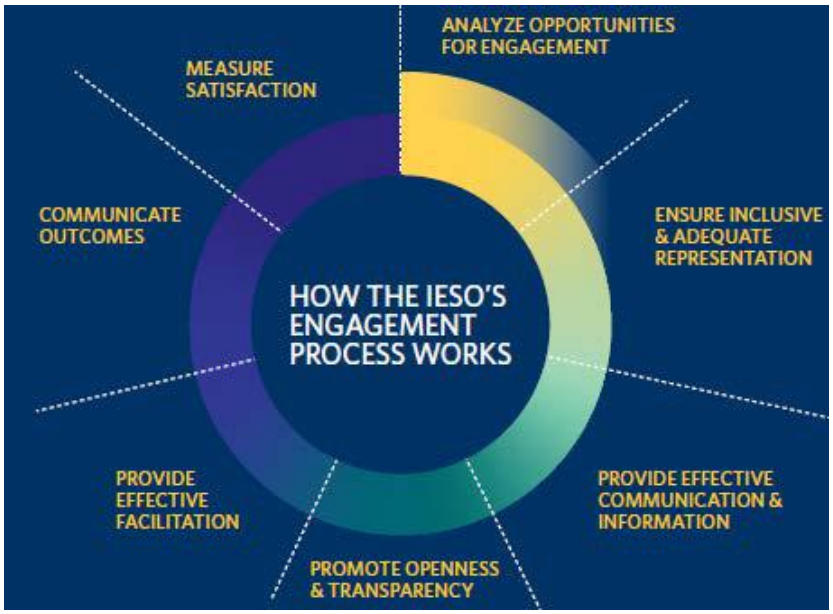
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Niagara IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

Figure 23 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Niagara Region

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Niagara Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Niagara Region Scoping Assessment Report finalization. A public webinar was held in August 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, targeted outreach then began with municipalities in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Niagara Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Niagara Region (including the City of Niagara Falls and Town of Fort Erie), have been considered and accounted for in the IRRP work;
- Ensuring there are procedures to alter the implementation of plan recommendations should changes occur in the region; and
- Keeping lines of communication following the plan completion to share information and updates.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Niagara Region subscribers, municipalities, and Indigenous and Métis communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion and employment areas as outlined in the updated Niagara Region Official Plan). This insight has been valuable to the IESO – it supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Niagara IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region:

- Strong population growth across the Niagara Region based on 2051 growth projections and in some areas above and beyond the regional forecast (i.e. even higher growth expected in the City of Welland);
- Notable growth in the Town of Lincoln (greenhouses, Secondary Plan areas, potential GO Transit development), along the QEW corridor in Grimsby, and in Thorold;

- Strong economic development around the Welland Canal (e.g. Thorold Multimodal Hub "Niagara Ports");
- Key areas of growth in the City of Niagara Falls within intensification nodes and corridors, projects around the GO Transit Station and the new Niagara South Hospital, wastewater treatment plant, and residential new construction;
- Industrial, commercial, institutional, and residential development in the Town of Fort Erie and Secondary Plan areas; and
- Potential urban boundary expansion in the region totaling 130 hectares of residential and 150 hectares of employment lands.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Niagara Region throughout the development of the plan. This includes the communities of the Mississaugas of the New Credit, Oneida Nation of the Thames and Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council) and Métis Nation of Ontario Niagara Region Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

The Niagara IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2041, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends load transfers off Beamsville TS and a new or expanded 230 kV station supplied by Q23BM and Q25BM. The IRRP also recommends the implementation of control actions on the Niagara 115 kV sub-system to manage overloads during outage conditions, plus the replacement of Crowland TS with a new 230 kV station supplied by new 230 kV lines from Q24HM and Q29HM. Q28A should be uprated, and a portion of the load at Murray TS (T11/T12) should be transferred to Murray TS (T13/T14). Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth in the Niagara 115 kV sub-system, Carlton TS, and Kalar MTS to determine if or when further reinforcements will be needed. This includes monitoring any future community energy planning or electrification trends. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region – particularly to the Beamsville TS/Vineland DS/Niagara West MTS areas and 115 kV sub-system in the near-term, and Kalar MTS in the long-term.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.



NIAGARA
REGIONAL INFRASTRUCTURE PLAN

July 12, 2023

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Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Niagara Technical Working Group

DISCLAIMER

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

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

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

EXECUTIVE SUMMARY

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

The participants of the Niagara Region Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Alectra Utilities Corporation ("Alectra")
- Canadian Niagara Power Inc. ("CNP")
- Grimsby Power Inc. ("Grimsby Power")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Niagara-on-the-Lake Hydro Inc. ("NOTL")
- Niagara Peninsula Energy Inc. ("NPEI")
- Welland Hydro Electric System Corp. ("Welland Hydro")

This RIP is the final phase of the second cycle of the Niagara Region regional planning (RP) process and it follows the completion of the Niagara Region Integrated Regional Resource Plan ("IRRP") [1] in December 2022; and the Niagara Region Needs Assessment ("NA") [2] and Scoping Assessment ("SA") in May 2021 and August 2021, respectively. This RIP provides a consolidated summary of needs and recommended plans for the Niagara Region over a 10-year planning horizon (2023-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer-term needs and trend. All needs for this long-term horizon will be covered and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in March 2017 with the publication of the Niagara Region RIP [3], which provided a description of needs and recommendations of preferred wires plans to address near-term needs. Since the previous planning cycle, the following projects have been completed:

- Decew Falls SS (2017) – Five (5) 115kV breakers were replaced with sulfur hexafluoride (SF_6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – The existing 40/53/67 MVA, 115/13.8 kV transformer T2 was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Some 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – The 28/37/47 MVA, 115/27.6 kV transformers T61 and T62 were replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

The recommended major infrastructure investments including assets replacements in the Niagara Region over the near and medium-term (2023-2032) period are given in Table 1 on the next page, along with their planned in-service date and budgetary estimate for planning purposes.

The Niagara Region TWG recommends that:

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

The next regional planning cycle for the Niagara Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will be initiated in 2026. However, the next regional planning cycle can be started earlier if required to address any new emerging needs.

Table 0-1 Niagara Region - Recommended Plans over the 2023-2032 Study Period

No.	Investments	I/S Date	Cost[1]
A	**Increase Capacity**		
1	230 kV circuit Q28A – Uprate circuit between Beck 2 SS and Abitibi Jct.	TBD	$3M
2	Lincoln Area: Build new 230/27.6 kV, 50/83 MVA transformer station	2026	$45M
4	Crowland TS: Convert station to 230 kV with new 230/27.6 kV, 75/125 MVA transformer station and build a new 18 km of double circuit line from Abitibi Jct to Crowland TS	2027	$128M
5	Murray TS: Uprate T11/T12 75 MVA transformers with new 100MVA units	2027	$41M
6	Carlton TS: Transfer excess load to Bunting TS	2029	$5M
B	**Asset Replacement**		
1	Thorold TS: Replace Transformer T1	2024	$43M
2	Glendale TS: Replace Transformers T1 and T2	2027	$55M
3	Carlton TS: Replace LV Switchgear	2027	$55M
4	Bunting TS: Replace existing Transformers T1 and T2	2029	$45M
5	Murray TS: Replace Transformers T13 and T14	2031	$27M
6	Vansickle TS: Replace LV Switchgear	2032	$14M
7	Allanburg TS: Replace Transformer T3	2032	$20M
8	115kV Line D1A/D3A: Refurbish line section between Gibson Jct and Thorold TS	2024	$4M
9	115kV Line Q2AH: Refurbish line section between Rosedene Jct. and St. Anns Jct.	2025	$10M

[1] These costs are budgetary estimates for planning purposes only.

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1 INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Niagara Region Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Alectra Utilities Corporation ("Alectra")
- Canadian Niagara Power Inc. ("CNP")
- Grimsby Power Inc. ("Grimsby Power")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Niagara-on-the-Lake Hydro Inc. ("NOTL")
- Niagara Peninsula Energy Inc. ("NPEI")
- Welland Hydro Electric System Corp. ("Welland Hydro")

The Niagara Region includes the Regional Municipality of Niagara as shown in Figure 1-1. It includes the Cities of Niagara Falls, Port Colborne, St. Catharines, Thorold and Welland, the Towns of Fort Erie, Grimsby, Lincoln, Niagara-on-the-Lake and Pelham and the Townships of Wainfleet and West Lincoln.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck Generating Station (GS) #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) connecting the Sir Adam Beck #2 Switching Station (SS) to stations in the Hamilton/Burlington area. The summer 2022 non-coincident peak load of the Region was about 977 MW.



Figure 1-1: Niagara Region Map

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near- and medium-term needs (2023-2032) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2023-2032 period and wires plans to address these needs based on new and/or updated information;
- Consideration of long-term needs identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

[1] also referred to as Needs Screening

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

The RIP phase is the final stage of the regional planning process and involves confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, plan level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

- Planning activities that were already underway in the region prior to the regional planning process taking effect;
- The NA, SA, IRRP and LP phases of regional planning;
- Conducting wires planning as part of the RIP for the region or sub-region;
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

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

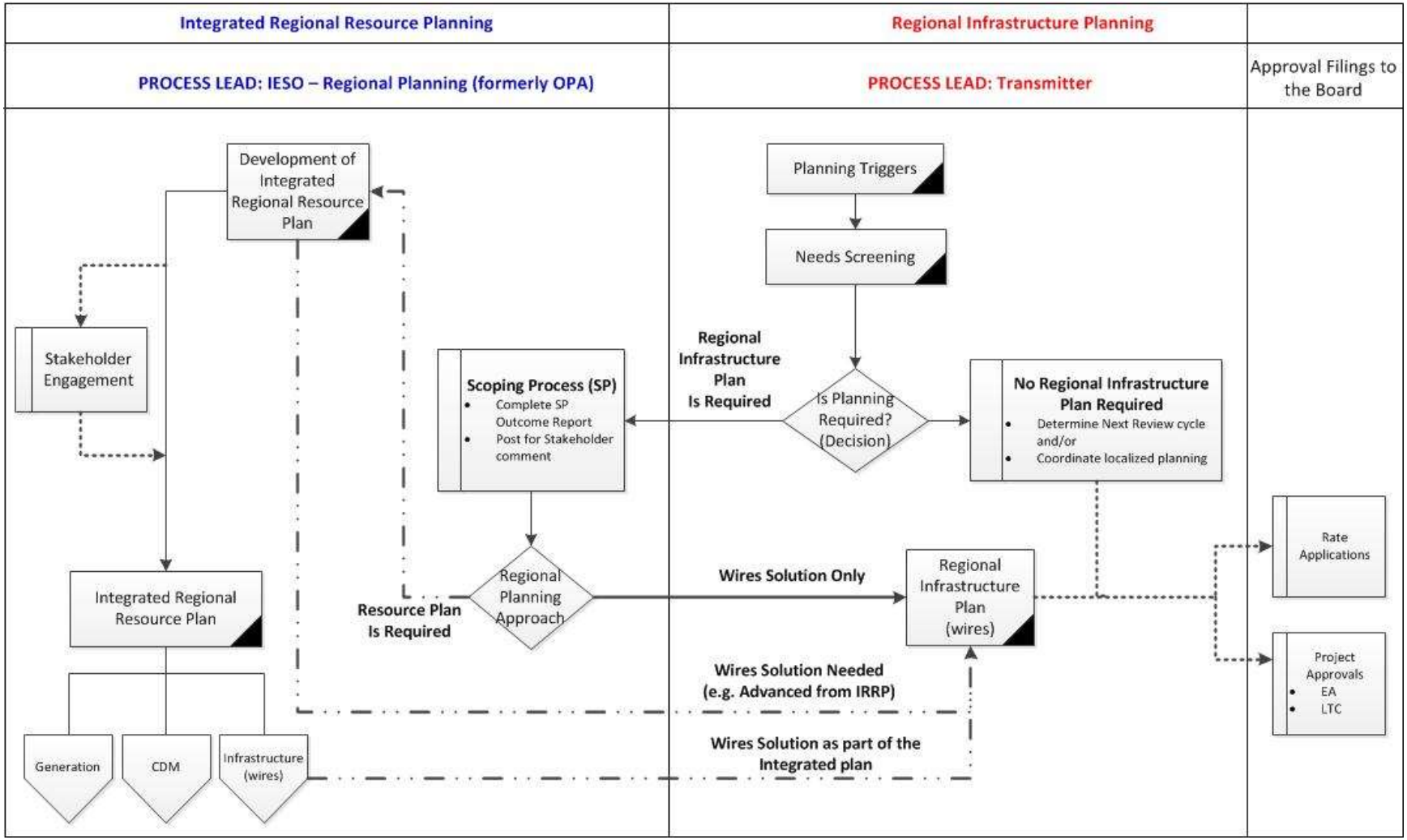


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see

Figure 2-2) as follows:

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

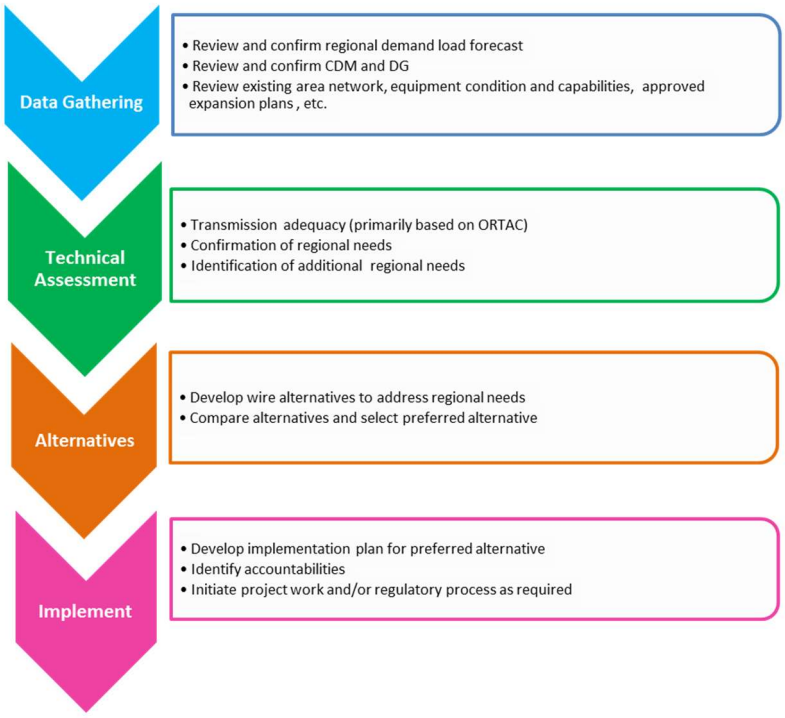


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE NIAGARA REGION COVERS THE REGIONAL MUNICIPALITY OF NIAGARA AND INCLUDES THE CITIES OF NIAGARA FALLS, PORT COLBORNE, ST. CATHARINES, THOROLD AND WELLAND, THE TOWNS OF FORT ERIE, GRIMSBY, LINCOLN, NIAGARA-ON-THE-LAKE AND PELHAM AND THE TOWNSHIPS OF WAINFLEET AND WEST LINCOLN.

The Local Distribution Companies in the Niagara Region are Alectra Utilities Corporation, Canadian Niagara Power Inc., Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara-on-the-Lake (NOTL) Hydro Inc., Niagara Peninsula Energy Inc., and Welland Hydro Electric System Corp. A listing of the LDCs along with the associated supply stations is given in Appendix C. The high-voltage system in this Region also provides supply to number of direct transmission-connected customers transformer stations.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck GS #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. The 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS connect this region to Hamilton/Burlington. The power is distributed through thirteen (13) HONI and six (6) LDC owned step-down transformer stations (please see Appendix B for a complete list. The distribution system in this Region is at two voltage levels, 27.6 kV and 13.8 kV. An electrical single line diagram for the Niagara Region transmission facilities is shown in Figure 3-1. The circuits and stations are provided in Table 3-1.

Table 3-1: Station and Circuits in the Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
Q3N, Q4N, Q11S, Q12S, A36N, A37N, A6C, A7C, D9HS, D10S, D1A, D3A, Q2AH	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q10P	Allanburg TS*, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Niagara Murray TS, Niagara West MTS, NOTL York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI Station #17 MTS, CNPI Station #18 MTS	Sir Adam Beck GS #1, Sir Adam Beck GS #2, Sir Adam Beck PGS, Thorold CGS, Decew Falls GS

*Station with Autotransformers installed

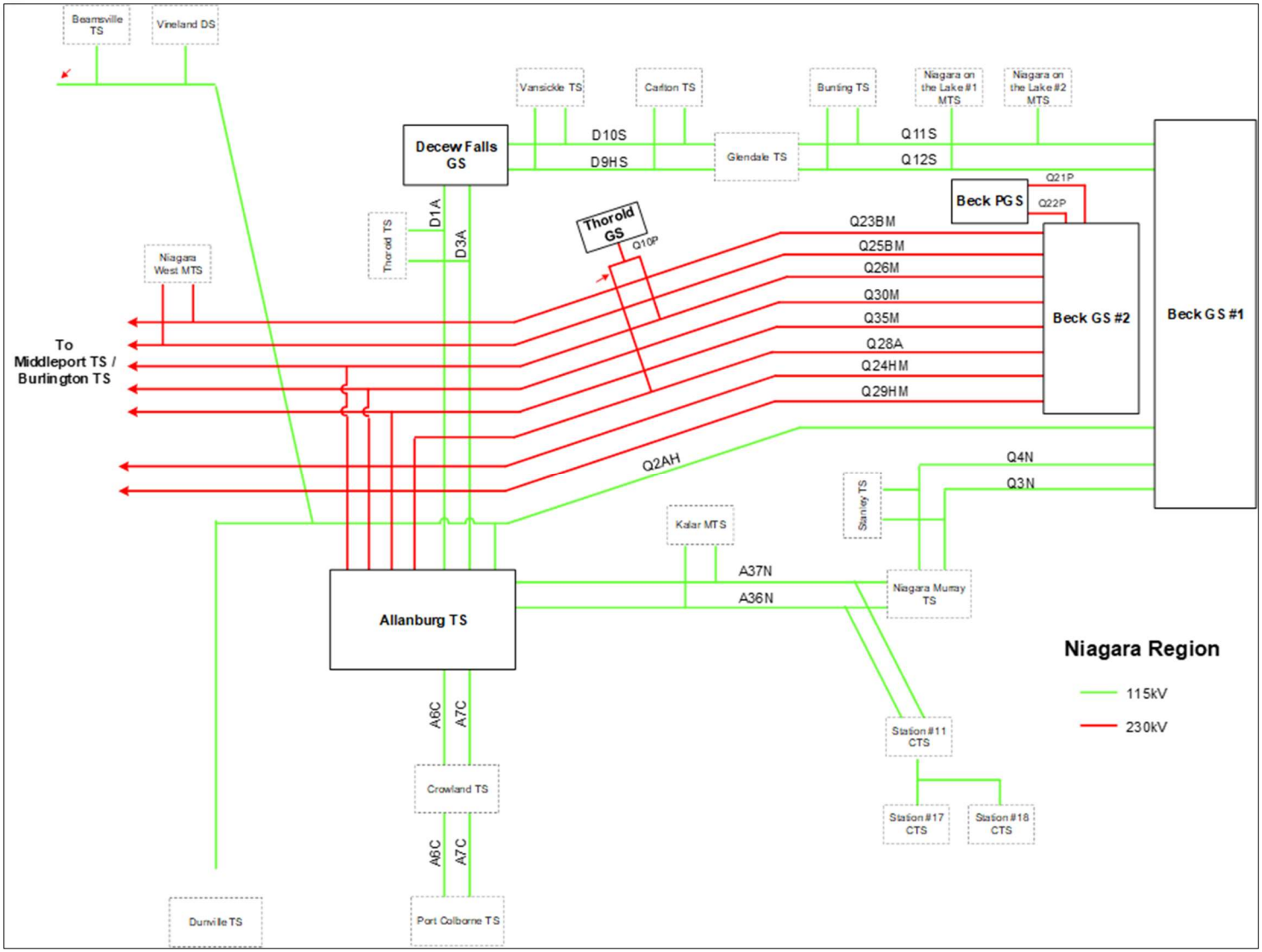


Figure 3-1: Niagara Region Single Line Diagram

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

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE NIAGARA REGION.

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

Projects Completed

- Decew Falls SS (2017) – Existing five (5) 115kV breakers were replaced with sulfur hexafluoride (SF6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – Existing 40/53/67 MVA T2 transformer was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Work at 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – Existing T61 and T62 28/37/47 MVA transformers was replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

A detailed load forecast for the Niagara region was developed as part of the area IRRP study. The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast.

The IRRP forecast used in this RIP study includes minor increases at a few stations as per the LDCs[2]. Also included is a LDC connected industrial customer with curtailable load under specific outage conditions.

The load in the Niagara Region is expected to grow at an average rate of approximately 2.3% annually from 2023 to 2032. However, a major portion of this load increase is due to industrial customers. The growth rate for the LDCs, not accounting for the industrial customers, is about 1.3%. Longer term growth rate between 2033 to 2042 for all customers is forecast to be about 0.9%.

Figure 5-1 shows the Niagara region extreme summer weather net forecast from 2023-2042. The forecast shown is the regional non-coincident forecast and shows the load for all Niagara customers as well as the load for all the LDCs. The regional non-coincident peak load is forecast to increase from approximately 1092MW in 2023 to about 1505MW in 2042.

[2] Loading at Crowland TS adjusted as per new forecast from Welland Hydro. Loading at NOTL #2 MTS and NOTL York MTS adjusted as per new forecast from NOTL Hydro.

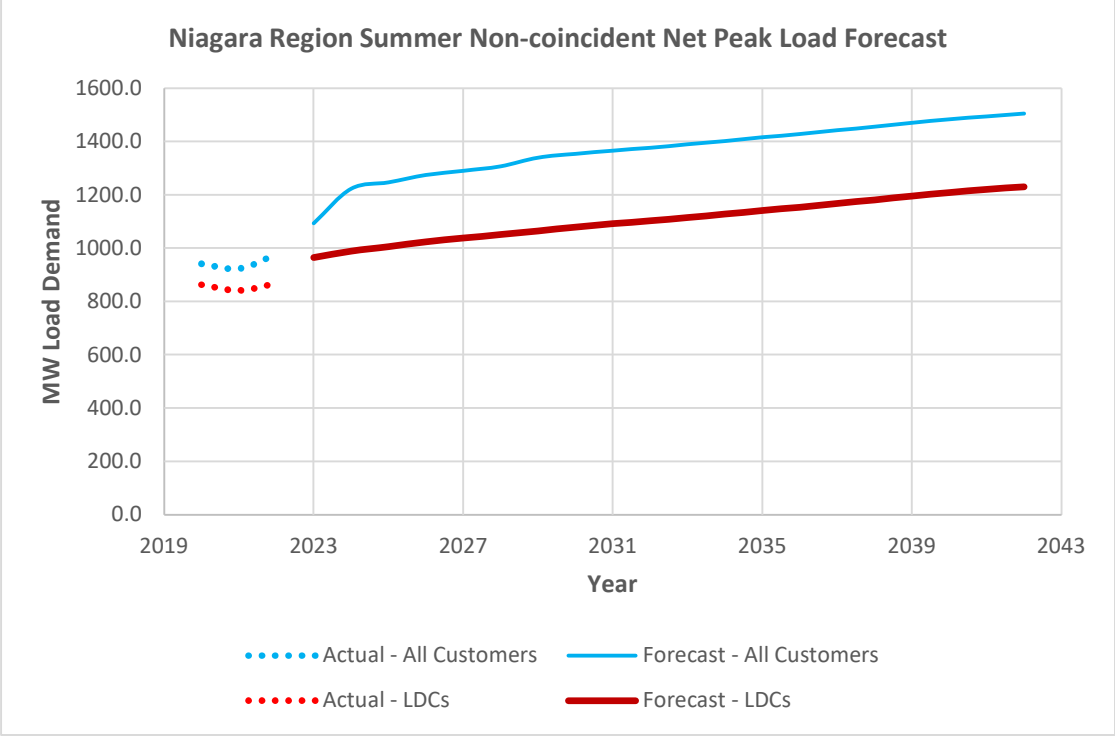


Figure 5-1: Niagara Region Summer Non-Coincident Weather Corrected Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the Niagara region IRRP.
- LDCs reconfirmed load forecasts up to 2041. The additional year of forecast to 2042 was extrapolated to complete the 20 year period.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings for this region. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, where the power factor used for the load stations are from the IRRP Appendix G.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Radial line adequacy is assessed using non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6 SYSTEM ADEQUACY AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE NIAGARA REGION AND LISTS FACILITIES REQUIRING REINFORCEMENT OVER THE 2023-2032 PERIOD.

In the current regional planning cycle, the three regional assessments were completed for the Niagara Region and their findings were used as inputs to this RIP report. These assessments are:

- Niagara Region Needs Assessment (NA) Report, May 2021.
- Niagara Region Scoping Assessment (SA) Report, August 2021
- Niagara Region Integrated Regional Resource Plan (IRRP), December 2022 and Appendices, February 2023

The NA and IRRP reports identified several needs because of the forecasted load demand and condition of major high voltage transmission assets. This section reviews the adequacy of the transmission lines and stations in the Niagara Region based on the updated regional load forecast provided in Appendix C. Sections 6.1 to 6.3 present the results of this review. Asset replacement needs identified in the previous NA report are discussed in Section 6.4 of this report. Load security and load restoration needs are discussed in Section 6.5.

6.1 230 kV and 115kV Transmission Circuits

All 230 kV transmission circuits in the Niagara Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the Ontario's transmission system, carry power from the Niagara River Generation to the rest of Ontario and are part of the interconnection path that connects Ontario to neighboring New York State at the Beck 2 SS. The 230 kV circuits Q26M, Q28A, Q30M and Q35M circuits also supply the 230/115 kV autotransformer station at Allanburg TS to serve local area stations within the region. The power flow on these circuits depend on the bulk system transfers as well as the local area loads.

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Niagara Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 6-1 below. The need date defines the time when the peak load forecast exceeds the most limiting summer Limited Time Ratings. Mitigation measures are discussed in Section 7.1.

Table 6-1: Niagara Region - Lines Sections Exceeding Ratings

No.	Voltage	Line	Section	Contingency	Line Rating MW	Need Date
1	230kV	Q28A	Beck 2 x Abitibi Jct.	N-2[1]	386	2024[2]
2	115kV	A6C/A7C	Allanburg TS x Crowland TS	N-1	214	2029

1. Loss of double circuit line Q26M/Q35M
2. Need date dependent on customer forecast load increase

6.2 230/115kV Transformation Facilities

Almost ninety percent of the Niagara Region load is supplied from the 115 kV transmission system. This power is supplied to the 115kV system through the four 230/115 kV autotransformers at Allanburg TS together with 115kV generation at Sir Adam Beck #1 GS and Decew Falls GS.

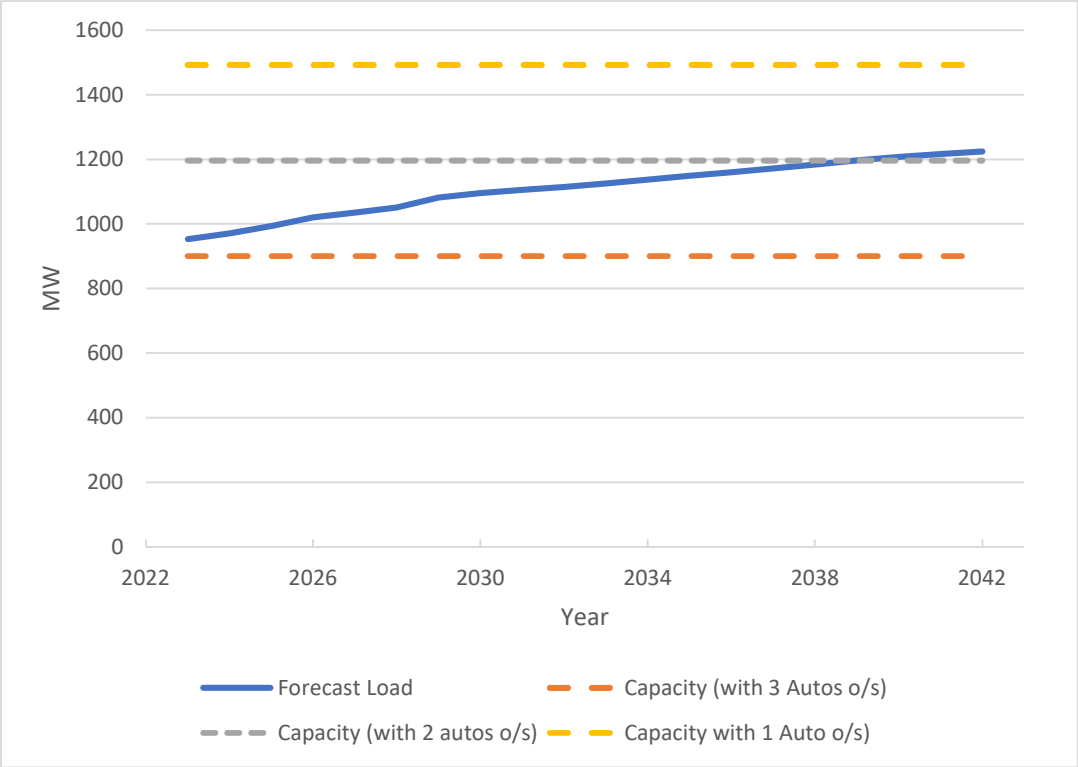


Figure 6-1: Niagara Region – 115kV Area Load and Supply Capacity

The forecast loading on the 115kV system is shown in Figure 6-1, together with the supply capacity with one, two and three autotransformers out of service at Allanburg TS and the local 115kV generation at 605MW[3]. There is adequate supply capacity in the region for the loss of up to 2 of the 4 autotransformers beyond the 2023-2032 RIP study period. However, since the autotransformers are connected to the 230kV circuits directly – loss of up to three autos can occur under an outage condition followed by a double circuit line outage – resulting in load exceeding supply capacity (N-1-2 contingency). Mitigation measures to address this issue are described in Section 7.2.

6.3 Step Down Transformation Facilities

There are a total of twenty-six (26) step-down transformer stations supplying power to customers in the Niagara Region as listed in Table 6-2. These include thirteen stations owned by Hydro One, six by area LDCs and seven (7) by direct industrial customers. The stations' summer peak load forecast is given in Appendix D Table D-1.

Table 6-2: Niagara Region - Step-Down Transformer Stations

Allanburg TS	CNPI Station #18 MTS	Murray TS	Stanley TS
Beamsville TS	Crowland TS	Niagara West MTS	Thorold TS
Bunting TS	Dunnville TS	NOTL #2 MTS	Vansickle TS
Carlton TS	Glendale TS	NOTL York MTS	Vineland DS
CNPI Station #17 MTS	Kalar MTS	Port Colborne TS	CTS #1
CTS #2	CTS #3	CTS #4	CTS #5
CTS #6	CTS #7		

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV transformer stations within the Niagara Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 6-3.

[3] Beck GS #1 is assumed at 490MW and Decew Falls GS at 115 MW.

The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time Ratings. Mitigation measures to address this issue are described in Section 7.3.

Table 6-3: Niagara Region Station Capacity Needs in the Study Period

No.	Station Name	Capacity (MVA)	2023 Loading (MW)	Station 10- day LTR (MW)	Need Date
1	Beamsville TS	25/42	64.2	59.0	2023
2	Murray TS T11/T12	45/75	77.7	73.2	2023
3	Niagara West MTS	40/67	54.6	66.0	2024
4	Crowland TS	50/83	100.9	101.7	2024
5	Carlton TS	45/75	89.2	95.4	2029

6.4 Asset Replacement Needs for Major High Voltage (HV) Transmission Equipment

Several Hydro One facilities in the Niagara Region will require asset renewal work over the 2023-2032 study period. These needs are determined by asset condition based on a range of considerations such as equipment deterioration, technical obsolescence due to outdated design, lack of spare parts availability or manufacturer support, and/or potential health and safety hazards.

Asset replacement work is planned over the study period at area transformer stations and lines listed in Table 6-4. The options and preferred solutions to address these needs are discussed further in Section 7.4 of the report.

Table 6-4: Niagara Region - Planned Replacement Work

No.	Station	Planned I/S Date
A - Station Work		
1	Thorold TS	2024
2	Glendale TS	2027
3	Murray TS T11/T12	2027
4	Carlton TS	2027
5	Crowland TS	2027
6	Bunting TS	2029
7	Murray TS T13/T14	2031
8	Vansickle TS	2032
9	Allanburg TS	2032
B – Lines Work		
1	115kV D1A/D3A	2024
2	115kV Q2AH	2025

6.5 Load Security and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study and one load security need has been identified for the region. The ORTAC requires that not more than 150MW of load may be interrupted by planned load curtailment or load rejection and the Allanburg Load Rejection scheme does not meet the criteria.

6.5.1 A6C/A7C Load Security

The loss of the 230kV double circuit line Q26M/Q28A, will result in the coincidental loss of autotransformers T1 and T2 at Allanburg TS and the separation of the 115kV A6C/A7C and D1A and A36N circuits from the Allanburg TS 115kV bus. Under this scenario the Allanburg Load Rejection scheme trips the A6C and A7C circuits to prevent loads connected to the A6C/A7C circuits from excessive voltage declines. The load on the A6C/A7C is currently about 200MW and forecast to increase to 278MW by the end of the plan period. The amount of load rejected is thus more than the permitted amount of 150 MW allowed under ORTAC. Mitigation measures to address this need are discussed in Section 7.5.

7 REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE NIAGARA REGION.

The electrical infrastructure needs for the Niagara Region are summarized in Table 7-1. These needs include those previously identified in the Niagara Region NA and IRRP as well as those resulting from the adequacy assessment carried out as part of this RIP report. The details of the project/plan to address these needs are provided in Sections 7.1 through 7.5.

Table 7-1: Niagara Region – Identified Near and Medium-Term Needs

Section	Facilities	Need	Timing
Transmission Line Capacity Needs			
7.1.1	Q28A -Beck 2 TS to Abitibi Jct.	Line Capacity Exceeded	2024
7.1.2	115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS	Line Capacity Exceeded	2029
230/115 kV Transformation Capacity/115kV Supply Area Capacity			
7.2	Allanburg TS	Loading exceeds Capacity at Allanburg TS	2023
Station Capacity			
7.3.1	Beamsville TS and Niagara West MTS	Forecast load exceeds normal supply capacity	2023
7.3.2	Crowland TS	Forecast load exceed normal supply capacity	2024
7.3.3	Murray TS and Kalar TS	Forecast load exceed normal supply capacity	2028
7.3.4	Carlton TS	Forecast load exceed normal supply capacity	2029
Asset Replacement			
7.4	Thorold TS	Transformer T1 replacement	2024
7.4	Carlton TS	LV Switchyard refurbishment	2027
7.4	Glendale TS	Transformers T1 and T2 replacement	2027
7.4	Crowland TS	Transformer T5 and T6 replacement	2027
7.4	Murray TS	Transformers T11 and T12 replacement	2027
7.4	Bunting TS	Transformers T1 and T2 replacement	2029
7.4	Murray TS	Transformers T13 and T14 replacement	2031
7.4	Vansickle TS	LV Switchyard refurbishment	2032
7.4	Allanburg TS	Transformer T3 replacement	2032
7.4	115kV Line D1A/D3A	Gibson Jct. x Thorold TS	2024
7.4	115kV Line Q2AH	Rosedene Jct. x St. Anns Jct.	2025
Load Security			
7.5	115kV A6C/A7C Load Security	Forecast exceeds ORTAC load rejection Criteria	2023

7.1 Transmission Line Capacity

This section describes work required to address the transmission line capacity needs associated with the 230kV circuit Q28A and 115kV circuits A6C and A7C as described in Section 6.1.

7.1.1 230kV circuit Q28A – Beck #2 TS x Abitibi Junction

7.1.1.1 Introduction

The 230kV circuit Q28A is part of the eight transmission circuits egressing from Beck #2 GS and connects to Allanburg TS. The planning forecast based on new customer load indicates that the loading will exceed the circuit 980A rating by summer 2024 for a loss of the double circuit line Q26M/Q35M.

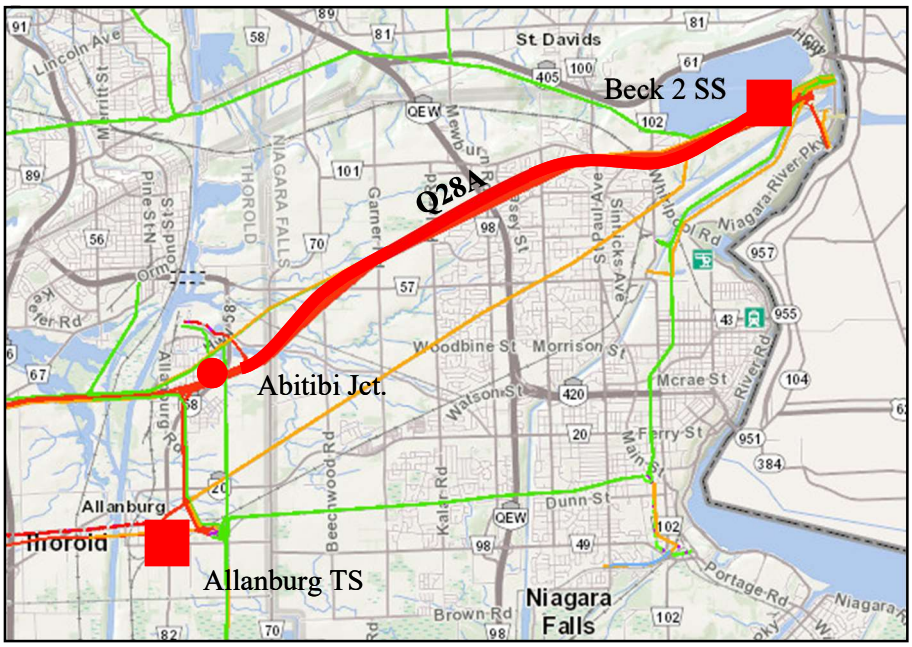


Figure 7-1: Uprate Q28A Circuit

7.1.1.2 Alternatives and Recommendation

The following alternatives were considered to address the 230kV circuit Q28A capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate 230kV Q28A Circuit:** This alternative considers uprating the conductor by tensioning the conductors to reduce the line sag and allow the line conductor to operate at a higher temperature. This will increase the circuit rating from 980A to 1310A. The estimated cost of the work is about $3M.

The TWG recommends Alternative 2 as the preferred and cost-effective alternative for increasing the capacity of the line. Hydro One has advised the customer of the proposed work and will initiate the work once confirmed by the customer.

7.1.2 115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS

7.1.2.1 Introduction

The 115 kV double circuit line A6C/A7C supplies Crowland TS and Port Colborne TS along with several directly connected transmission customers as shown in Figure 7-2. The load connected on this line is forecast to exceed the line capacity by summer 2029 as shown in Table 7-2.

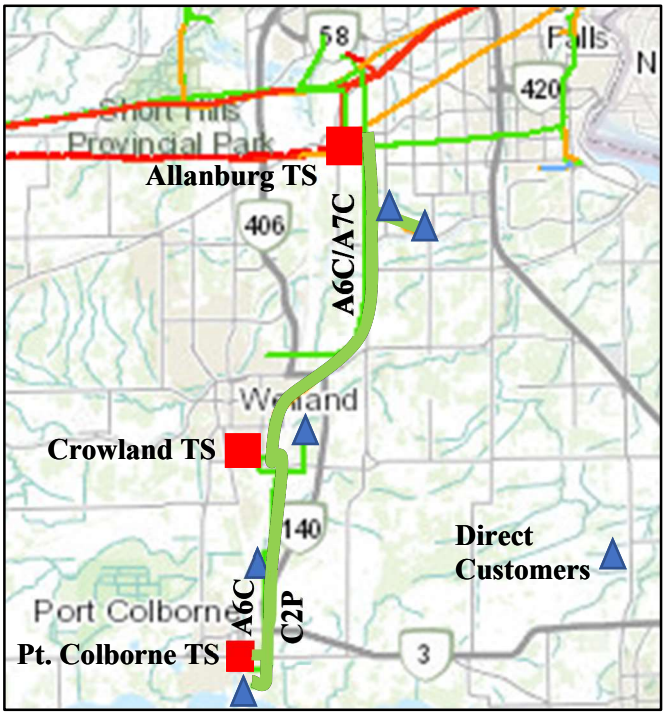


Figure 7-2: Map of 115kV A6C/A7C Circuits

Table 7-2: 115kV circuit A6C/A7C -Connected Loads

Load	Circuit Limit	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
A6C/A7C[2]	213.9[3]	169.5	174.0	182.4	191.6	202.2	206.8	211.6	232.7	234.9	236.8	236.9	246.1	2029
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	---
A6C/A7C post Crowland[4]			-	-	-	-	92.7	95.7	115.1	115.3	115.5	115.7	117.6	---

1. Actual summer load adjusted for extreme weather
2. Loading excludes Allanburg TS DESN
3. Rating of A6C/A7C circuit between Allanburg TS DESN and Crowland TS

4. After Crowland TS conversion to 230KV as per Section 7.3.2 in 2027

7.1.2.2 Alternatives and Recommendation

The following alternatives were considered to address the overloading issue on the 115kV line A6C/A7C line:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate the A6C and A7C Circuits:** This alternative considers reconductoring the A6C/A7C line between Allanburg TS and Crowland TS (~ 14.5 km) using a higher rated conductor. This will increase the circuit rating from 214 MW to about 280 MW. The estimated cost of the work is $23M.
- **Alternative 3 – Reduce Loading on A6C/A7C:** This alternative reduces loading on circuits A6C and A7C by rebuilding Crowland TS[4] as a 230/27.6 kV station supplied from and supplying it from a new 230kV circuit line.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative addressing the overloading issue on the A6C/A7C line. Transferring of Crowland TS to a 230 kV supply also addresses multiple other issues; reduces load on the Allanburg TS autotransformers (See Section 7.2.2), allows increase capacity at Crowland TS (see Section 7.3.2), and reduces the severity of the load security issue (Section 7.5).

7.2 115kV Supply Area Capacity

7.2.1 Introduction

As shown in Section 6.2, the loads on the Niagara Region 115kV system exceeds the 115 kV system supply capability under certain contingency conditions which result in three out of the four autotransformers being out of service at Allanburg TS. Specifically, this occurs under a 230kV outage condition followed by a double 230kV circuit line outage (N-1-2 contingency).

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the 115 kV supply capacity:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.

[4] Crowland TS needs to be refurbished and will be rebuilt. Please refer to Section 7.3.2 and 7.4 for more details.

- **Alternative 2 – Modify Existing Load Rejection Scheme for 115kV Subsystem:** This alternative modifies the Allanburg load rejection scheme to include rejection of up to 150MW of load whenever three autotransformers are out. The estimated cost of this alternative is about $8M.
- **Alternative 3 – New 230kV Switchyard at Allanburg TS:** The work required in this alternative is to build a new 230kV switchyard to eliminate the N-1-2 contingency at Allanburg TS (loss of three autotransformers contingency) to supply more power to the 115kV network. The work required would consist of four new 230kV bus diameters, each accommodate an autotransformer to eliminate any coincidental loss of the autotransformers. This work has an estimated cost of $253M.
- **Alternative 4** – **Reduce load on 115kV system by introducing 230kV Supply to the Welland Area** - This alternative would transfer Crowland TS to 230kV supply by building a 18km double circuit 230kV transmission line from Q24HM/Q29HM to connect to a new 230/27.6kV transformer station at the Crowland TS site. The new TS will replace the existing station that requires replacement. This work has an estimated cost of $128M.

The TWG recommends Alternative 4 as the most cost effective and preferred alternative. Besides addressing the 115kV supply capacity needs, this alternative also addresses; the A6C/A7C overloading issue (Section 7.1.2); the Crowland TS capacity needs (Section 7.3.2); the Crowland TS asset renewal needs (Section 7.4); and reduces the severity of the A6C/A7C load security issue (Section 7.5). The work is planned to be in service by summer 2027.

7.3 Station Capacity Needs

This section describes the work required to address the station capacity needs identified in Section 6.3.

7.3.1 Beamsville TS, Vineland DS, Niagara West MTS – 115kV Lincoln Area

7.3.1.1 Introduction

Beamsville TS and Vineland DS are 115/27.6kV stations and Niagara West MTS is a 230/27.6kV station which supplies the towns of Grimsby, West Lincoln, and Lincoln. The area is experiencing load growth where the summer weather extreme demand forecast will exceed the area normal supply capacity.

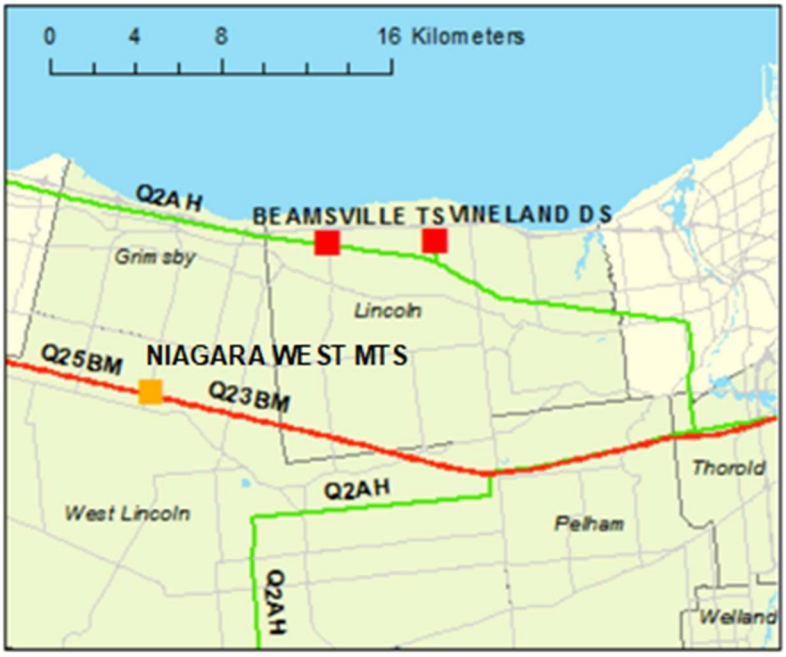


Figure 7-3: Map of 115kV Lincoln Area

Beamsville TS presently has 115kV/27.6kV 42MVA transformers (T3/T4) with a summer LTR of 59.0MW. This station has operated at or slightly over the LTR over the past few years.

Table 7-3 shows the forecast for the three area stations. The forecast shows that the combined capacity of the three stations would be exceeded by summer 2024. The TWG agrees that a solution is required to address the upcoming supply capacity needs.

Table 7-3: 115kV Lincoln Area Stations Load Forecast

Station	LTR MW	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Beamsville	59.0	63.1	77.2	79.2	80.5	81.4	82.1	82.9	83.7	84.6	85.6	86.5	101.9	---
Niagara West MTS[2]	63.4	41.6	49.0	56.8	57.6	58.2	58.9	60.3	61.7	63.2	64.7	66.2	84.3	---
Vineland DS	26.4	20.5	20.7	20.9	21.1	21.3	21.6	22.5	23.5	24.5	24.7	25.0	27.6	---
Total	148.8	125.3	147.0	156.9	159.2	161.0	162.5	165.7	168.9	172.3	175.0	177.7	213.8	2024

1. Actual summer load adjusted for extreme weather

7.3.1.2 Alternatives and Recommendation

The following alternatives were considered to address the area capacity need:

- **Alternative 1 – Maintain Status Quo:** This solution is not recommended as it does not address the supply capacity needed in the area. This solution will also prevent load growth in this area.

- **Alternative 2 – Load Transfer to Neighbouring Stations:** This solution is not viable as there is no nearby station where the load can be transferred.
- **Alternative 3 – Replace Beamsville and Niagara West transformers:** Replace existing Beamsville TS T3/T4 transformers and Niagara West MTS T1/T2 with larger 50/83MVA units, providing total additional capacity of 100 MW at both stations to address the existing and future load demand. Additional feeder positions will be required at both stations to utilize the additional capacity. The cost of this work is estimated to be about $48M.
- **Alternative 4 – Build new 230/27.6kV DESN station in Local Area:** This alternative would build a new 230/27.6kV DESN station to supply the increased load demand forecast required in the local area. The new station would be supplied by the double circuit 230kV transmission line Q23BM/Q25BM with new 50/83MVA transformers. The new station will provide about 102 MW of new capacity. The estimated cost of this alternative is about $45M.

The TWG recommends proceeding with Alternative 4. This alternative provides a robust transmission solution to meeting the area LDCs demand forecast and will also allow for future load growth beyond the study period on the 230kV system. This solution will also provide better reliability for future loads as the new station will have dual incoming transmission supplies into station instead of being on a single supply like Beamsville TS. Loads will be managed by the respective LDCs between 2024 and 2027 when the new facility is expected to go into service.

Hydro One will work with all the respective parties to find a suitable location to meet the load. Possible locations could be an expansion at Niagara West MTS or a location central to Vineland DS and Beamsville TS to supply local growth (e.g., the southwest corner in the Town of Lincoln).

7.3.2 Crowland TS

7.3.2.1 Introduction

Crowland TS is a 115/27.6kV 50/83MVA transformer station located in Welland. The station load is at or near its 10-day LTR of 101.7 MW and load is forecasted[5] to increase up to 121MW by the end of 2032 as shown in Table 7-4 below. A permanent supply solution is required for the increased load growth as the current loading will surpass the station capacity in 2024.

The transformers, T5 and T6, at Crowland TS are about 55 years old and based on asset condition assessment Crowland TS has been identified for asset renewal by summer 2027.

[5] Forecast updated from IRRP as per Welland Hydro



Figure 7-4: Map of Crowland TS

Table 7-4: Crowland TS Load Forecast

Station	LTR MW	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Crowland TS	101.7	93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	2024

1. Actual summer load adjusted for extreme weather

7.3.2.2 Alternatives and Recommendation

The following alternatives were considered to address Crowland TS capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.
- **Alternative 2 – Rebuild existing DESN at Crowland TS and add a second DESN at Crowland TS:** Under this alternative the existing Crowland TS transformers will be replaced, and the station refurbished. A new second DESN would be built to handle the increased load. This alternative would maintain the existing 115kV loading on the Allanburg autotransformers and work will be required to address the issue. Work also would be required to address the capacity need on the A6C/A7C circuits and address the load security concern at Allanburg TS. This alternative is estimated to cost $78M for the refurbishment work and new DESN at Crowland TS. An additional $253M will be required to provide additional switching at Allanburg TS to reinforce the 115kV supply.

- **Alternative 3 – Provide a new 230kV Supply to Welland Area and convert Crowland TS to 230kV:** Under this alternative the existing Crowland TS would be replaced with a new 230/27.6 kV DESN station with 75/125 MVA transformers to supply the increased load demand. A new 18km double circuit 230kV transmission line will be constructed to supply this new transformer station from the double circuit 230 kV line Q24HM/Q29HM. This new station would allow the station LTR to increase to approximately 170 MW (summer) with 75/125MVA transformers. The estimated cost of this alternative is about $128M.

The TWG recommends Alternative 3 as it is the lowest cost alternative. It provides new area transmission and load growth opportunities. The conversion of Crowland TS to 230kV will reduce the loading on the 115kV autotransformer at Allanburg TS, alleviating the constrained supply to the 115 kV sub-system described previously. It will also remove the existing Crowland TS loads from the 115kV A6C/A7C circuits, alleviating the severity of the load security constraint at Allanburg TS. This alternative will also provide a parallel opportunity for load growth on the 115kV A6C/A7C circuits as the Crowland TS load is removed from the 115kV system.

7.3.3 Murray TS and Kalar MTS – Niagara Falls

7.3.3.1 Introduction

Murray TS and Kalar TS are two transformer stations located in Niagara Falls. Murray TS has two 115/13.8 DESNs, T11/T12 and T13/T14, with a summer LTR of 73.2MW and 79.8MW respectively. Kalar MTS has one 115/13.8 kV DESN with a summer LTR of 72.0 MW. The stations forecast loads are given in Table 7-5. Considerable new loads are expected to connect in the area. Loading on the Murray TS T11/T12 DESN is forecast to exceed its LTR by summer 2023. Loading on Kalar MTS is forecast to exceed LTR by summer 2028.

The Murray TS transformers, T11, T12, T13 and T14 are between 46 and 52 years old and have been identified for replacement due to asset condition. It is planned to replace T11 and T12 by summer 2027. This will be followed by the replacement of the T13 and T14 transformers by summer 2031.

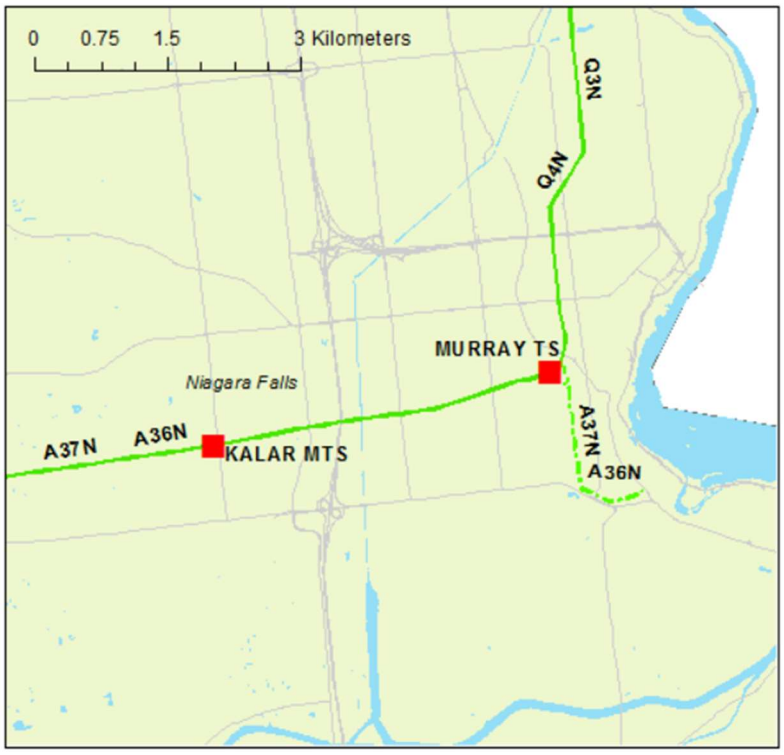


Figure 7-5: Map of Murray TS and Kalar MTS

Table 7-5: Murray TS, and Kalar MTS Load Forecast

Station	LTR MW	Act[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Murray TS T11/T12	73.2	66.3	77.7	77.7	77.8	78.0	77.9	78.1	78.3	78.7	78.9	79.1	86.2	2023[2]
Murray TS T13/T14	79.8	41.7	42.0	42.2	42.4	42.6	42.9	43.1	43.3	43.5	43.8	44.0	46.6	Note[3]
Kalar MTS	72.0	46.5	46.9	47.4	54.2	60.7	64.4	65.8	67.1	68.6	68.8	69.0	75.1	2039
Total	225.0	166.3	166.6	167.3	174.4	181.3	185.2	187.0	188.7	190.8	191.5	192.1	207.9	

1. Actual summer load adjusted for extreme weather
2. Earliest replacement to happen by 2027
3. The transformers T13 and T14 will be replaced in 2031as per asset condition.

7.3.3.2 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the need as the near and mid-term load forecast exceeds the LTR at Murray TS T11/T12. Asset renewal needs are also not addressed.
- **Alternative 2 – Replace T11/T12 at Murray TS with 60/100MVA transformers:** This alternative would replace the T11/T12 transformers with larger 60/100MVA transformers, with an approximate

LTR of 130MW instead of the 45/60/75MVA units specified for the asset renewal project at Murray TS. This will increase supply capacity of approximately 43MW at Murray TS at an estimated incremental cost of $2M to the asset renewal upgrade cost of $39M. The earliest this work can be done is summer 2027.

- **Alternative 3 – Transfer T11/T12 load to T13/T14 at Murray TS:** This alternative would transfer load from T11/T12 to T13/T14 at a cost of $5M. The T13/T14 bus supplies a large industrial load customer with fluctuating load and customers connected to the bus would experience power quality issues.
- **Alternative 4 – Build new 115kV/13.8kV Station near Kalar MTS:** This alternative would build a new 115/13.8kV DESN station with 25/41.7MVA transformers to supply the increased load demand forecast required at Kalar MTS and Murray TS T11/T12. This new station would provide the station an LTR of 51MW (summer). The estimated cost for this alternative is expected to be $40M.

The TWG recommends Alternative 2 as the preferred alternative for addressing the capacity need as it is the most economical alternative with the ability to increase supply capacity. Alternative 3 is not recommended since is more expensive, will introduce power quality issues to the transferred load and is not acceptable to the LDC. Loading will be monitored and managed at Murray TS by the LDC and Hydro One in the interim before the additional capacity is provided in 2027. The Kalar MTS load growth will be monitored to verify if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and can transfer the extra load from Kalar MTS to Murray TS.

7.3.4 Carlton TS and Bunting TS – St. Catharines

Carlton TS and Bunting TS are two transformer stations located in St. Catharines. Carlton TS has one 115/13.8 kV T1/T2 DESN with a summer LTR of 95.4 MW. Bunting TS has one 115/13.6 kV T1/T2 DESN with a summer LTR of 78.2 MW. The stations forecast loads are given in Table 7-6. Loading on Carlton TS is forecast to exceed its LTR by summer 2029. Bunting TS is adequate over the study period.

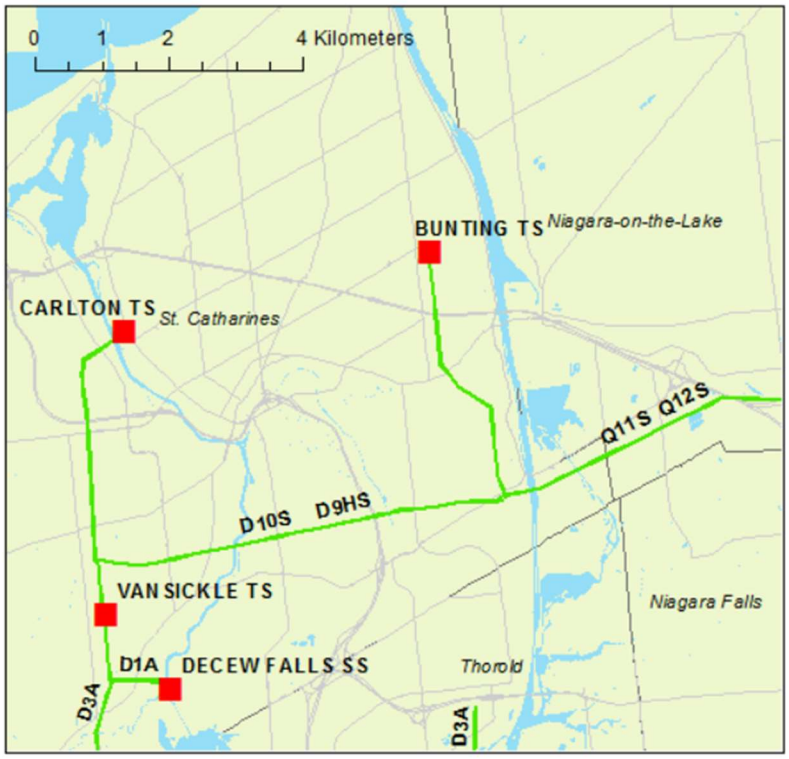


Figure 7-6: Map of Carlton TS and Bunting TS

Table 7-6: Carlton TS and Bunting TS Load Forecast

Station	LTR MW	Act. [1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Carlton TS	95.4	82.6	89.2	90.1	91.1	92.2	93.3	94.6	95.9	97.3	98.9	100.3	105.7	2029
Bunting TS	78.2	54.4	57.8	58.3	58.8	59.6	60.4	61.4	62.4	63.6	64.7	65.9	77.1	---
Total	173.6	137.0	147.1	148.4	149.9	151.8	153.7	156.0	158.3	160.9	163.6	166.2	182.8	----

1. Actual summer load adjusted for extreme weather

Both Carlton TS and Bunting TS also have renewal work planned. The LV switchyard at Carlton TS is over 50 years old and refurbishment is required. The Transformer T3 at Bunting TS is also over 50 years and identified for replacement.

7.3.4.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the stations sustainment need. Carlton TS load also exceeds its LTR and action is required to address the issue.

- **Alternative 2 –Carry out Asset Renewal at Carlton TS and Bunting TS**: Monitor Carlton TS loading and transfer excess load to Bunting TS: The station refurbishment work will be carried out at both stations. Carlton TS load growth will be monitored to see if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and transfer the excess load over the LTR from Carlton TS to Bunting TS. The cost to transfer the load between stations is estimated to be $5M.

The TWG recommendation is that it is prudent to monitor the area load and complete load transfer at nearby stations with available station capacity when required. The TWG recommends Alternative 2 as the preferred and cost-effective alternative for addressing the need.

7.4 Asset Replacement for Major HV Transmission Equipment

As discussed in Section 6.3, Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at several Niagara Region Hydro One stations as well as two small line sections. Details of the work along with its planned in-service year is given in Table 7-7.

Table 7-7: Niagara Region – Asset Replacement Plans

No.	Station /Line	Planned Work	Planned I/S Date[1]
1	Thorold TS	Replace the existing 45/60/75 MVA T1 transformer with a new 45/60/75 MVA unit.	2024
2	Glendale TS	Replace the existing T1/T2 45/60/75 MVA transformers, with new 45/60/75 MVA units.	2027
3	Crowland TS	The existing 115/27.6 kV T5/T6 DESN will be replaced by a new 230/27.6 kV DESN rated for 170 MW.	2027
4	Murray TS	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units. Replace the existing 45/60/75 MVA transformers T13 and T14 with new 60/80/100MVA units.	2027 2031
5	Bunting TS	Replace the existing 40/53/67 MVA transformers, with new 45/60/75 MVA units	2029
6	Vansickle TS	Replace LV Switchgear	2032
7	Allanburg TS	Replace Autotransformer T3	2032
8	115kV Line D1A/D3A	115kV kV line refurbishment of a 5 km line section between Gibson Jct and Thorold TS with conductor to be replaced due to asset condition	2024
9	115kV Line Q2AH	115kV line refurbishment of 11.2km between Rosedene Jct. and St. Anns Jct. with conductor to be replaced due to asset condition	2025

1. The planned in-service date is tentative and is subject to change

The TWG recommends that Hydro One proceed with the above work to ensure that the system meets reliability criteria and supply to customers is not affected.

7.5 Load Security – 115kV circuits A6C/A7C

As discussed in Section 6.4.1 the *Allanburg Load Rejection scheme* trips 115kV circuits A6C/A7C under certain contingencies to prevent stations supplied from these circuits being subjected to excessive voltage declines.

The *Allanburg Load Rejection Scheme* is designed to address post contingency voltage decline issues following the coincident loss of Allanburg 230/115 kV Autotransformers T1 and T2. The coincidental loss of Allanburg T1 and T2 transformers will result in circuits A6C and A7C being disconnected from the Allanburg TS 115kV and buses radially connected to circuits D1A and A36N, respectively. As such, this causes excessive voltage to decline at stations supplied from circuits 115kV A6C and A7C. The scheme rejects the load connected to circuits A6C and A7C and will prevent the radial feeds (from Decew Fall GS on D1A and the Niagara Corridor on A36N) from trying to support the load of A6C and A7C.

The load security need arises from Section 7.1 of the ORTAC. As defined under this section, Not more than 150MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management. The A6C/A7C load forecast is provided in Table 7-8.

Table 7-8: 115kV Circuit A6C/A7C -Connected loads

Load	ORTAC L/R Limit	Act.[1]	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042
A6C/A7C	150	209.6	219.3	227.8	237.1	247.9	252.6	257.5	278.7	281.1	283.1	283.4	297.0
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5
A6C/A7C post Crowland[2]		-	-	-	-	-	138.5	141.7	161.2	161.5	161.9	162.2	168.5

1. Actual summer load adjusted for extreme weather
2. After Crowland TS conversion to 230KV as per Section 7.3.2

This forecast exceeds the permissible limit set by ORTAC. It also exceeds the A6C/A7C line limit for loss of one of the two circuits.

7.5.1.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the ORTAC load security need.
- **Alternative 2 – Reduce Loading on A6C/A7C:** This alternative reduce loading on 115kV circuits A6C and A7C by removing Crowland TS from the A6C/A7C supply. Crowland TS is rebuilt as a 230/27.6 kV station supplied from a new 230kV double circuit line.

The TWG recommends Alternative 2 as the preferred alternative to addressing the load security issue in the ORTAC. This alternative will be partially addressed by converting Crowland TS to a 230kV supply as described in Section 7.3.2. Since the Crowland TS work will not be completed till 2027, the issue will be

managed by operational measures. Load can be restored within 15 minutes by opening both T1 and T2 disconnect switches and supplying all the Allanburg 115kV load from the remaining T3 and T4 autotransformers during a coincident T1 and T2 outage. This work reduces the severity of the load security issue. The loading on the A6C/A7C will continue to be monitored and reviewed in the next planning cycle with the option to transfer Allanburg TS DESN to 230kV.

8 CONCLUSION AND RECOMMENDATION

This Regional Infrastructure Plan report concludes the Regional Planning process for the Niagara Region.

The major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2032 are provided in Table 8-1 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 8-1: Recommended Plans over the next 10 Years

No.	Need	Recommended Action Plan	Lead	Timing[1]	Budgetary Estimates[2]
1	230 kV circuit Q28A – Additional capacity required	Uprate circuits between Beck 2 SS and Abitibi Jct. to meet expected load demand	Hydro One	TBD[3]	$3M
2	Loading in the Lincoln area exceeding supply capability	Build new 2 x 50/83MVA, 230kV/27.6 station	Hydro One	2028	$45M
3	Crowland TS: Station loading exceeds LTR	Build new 2 x 75/125MVA, 230kV/27.6 station and a new 18 km line from Abitibi Jct to Crowland TS	Hydro One	2027	$128M
4	Murray TS T11/T12 DESN: DESN loading exceeds LTR. Transformers T11/T12 need to be replaced	Replace existing 45/75MVA transformers with larger 60/100MVA units	Hydro One	2027	$41M
5	Carlton TS: T1/T2 DESN loading exceeds LTR	Transfer excess load to Bunting TS	Alectra	2029	$5M
6	**Asset Replacement:** Thorold TS Glendale TS Carlton TS Bunting TS Murray TS T13/T14 Vansickle TS Allanburg TS 115kV Line D1A/D3A 115kV Line Q2AH	Refurbish/replace major high voltage transmission equipment	Hydro One	 2024 2027 2027 2029 2031 2032 2032 2024 2025	 $43M $55M $55M $45M $27M $14M $20M $4M $10M

1. The planned in-service dates are tentative and subject to change
2. Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)
3. Contingent on customer

9 REFERENCES

[1] Niagara Region Integrated Resource Plan - Dec 2022

[2] Niagara Region NA report - May 2021

[3] Niagara Region Regional Infrastructure Plan Report - March 2017

APPENDIX A: NIAGARA REGION - STEP-DOWN TRANSFORMER STATIONS AND SUPPLY CIRCUITS

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Allanburg TS	115	A6C/A7C
2	Beamsville TS	115	Q2AH
3	Bunting TS	115	Q11S/Q12S
4	Carlton TS	115	D9HS/D10S
5	CNPI Station #17 MTS	115	A37N
6	CNPI Station #18 MTS	115	A37N
7	Crowland TS	115	A6C/A7C
8	Dunnville TS	115	Q2AH
9	Glendale TS	115	Q11S/Q12S, D9HS/D10S
10	Kalar MTS	115	A36N/A37N
11	Murray TS	115	A36N/A37N
12	Niagara West MTS	230	Q23BM/Q25BM
13	NOTL #2 MTS	115	Q11S
14	NOTL York MTS	115	Q12S
15	Port Colborne TS	115	A6C/A7C
16	Stanley TS	115	Q3N/Q4N
17	Thorold TS	115	D1A/D3A
18	Vansickle TS	115	D9HS/D10S
19	Vineland DS	115	Q2AH

APPENDIX B: NIAGARA REGION - DISTRIBUTORS

No.	Name of LDC
1	Alectra Utilities
2	Canadian Niagara Power Inc.
3	Grimsby Power Inc.
4	Hydro One Networks Inc. (Distribution)
6	Niagara-on-the-Lake Hydro Inc.
7	Niagara Peninsula Energy Inc.
8	Welland Hydro Electric System Corp.

APPENDIX C: NIAGARA REGION – STATIONS LOAD FORECAST (MW)

Station	LTR MW	2022 Actual[1]	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Allanburg TS	58.7	40	45	45	45	46	46	46	46	46	46	47	47	47	48	48	49	49	50	50	51	51
Beamsville TS	59.0	63	77	79	81	81	82	83	84	85	86	86	88	89	90	92	93	95	97	98	100	102
Bunting TS	78.2	54	58	58	59	60	60	61	62	64	65	66	67	68	70	71	73	74	76	77	77	77
Carlton TS	95.4	83	89	90	91	92	93	95	96	97	99	100	102	104	106	105	105	105	105	106	106	106
CNPI Station #17 MTS	59.4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	27
CNPI Station #18 MTS	59.4	37	36	36	36	36	36	35	35	35	35	35	35	35	35	35	35	36	36	36	36	36
Crowland TS	101.7	94	101	109	111	113	114	116	118	120	121	121	121	122	122	123	124	125	126	126	128	129
Dunnville TS	53.3	30	36	36	37	37	37	38	38	38	39	39	39	40	40	40	41	41	41	42	42	42
Glendale TS (T1/T2)	96.3	41	31	32	32	32	33	33	34	35	35	36	37	37	38	39	40	40	41	42	42	42
Glendale TS (T3/T4)	20.1	14	6	6	6	7	7	7	7	7	8	8	8	9	9	9	10	10	10	11	11	11
Kalar MTS	72.0	44	47	47	54	61	64	66	67	69	69	69	69	70	70	71	72	72	73	74	75	75
Murray TS (T11/T12)	73.2	66	78	78	78	78	78	78	78	79	79	79	79	80	80	81	82	83	83	84	85	86
Murray TS (T13/T14)	79.8	44	42	42	42	43	43	43	43	44	44	44	44	45	45	45	45	45	46	46	46	47
Niagara West MTS	63.4	41	49	57	58	58	59	60	62	63	65	66	68	69	71	73	75	77	78	80	82	84
NOTL #2 MTS	63.5	48	33	34	36	38	39	40	40	41	42	43	44	45	45	46	47	48	49	50	51	52
NOTL York MTS	75.5	17	18	18	19	20	21	22	22	23	23	24	24	25	25	26	26	27	27	28	28	29
Port Colborne TS	50.8	37	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38	38	38	39	39	39
Stanley TS	103.6	57	60	61	62	62	63	64	64	65	65	66	67	67	68	69	69	70	71	72	72	73
Thorold TS	91.3	23	24	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	27	28	28	28
Vansickle TS	99.5	47	52	52	53	53	54	55	56	57	58	59	60	62	63	64	66	67	68	68	68	68
Vineland DS	26.4	20	21	21	21	21	22	23	23	24	25	25	25	25	26	26	26	27	27	27	27	28
Industrial Customer 1	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Industrial Customer 2	-	7	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 3	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 4	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer 5	-	20	17	17	24	32	35	38	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Industrial Customer 6	-	4	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 7	-	24	80	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Industrial Customer 8[2]	-	-	10	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50

1. Actual summer load adjusted for extreme weather.
2. Curtailable load under specific outage conditions.

APPENDIX D: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



NEEDS ASSESSMENT REPORT

Niagara Region

July 20th, 2026

Needs Assessment Report
Niagara Region
July 20th 2026

Lead Transmitter:
Hydro One Networks Inc.

Prepared by: Niagara Region Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Niagara Region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on the best available information throughout the planning process.

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Executive Summary

REGION Niagara Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: March 24th 2026 **END DATE:** July 20th 2026

The 2nd cycle Regional Planning cycle for the Niagara Region was completed in July 2023 with the publication of the Regional Infrastructure Plan ("RIP") report.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in March 2026 for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

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

The Technical Working Group (TWG) comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and operational concerns.
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Needs that require further regional coordination.

#	Need Location	Need Description
1	Allanburg DESN TS	Load demand at Allanburg TS exceeds its capacity in 2028.
2	Carlton TS	Load demand at Carlton TS exceeds its capacity in 2028.
3	D9HS/D10S – Vansickle TS x Louth Jct	The section of the D9HS/D10S between Vansickle TS x Louth Junction is approaching its limit by 2035.

Needs that do not require further regional coordination.

#	Need Location	Need Description
1	Glendale TS T1/T2	Replace the existing T1/T2 45/60/75 MVA transformers with like-for-like units.
2	Murray TS T11/T12	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units.
3	Murray T13/T14	Replace the existing 45/60/75 MVA transformers T13 and T14 with like-for-like units.
4	Allanburg TS T3	Replace the existing 150/250 MVA autotransformer with a like-for-like unit.
5	Vansickle TS LV Switchyard	Replace the BY MV switchgear with like-for-like unit.
6	Bunting TS T3	Replace the existing 45/60/75 MVA T3 transformer like-for-like unit.
7	115kV Q2AH – Rosedene Jct. x St. Anns Jct	Line refurbishment to address asset renewal need.

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities
- Canadian Niagara Power
- Grimsby Power
- Hydro One Distribution
- Niagara-on-the-Lake Hydro
- Niagara Peninsula Energy
- Welland Hydro Electric System

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Niagara Region was completed in July 2023 with the publication of the Regional Infrastructure Plan ("RIP") report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the Niagara Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

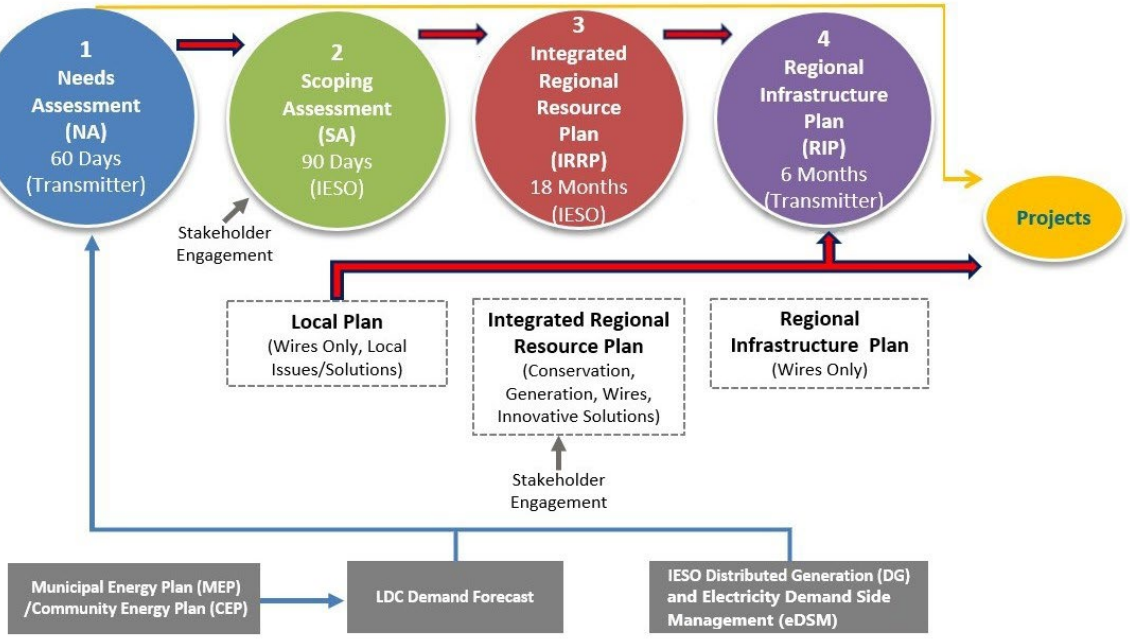


Figure 1: Regional Planning Process

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

Table 1: Niagara Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Alectra Utilities
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Hydro One Networks Inc. (Distribution)
6	Independent Electricity System Operator
7	Niagara-on-the-Lake Hydro Inc.
8	Niagara Peninsula Energy Inc.
9	Welland Hydro Electric System Corp.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the Niagara Region.

3. SCOPE OF NEEDS ASSESSMENT

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

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no

regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region.

The Local Distribution Companies in the Niagara Region are Alectra Utilities Corporation, Canadian Niagara Power Inc., Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara-on-the-Lake (NOTL) Hydro Inc., Niagara Peninsula Energy Inc., and Welland Hydro Electric System Corp. The high-voltage system in this Region also provides supply to several direct transmission-connected industrial customers transformer stations.

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS.

The 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS connect this region to Hamilton/Burlington. The power is distributed through thirteen (13) HONI and six (6) LDC owned step-down transformer stations. The distribution system in this Region is at two voltage levels, 27.6 kV and 13.8 kV.

The geographical boundaries of the Niagara Region are shown in Figure 2.

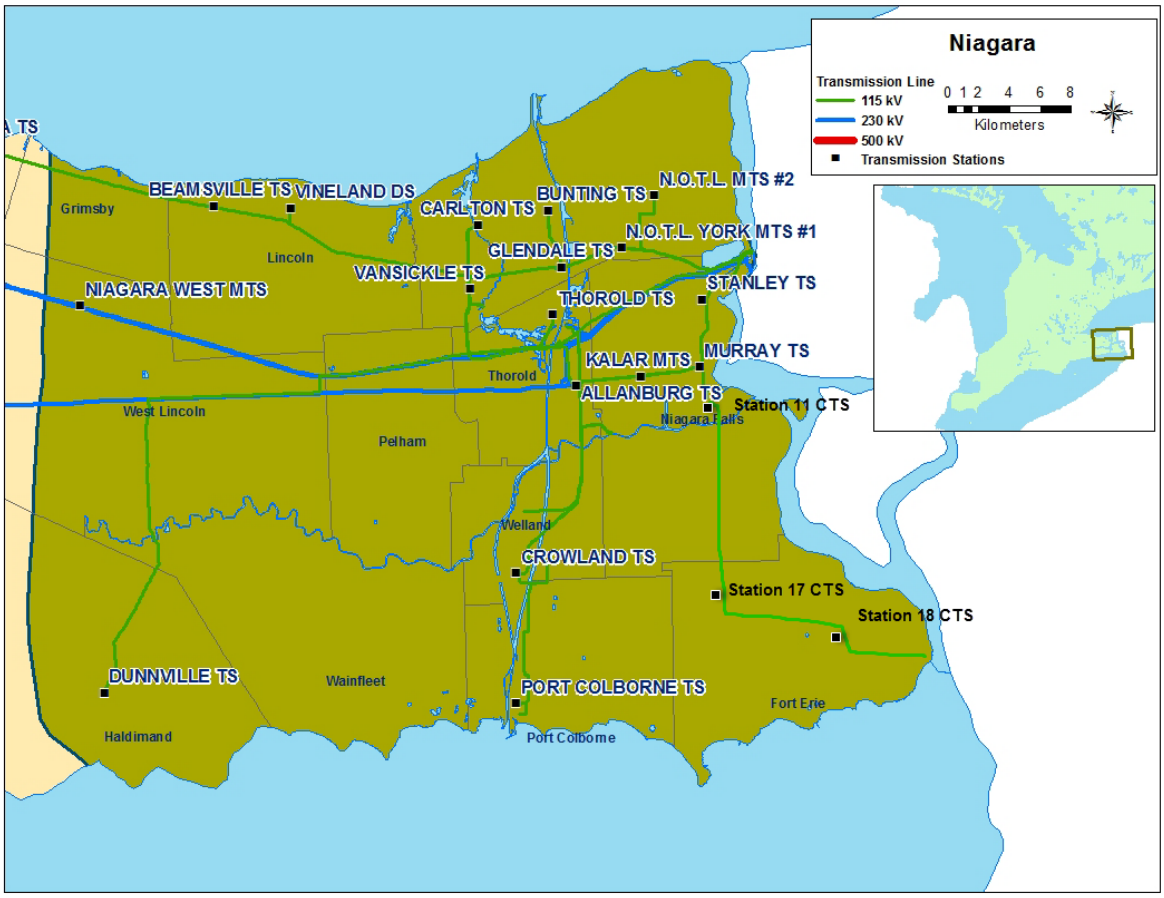


Figure 2: Map of Niagara Region Planning Area

The circuits and stations of the area are summarized in Table 2 below:

Table 2: Transmission Station and Circuits in the Niagara Region

115kV circuits	230kV circuits	Transformer Stations	Generation Stations
Q3N, Q4N, Q11S, Q12S, A36N, A37N, A6C, A7C, D9HS, D10S, D1A, D3A, Q2AH	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q10P	Allanburg TS*, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Niagara Murray TS, Niagara West MTS, NOTL York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI Station #17 MTS, CNPI	Sir Adam Beck GS #1, Sir Adam Beck GS #2, Sir Adam Beck PGS, Thorold CGS, Decew Falls GS

		Station #18 MTS	

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of Niagara Region is shown in Figure 3 below.

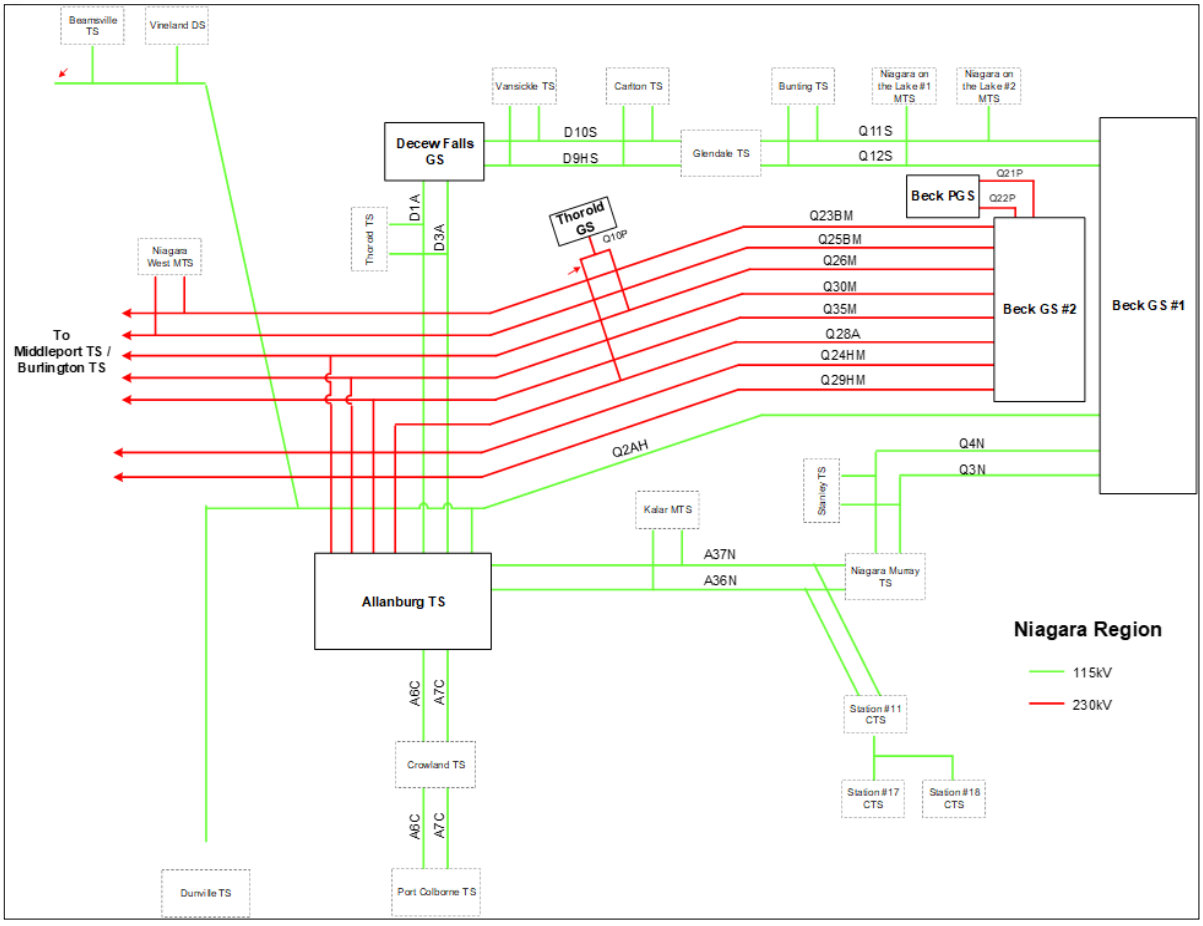


Figure 3: Niagara Region Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Niagara Region Needs Assessment. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called “Load Forecast Guideline for Ontario” in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC’s load forecast that is called for in this

guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.
The information provided includes the following:

- Niagara Region 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs). Sensitivity analysis is undertaken which captures uncertainties via different growth scenarios.
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the Niagara Region.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing”; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer peak loads. Three forecasts were developed i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2026-2035.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Line capacity adequacy is assessed by using coincidence peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations

having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.

- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the Niagara Region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided an Electricity Demand Side Management ("eDSM"), and Distributed Generation ("DG") forecast for the Niagara Region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2025 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme summer weather forecasts were produced by reducing the gross load forecasts for each station by the percentage eDSM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Niagara Region is given in Appendix A.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios is provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

Relevant information regarding system reliability and operational issues in the region as feedback provided by the IESO during the NA phase.

7. NEEDS

This section describes emerging new needs identified in the Niagara Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. Circuit D1A/D3A (Gibson Jct x Thorold TS) Replacement – Line refurbishment to address asset renewal need. Completed in Q4 2023.
2. Thorold TS T1 Transformer Replacement – Replace existing 45/60/75 MVA T1 transformer with a new 45/60/75 MVA unit. Completed in Q4 2023.
3. Station No. 11 CSS 2nd Breaker Replacement - Completed in Q4 2025.
4. Circuit Q28A Additional Supply Capacity Need - Re-tensioning to higher capacity is in progress and planned to be placed in service in Q2 2027.
5. Lincoln Area Supply Capacity Need – Project to build a new 2 x 50/83MVA, 230kV/27.6 station is in progress and planned to be placed in service in Q4 2027.
6. Carlton TS LV Switchyard Refurbishment – Project is in progress and planned to be placed in service in Q1 2028.
7. Crowland TS Station Capacity Need – Replace 115/27.6 kV T5/T6 DESN with a new 230/27.6 kV DESN and supply with a new 230kV transmission circuit. Project is in progress and planned to be placed in service in Q3 2029.
8. Carlton TS Station Capacity: Project to transfer excess load from Carlton T1/T2 DESN to Bunting TS is in progress and planned to be completed in Q4 2029.

The planned in-service year for the above underway projects is tentative and is subject to change.
All near and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update	NA Report Section
Asset Renewal Needs		
Glendale TS T1/T2	Replace the existing T1/T2 45/60/75 MVA transformers with like-for-like units. Expected in service date is updated as Q4 2031.	7.1.1
Murray TS T11/T12	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units. Expected in service date is updated as Q4 2032.	7.1.2
Murray T13/T14	Replace the existing 45/60/75 MVA transformers T13 and T14 with like-for-like units. Expected in service date is updated as Q4 2032.	7.1.2
Allanburg TS T3	Replace the existing 150/250 MVA autotransformer with a like-for-like unit. Expected in service date is updated as Q4 2032.	7.1.3
Vansickle TS LV Switchyard	Replace the BY MV switchgear with like-for-like unit. Expected in service date is updated as Q4 2034.	7.1.4
Bunting TS T3	Replace the existing 45/60/75 MVA T3 transformer like-for-like unit. Expected in service date is updated as beyond 2035.	7.1.5
Q2AH - Rosedene Jct. x St. Anns Jct	Line refurbishment to address asset renewal need. Expected in service date is updated as Q4 2031.	7.1.6
Station Capacity Needs		
Allanburg DESN TS	Load demand at Allanburg TS exceeds its capacity in 2028.	7.2.1
Carlton TS	Load demand at Carlton TS exceeds its capacity in 2028.	7.2.2
Murray TS	Load demand at Murray TS exceeds its capacity in 2031.	7.2.3
Transmission Line Capacity Needs		
115kV D9HS/D10S – Vansickle TS x Louth Junction	The section of the D9HS/D10S between Vansickle TS x Louth Junction is approaching its limit by 2034.	7.3.1

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and the TWG identified new asset renewal needs for major HV transmission equipment over the next 10 years in the Niagara Region. They are listed in Table 4 below. Hydro One and Canadian Niagara Power are the only Transmission Asset Owners (TAO) in the Region.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

There are no major HV transmission assets requiring replacement in the Niagara Region in the next 10 years.

7.1.1 Glendale TS – T1/T2 Replacement

Glendale TS is comprised of two DESN units, T1/T2 and T3/T4. The T1 transformer has been identified for asset renewal. The scope of the project is to replace the existing 45/60/75 MVA T1 transformer with a like-for-like new 45/60/75 MVA unit. The in-service date for this asset renewal has been updated to Q4 2031.

7.1.2 Murray TS – T11/T12, T13/T14 Replacement

Murray TS is currently comprised of two DESN units, T11/T12 and T13/T14. All four existing transformers units have a rating of 45/75MVA. The current asset renewal plan is to replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units, while the T13/T14 units will be like-for-like new 45/75MVA units. The in-service date for this asset renewal has been updated to Q4 2032.

7.1.3 Allanburg TS – T3 Replacement

Allanburg TS is comprised of four autotransformer units, T1, T2, T3, and T4. The T3 transformer has been identified for asset renewal. The scope of the project is to replace the existing 150/250 MVA T3 transformer with a like-for-like new 150/250 MVA unit. The in-service date for this asset renewal has been updated to Q4 2032. The need for this asset renewal is subject to change based on the findings of the IESO's Niagara Bulk Plan study, currently scheduled for completion in Q3 2027.

7.1.4 Vansickle TS – LV Switchyard Replacement

Vansickle TS is comprised of two DESNs, BY and JQ, supplied by T5 and T6. The BY MV switchgear has been identified for asset renewal. The scope of the project is to replace the existing switchgear. The in-service date for this asset renewal has been updated to Q4 2034.

7.1.5 Bunting TS – T3 Replacement

Bunting TS is comprised of a single DESN supplied by transformers T3/T4. The T3 transformer has been identified for asset renewal. The scope of the project is to replace the existing 45/60/75 MVA T3 transformer with a like-for-like new 45/60/75 MVA unit. The in-service date for this asset renewal has been updated to beyond 2035.

7.1.6 Q2AH - Rosedene Jct. x St. Anns Jct – Line Refurbishment

The portion of the single 115kV circuit Q2AH supplying Dunnville TS, between Rosedene Jct and St.Anns Jct, has been identified for asset renewal. The length of this portion of circuit is approximately 11km. The scope of the project is to replace the asset with a like-for-like equivalent conductor size. The in-service date for this asset renewal has been updated to Q4 2031.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2026-2035 for the 230kV and 115kV Transforming stations in the Niagara Region using either the summer or winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 115kV Allanburg TS – Station Capacity

The load at Allanburg TS is expected to exceed its 10-Day LTR within the 2027-2035 time period.

Allanburg TS is comprised of one DESN with transformers T7/T8 with a rating of 25/42MVA, having a summer 10-Day LTR of 58.0 MW. The station's actual non-coincident summer peak load in 2025 was about 48MW and is forecasted to almost 79MW (net adjusted for extreme weather) by 2035. However, there is an immediate need by 2028 to increase the station capacity. This unexpected increase in forecasted load was identified during the Needs Assessment process.

The TWG recommends reviewing the load forecast and if necessary, initiating discussions for transformer replacement at Allanburg TS with larger units.

7.2.2 115kV Carlton TS – Station Capacity

The load at Carlton TS is expected to exceed its 10-Day LTR within the 2029-2035 time period.

Carlton TS is currently a single DESN facility, with transformers T1 and T2. The existing transformers T1/T2 have a rating of 45/75MVA, with a summer 10-Day LTR of 99.6MW. The station's actual non-coincident summer peak load in 2025 was about 84.4MW and is forecasted to be approximately 122.4MW (net adjusted for extreme weather) by 2035.

However, there is a need by 2028 to increase the station capacity. This unexpected increase in forecasted load was identified during this Needs Assessment process. At this time, the LDC planned load transfers to Bunting TS by 2029 and additional capacity through expansion from Vansickle TS is expected to aid capacity needs over the current planning horizon. Station capacity needs at Carlton TS will continue to be monitored. Should additional capacity be required, transformer upgrades to 60/100 MVA could be considered to address future capacity needs.

7.2.3 115kV Murray TS – Station Capacity

The load at Murray TS (T11/T12) is expected to exceed its 10-Day LTR by 2031 with its current transformers.

Murray TS is currently comprised of two DESN units, T11/T12 and T13/T14. Both DESNs are currently considered for asset renewal by 2032. The existing transformers T11/T12 have a rating of 45/75MVA, with a summer 10-Day LTR of 71.6MW. The station's 2025 actual non-coincident summer peak load was about 66.8MW and is forecasted to be approximately 72MW (net adjusted for extreme weather) by 2031. The current asset renewal plan is to replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units, which will provide approximately a 10-Day LTR of 122MW. Expected in service date is updated as Q4 2032.

At this time, the asset renewal project and forecast will be both closely monitored and adjusted to ensure the station capacity meets the future load requirement.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2026-2035 for the 230kV and 115kV Transmission line circuits in the Niagara Region by assessing thermal limits of the circuit and the voltage range as per ORTAC Local Area Contingency-Based Assessment to cater to this need.

Based on the results, the following line capacity needs have been identified during the study period.

7.3.1 115kV D9HS/D10S – Vansickle TS x Louth Junction

The double 115kV circuits D9HS/D10S between Decew Falls GS and Glendale TS are an alternate supply path for loads in the St.Catharines area, via Carlton TS and Glendale TS.

With the increasing demand forecasted on this corridor, a section of the D9HS/D10S is potentially overloaded in the long term, specifically the 1km of overhead D9HS/D10S section between Vansickle TS x Louth Junction following the loss of all generation from 115kV Sir Adam Beck GS via the Beck E-bus contingency.

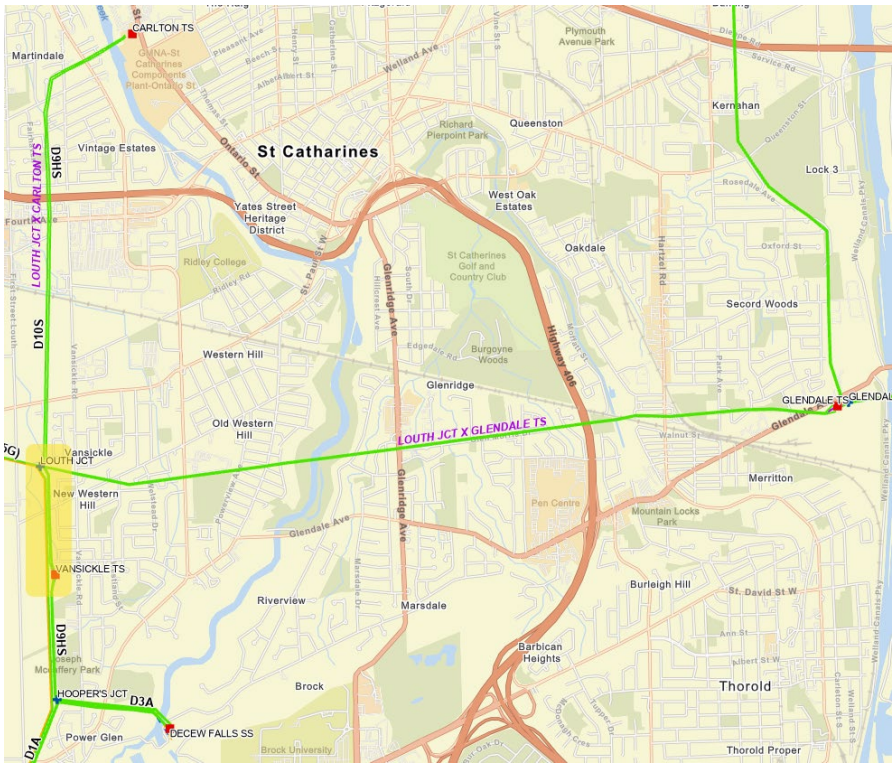


Figure 4: 115kV D9HS/D10S – Vansickle TS x Louth Junction (highlighted)

This section is shown in Figure 4. The calculated need for this line capacity upgrade is by 2035 if the current load forecast in this area holds true.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been carried out, considering the net coincident load forecast and the loss of one element over the study period 2026-2035 to cater for this need**.** Based on the results, no significant new system reliability, operating and restoring issues have been identified for this Region.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Niagara Region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.
The TWG reviewed EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%. The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 4: Impact of Sensitivity Analysis on Station/Line capacity Needs in the Region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Allanburg DESN TS	2028	2028	2028
2	Carlton TS	2028	2028	2030
3	Murray T11/T12 TS	2031	2029	2034
4	115kV D9HS/D10S Vansickle TS x Louth Junction	2035	2034	-
5	Bunting TS	-	2032	-

The sensitivity analysis identified the additional capacity needs for Bunting TS towards the end of the study period. These needs will be assessed again during the next phases of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 5: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
1	Glendale TS T1/T2	Replace the existing T1/T2 45/60/75 MVA transformers with like-for-like units.
2	Murray TS T11/T12	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units.
3	Murray T13/T14	Replace the existing 45/60/75 MVA transformers T13 and T14 with like-for-like units.
4	Allanburg TS T3	Replace the existing 150/250 MVA autotransformer with a like-for-like unit.
5	Vansickle TS LV Switchyard	Replace the BY MV switchgear with like-for-like unit.
6	Bunting TS T3	Replace the existing 45/60/75 MVA T3 transformer like-for-like unit.
7	115kV Q2AH – Rosedene Jct. x St. Anns Jct	Line refurbishment to address asset renewal need.

Table 6: Needs that Require Further Regional Coordination

#	Need Location	Need Description
1	Allanburg DESN TS	Load demand at Allanburg TS exceeds its capacity in 2028.
2	Carlton TS	Load demand at Carlton TS exceeds its capacity in 2028.
3	D9HS/D10S – Vansickle TS x Louth Jct	The section of the D9HS/D10S between Vansickle TS x Louth Junction is approaching its limit by 2035.

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities
- Canadian Niagara Power
- Grimsby Power
- Hydro One Distribution
- Niagara-on-the-Lake Hydro
- Niagara Peninsula Energy
- Welland Hydro Electric System

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: Niagara Region - Non-Coincident – Normal Growth Net Load Forecast

Station	LTR MW	2025 Actuals	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allanburg TS	58.0	47.7	52.8	55.5	66.3	70.0	69.6	71.6	74.2	75.6	77.1	78.8
Beamsville TS	56.5	58.4	57.5	57.8	58.3	39.2	39.0	39.2	39.5	39.9	40.4	41.0
Bunting TS	74.9	55.0	54.8	57.2	60.6	65.9	66.4	67.6	68.8	69.1	70.5	72.0
Carlton TS	99.6	84.4	86.2	92.3	100.4	107.3	115.0	116.6	117.3	118.2	120.1	122.4
CNPI Station #17 MTS	56.3	23.3	23.9	23.9	23.9	24.0	23.7	23.7	23.7	23.7	23.8	23.9
CNPI Station #18 MTS	56.3	54.1	55.5	55.5	55.5	55.6	55.0	55.0	55.0	55.0	55.2	55.5
Crowland TS	101.7	90.8	93.0	92.5	92.1	91.7	91.0	91.3	91.6	92.1	96.8	97.7
Dunnville TS	55.8	30.7	35.0	34.9	35.1	36.7	36.4	36.5	36.6	36.8	36.9	37.3
Glendale TS (T1/T2)	93.2	27.1	29.4	32.1	33.8	34.5	35.6	36.2	36.7	38.3	38.9	40.6
Glendale TS (T3/T4)	18.1	9.0	11.2	13.0	13.9	14.8	14.4	15.2	15.1	15.9	15.8	15.7
Kalar MTS	67.5	46.8	49.2	49.7	51.2	51.7	51.6	52.1	52.5	53.0	53.6	54.4
Murray TS (T11/T12)	71.6	66.8	69.5	70.1	70.8	71.6	71.4	72.0	72.6	73.4	74.3	75.4
Murray TS (T13/T14)	77.2	37.5	37.7	37.8	38.0	38.3	38.1	38.3	38.5	38.7	39.0	39.5
Niagara West MTS	60.0	54.4	56.9	57.4	56.8	57.4	56.2	56.8	56.2	56.7	58.6	59.5
Spring Creek MTS	96.3	0.0	0.0	0.0	5.8	25.7	26.1	26.7	26.9	27.5	28.3	27.4
NOTL #2 MTS	59.0	36.3	36.0	36.1	36.3	36.4	36.5	36.5	36.7	36.9	37.1	37.4
NOTL York MTS	74.7	25.7	60.9	60.2	59.6	59.1	57.8	57.1	56.5	56.0	55.5	55.2
Port Colborne TS	108.0	38.4	39.4	39.3	44.1	46.4	47.0	47.6	47.9	47.8	48.1	49.5
Stanley TS	99.2	68.0	70.6	71.0	71.8	72.5	72.4	73.0	73.7	74.4	75.3	76.5
Thorold TS	88.4	25.2	28.5	28.4	28.5	28.5	28.3	28.3	28.3	28.4	28.5	28.7
Vansickle TS	97.4	52.8	51.7	55.2	61.6	66.9	68.4	69.5	70.6	71.8	73.2	74.8
Vineland DS	25.0	20.8	21.7	21.6	22.4	23.1	23.8	23.8	23.8	24.0	24.0	24.1
Industrial Customer 1			5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Industrial Customer 2			2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Industrial Customer 3			3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Industrial Customer 4			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Industrial Customer 5			51.5	59.5	63.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
Industrial Customer 6			3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Industrial Customer 7			87.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Industrial Customer 8			0.2	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Industrial Customer 9			5.0	11.0	23.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0
Industrial Customer 10			0.0	0.0	0.0	0.0	79.0	79.0	79.0	79.0	79.0	79.0
Industrial Customer 11			0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0

Table A.2: Niagara Region - Coincident – Normal Growth Net Load Forecast

Station	LTR MW	2025 Actuals	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allanburg TS	58.0	43.3	52.8	55.5	66.3	70.0	69.6	71.6	74.2	75.6	77.1	78.8
Beamsville TS	56.5	57.9	57.5	57.1	57.6	38.4	38.2	38.5	38.8	39.2	39.7	40.3
Bunting TS	74.9	48.3	49.0	51.1	54.1	59.0	59.4	60.3	61.3	61.5	62.7	64.0
Carlton TS	99.6	65.8	66.5	71.0	76.9	82.0	88.5	89.4	89.7	90.1	91.4	93.0
CNPI Station #17 MTS	56.3	23.3	23.9	23.9	23.9	24.0	23.7	23.7	23.7	23.7	23.8	23.9
CNPI Station #18 MTS	56.3	54.1	55.5	55.5	55.5	55.6	55.0	55.0	55.0	55.0	55.2	55.5
Crowland TS	101.7	81.2	83.1	82.5	82.1	81.6	80.8	80.9	81.1	81.4	86.0	86.8
Dunnville TS	55.8	29.3	33.3	33.2	33.3	34.9	34.6	34.7	34.8	34.9	35.1	35.4
Glendale TS (T1/T2)	93.2	23.8	25.9	28.3	29.7	30.3	31.2	31.6	32.1	33.4	33.9	35.3
Glendale TS (T3/T4)	18.1	9.8	11.2	13.0	13.9	14.8	14.4	15.2	15.1	15.9	15.8	15.7
Kalar MTS	67.5	41.7	43.1	43.4	44.8	45.2	45.0	45.3	45.6	46.0	46.4	47.1
Murray TS (T11/T12)	71.6	61.3	63.3	63.8	64.4	65.1	64.8	65.2	65.8	66.4	67.1	68.1
Murray TS (T13/T14)	77.2	34.7	37.7	37.8	38.0	38.3	38.1	38.3	38.5	38.7	39.0	39.5
Niagara West MTS	60.0	36.4	37.5	37.6	37.1	37.3	36.0	36.2	35.6	35.8	37.6	38.1
Spring Creek MTS	96.3	0.0	0.0	0.0	5.8	25.7	26.1	26.7	26.9	27.5	28.3	27.4
NOTL #2 MTS	59.0	32.3	34.1	34.2	34.3	34.4	34.4	34.5	34.7	34.8	34.9	35.2
NOTL York MTS	74.7	13.0	60.9	60.2	59.6	59.1	57.8	57.1	56.5	56.0	55.5	55.2
Port Colborne TS	108.0	33.6	34.4	34.3	38.3	40.3	40.7	41.1	41.2	41.2	41.4	42.6
Stanley TS	99.2	52.3	53.9	54.2	54.6	55.0	54.6	54.8	55.1	55.5	55.9	56.8
Thorold TS	88.4	22.2	25.1	24.9	24.9	25.0	24.7	24.6	24.6	24.7	24.7	24.9
Vansickle TS	97.4	46.3	49.9	53.2	59.4	64.5	65.8	66.9	68.0	69.1	70.4	71.9
Vineland DS	25.0	18.3	18.9	18.8	19.4	20.1	20.6	20.6	20.6	20.7	20.7	20.8
Industrial Customer 1			5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Industrial Customer 2			2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Industrial Customer 3			3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Industrial Customer 4			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Industrial Customer 5			51.5	59.5	63.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
Industrial Customer 6			3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Industrial Customer 7			87.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Industrial Customer 8			0.2	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Industrial Customer 9			5.0	11.0	23.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0
Industrial Customer 10			0.0	0.0	0.0	0.0	79.0	79.0	79.0	79.0	79.0	79.0
Industrial Customer 11			0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0

Table A.3: Niagara Region Non-Coincident – High Growth Net Load Forecast

Station	LTR MW	2025 Actuals	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allanburg TS	58.0	47.7	52.8	56.8	73.0	78.6	78.0	81.0	85.0	86.9	89.2	91.8
Beamsville TS	56.5	58.4	57.5	58.0	58.7	39.6	39.3	39.7	40.1	40.7	41.5	42.3
Bunting TS	74.9	55.0	54.8	58.4	63.5	71.4	72.3	74.0	75.8	76.3	78.3	80.7
Carlton TS	99.6	84.4	86.2	95.3	107.4	117.9	129.4	131.8	132.8	134.2	137.1	140.6
CNPI Station #17 MTS	56.3	23.3	23.9	23.9	24.0	24.1	23.5	23.5	23.5	23.5	23.7	24.3
CNPI Station #18 MTS	56.3	54.1	55.5	55.5	55.6	55.7	54.8	54.7	54.7	54.8	55.0	55.5
Crowland TS	101.7	90.8	93.0	92.2	91.6	91.1	90.0	90.4	90.9	91.6	98.7	100.1
Dunnville TS	55.8	30.7	35.0	34.9	35.1	37.5	37.1	37.2	37.4	37.6	37.9	38.4
Glendale TS (T1/T2)	93.2	27.1	29.4	33.5	36.0	37.0	38.8	39.6	40.4	42.7	43.6	46.2
Glendale TS (T3/T4)	18.1	9.0	11.2	14.0	15.3	16.6	16.3	17.4	17.3	18.5	18.3	18.2
Kalar MTS	67.5	46.8	49.2	49.9	52.2	53.0	52.8	53.5	54.1	54.9	55.8	57.0
Murray TS (T11/T12)	71.6	66.8	69.5	70.4	71.5	72.6	72.4	73.3	74.2	75.3	76.6	78.4
Murray TS (T13/T14)	77.2	37.5	37.7	37.8	38.2	38.6	38.3	38.5	38.8	39.2	39.7	40.4
Niagara West MTS	60.0	54.4	56.9	57.6	57.1	58.0	56.8	57.6	57.0	57.8	60.6	61.9
Spring Creek MTS	96.3	0.0	0.0	0.0	5.8	25.7	26.4	27.2	27.5	28.4	29.7	28.3
NOTL #2 MTS	59.0	36.3	36.0	36.2	36.4	36.6	36.7	36.8	37.1	37.3	37.6	38.1
NOTL York MTS	74.7	25.7	60.9	60.2	59.6	59.1	57.8	57.1	56.5	56.0	55.5	55.2
Port Colborne TS	108.0	38.4	39.4	39.3	46.4	50.0	50.9	51.7	52.1	52.1	52.5	54.6
Stanley TS	99.2	68.0	70.6	71.3	72.4	73.5	73.3	74.2	75.2	76.3	77.6	79.5
Thorold TS	88.4	25.2	28.5	28.3	28.4	28.5	28.3	28.3	28.3	28.5	28.6	29.0
Vansickle TS	97.4	52.8	51.7	56.9	66.5	74.6	76.7	78.4	80.1	81.9	84.0	86.3
Vineland DS	25.0	20.8	21.7	21.6	22.7	23.9	24.9	24.9	24.9	25.1	25.2	25.4
Industrial Customer 1			5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Industrial Customer 2			2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Industrial Customer 3			3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Industrial Customer 4			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Industrial Customer 5			51.5	59.5	63.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
Industrial Customer 6			3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Industrial Customer 7			87.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Industrial Customer 8			0.2	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Industrial Customer 9			5.0	11.0	23.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0
Industrial Customer 10			0.0	0.0	0.0	0.0	79.0	79.0	79.0	79.0	79.0	79.0
Industrial Customer 11			0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0

Table A.4: Niagara Region – Coincident – High Growth Net Load Forecast

Station	LTR MW	2025 Actuals	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Allanburg TS	58.0	47.7	52.8	56.8	73.0	78.6	78.0	81.0	85.0	86.9	89.2	91.8
Beamsville TS	56.5	58.4	57.5	56.9	57.6	38.5	38.2	38.6	39.0	39.6	40.4	41.2
Bunting TS	74.9	55.0	49.0	52.1	56.6	64.0	64.6	66.0	67.5	67.8	69.5	71.5
Carlton TS	99.6	84.4	66.5	73.2	82.2	89.8	99.6	100.9	101.2	101.9	103.8	106.2
CNPI Station #17 MTS	56.3	23.3	23.9	23.9	23.9	24.0	23.6	23.6	23.6	23.6	23.7	23.9
CNPI Station #18 MTS	56.3	54.1	55.5	55.5	55.6	55.7	54.8	54.7	54.7	54.8	55.0	55.5
Crowland TS	101.7	90.8	83.1	82.2	81.6	81.1	80.3	80.4	80.7	81.2	88.0	89.3
Dunnville TS	55.8	30.7	33.3	33.1	33.3	35.7	35.4	35.5	35.7	35.9	36.1	36.5
Glendale TS (T1/T2)	93.2	27.1	25.9	29.4	31.6	32.4	33.8	34.5	35.1	37.1	37.8	40.0
Glendale TS (T3/T4)	18.1	9.0	11.2	14.0	15.3	16.6	16.3	17.4	17.2	18.4	18.3	18.2
Kalar MTS	67.5	46.8	43.1	43.6	45.7	46.3	46.1	46.5	47.0	47.5	48.2	49.2
Murray TS (T11/T12)	71.6	66.8	63.3	64.1	65.0	65.9	65.6	66.3	67.1	68.0	69.1	70.6
Murray TS (T13/T14)	77.2	37.5	37.7	37.8	38.2	38.6	38.4	38.6	38.9	39.3	39.8	40.5
Niagara West MTS	60.0	54.4	37.5	37.7	36.9	37.2	35.3	35.6	34.7	34.9	37.7	38.4
Spring Creek MTS	96.3	0.0	0.0	0.0	0.0	25.7	26.4	27.2	27.5	28.4	29.7	28.3
NOTL #2 MTS	59.0	36.3	34.1	34.2	34.4	34.6	34.6	34.7	34.9	35.1	35.4	35.8
NOTL York MTS	74.7	25.7	60.9	59.9	59.0	58.2	56.9	55.9	55.0	54.1	53.4	53.1
Port Colborne TS	108.0	38.4	34.4	34.3	40.3	43.3	43.8	44.4	44.7	44.6	44.9	46.7
Stanley TS	99.2	68.0	53.9	54.4	55.0	55.6	55.1	55.5	55.9	56.5	57.2	58.5
Thorold TS	88.4	25.2	25.1	24.8	24.9	24.9	24.6	24.6	24.6	24.6	24.7	25.0
Vansickle TS	97.4	52.8	49.9	54.9	64.1	71.8	73.8	75.4	77.0	78.7	80.6	82.8
Vineland DS	25.0	20.8	18.9	18.8	19.7	20.7	21.5	21.4	21.4	21.6	21.6	21.7
Industrial Customer 1			5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Industrial Customer 2			2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Industrial Customer 3			3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Industrial Customer 4			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Industrial Customer 5			51.5	59.5	63.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
Industrial Customer 6			3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Industrial Customer 7			87.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Industrial Customer 8			0.2	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Industrial Customer 9			5.0	11.0	23.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0
Industrial Customer 10			0.0	0.0	0.0	0.0	79.0	79.0	79.0	79.0	79.0	79.0
Industrial Customer 11			0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0

Appendix B: Lists of Step-Down Transformer Stations

Transformer Station	Voltage (kV)	Supply Circuits
Allanburg TS	230kV	Q26M, Q28A, Q30M, Q35M
Allanburg TS (DESN)	115kV	A6C, A7C
Beamsville TS	115kV	Q2AH
Bunting TS	115kV	Q11S, Q12S
Carlton TS	115kV	D9HS, D10S
Crowland TS	115kV	A6C, A7C
Dunnville TS	115kV	Q2AH
Glendale TS	115kV	Q11S, Q12S
Kalar MTS	115kV	A36N, A37N
Niagara Murray TS	115kV	Q3N, Q4N (T11/T12) A36N, A37N (T13/T14)
Niagara West MTS	230kV	Q23BM, Q25BM
NOTL York MTS	115kV	Q12S
NOTL #2 MTS	115kV	Q11S
Port Colborne TS	115kV	A6C, A7C
Stanley TS	115kV	Q3N, Q4N
Thorold TS	115kV	D1A, D3A
Vansickle TS	115kV	D9HS, D10S
Vineland DS	115kV	Q2AH
CNPI Station #17 MTS	115kV	A37N
CNPI Station #18 MTS	115kV	A37N

Appendix C: List of Municipalities in the Niagara Region

Name of Municipality
City of Port Colborne
City of Welland
City of Thorold
City of Niagara Falls
Town of Niagara-on-the-Lake
City of St. Catharines
Town of Fort Erie
Town of Lincoln
Township of West Lincoln
Town of Grimsby
Township of Wainfleet
Town of Pelham

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	Electricity Demand Side Management
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan

Acronym	Description
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station



North & East of Sudbury: Integrated Regional Resource Plan

April 2023

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List of Acronyms

BKF	Breaker Failure
CDM	Conservation and Demand Management
DG	Distributed Generation
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station

1. Introduction

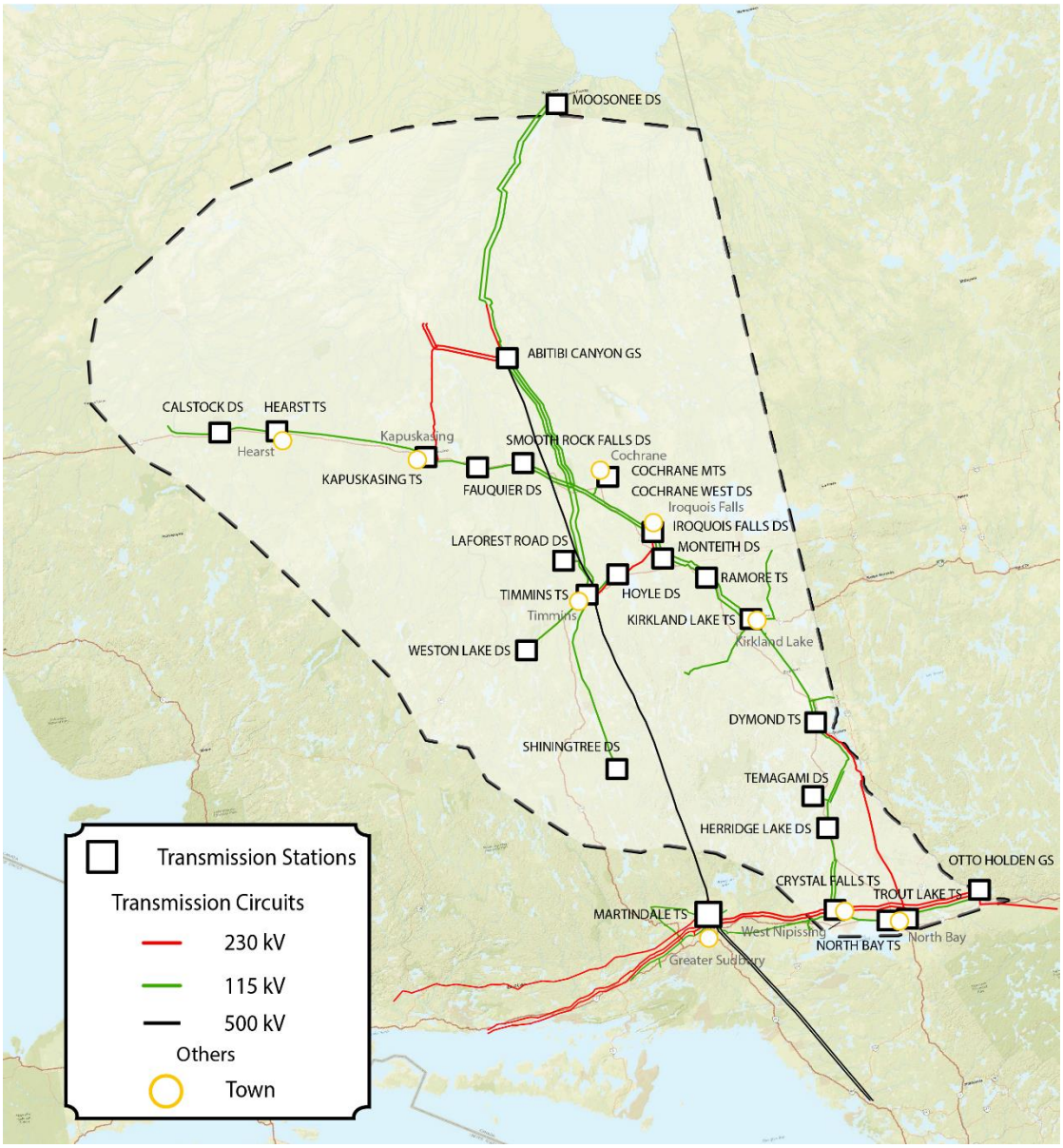
1.1 Overview of Region and Background

The North & East of Sudbury region is a large area supplied by the electricity infrastructure that extends north and east from, but not including, the City of Sudbury. Extending from south of the town of Moosonee in the north to the City of North Bay and town of East Ferris in the south, it includes the towns of Hearst, Kapuskasing, Smooth Rock Falls, Cochrane, Foleyet, Iroquois Falls, Kirkland Lake and Englehart. It also includes the townships of Black River Matheson and East Ferris, the cities of North Bay, Temiskaming Shores and Timmins and the municipality of West Nipissing. The North & East of Sudbury region is also home to First Nation communities listed in Table 1. A map of the area indicating the location of transmission assets is found in Figure 1.

Table 1 | List of First Nation Communities in the North & East of Sudbury Region

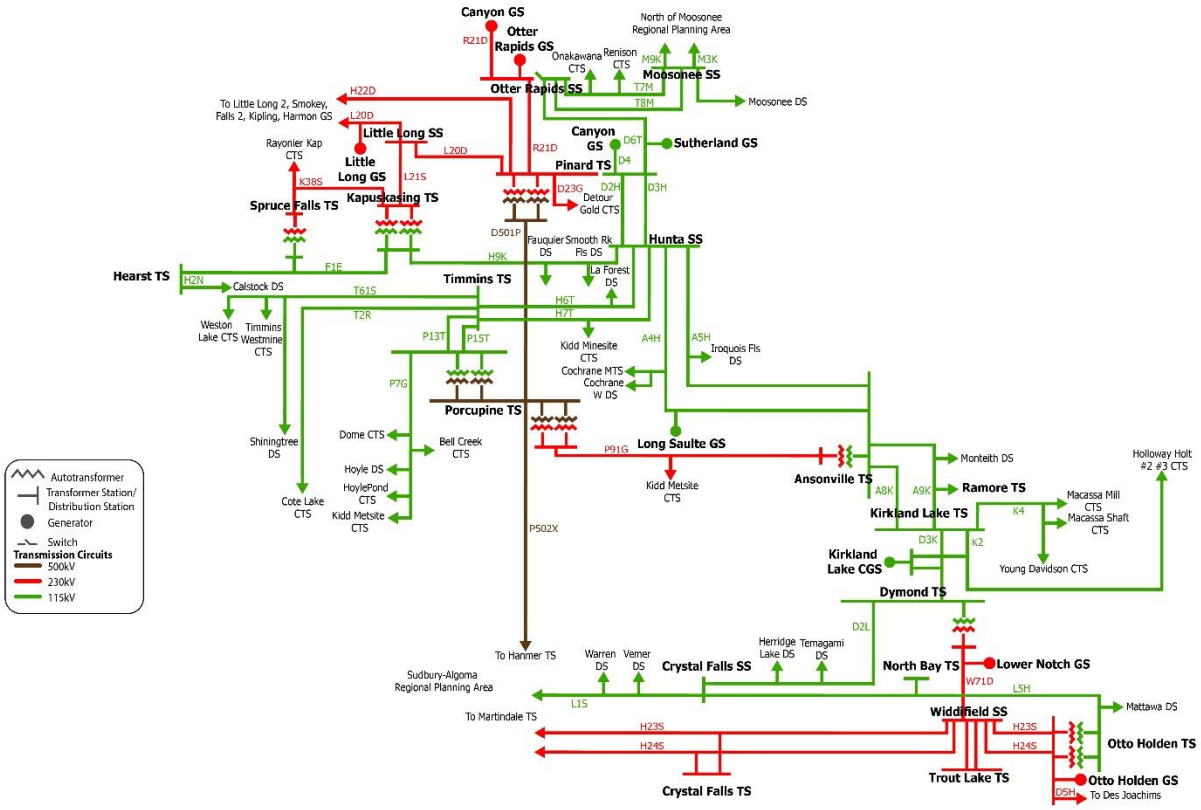
Constance Lake First Nation
Flying Post First Nation
Matachewan First Nation
Mattagami First Nation
Missanabie Cree First Nation
Moose Cree First Nation
Nipissing First Nation
Taykwa Tagamou First Nation
Temagami First Nation
Wahgoshig First Nation
Wahnapitae First Nation

Figure 1 | Map of the North & East of Sudbury Area



Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region is supplied through 500/230 kV autotransformers at Porcupine TS and Pinard TS and encompasses the 230 kV circuits east of Martindale TS in the west to Otto Holden TS in the east as well as the 500 kV circuits from Hammer TS to Pinard TS and the 115 kV sub-systems in between. For clarity, the North & East of Sudbury region does not include the area north of Moosonee. There are non-synchronous interconnections with Quebec at Dymond TS and Otto Holden TS. At Dymond TS, intertie circuit D4Z at Dymond TS can deliver imports from generation located in Quebec, and industrial load in Quebec (i.e., a paper plant in Témiscaming, Quebec) can be supplied radially via the 115 kV intertie circuit H4Z. This Quebec load is not part of this study as it can also be supplied from Quebec. A single line diagram of the electricity infrastructure in the region is shown in Figure 2.

Figure 2 | Electricity Infrastructure in the North & East of Sudbury Region



Demand in this region is winter peaking and a large share of this demand is high electricity intensity industries, primarily mining and forestry operations. Demand growth in this area is primarily forecast to be in the mining sector, where project development is highly dependent on factors such as commodity prices and access to financing.

The region has over 2,600 MW of generation, including numerous hydroelectric facilities, solar, gas and bio-fuel facilities. The lead transmitter for the region is Hydro One Networks Inc. and the local distribution companies (LDCs) are North Bay Hydro, Northern Ontario Wires Inc., Hearst Power Distribution Co., Greater Sudbury Hydro, and Hydro One Networks Inc. (Distribution).

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the North & East of Sudbury region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options that considers reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

Table 2 summarizes the needs identified in this study and the IRRP's recommendations to address them.

Table 2 | Summary of Needs and Recommendations for North & East of Sudbury IRRP

No.	Need Description	Recommendation	Need Date
1	Station Capacity at Ramore TS	Load growth at Ramore TS will be monitored and revisited in the next cycle of regional planning	2033
2	Voltage control issues with existing capacitors at Dymond TS	Hydro One to investigate options to improve operability of existing capacitors in the upcoming RIP	2030
3	Voltage control issues in the Kirkland Lake area	Hydro One to investigate options of adding reactive devices in the Kirkland Lake area in the upcoming RIP	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Various recommendations, including a new RAS, replacing failed equipment and additional voltage support	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	The new Kirkland Lake RAS installed in 2022 addresses this issue. Additional load in the area beyond the current forecast will require further study	2030
6	A4H/A5H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2027

No.	Need Description	Recommendation	Need Date
7	D2H/D3H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Partially addressed by the recent Northeast Bulk Plan. An update to this plan is recommended should significant new resources and/or load connect to the North & East of Sudbury region.	Existing Need
9	Difficulty supplying loads during planned outages to circuit D501P	Study this need as part of the next bulk system plan for Northeast Ontario in combination with other drivers of system expansion as they develop	Existing Need

3. Development of the IRRP

3.1 The Regional Planning Process

In 2013, the OEB created a formal process for regional planning which is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The regional planning formal process sets out 21 electricity planning regions for the province. Regional planning assesses the interrelated needs of a region over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the lead transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;
3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A Regional Infrastructure Plan (RIP), led by the lead transmitter, which provides further details on recommended wires solutions.

Further details on the components of the regional planning process in Ontario and the IESO's approach to regional planning can be found in Appendix A.

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues, and distribution network planning considers the adequacy and reliability of the distribution system(s) supplying customers within a particular community. Regional planning sits between bulk planning and distribution planning and focuses on ensuring that an area can be reliably supplied given forecast demand growth and other developments in a region.

A review of the regional planning process was finalized in 2021 following the completion of the first cycle of regional planning for all 21 regions. The Regional Planning Process Review Final Report is published on the IESO's website.

3.2 North & East of Sudbury and IRRP Development

The process to develop the North & East of Sudbury IRRP was initiated following the publication of Hydro One's North & East of Sudbury Needs Assessment report in May 2021 and the IESO's Scoping Assessment Outcome report in August 2021. The Scoping Assessment report recommended that the needs identified for the North & East of Sudbury region be considered through an IRRP using a coordinated regional approach. The Scoping Assessment Working Group, consisting of the IESO, the transmitter and the LDCs in the region, was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options and recommend solutions for the North & East of Sudbury region.

4. Background and Study Scope

This is the second cycle of regional planning for the North & East of Sudbury region. During the first cycle of regional planning, a Needs Assessment was conducted in April 2016 that was led by the transmitter, Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination was not required and a Regional Infrastructure Plan, also led by the transmitter, was published in April 2017.

This cycle of regional planning started with a Needs Assessment published by Hydro One in May 2021 which identified a number of needs requiring further regional coordination. This was followed by a Scoping Assessment process which was finalized in August 2021. The Scoping Assessment Outcome report recommended that an IRRP be initiated. This report is the outcome of the IRRP process and presents an integrated regional electricity plan for the next 20-year period from 2021 to 2040.

4.1 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the North & East of Sudbury region of the study period with a focus on providing an adequate, reliable supply to support community growth. The plan includes consideration of forecast electricity demand growth, conservation and demand management (CDM), distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The full scope of the study can be found in Appendix D.

4.1.1 Planned Projects Considered in the IRRP

The following projects were already planned or underway when the IRRP was initiated, and were assumed to be in service in developing the IRRP assumptions.

1. Ansonville to Kirkland Lake Line Upgrade: Upgrading of end-of-life circuits A8K and A9K from 230 A to 550 A capacity.
2. Kapuskasing Area Reinforcement: Upgrading two sections of circuit H9K (from Spruce Falls JCT to Carmichael Falls JCT and Gemini Smooth Rock Falls JCT to H9K Structure 127A JCT) to higher 550 A capacity.

The North & East of Sudbury IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast;
- Examining the capacity and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC planning criteria, and considered the findings and recommendations made through other planning processes being carried out in parallel, namely the Northeast Bulk Plan;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO controlled grid as described in section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible wires alternatives (e.g., transmission and/or distribution) and non-wires alternatives (e.g., energy efficiency, local generation, storage and other distributed energy resources);
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

4.2 Coordination with Bulk Planning Initiatives

In addition to the Regional Planning activities being undertaking for the North & East of Sudbury region, a number of Bulk Planning initiatives have recently been undertaken or are currently underway with the potential to affect assumptions and outcomes in the area. Two initiatives in particular, the Northeast Bulk Plan, and the Northern Voltage Study, have implications for the current Regional Planning process, with further details described below.

4.2.1 Northeast Bulk Planning Study

A bulk planning study was initiated for northeastern Ontario in 2021 that was completed in October 2022. This study examined a number of needs in the area, and paid particular focus to improving supply security for growing demand in and around the cities of Sault Ste. Marie and Timmins. Compared to a regional planning focus, the goal of the bulk study was to ensure sufficient power could be delivered to load centres, but did not include final customer delivery, including step down or local voltage needs.

Recommendations made during this study were treated as input assumptions for the current North & East of Sudbury IRRP, and were assumed to come into service at their target date. The Northeast Bulk Plan recommended the following system reinforcements.

1. A new ~260 km single circuit 230 kV transmission line (built to 500 kV standards) between Wawa Transformer Station (TS) and Porcupine TS to be in-service in 2030;
2. A new ~205 km single circuit 500 kV transmission line between Mississagi TS and Hanmer TS and addition of two new autotransformers at Mississagi TS to be in-service in 2029; and
3. A new ~75 km double circuit 230 kV transmission line between Mississagi TS and Third Line TS to be in-service in 2029.

Additional information on this study is available on the IESO website, here.

4.2.2 Northern Voltage Study

The Northern Voltage Study was initiated recognizing that the voltage profile across northern Ontario was set to change with system expansions planned in northeast Ontario (i.e., the Northeast Bulk Plan recommendations) as well as in northwestern Ontario (i.e., the East West Tie expansion, the Waasigan line and the Wataynikaneyap line). The study examines reactive requirements associated with these new lines and the resulting changes to the voltage profile. In addition, it addresses existing challenges managing system voltages in northern Ontario as reported by the IESO's control room operators and identifies requirements to improve operability.

Although the scope of the Northern Voltage study is much wider than the North & East of Sudbury IRRP, and tends to focus on contingencies and operational concerns outside the typical scope of Regional Planning, the potential for needs and recommended solutions from one study to affect system assumptions for the other required that these two studies be carried out in a coordinated manner. Since bulk system reactive requirements were being studied through the Northern Voltage Study, the North & East of Sudbury IRRP did not address these issues and instead focused on identifying and addressing localized voltage concerns in the region.

5. Electricity Demand Forecast

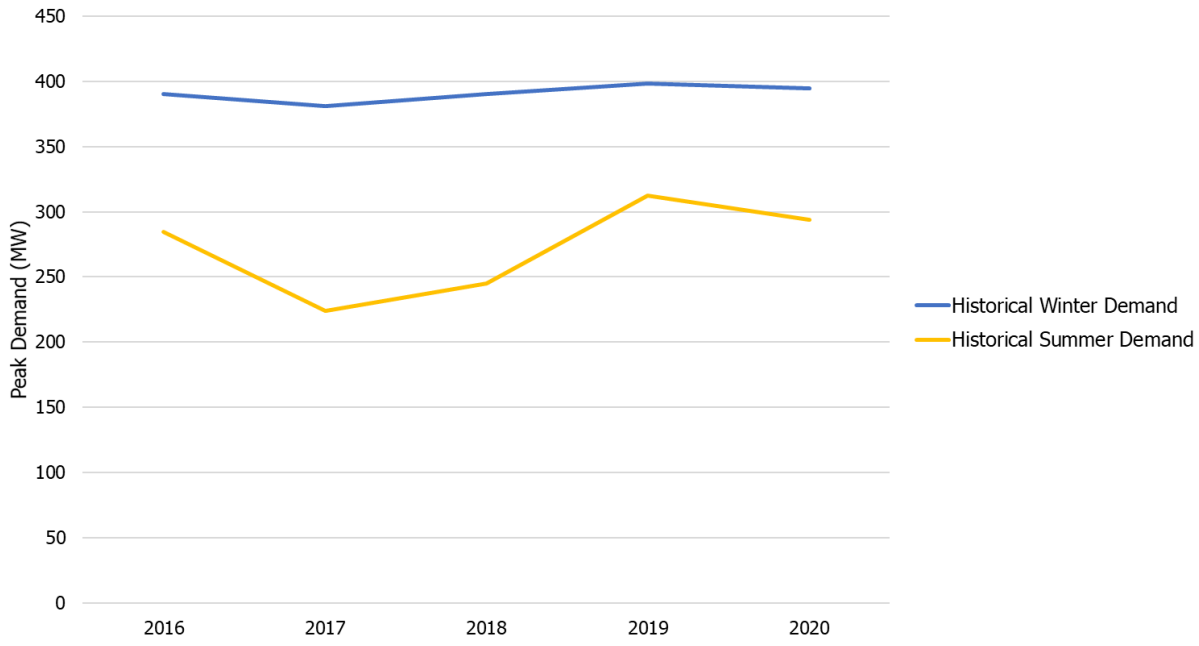
Regional planning is driven in large part by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the North & East of Sudbury region, which is comprised of an LDC demand forecast as well as a forecast of transmission-connected loads (i.e., large industrial customers). It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the North & East of Sudbury region, the peak loading hour for each year occurs in the winter season.

5.1 Historical LDC Electricity Demand

Historical LDC electricity demand in the North & East of Sudbury region is primarily driven by residential and commercial customers (with the exception of Ramore TS and North Bay TS which are largely industrial driven) and demand typically peaks during the winter months. Winter demand is also typically much higher than summer demand as seen in Figure 3 below.

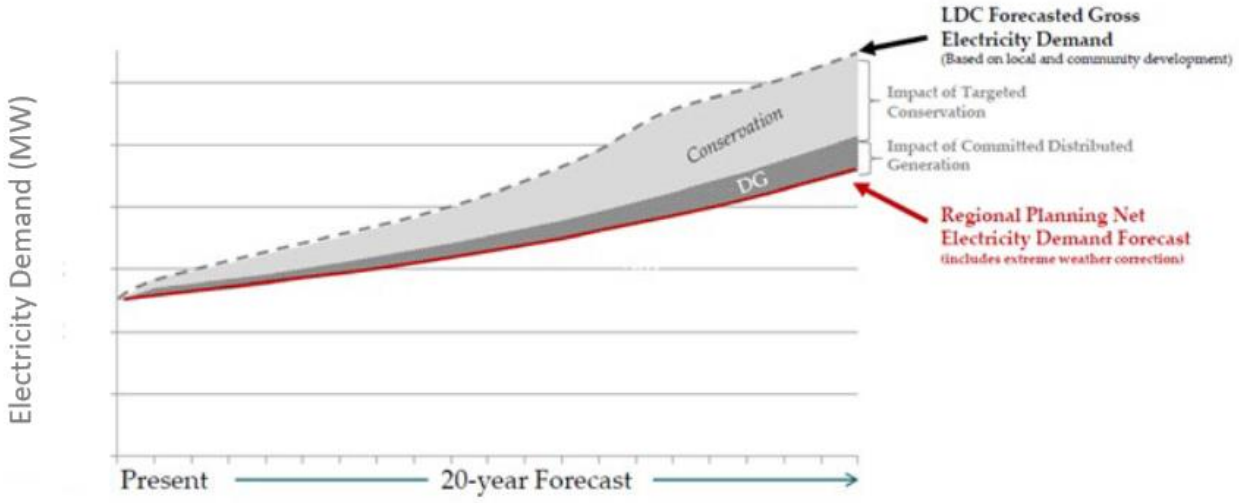
Figure 3 | Historical LDC Winter and Summer Peak Demand for the North & East of Sudbury Region



5.2 LDC Demand Forecast Methodology

A 20-year regional peak demand forecast was developed to assess reliability needs for the North & East of Sudbury sub-region; Figure 4 shows the steps taken to develop this. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions i.e., normal weather, were provided by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation savings and DG contracted through previous provincial programs such as FIT and microFIT. The forecasts were then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments to assess the electricity needs in the region. An illustrative example is provided in Figure 4. Additional details related to the development of the demand forecast are provided in Appendix B.

Figure 4 | Illustrative Development of the Demand Forecast



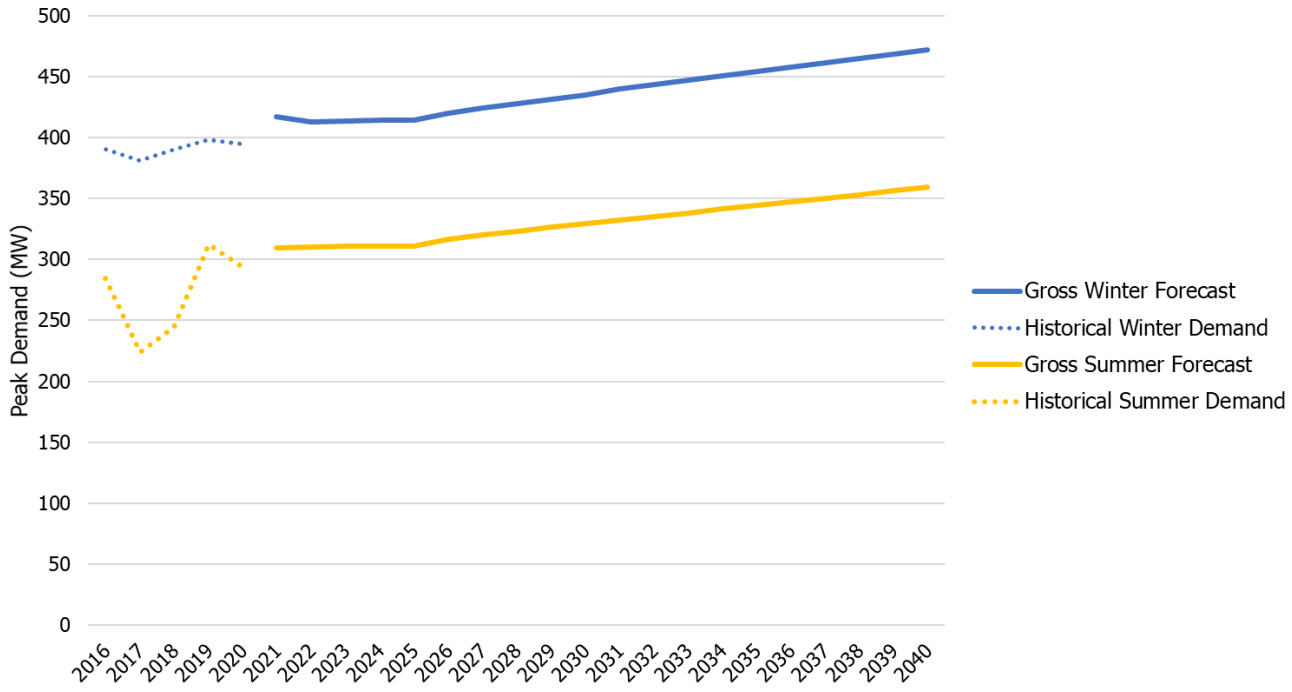
5.3 LDC Gross Demand Forecast

Gross demand forecasts were submitted by each participating LDC in the North & East of Sudbury region. LDCs have knowledgeable insights into future local demand growth and drivers due to their direct involvement with their customers. These insights include future connection applications and knowledge of typical electrical demand trends for different types of customer groups.

The LDC gross demand forecasts account for increases in demand due to factors such as new or intensified development, economic growth, population growth, changes in consumer behaviour. Most LDC's cited alignment with municipalities and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for by the IESO as discussed in Section 5.4 below. The gross LDC forecast assumes median on-peak weather conditions.

More details on the individual LDCs' load forecast methodology can be found in Appendix B. Figure 5 below shows the total gross coincident LDC forecast for both summer and winter demand.

Figure 5 | Gross Winter and Summer LDC Forecast for the North & East of Sudbury Region



5.3.1 Contribution of Conservation to the LDC Demand Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

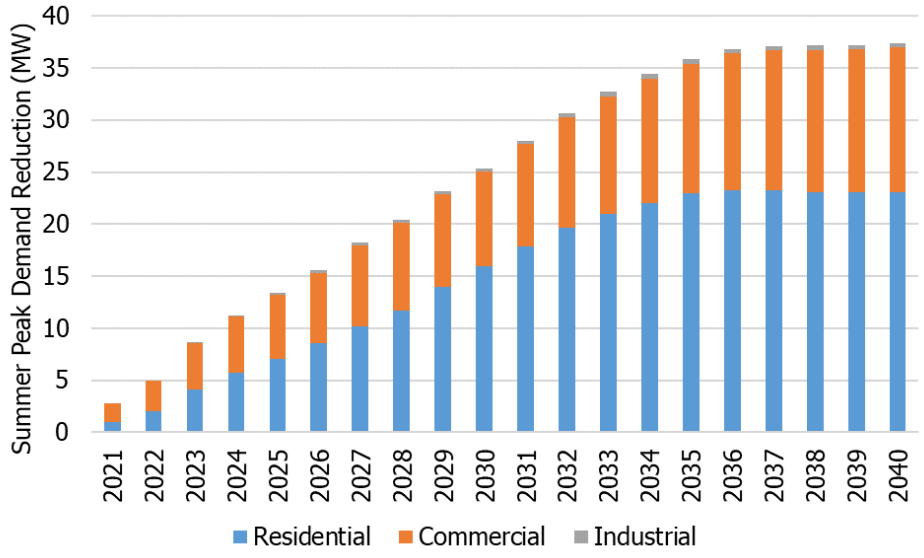
The estimate of demand reduction due to codes and standards is based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e. residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the provincial 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and assumptions regarding continuing provincial CDM programming after 2024.

CDM savings have been applied to the North & East of Sudbury region's LDC gross peak demand forecast for median weather, along with DG (as described in Section 5.3.2) to determine the net peak demand for the region. This takes into account both conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

Figure 6 shows the estimated total yearly reduction to the LDC demand forecast due to conservation from codes, standards and CDM programs for each of the residential, commercial and industrial consumers. Additional details are provided in Appendix B.3.1.

Figure 6 | Estimated total yearly reduction to the LDC demand forecast due to conservation



5.3.2 Contribution of Distributed Generation to LDC Demand Forecast

The effect of Distributed Generation (DG) in offsetting demand is also factored in to the North & East of Sudbury region gross peak demand forecast for median weather. No assumptions were made regarding DG growth as in the long term, as the contribution of DG is expected to diminish as contracts expire. The resources that were included in the DG forecast were comprised of solar and hydroelectric projects. Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output.

The following load supply stations included in this IRRP have embedded DG resources:

- Crystal Falls TS
- Kapuskasing TS
- Ramore TS
- Timmins TS
- Dymond TS
- Trout Lake TS

The effective winter capacity of DG across the region totaled 16 MW in 2022. The expected annual peak demand contribution of contracted DG in the North & East of Sudbury region and capacity contribution factors can be found in Appendix B.

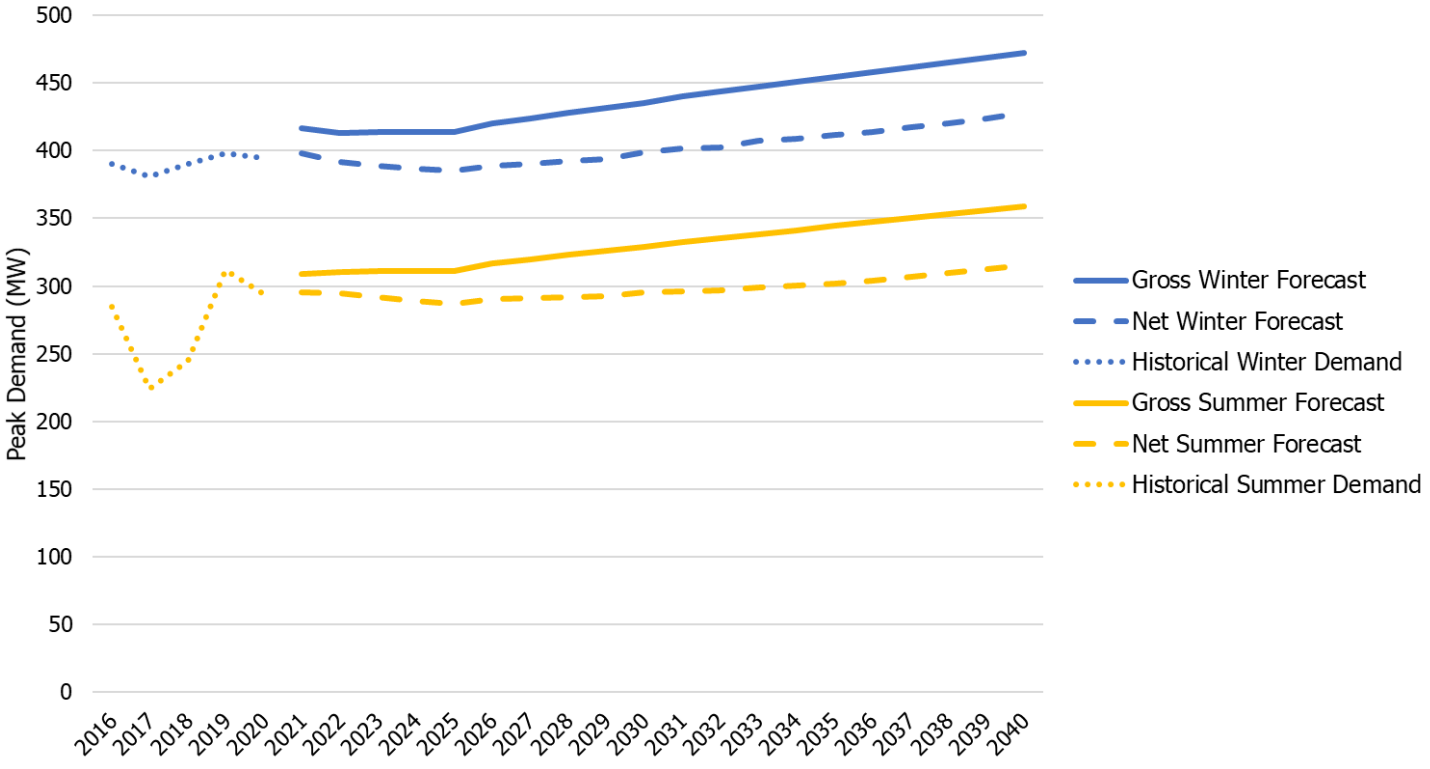
5.3.3 LDC Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the region and is used to carry out system studies for identifying potential needs in the North & East of Sudbury region. This forecast is created in three steps:

1. The gross median weather forecast, provided by the LDCs, is adjusted to extreme weather conditions, according to the methodology described in Appendix B. The result is a gross extreme weather forecast.
2. The impacts of forecast CDM savings and DG output are subtracted from the gross extreme weather forecast to produce a net extreme weather forecast, or planning forecast.
3. A coincidence factor is applied to the forecast at each station to create a non-coincident forecast. The coincidence factor is based on the contribution of each station to the region's coincident peak over the past five years. Non-coincident station forecasts are utilized for assessing the capacity adequacy of each transformer station in the region.

The gross and net extreme weather coincident forecasts for the North & East of Sudbury region are shown in Figure 7 below for summer and winter.

Figure 7 | Extreme Weather Gross and Net Winter and Summer LDC Forecasts for the North & East of Sudbury Region



5.4 Transmission-Connected Forecast

Forecast demand growth among transmission-connected customers in the North & East of Sudbury area primarily consists of new or expanded mining projects and associated industrial processes (e.g. refining). The transmission-connected forecast represents the most up to date information on the timing, size and likelihood of these mining customers either increasing their existing demand or connecting to the system as a new customer.

The mining forecast is project-based and built from the bottom up based on known mining exploration or projects collected from proponents, industry publications, utility companies, and government. Each project is assigned one of four "likelihood" factors ranging from "most likely" to "least likely" that represents the probability of its electricity demand materializing to enable the creation of scenarios that represent different potential future outcomes.

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 3 below.

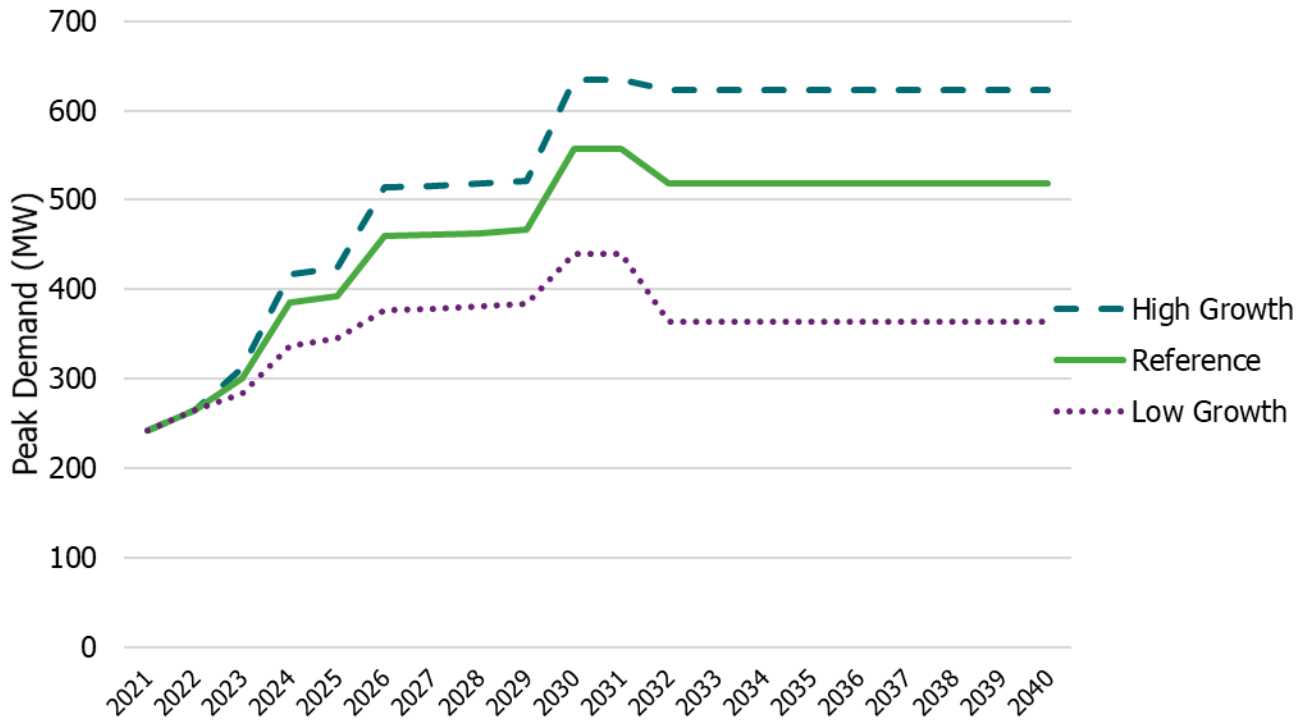
Table 3 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included
Reference	- Includes all demand in the low scenario plus demand forecast from projects classified as "most likely" and "likely" discounted according to their likelihood classification: o "Most likely" project forecasts are not discounted o "Likely" project forecasts discounted to 80% of their full project demand - Aligned with 2021 Annual Planning Outlook[1] reference scenario
High	- Includes all known mining projects with each project's demand forecast discounted according to their likelihood classification: o "Most likely" project forecasts are not discounted o "Likely" project forecasts discounted to 80% of their full project demand o "Less likely" project forecasts discounted to 50% of their full project demand o "Least likely" project forecasts discounted to 20% of their full project demand - Aligned with 2021 Annual Planning Outlook high scenario

The transmission-connected forecast for the North & East of Sudbury area is comparable in size to the LDC forecast. However, transmission-connected customers tend to have a more noticeable impact on the transmission system as they tend to have a flat demand profile (i.e., 24/7 operation) and are large loads. Large step increases in demand from new or expanded transmission-connected customers can stress the system more quickly than growth in LDC load which tends to have a more predictable and slower growth rate as seen in Figure 7 above. Therefore, these transmission-connected customers are more likely to drive system enhancements to support their growth/new connections. The transmission-connected forecast is shown in Figure 8 below.

[1] The Annual Planning Outlook forecasts electricity demand, assesses the reliability of the electricity system, identifies capacity and energy needs, and explores the province's ability to meet them. The latest Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

Figure 8 | Transmission-Connected Forecast



5.5 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over a 20 year forecast horizon) for a station with an identified capacity need were developed to characterize these needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather impacts (e.g. extreme weather events like ice storms or heat waves). The profiles are then scaled to match the annual peak demand forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of non-wires alternatives options.

Additional load profile details including summary tables and hourly heat maps for each need (where appropriate) can be found in Section 6.2.1.1 and Appendix B.

6. Electricity System Needs

6.1 Needs Assessment Methodology

Based on the net extreme weather planning demand forecast, the transmission-connected forecast, the transmitter's identified end-of-life asset replacement plans, and the application of ORTAC planning criteria and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Working Group identified electricity needs for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the load meeting capability (LMC) of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulation analysis. An area's LMC can be limited by the thermal ratings of the equipment, or the voltage levels/changes following a contingency in the area.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

In addition, for the North & East of Sudbury IRRP, several existing operational needs were identified through discussion with the IESO's control room operators and outage planning staff. These needs include localized voltage control issues and difficulty planning 500 kV outages while still maintaining supply to customers in the area.

Technical study results can be found in Appendix D. The needs identified in this IRRP are discussed in the section below.

6.2 Needs Identified

Table 4 below summarizes the needs identified by the North & East of Sudbury IRRP. Some needs previously identified (e.g. Kirkland Lake TS capacity need in 2040, higher than standard operating voltages in the Porcupine to Hunta area) were deferred to the next round of regional planning. For Kirkland Lake TS, the uncertainty regarding certain mining loads and the long term nature of the need means that the need could be deferred. The high operating voltages from Porcupine to Hunta requires more coordination and discussion with existing customers whose equipment are designed to operate at these high voltages. Furthermore, the North of Moosonee region will need to be studied to see if lower operating voltages can be accommodated. Such an activity is outside the scope of this regional plan and is suggested to be addressed in the North of Moosonee regional planning process.

Table 4 | Summary of Needs for North & East of Sudbury IRRP

No.	Need Description	Need Date
1	Station Capacity at Ramore TS	2033
2	Voltage control issues with existing capacitors at Dymond TS	2030
3	Voltage control issues in the Kirkland Lake area	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	2030
6	A4H/A5H End-of-Life Need	2027
7	D2H/D3H End-of-Life Need	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Existing Need
9	Difficulty supplying loads during planned outages to circuit D501P	Existing Need

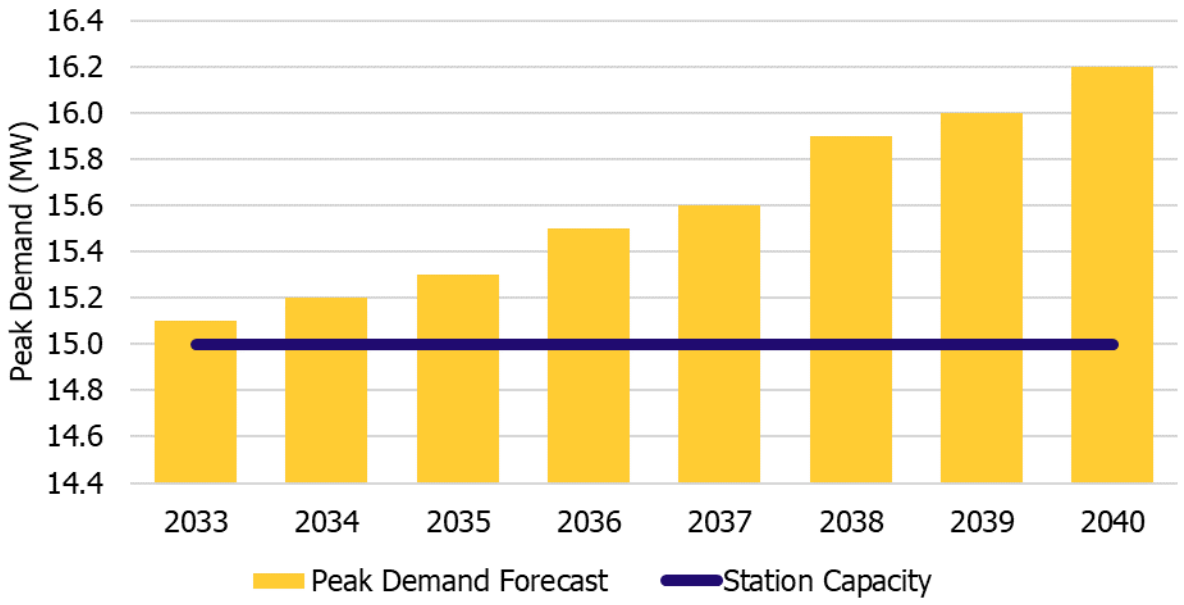
6.2.1 Station Capacity Needs

6.2.1.1 Ramore TS

Winter peak demand growth at Ramore TS is expected to exceed the station's capacity in 2033. The non-coincident winter peak forecast for Ramore TS is found in Figure 9 below.

Note that load growth in the Ramore TS service area is expected to be primarily driven by new or expanding industrial customers. These types of loads are inherently more difficult to forecast beyond the near term as growth tends to occur in large blocks if/when economic conditions support investment. As a result, the timelines associated with this need are understood to be beyond the near term (when actual applications for connection would already be known), but may be triggered with relatively short lead time thereafter. Potential options to address this need should be evaluated to ensure any necessary upgrades can be triggered with minimal planning lead time when required, as opposed to working towards a firm anticipated in-service date of 2033.

Figure 9 | Ramore TS Winter Peak Forecast



6.2.2 Supply Capacity Needs

6.2.2.1 Dymond TS Voltage Control

IESO control room operators report existing operational issues associated with the two existing capacitors at Dymond TS. They observe that the two capacitors at Dymond TS cannot be placed into service without exceeded the maximum voltage allowed by IESO Market Rules, an indication that they are too large for the area under current system conditions.[2] They also note that the existing Dymond capacitor switching scheme is a manual scheme with no telemetered status to either the IESO's or Hydro One's control rooms. This means that staff must be called out to the station to confirm or update the status of the scheme, and this can cause delays in responding to outages.

System studies show that a failure of the AL3 breaker at Dymond TS to open when called upon to clear a fault can cause voltage decline at Dymond TS, beginning in 2030. Voltage decline usually occurs when there is a large amount of load and/or lack of available reactive power resources (e.g. shunt capacitors) to provide voltage support. There are currently capacitors at Dymond TS that may address this issue. However, operators have found the current capacitors are too large to use to prevent this voltage depression.

6.2.2.2 Kirkland Lake Area Voltage Control

IESO system operators report difficulties maintaining minimum operating voltages in the Kirkland Lake area under outage conditions with recent demand growth and changes to the operation of local gas generation. System studies confirm that concurrent outages to the Kirkland Lake SVC and all units at the Northland Power Kirkland Lake Generating Station cause voltage decline issues in the Kirkland Lake area. Specifically, minimum voltages cannot be maintained at the end of the radial K2 circuit.

[2] It is likely that when these capacitors were designed, they were sized appropriately for the area but changing system conditions over time have led to them being oversized.

6.2.2.3 Ansonville, Hunta, Kapuskasing Area Voltage Control

There are post contingency voltage control issues at Ansonville TS, Kapuskasing TS and Hunta TS for the loss of Ansonville T2 and Canyon Units.

6.2.2.4 D3K Thermal Overload

D3K is a 115 kV circuit that supplies Kirkland Lake TS from the south. Kirkland Lake TS is also supplied from the north by two 115 kV circuits, A8K and A9K. Upon the loss of either A8K or A9K when its companion is on outage, Kirkland Lake is supplied radially from the south via D3K. With forecast demand growth in the area, this outage condition will cause D3K to be thermally overloaded (102% of LTE) beginning in 2030.

6.2.3 End-of-Life Refurbishment Needs

6.2.3.1 A4H/A5H End-of-Life

Conductors on sections of A4H and A5H, namely the 25 km sections from Tunis JCT to Fournier JCT, are reaching end-of-life and are planned for replacement in 2027. This IRRP investigated whether there are other needs in the region for which there is an opportunity to right-size the ampacity of the conductors.

6.2.3.2 D2H/D3H End-of-Life

Conductors on sections of D2H and D3H, namely the 90 km sections of these circuits from Pinard TS to Hunta SS, are reaching end-of-life and are planned for replacement in 2026. This IRRP investigated whether are other needs in the region for which there is an opportunity to right-size the ampacity of the conductors.

6.2.4 Load Security and Restoration Needs

6.2.4.1 500 kV Load Security

The North & East of Sudbury region is supplied by two 500 kV circuits, P502X from Hanmer TS to Porcupine TS and D501P from Porcupine TS to Pinard TS, that are operated in parallel with a relatively weak 115 kV system. The system was developed not only to supply loads in the region, but also to integrate a substantial amount of hydroelectric generation on the Moose River which, when generating at full output result in substantial southbound flows on the 500 kV system. The need to respect the loss of either of these 500 kV circuits significantly limits the capability of this system because the 115 kV path cannot handle the post-contingency flows that would result when the 500 kV system is loaded to capacity. To address this, the system was designed around a Remedial Action Scheme (RAS), the Northeast Load and Generation Rejection Scheme (the "Northeast LGR") that enables full use of the system pre-contingency, while protecting it post-contingency by arming generation, loads, or the cross-tripping of circuits (which may also reject generation or loads by configuration) for the loss of the 500 kV path. This is a legacy system that does not meet today's planning criteria. For example, ORTAC planning criteria do not permit the use of load rejection following the loss of a single transmission element. However, bringing it up to current standards would involve substantial capital investment that is difficult to justify without the introduction of new needs (e.g., additional demand growth or resource development that would outstrip the system's current capability).

Nonetheless, the IESO recognizes customer reliability concerns and the need to work toward bringing this system up to current standards over time through its bulk and regional planning processes. The recent Northeast Bulk Plan recommendation to add a new single-circuit 500 kV line (operated at 230 kV) between Porcupine TS and Wawa TS, is a first step toward reducing reliance on load rejection in the North & East of Sudbury area. This new line is expected to reduce the frequency and amount of load rejection arming needed to respect the loss of P502X as it provides another supply point into Porcupine TS. This will, however, not address reliability concerns following the loss of D501P, which supplies the most northeastern portions of the system.

6.2.4.2 Difficulty supplying loads during planned outages to circuit D501P

IESO's outage planning staff have also identified that during recent outages to D501P, it has not been possible to supply all customer load in the area due to limitations on the 115 kV system, and certain industrial customers have been forced to reduce their production. These concerns have also been raised by these customers themselves. During D501P outages, generation must also be significantly curtailed, which can remove substantial capacity from the Ontario system.

6.2.4.3 Load Restoration Needs

No load restoration needs were identified in this IRRP.

7. Plan Options and Recommendations

In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

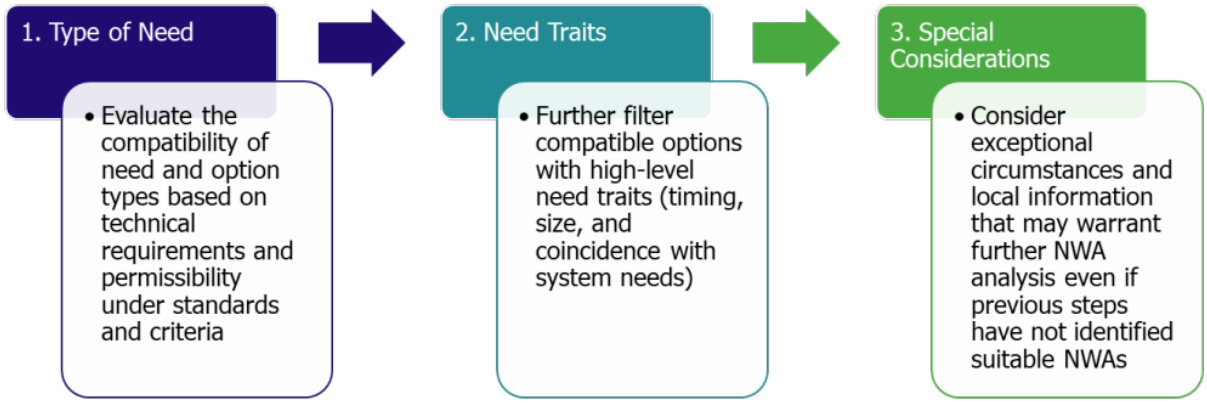
Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include recommendations such as new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
2. Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as "non-wires" alternatives and can include recommendations such as local generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need. Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 10.

The screening process resulted in NWA being considered for the station capacity need at Ramore TS. NWAs were found to not be suitable for end-of-life and voltage control needs. A like-for-standard sustainment plan is appropriate for the end-of-life needs given that the system studies did not identify any regional needs related to these assets. Needs characterization was completed for the Ramore TS station capacity need.

Figure 10 | IRRP Options Screening Mechanism



7.1 Options and Recommendations for Meeting Near- and Medium-Term Needs

7.1.1 Ramore TS Station Capacity Need

Options to address station capacity needs can be broadly sorted into two categories:

1. Keep peak loading below existing capacity, using measures such as conservation or distributed energy resources ("Non-wires alternatives), or;
2. Upgrade the station to enable additional capacity (conventional, or "Wires" solution)

Often the two categories can be considered together, with measures to offset peak demand relied upon until no longer feasible or cost effective, at which point an infrastructure upgrade becomes preferred. This type of approach can be preferable if peak capacity is expected to only marginally exceed ratings for the first few years (common in areas with relatively slower load growth), if there is insufficient lead time to accommodate a station upgrade before the need is triggered, or if uncertainty exists in the demand forecast, meaning a capacity upgrade could be "stranded" if the need never materializes. In the case of Ramore TS, there is significant uncertainty in the actual need date due to the high proportion of industrial load at the station, plus under the existing forecast assumptions, load will be only marginally above existing capacity within the study horizon. For both of these reasons, Ramore TS is considered to be a good candidate to consider non-wires measures to keep loading below existing capacity, and consider a station upgrade if and when required. Two non-wires options in particular may be beneficial for this need.

7.1.1.1 Conservation/Energy Efficiency

Conservation (or energy efficiency) involves the use of incentive programs to reduce electricity demand by upgrading/replacing existing equipment with more energy efficient alternatives. In Ontario, the IESO is currently delivering a suite of province-wide programs under the 2021-2024 Conservation and Demand Management Framework. The framework is designed to produce energy savings and offset system peak demand (which occurs in the summer). A component of this framework is the Local Initiatives Programs, which enables the IESO to pursue additional conservation in specific areas to address local electricity system needs while also contributing to meeting provincial system needs.

Given the size and timing of the need, the inherent difficulties of predicting blocky industrial load, and the misalignment with current (summer) system peak, it is recommended to defer a review and decision on targeting conservation as a solution to the Ramore TS need until the next IRRP cycle.

7.1.1.2 Distributed Energy Resources

In order to assess the appropriate DER option, a load duration forecast was created for Ramore TS. This duration forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using DERs to address the region's needs and determine which type of DERs may be best suited to meet the needs.

Based on the profiles generated for Ramore TS, it was determined that a battery storage solution would be the best fit for the need. The battery storage solution would have a capacity of 1.2 MW and would be able to provide energy for up to six hours. The estimated cost of this battery storage solution is $3 to $3.7 million.

Given that the anticipated need for Ramore TS capacity upgrade is still several years out, it is not recommended that a non-wires alternative be developed at this time. Instead these options should be considered as potential deferral strategies and would be best pursued when actual demand and/or connection requests suggest a capacity need within the next 2-3 years. If these options prove to be insufficient to meet demand, or costlier than a wires alternative, then development work should be initiated to upgrade the station.

7.1.1.3 Station Upgrade

Ramore TS is current made up of a single 10/17 transformer, with a winter LTR of 15 MW. Hydro One has indicated that the station could be upgraded by adding a second, equally sized transformer. This type of upgrade would be expected to cost around $10-$15 million, and can be implemented with about three years' lead time.

Table 5 below shows a comparison of these alternatives, their potential capacity impact, and estimated cost. Note that due to the lead time expected before this work would be triggered, all cost and timing estimates should be considered preliminary, as they will need to be updated closer to when the work is undertaken.

Table 5 | Comparison of Ramore TS options

Option	Capacity Impact	Estimated Cost	Lead Time
Distributed Energy Resources	Increase by 1.2 MW	$3 to $3.7 million	Three years
Station Upgrade	Increase by 15 MW	$10-15 million	Three years

NWA can be viable alternatives should demand grow as projected in Section 6.2.1.1. Otherwise, new solutions may have to be drawn up should a large industrial customer wish to connect to the station. Based on the options above, the Working Group recommends that the station loading at Ramore TS be monitored in between cycles in preparation for the next regional planning cycle.

7.1.2 A4H/A5H End-of-Life Needs

No other regional needs were identified that could be addressed by right-sizing the end-of-life replacement of the A4H/A5H circuits, based on the IRRP demand forecast. Therefore, the Working Group recommends that Hydro One proceed with a like-for-standard replacement for these end-of-life needs. Nonetheless, future system developments (e.g., additional demand growth or resource development in the area) could drive a need for reinforcement in this area in the future. Therefore, the Working Group recommends continued monitoring of developments in the area between regional planning cycles, and that Hydro One touch base with the Working Group before the like-for-standard replacement project is committed, to determine if this recommendation should be revisited.

7.1.3 D2H/D3H End-of-Life Needs

No other regional needs were identified in the IRRP that could be addressed by right-sizing the end-of-life replacement of the D2H/D3H circuits. The Working Group recommends that Hydro One proceed with a like-for-standard replacement for these end-of-life needs.

7.1.4 D3K Thermal Overload

This need was identified in the Needs Assessment stage of regional planning. Since that time, a new RAS has come into service in the Kirkland Lake area to maintain system reliability following various contingencies in the Kirkland Lake area. This RAS will be able to address the identified post-contingency overloading of D3K by arming load rejection for the appropriate A8K or A9K contingency. Therefore, at this time, the Working Group does not recommend any further actions to address this need.

However, the RAS may need to be expanded and/or the system may need to be reinforced should additional demand beyond what was included in the IRRP forecast connect to the system in the Kirkland Lake area. The Working Group recommends that this area be monitored in between regional planning cycles.

7.1.5 Ansonville, Hunta, Kapuskasing Area Voltage Control

The IRRP reviewed the post contingency voltages at Ansonville TS and Hunta SS following the loss of Ansonville T2 and Canyon GS units. The IRRP found that post contingency voltage levels meet ORTAC criteria (Hunta SS is permitted to operate up to 138 kV). Hydro One is currently studying a possible expansion to the Kirkland Lake RAS. This will allow operators to take control actions following the loss of Ansonville T2, among other contingencies. This will give more flexibility to operators should post contingency voltage issues be seen in the future. The Working Group recommends that Hydro One continue to study the possible expansion of the Kirkland Lake RAS. New reactive devices (a 10 MVAr reactor and a 10 MVAr capacitor), controlled by a new remedial action scheme will soon come into service in the Kapuskasing area. These improvements were designed to ensure voltage criteria is met following certain contingencies at Kapuskasing TS, Spruce Falls TS, and Pinard TS. No additional recommendations are required in this IRRP to address voltage control issues in the Kapuskasing area.

Additional reactive devices will be recommended in the Northern Voltage Study to support the broader bulk system across northern Ontario (see Section 4.2.2). The recommendations of this study will provide further reactive support to help alleviate voltage control issues in the North & East of Sudbury area.

7.2 Options and Recommendations for Meeting Longer-Term Needs

7.2.1 Dymond Area Voltage Control Needs

The Working Group recommends that Hydro One investigate right-sizing the capacitors at Dymond TS so that they may be used more effectively to manage voltage in the area. This can be accomplished by reducing the size of the existing capacitors to improve their flexibility. The Working Group recommends that the exact sizing be explored in the RIP in coordination with gathering information on feasible resizing options. The Working Group also recommends Hydro One investigate the feasibility of introducing remote monitoring of the status of the Dymond TS capacitor switching scheme to improve operational visibility.

7.2.2 Kirkland Lake Area Voltage Control Needs

Based on system studies performed in the IRRP, it was found that under the conditions noted in section 6.2.2.2, a 20 MVAr reactive device located at Kirkland Lake TS or a 10 MVAr reactive device at the remote end of circuit K2 would address this need. The Working Group recommends that Hydro One, in the upcoming RIP, further develop options for adding reactive support in the Kirkland Lake area.

7.3 Load Security

7.3.1 Considerations on existing reliance on Remedial Action Schemes in the Northeast and Load Security Needs

Several investments were made over the years to strengthen the area (e.g. Kapuskasing Area Reinforcement). Despite these investments, the reliability issues following the loss of D501P still remains. While proven reliable to protect the rest of the system, the continued long-term reliance on the Northeast LGR may hamper growing interest to connect additional loads (e.g. new mines, mining expansions) and generators in the area.

As the circuit D501P is part of the Bulk Power System, the Working Group recommends that the next bulk system plan in Northeast Ontario address the load security concerns following an outage on D501P. This bulk plan should be triggered if substantial load increases/new resources are expected in the Kapuskasing and northern Cochrane areas.

7.4 Summary of Recommended Actions and Next Steps

Table 6 below shows a summary of all recommended actions as outlined in Section 7.

Table 6 | Summary of Recommended Actions and Next Steps

No.	Need Description	Recommendation	Need Date
1	Station Capacity at Ramore TS	Load growth at Ramore TS will be monitored and revisited in the next cycle of regional planning	2033
2	Voltage control issues with existing capacitors at Dymond TS	Hydro One to investigate options to improve operability of existing capacitors in the upcoming RIP	2030
3	Voltage control issues in the Kirkland Lake area	Hydro One to investigate options of adding reactive devices in the Kirkland Lake area in the upcoming RIP	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Various recommendations, including a new RAS and additional voltage support	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	The new Kirkland Lake RAS installed in 2022 addresses this issue. Additional load in the area beyond the current forecast will require further study	2030
6	A4H/A5H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2027
7	D2H/D3H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Partially addressed by the recent Northeast Bulk Plan. An update to this plan is recommended should significant new resources and/or load connect to the North & East of Sudbury region.	Existing Need

No.	Need Description	Recommendation	Need Date
9	Difficulty supplying loads during planned outages to circuit D501P	Study this need as part of the next bulk system plan for Northeast Ontario in combination with other drivers of system expansion as they develop	Existing Need

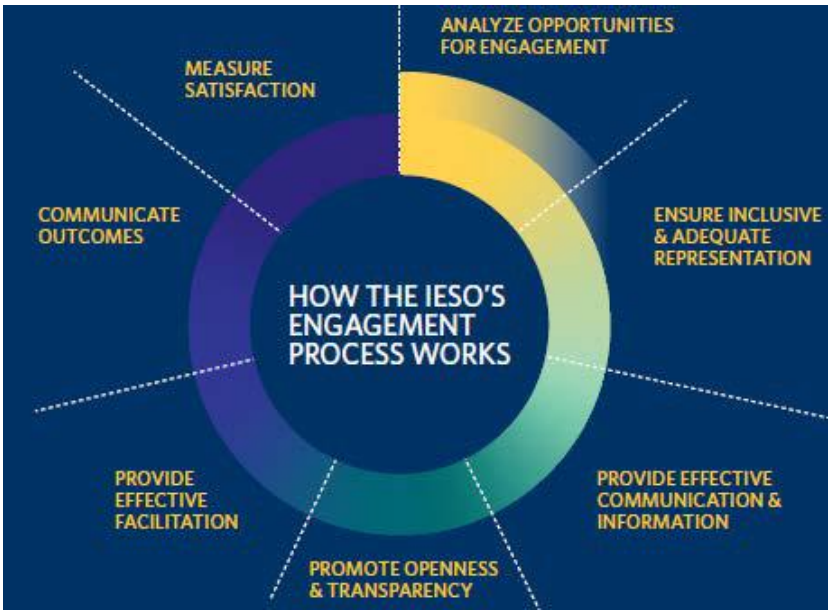
8. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for the IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 11 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for North & East of Sudbury

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Targeted individual and small group meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

Preliminary discussions were held to help inform the engagement approach and lay the foundation for dialogue in this region where the IESO has not actively engaged with communities and stakeholders. This started with an invitation to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and opportunity to provide input on the North & East of Sudbury Region Scoping Assessment Outcome Report. A public webinar was held in June 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach to address them moving forward. Interested parties were invited to submit written feedback on a draft report that was posted for review over a three-week comment period. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following the publication of the final Scoping Assessment, targeted outreach began with municipalities in the region to inform early discussions in the development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed to ensure all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a

cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received were primarily focused on:

- Pockets of development in certain areas (I.e. City of Temiskaming Shores, Town of Iroquois Falls and Town of Moosonee)
- Interest in exploring DERs and other non wires alternatives to address regional needs and defer the need for new transmission or large scale generation
- Reliability is a key issue and priority
- Engagement with local First Nations communities, customers and stakeholders is important to understand planned growth and opportunities to participate in developing solutions to meet emerging needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to North & East of Sudbury subscribers, municipalities, and Indigenous and Métis communities. All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's North & East of Sudbury engagement webpage.

Ongoing discussions will be encouraged through the IESO's Northeast Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle. Join the Northeast Network on the IESO website.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP.

This targeted outreach was undertaken in tandem with the Northeast Bulk Plan work and engagement given the interrelations of some of the needs at the provincial and regional level, as well as to streamline discussions with local communities. Discussions were held with the Federation of Northern Ontario Municipalities (FONOM) Board of Directors, City of Timmins, Town of Iroquois Falls and Town of Cochrane. These discussions helped to build an understanding about the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular communications were sent to Indigenous communities within the North & East of Sudbury electricity planning region or that may have interests in the region throughout the development of the plan. This includes the First Nation communities of Constance Lake First Nation, Flying Post First Nation, Matachewan First Nation, Mattagami First Nation, Missanabie Cree, Moose Cree First Nation, MoCreebec Council of the Cree Nation, Nipissing First Nation, Taykwa Tagamou First Nation, Temagami First Nation, Wahgoshig First Nation, Wahnapitae First Nation, Northern Lights Métis Council, Timmins Métis Council, Temiskaming Métis Council and Chapleau Métis Council. This electricity planning initiative was also discussed during broader outreach meetings with Indigenous communities in the region.

9. Conclusion

The North & East of Sudbury IRRP identifies electricity needs in the region and opportunities to improve system reliability and operability for the next 20 years. This report recommends a plan to address near- to medium-term issues, and lays out actions to monitor, defer, and/or address long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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REGIONAL INFRASTRUCTURE PLAN REPORT

[North and East of Sudbury]

Regional Infrastructure Plan Report

North and East of Sudbury

[Date: November 03, 2023]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

North & East of Sudbury Technical working group

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Disclaimer

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

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

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

Executive Summary

REGION	**North and East of Sudbury** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: May 10,2023	**END DATE:** November 03, 2023

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the North & East of Sudbury Region, preceded by, the publication of Needs Assessment (NA) report in May 2021 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in August 2021 and in April 2023 published by the IESO respectively.

Hydro One as the lead transmitter undertake the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs. This is second cycle of RIP.

2. OBJECTIVES AND SCOPE

Objectives:

- Provide a comprehensive summary of needs and wires plans to address the needs for the North & East of Sudbury Region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

Scope:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs [2023-2033] identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2023-2043 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the North & East of Sudbury IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure Plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the North & East of Sudbury Region though a regional planning area map and a Single Line diagram.

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Hanmer TS to Pinard TS.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

This section provides a summary and brief description of all the projects completed or are currently underway in past ten years.

I. Following Major projects were completed during the last ten years:

- Kapuskasing Area Reinforcement – H9K Circuit Upgrade (2020)
- Kirkland Lake TS (T12/T13) transformers (2017)
- Dymond TS (T3/T4) transformers (2016)
- Timmins TS (T63/T64) with single 83MVA (2016)
- Hanmer TS Northern Station Replacement Project (2022)

II. Following Major projects are underway:

- Kapuskasing Area Reinforcement – Install 115kV Reactive Devices (2023)
- Kirkland Lake TS – Replace low voltage breakers, Instrument Transformers, P&C equipment (2025)
- Hearst TS - Replace low voltage breakers, P&C Equipment, switches (2028)
- Hunta SS - Replace P&C Equipment (2025)
- Porcupine TS – Replace 1 - 500kV/230kV autotransformer (T7), 2- 500kV/115kV autotransformers (T3/T4), switches, station service and P&C equipment (2025)

- Otto Holden TS - Replace 2 – 230 kV/115 kV autotransformers (T3/T4), high voltage breakers, switches, station service equipment, and protections (2027)
- K4 circuit - Refurbish Kirkland Lake TS X Matachewan JCT (10km) (2024)
- A8K/A9K circuits – Refurbish A8K/A9K (90km) (2023)

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the North & East of Sudbury Region is expected to grow at an average annual rate of approximately 0.50% in winter and 0.25% in summer from 2023 to 2043.

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2043.
- LDCs reconfirmed load forecasts up to 2040. The additional 3 years of forecasts were extrapolated based on the growth rate as a reasonable position to complete the 20-year period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Regional transmission line and auto transformer capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Resources assumptions align with the IRRP.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the North & East of Sudbury Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment

- Kirkland Lake TS
- Hunta SS
- Porcupine TS
- Otto Holden TS
- Hearst TS
- Timmins TS
- Kapuskasing TS
- Dymond TS
- Ansonville TS
- Crystal Falls TS
- Trout Lake TS
- A8K/A9K circuits
- K4 circuit
- T61S circuit
- K1/K2 circuits
- D2H/D3H circuits
- A4H/A5H circuits

b. Station Capacity

- Ramore TS

c. Transmission Line Capacity

- D3K

d. System Reliability, Operation and Load restoration

- Dymond TS - Voltage violation
- Kirkland Lake TS - Voltage control
- Ansonville, Hunta, Kapuskasing TS - Voltage control
- ORTAC load security criteria not met for 500 kV circuit outages
- Difficulty supplying loads during planned outages to circuit D501P

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the North & East of Sudbury Region. The needs include those previously identified in the NA and IRRP for the North & East of Sudbury Region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the North & East of Sudbury Region is given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	Hydro One Transmission	2025	36
Hunta SS	Replacement of P&C and telecom equipment.	Hydro One Transmission	2025	12
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	Hydro One Transmission	2026	91
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	Hydro One Transmission	2027	74
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	Hydro One Transmission	2028	19
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	Hydro One Transmission	2028	14

Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	Hydro One Transmission	2030	24
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	Hydro One Transmission	2031	42
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	Hydro One Transmission	2031	11
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	Hydro One Transmission	2031	32
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	Hydro One Transmission	2033	17
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	Hydro One Transmission	2024	4
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	Hydro One Transmission	2024	
K1/K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	Hydro One Transmission	2024	4
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	Hydro One Transmission	2029	96
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	Hydro One Transmission	2027	22
Station Capacity Needs				
Ramore TS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
Transmission Line Capacity Needs				
D3K	Monitoring & further exploration in future RIP cycle	Hydro One Transmission	NA	NA

System Reliability, Operation and Load restoration Needs				
Dymond TS	Continue to investigate sizing of the existing 115kV SC11 & SC12 capacitor banks	Hydro One Transmission	NA	NA

Note:

a) The planned in-service dates are tentative and subject to change
b) Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process where, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The second cycle of the Regional Planning process for the North & East of Sudbury Region was initiated with the publication of Needs Assessment (NA) report in May 2021 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in August 2021 and in April 2023 published by the IESO respectively.

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

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

Table 1: North & East of Sudbury Region TWG Participants

Hydro One Networks Inc. (Lead Transmitter)	Lead Transmitter
Independent Electricity System Operator ("IESO")	System Operator
Hydro One Networks Inc. (Distribution)	LDC
North Bay Hydro	LDC
Northern Ontario Wires Inc.	LDC
Hearst Power Distribution Co.	LDC
Greater Sudbury Hydro Inc.	LDC

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the North & East of Sudbury Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2023-2033) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2023-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the North & East of Sudbury IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most

essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess, and document which of the needs

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the Independent Electricity System Operator (IESO) initiates the Scoping Assessment (SA) phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), Integrated Regional Resource Plan (IRRP) and/or Regional Infrastructure Plan (RIP).

The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

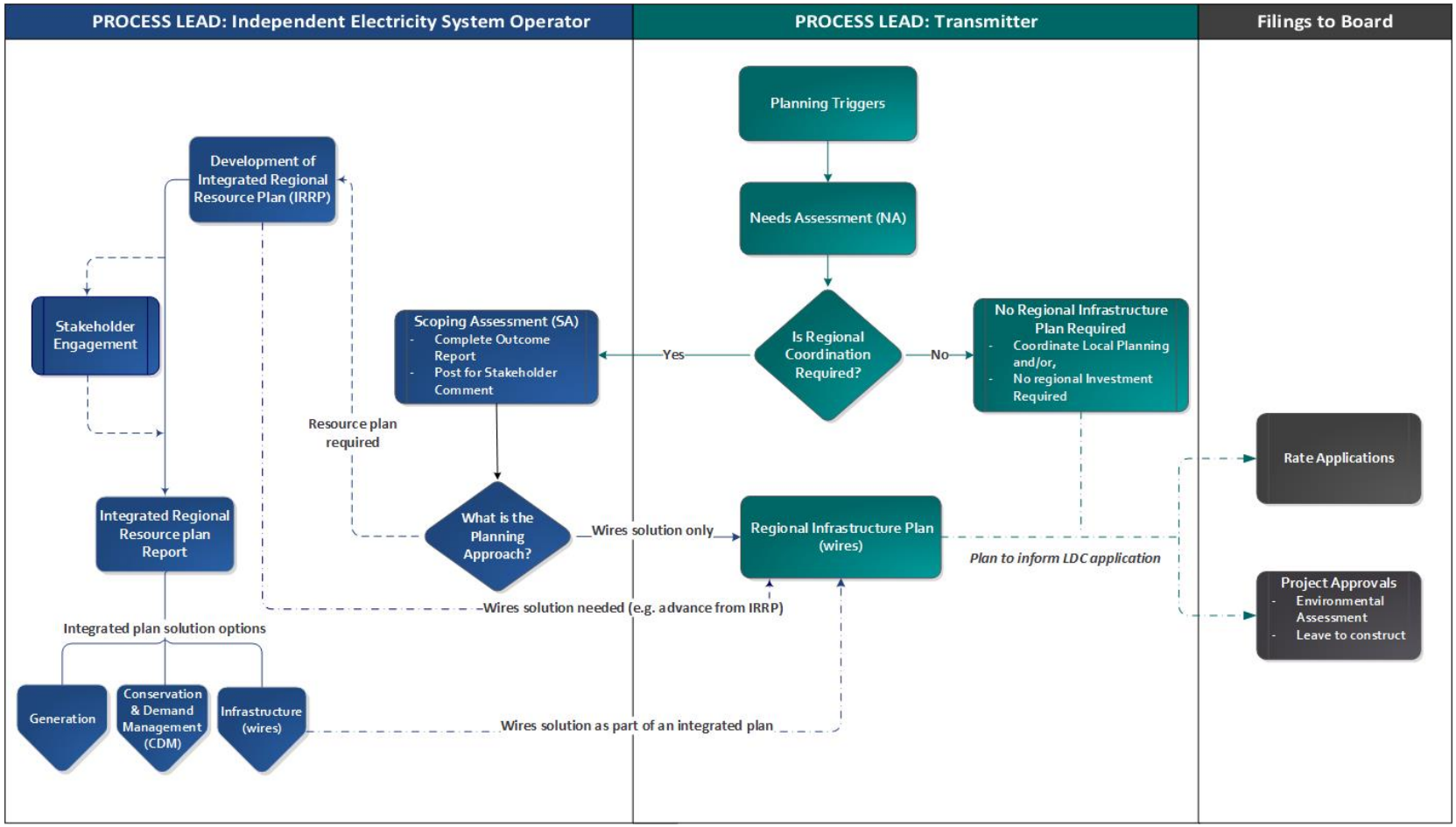
If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the

region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the Ontario Energy Board (OEB) timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

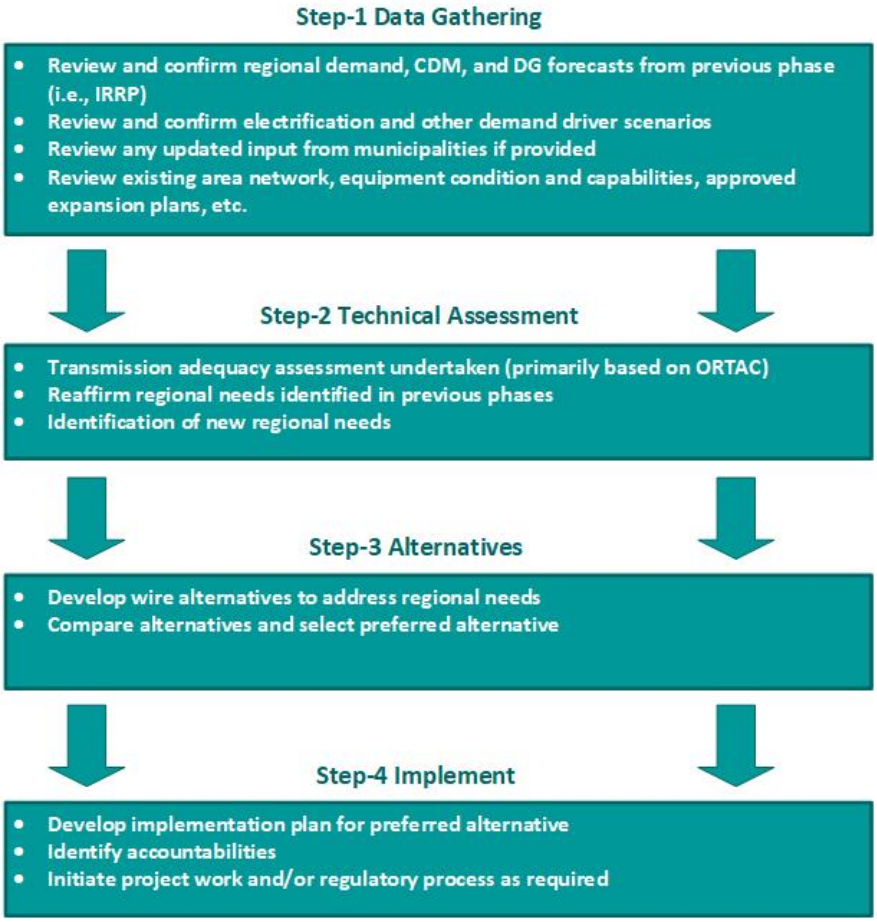
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure-1.

Figure-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.

- Review and confirm electrification and other growth scenarios which effects the projects recommended in in previous stages and also update the inputs provided by the Municipalities.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

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

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. The geographical boundaries of the North & East of Sudbury region is shown in Figure 3 below.

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Hanmer TS to Pinard TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.
- Greater Sudbury Hydro Inc.

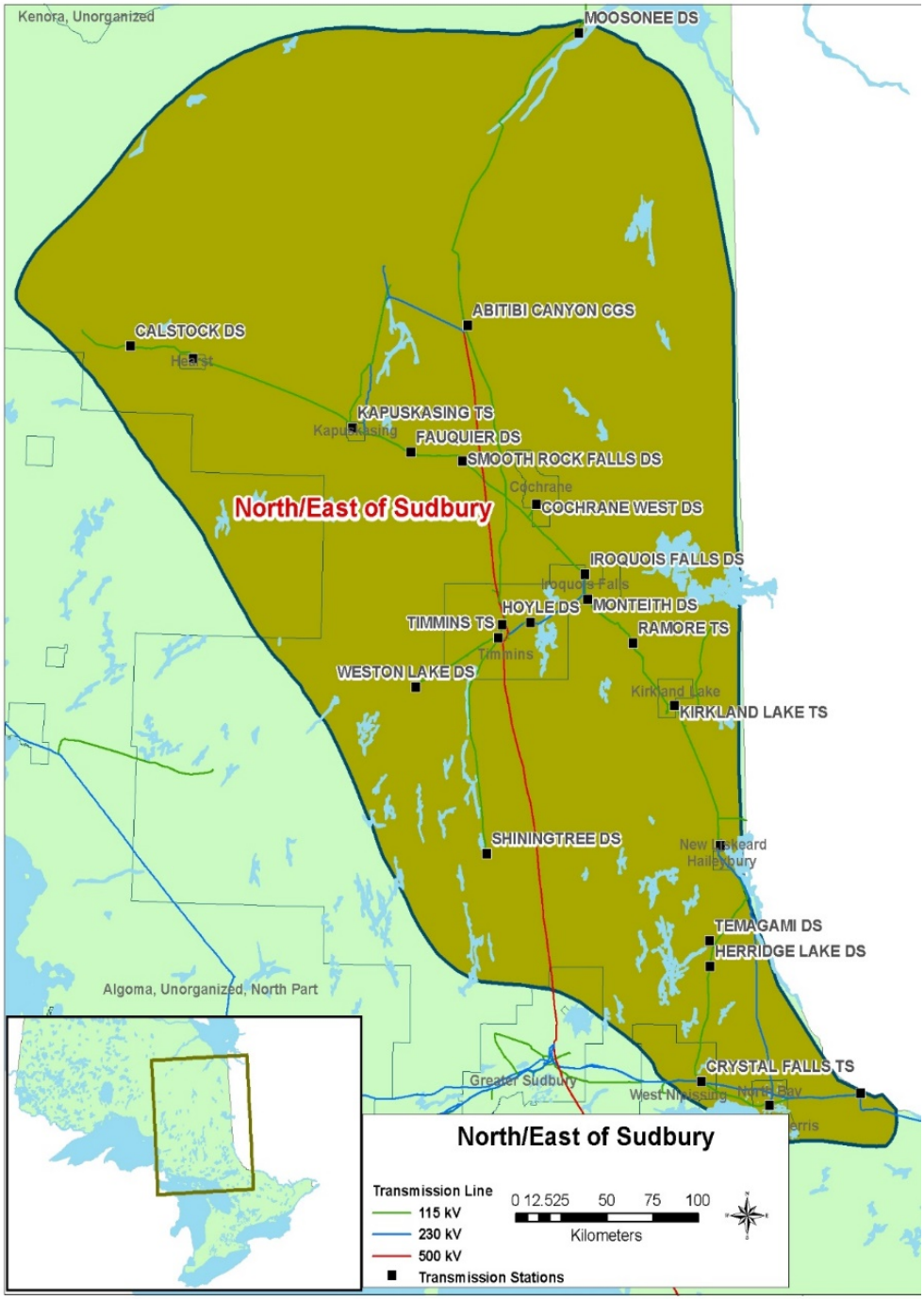


Figure 3: Map of North & East of Sudbury Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the North & East of Sudbury Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
A4H/A5H	D23G	Ansonville TS*	Otter Rapids GS
A8K/A9K	H22D	Crystal Falls TS	Abitibi Canyon GS
D2H/D3H	H23S/H24S	Dymond TS*	Empire CGS (10 MW)
H6T/H7T	K38S	Hearst TS	Martin's Meadows CGS (10 MW)
P13T/P15T	L20D	Hunta SS	Abitibi CGS (10 MW)
T7M/T8M	L21S	Kapuskasing TS	Long Lake CGS (10 MW)
D2L	P91G	Kirkland Lake TS	Kipling GS (164 MW)
H9K	R21D	Little Long SS	Kipling 2 GS (79 MW)
K2	W71D	Moosonee SS	Harmon GS (140 MW)
K4		North Bay TS	Harmon 2 GS (78 MW)
L1S		Otter Rapids SS	Smoky Falls 2 GS (264 MW)
L5H		Otto Holden TS*	Little Long GS (MW)
D3K		Pinard TS*	Little Long 2 GS (70 MW)
P7G		Porcupine TS*	A.P. Kapuskasing CGS (57 MW)
T61S		Ramore TS	Nagagami CGS (18 MW)
F1E		Spruce Falls TS	A.P. Calstock CGS (39 MW)
T2R		Timmins TS	Carmichael Falls CGS (18 MW)
		Trout Lake TS	Smooth Rock Fall CGS (8 MW)
		Widdifield SS	Yellow Falls CGS (16 MW)
			Iroq Falls Power CGS (126 MW)
			New Liskeard CGS (30 MW)
			Northland Power Kirkland Lake CGS (172 MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of North & East of Sudbury region is shown in Figure 4 below.

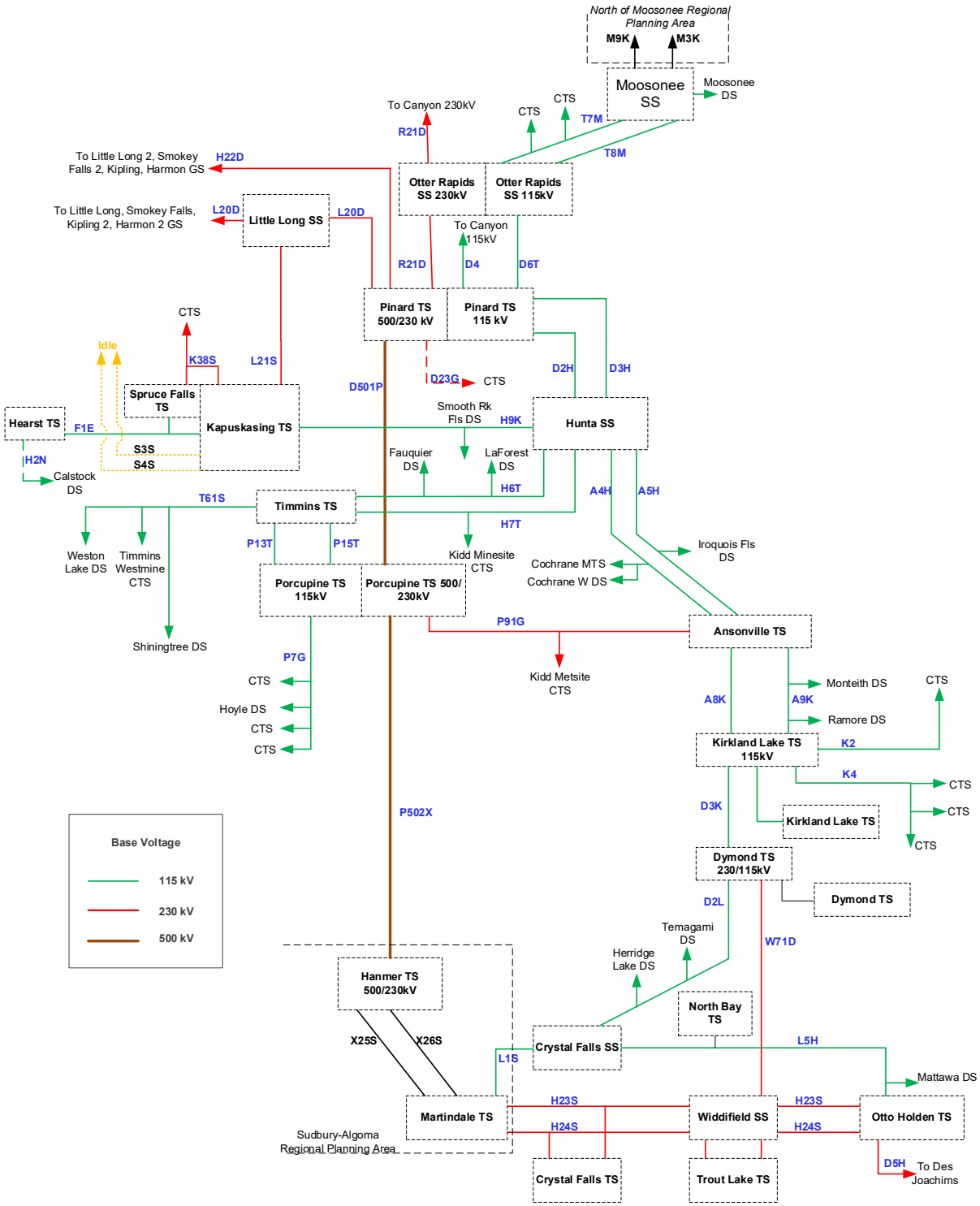


Figure 4: North & East of Sudbury Transmission Single Line Diagram

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the **North & East of Sudbury** Region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner (TAO) in the region have undertaken execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

- Kapuskasing Area Reinforcement – H9K Circuit Upgrade (ISD 2020)
- Kirkland Lake TS (T12/T13) transformer replacement (ISD 2017)
- Dymond TS (T3/T4) transformer replacement (ISD 2016)
- Timmins TS (T63/T64) replace with a single 83MVA (ISD 2016)

II. Following Major projects are underway:

- Kapuskasing Area Reinforcement – Install 115kV Reactive Devices (ISD 2023)
- Kirkland Lake TS – Replace low voltage breakers, Instrument Transformers, P&C equipment (ISD 2025)
- Hearst TS - Replace low voltage breakers, P&C Equipment, switches (ISD 2028)
- Hunta SS - Replace P&C Equipment (ISD 2025)
- Porcupine TS – Replace 1 - 500kV/230kV autotransformer (T7), 2- 500kV/115kV autotransformers (T3/T4), switches, station service and P&C equipment (ISD 2025)
- Otto Holden TS - Replace 2 – 230 kV/115 kV autotransformers (T3/T4), high voltage breakers, switches, station service equipment, and protections (ISD 2027)
- K4 circuit - Refurbish Kirkland Lake TS X Matachewan JCT (10km) (ISD 2024)
- A8K/A9K circuits – Refurbish A8K/A9K (90km) (ISD 2023)

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

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

The TWG participants reviewed and verified that there is no material change in load forecast from those used in the North & East of Sudbury Region IRRP Load Forecasts (April 2023). Thus, the IRRP forecasts were used in development of this Report. TWG participants, including representatives from LDC's, IESO and Hydro One, provided information and input for the IRRP Load forecast, which also includes the inputs from the Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). New industrial/mining load connections requests have been received after publication of IRRP report. These new potential load connections have not been explicitly listed in the load forecast tables, however these loads have been studied in the RIP to assess their impact to the area.

During the study period, the load in the North & East of Sudbury Region is expected to grow at an average annual rate of approximately 0.50% in winter and 0.25% in summer from 2023 to 2043. The Region is winter peaking, so this assessment is based on winter peak loads. This growth does not include significant increases in the industrial sector.

Figures 5 & 6 shows the North & East of Sudbury Region extreme summer/winter weather net coincident and non-coincident load forecast from 2023 to 2043. The load forecasts from the North & East of Sudbury Region were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident and coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

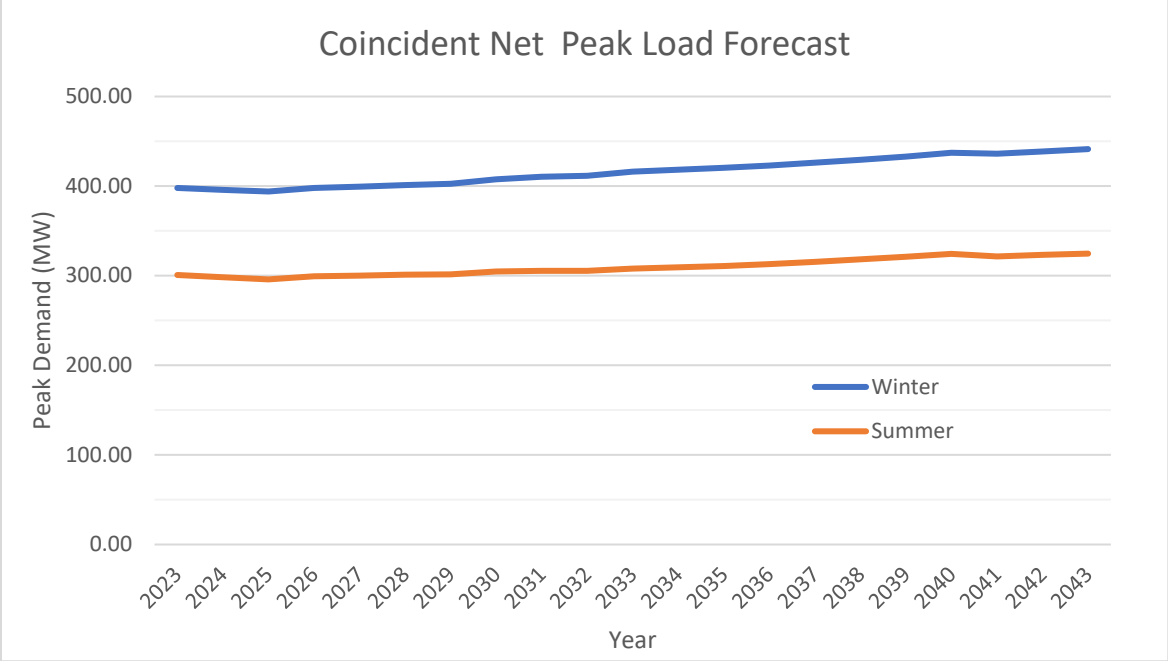


Figure 5: North & East of Sudbury Region summer/winter coincident Net Peak Load Forecast

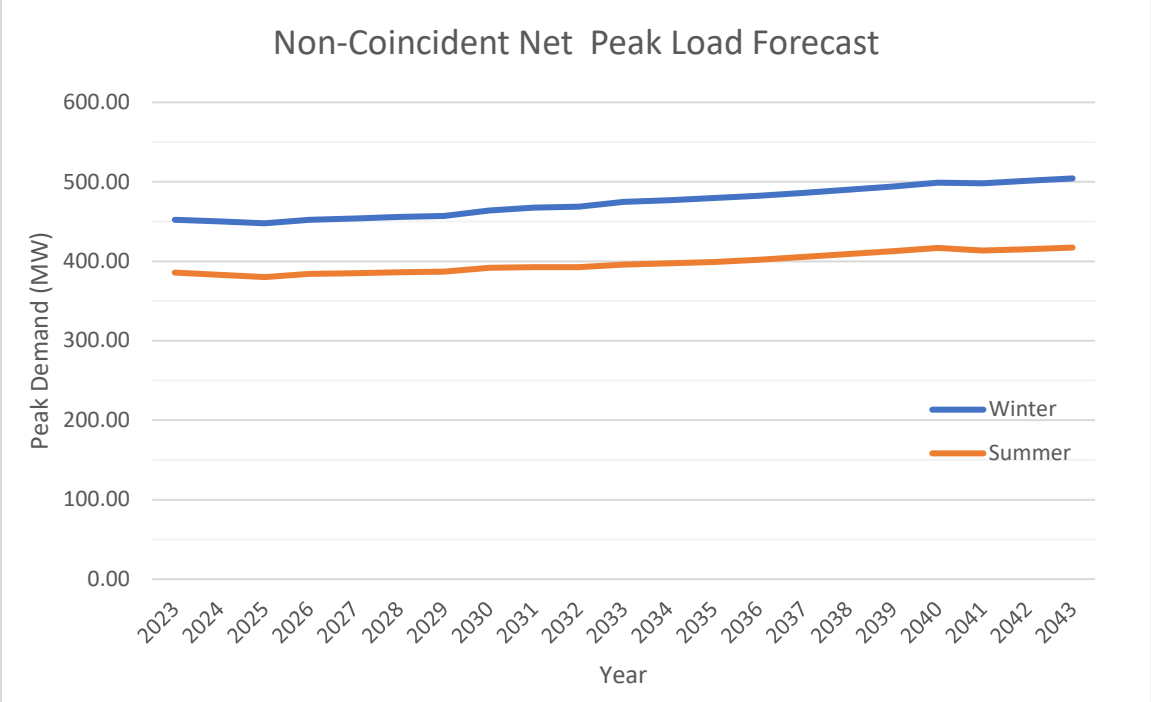


Figure 6: North & East of Sudbury Region summer/winter Non-coincident Net Peak Load Forecast

6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2043.
- LDCs reconfirmed load forecasts up to 2040. The additional 3 years of forecasts were extrapolated based on the growth rate as a reasonable position to complete the 20-year period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the winter 10-day Limited Time Rating (LTR).
- Regional transmission line and auto transformer capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Resources assumptions align with the ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the North & East of Sudbury Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- North & East of Sudbury Region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- North & East of Sudbury Region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- North & East of Sudbury Region Second cycle Integrated Regional Resource Plan Report, Completed in April 2023 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the **North & East of Sudbury** Region. The complete list of major HV transmission equipment requiring replacement in the **North & East of Sudbury** Region is provided in table 3 in this sub-section. Hydro One is the only Transmission Asset Owner (TAO) in the Region

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 3: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	2025
Hunta SS	Replacement of P&C and telecom equipment.	2027

Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	2026
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	2027
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	2030
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	2028
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	2030
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	2031
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	2032
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	2031
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	2033
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	2024
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	2024
K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	2024
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	2029
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	2027

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

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

7.2. Station Capacity Needs

Over the study period [2023-2043] RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the North & East of Sudbury Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 4 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 4: North & East of Sudbury Region Station Capacity Needs in the study period

Station Name	Capacity (MW)	2023 Loading (MW)	Station 10 day LTR (MW)	Need Date
Ramore TS	15	12	15	2033

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period [2023-2033] RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the North & East of Sudbury Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 5 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 5: North & East of Sudbury Region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Contingency	Need Date
1	D3K	Dymond x Kirkland Lake	N-1-1 (AxK O/S + loss of companion circuit)	2030

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operation and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The post contingency voltage control issues have also been listed in Table 6 below.

Table 6: North & East of Sudbury Region System Operational Needs and Voltage Control in the study period

Sr.no.	Reliability / Operational Need	Description	Need Date
1	Dymond TS	Voltage control violations when switching existing 115kV Dymond TS capacitor banks	2030
2	Kirkland Lake TS	Voltage control challenges in Kirkland Lake area during concurrent outages to Kirkland Lake TS SVC and Northland Power Kirkland Lake GS.	2030
3	Ansonville, Hunta, Kapuskasing	Post contingency voltage control challenges for the loss of Ansonville T2 and Canyon Units.	Existing

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

4	ORTAC load security criteria not met for 500 kV circuit outages	Loss of load and resources during outages to any of the two major 500kV transmission lines in the Northeast	Existing
5	Difficulty supplying loads during planned outages to circuit D501P	Area loads cannot be adequately supplied during planned circuit outages	Existing

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the North & East of Sudbury Region. These needs include those previously identified in the NA and IRRP for the North & East of Sudbury Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 6 below:

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

8.1.1. Asset Name – Location

Table 7: Needs identified in the region

Station/Circuit	Need Description	Planned ISD
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers. This investment will replace equipment that is in poor condition and deemed end of life.	2025
Hunta SS	Replacement of P&C and telecom equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2025
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment. This investment will replace end of life transformers to reduce the risk of interruptions caused by transformer asset failure.	2026
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life. It will also replace end of life transformers to reduce the risk of interruptions caused by transformer asset failure. The new transformers will be installed in a greenfield location and connected to the existing 230kV bus at Holden CGS via a 230 conductor/bus. The replacement transformers and associated equipment will be constructed within the limits of a new station called Antonie TS	2027
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2028

Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2028
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections. This investment will replace equipment that is in poor condition and deemed end of life.	2030
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2031
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2031
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2031
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2033
A8K/A9K	Replace conductor and refurbish circuit Ansonvillle x Kirkland Lake (180km) This investment will replace the conductor and also increase the thermal capacity to meet system needs.	2023

K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
T61S	Replace conductor and refurbish circuit Timmins TS x Shining tree JCT (115km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
D2H/D3H	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km) This investment will replace the conductor with a like for standard conductor.	2029
A4H/A5H	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km) This investment will replace the conductor with a like for standard conductor.	2027

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period [2023-2043] for the 230kV and 115kV Transforming stations in the North & East of Sudbury Region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified in the during the study period:

8.2.1 Ramore TS

Ramore TS is a single transformer 115/27.6kV 17MVA station. The summer and winter 10-Day LTR is 15MW, and load at this station is expected to exceed the LTR in 2033.

Table 8: Ramore TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ramore TS	15	13.7	13.8	13.9	14	14.2	14.3	14.4	14.8	14.9	15	15.1

The following alternatives were considered to address Ramore TS capacity need:

Alternative 1 - Maintain Status Quo: Ramore TS will continue to operate with the existing installed capacity, and Hydro One will monitor load growth to ensure supply needs are met.

Alternative 2 – Replace T1 with a new 115/27.6 42MVA unit: Replacing T1 with the next largest standard size unit will increase the station LTR to 38MW. The station LTR will remain limited to the size of the transformer as there will still only be a single unit installed at the station. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire T1 transformer. This transformer remains in acceptable condition and is not scheduled to be replaced by Hydro One within the study period due to end-of-life needs.

The TWG recommends Alternative 1 as the preferred and cost effective alternative for addressing the need. The capacity need will arise in 2033 and will allow both Hydro One and area LDCs to monitor load growth and take corrective action when needed. This need will also be refreshed in the next cycle or regional planning.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period [2023-2043] for the 230kV and 115kV Transmission line circuits in the North & East of Sudbury Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

No new line capacity needs have been identified in this planning cycle.

8.3.1 D3K (Thermal Violation)

D3K is a single circuit 115kV transmission line which provides a critical network path between Dymond TS and Kirkland Lake TS. This circuit is approximately 80km in length and serves to provide connection to generating stations and provide a path for network flows. Sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The circuit section is described below;

1. Dymond TS x Kirkland Lake TS (80km) – For the loss of A8K and A9K, the companion circuit will exceed its Long-Term Emergency (LTE) rating. As studied in the IRRP and verified in the RIP this is expected to occur as early as 2030 based on demand forecast.

Solutions to address these needs will be further explored in future planning cycles given the long-term nature of this need. Flows on this line and its violations are heavily influenced by area resource assumptions, and demand forecast for customers in the Kirkland Lake area. In addition, a new Kirkland Lake RAS (Remedial Action Scheme) has been installed to initiate control actions such as load rejection for system contingencies. Currently, this RAS will trip loads and avoid the D3K thermal violation. This scheme will continue to be utilized by control room operators and it is expected that reliance on this scheme will gradually be reduced as system upgrades and replacements are complete in the future. The TWG will continue to monitor this need in future planning cycles and initiate an investment should this violation be advanced due to changing system conditions.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period [2023-2043] to cater this need**.**

8.4.1 Dymond TS – Voltage Control

IESO operations team has reported voltage violations at Dymond TS during capacitor bank switching. Dymond TS has two 115kV shunt capacitor banks (SC11/SC12) each rated at 24MVar. IESO has observed that switching the banks under certain system conditions voltages can exceed the maximum voltage and step change permitted by IESO Market Rules. These violations are largely dependent on system configuration (W71D O/S + Loss of D3K) and less sensitive to area loading patterns. Voltage violations are not observed during system conditions where all elements are In-service, or one element is O/S as there is sufficient reactive support from adjacent stations to support Dymond pre-contingency.

Alternative 1 - Maintain Status Quo: IESO and Hydro One operations will continue to control the system with other reactive devices in the northeast. The existing capacitor banks can continue to be utilized to help meet single contingency planning scenarios.

Alternative 2 – De-rate the Existing capacitor banks (SC11/SC12) Hydro One can de-rate the capacitor bank between 14-16MVar to ensure voltage limits upon cap bank switching remain within acceptable limits. This option helps with operations primarily for a W71D+D3K contingency. This option reduces the total var support at Dymond by 50% and due to the de-rating in size. It has been discussed with the TWG that operations may have to rely on other reactive devices in the northeast to provide steady state voltage support for other system configurations.

The TWG recommends to continue to investigating the need to a de-rate the existing capacitor banks and provide enhanced automation and visibilty.

8.4.2 Kirkland TS – Voltage Control

IESO has reported difficulties in maintaining adequate system voltages in the Kirkland Lake area during outage conditions. Concurrent outages to the Kirkland Lake SVC and Northland Power Kirkland Lake Generating facility result in declining voltages at the end of the radial K2 transmission line.

Kirkland Lake TS presently has a 115kV connection SVC, and shunt capacitor bank to help maintain voltages during steady state, and contingencies.

K2 circuit is a radial line with multiple industrial customers tapped of this circuit. Voltage performance on this circuit is directly attributed to the load pattern of these customers. It is expected that future loads connecting to this circuit will be required to maintain their voltage within reasonable limits as a condition to connect. A new Kirkland Lake RAS is also available to address thermal and voltage violations in the area as a control action and can be expanded to include additional inputs and outputs. Planning level cost for a new 115kV capacitor bank will cost between $10M-$15M, and will be largely influenced by the available space at the station and the control building.

The TWG recommends to monitor the voltage performance at Kirkland Lake TS bus and ensure that voltages on the K2 delivery points remain within reasonable limits. Hydro One and IESO will engage in further discussion on system operating limits, and resource options to mitigate this finding.

8.4.3 Ansonville, Hunta, Kapuskasing Voltage Control

Voltage violations at Ansonville TS, Hunta TS, and Kapuskasing TS can occur for the loss of Ansonville T2 and Abitibi Canyon generating units. This is coupled with the general challenge of maintaining system voltages within acceptable limits in the northeast as a whole. A new Kirkland Lake RAS (remedial action scheme) has been installed to help operators take control actions for system contingencies. This RAS can also be expanded to accommodate changing system needs which will help to provide operating flexibility

in the future. Kapuskasing RAS will also be installed to provide voltage support in the Kapuskasing area for system contingencies. This RAS can also be expanded when needed to meet future system needs.

Porcupine SVC will also be refurbished in the planning cycle and will provide much needed reactive support for the northeast.

The TWG will continue to address voltage control issues as needed to accommodate system needs. IESO and Hydro One continues to work towards finding robust solutions that provide voltage support without over reliance on load rejection and other adverse control actions. No additional investments are required from this regional infrastructure plan to address this need.

8.4.4 ORTAC load security criteria not met for 500 kV circuit outages

The North & East of Sudbury region is supplied by two 500 kV circuits, P502X from Hanmer TS to Porcupine TS and D501P from Porcupine TS to Pinard TS.

The system connects substantial amount of hydroelectric generation on the Moose River and loads in the region. The planning requirement to respect the loss of either of the 500kV circuits results in the need to rely on a Remedial Action Scheme (RAS), the Northeast Load and Generation Rejection Scheme (the "Northeast LGR"), that enables full use of the scheme following the loss of a single transmission element.

This is a legacy system that does not meet today's planning criteria for the use of load rejection following the loss of a single transmission element. However, bringing it up to current standards would involve substantial capital investment that is difficult to justify without the introduction of new needs. Future bulk projects such as the new 230kV line between Porcupine TS and Wawa TS will help to reduce reliance on area RASs following a P502X outage, however, does not address the loss of D501P and will still result in load rejection for area customers. The Working Group (TWG) recommends that the next bulk system plan in Northeast Ontario address the load security concerns following an outage on D501P and develop a plan to proactively reduced reliance on RAS.

8.4.5 Difficulty supplying loads during planned outages to circuit D501P

IESO's outage planning staff have also identified that during recent outages to D501P, it has not been possible to supply all customer load in the area due to limitations on the 115 kV system, and certain industrial customers have been forced to reduce their production. These concerns have also been raised by these customers themselves. During D501P outages, generation must also be significantly curtailed, which can remove substantial capacity from the Ontario system.

Hydro One recently implemented a protection scheme to allow D501P outages and working to address the shortfalls experienced during the implementation. TWG recommends to continue discussions with Hydro One and IESO operation to ensure future projects can be completed effectively during 500kV

outages and the project team will work to develop effective solutions for the specific projects in question. These solutions may include modifications/additions to area RASs schemes or new transmission facilities.

8.5 Long Term Considerations

Like many other regions in Ontario, load growth in North & East of Sudbury region will be directly impacted by new energy policies specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment. Future connection requests in the region will be assessed as needed to determine system requirements.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan Report for North & East of Sudbury Region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon [2023-2033] are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	Hydro One Transmission	2025	36
Hunta SS	Replacement of P&C and telecom equipment.	Hydro One Transmission	2025	12
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	Hydro One Transmission	2026	91
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	Hydro One Transmission	2027	74
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	Hydro One Transmission	2028	19
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	Hydro One Transmission	2028	14
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	Hydro One Transmission	2030	24
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	Hydro One Transmission	2031	42

Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	Hydro One Transmission	2031	11
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	Hydro One Transmission	2031	32
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	Hydro One Transmission	2033	17
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	Hydro One Transmission	2024	4
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	Hydro One Transmission	2024	
K1/K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	Hydro One Transmission	2024	4
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	Hydro One Transmission	2029	96
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	Hydro One Transmission	2027	22
Station Capacity Needs				
Ramore TS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
Transmission Line Capacity Needs				
D3K	Monitoring & further exploration in future RIP cycle	Hydro One Transmission	NA	NA
System Reliability, Operation and Load restoration Needs				
Dymond TS	Continue investigating to correctly size the existing 115kV SC11 & SC12 capacitor banks	Hydro One Transmission	NA	NA

Note:

a) The planned in-service dates are tentative and subject to change

b) Cost are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Winter Weather Adjusted Net Load Forecast

Table A.1: North & East of Sudbury Region – Winter Coincident- Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Winter Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																		
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	53.60	48.24	19.94	20.19	20.23	20.28	20.31	20.37	20.38	23.70	25.18	25.31	25.47	25.65	25.84	26.16	26.42	26.70	26.97	27.24	28.59	29.11	29.62
Hearst TS	T4	39.60	35.64	18.39	18.37	18.36	18.37	18.37	18.39	18.38	18.38	18.36	18.34	18.34	18.36	18.39	18.44	18.51	18.60	18.68	18.76	18.59	18.61	18.62
Kapuskasing TS	T5/T6	106.50	95.85	5.88	5.84	5.81	5.79	5.76	5.74	5.70	5.68	5.64	5.61	5.59	5.57	5.56	5.56	5.58	5.60	5.62	5.64	5.52	5.50	5.48
Kirkland Lake TS	T12/T13	57.60	51.84	40.32	40.24	40.21	40.21	40.18	40.19	40.19	40.22	40.17	40.11	40.11	40.12	40.14	40.16	40.26	40.38	40.50	40.62	40.34	40.35	40.36
North Bay TS	T1/T2	64.10	57.69	25.16	24.02	22.88	23.27	23.71	24.14	24.57	25.01	25.43	25.83	26.25	26.69	27.16	27.65	28.14	28.63	29.13	29.63	29.41	29.78	30.14
Ramone TS	T1	20.90	18.81	12.36	12.44	12.51	12.58	12.71	12.83	12.94	13.27	13.38	13.47	13.58	13.70	13.84	13.98	14.12	14.26	14.41	14.56	14.66	14.79	14.93
Timmins TS	T2/T4	113.10	101.79	52.77	52.81	52.92	53.09	53.22	53.42	53.58	53.78	53.87	53.93	54.09	54.28	54.48	54.69	55.03	55.41	55.78	56.16	55.85	56.04	56.22
Dymond TS	T3/T4	62.00	55.80	30.82	30.79	30.80	30.84	30.87	30.94	30.96	31.01	31.01	30.98	33.88	33.93	34.00	34.08	34.23	34.40	34.57	34.73	35.13	35.42	35.71
Trout Lake	T3/T4	209.50	188.55	98.85	97.86	96.96	100.18	100.79	101.50	102.00	102.58	103.32	103.85	104.79	105.56	106.38	107.38	108.51	109.69	110.87	113.07	112.08	112.92	113.76
Calstock DS	-	-	-	5.29	5.28	5.29	5.30	5.31	5.33	5.35	5.37	5.38	5.38	5.40	5.41	5.43	5.44	5.47	5.50	5.53	5.57	5.54	5.56	5.57
CochraneMTS	-	-	-	11.46	11.39	11.34	11.28	11.22	11.16	11.10	11.05	10.99	10.92	10.88	10.84	10.81	10.79	10.79	10.79	10.79	10.79	10.62	10.58	10.53
Cochran West DS	-	-	-	3.55	3.55	3.56	3.57	3.58	3.59	3.59	3.60	3.61	3.61	3.62	3.63	3.65	3.66	3.69	3.71	3.74	3.76	3.74	3.75	3.76
Fauquier DS	-	-	-	2.08	2.09	2.10	2.11	2.12	2.13	2.14	2.15	2.16	2.17	2.18	2.19	2.20	2.22	2.24	2.26	2.28	2.30	2.29	2.30	2.31
Herridge Lake DS	-	-	-	3.41	3.42	3.43	3.45	3.46	3.47	3.49	3.50	3.51	3.52	3.53	3.54	3.56	3.58	3.61	3.64	3.66	3.69	3.67	3.69	3.70
Hoyle DS	-	-	-	7.05	7.06	7.07	7.08	7.09	7.12	7.13	7.15	7.15	7.16	7.17	7.19	7.22	7.25	7.28	7.33	7.37	7.41	7.37	7.39	7.41
Iroquois Falls DS	-	-	-	5.19	5.16	5.15	5.13	5.11	5.09	5.07	5.06	5.03	5.01	5.00	4.99	4.98	4.98	4.98	4.99	5.00	5.01	4.94	4.93	4.91
Laforest Road DS	-	-	-	12.79	12.80	12.83	12.87	12.90	12.95	12.99	13.03	13.06	13.07	13.11	13.16	13.21	13.27	13.35	13.45	13.54	13.64	13.55	13.60	13.65
Mattawa DS	-	-	-	5.06	5.07	5.09	5.11	5.13	5.15	5.17	5.19	5.20	5.21	5.23	5.26	5.28	5.31	5.35	5.39	5.43	5.47	5.45	5.47	5.49
Monteith DS	-	-	-	2.93	2.94	2.96	2.97	2.99	3.00	3.02	3.03	3.04	3.05	3.06	3.08	3.10	3.12	3.15	3.18	3.21	3.23	3.22	3.23	3.25
Moosonee DS	-	-	-	14.31	14.31	14.33	14.37	14.40	14.45	14.48	14.53	14.55	14.56	14.59	14.63	14.68	14.74	14.82	14.91	15.00	15.09	15.01	15.05	15.09
Shiningtree DS	-	-	-	3.95	3.94	3.94	3.93	3.93	3.93	3.94	3.94	3.94	3.93	3.93	3.93	3.93	3.94	3.95	3.96	3.98	3.99	3.96	3.96	3.96
Smooth Rock Falls DS	-	-	-	1.80	1.80	1.80	1.81	1.81	1.81	1.81	1.82	1.82	1.82	1.82	1.82	1.82	1.83	1.84	1.85	1.86	1.87	1.85	1.86	1.86
Temagami DS 2	-	-	-	1.39	1.40	1.40	1.41	1.42	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.53	1.54	1.56	1.58	1.57	1.58	1.59
Verner DS	-	-	-	5.93	5.93	5.94	5.95	5.96	5.97	5.97	5.97	5.97	5.97	5.98	5.99	6.00	6.03	6.06	6.09	6.13	6.16	6.11	6.12	6.13
Warren DS	-	-	-	7.10	7.09	7.09	7.10	7.10	7.11	7.11	7.11	7.10	7.10	7.10	7.11	7.12	7.14	7.17	7.21	7.24	7.28	7.21	7.22	7.23

Table A.2: North & East of Sudbury Region – Winter non-Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Winter Weather Station Non Coincident to NE of Sudbury Region (MW)																			
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	53.60	48.24	29.98	30.36	30.42	30.49	30.54	30.63	30.65	35.63	37.87	38.06	38.30	38.57	38.86	39.34	39.74	40.15	40.56	40.96	42.99	43.77	44.55
Hearst TS	T4	39.60	35.64	20.41	20.38	20.38	20.39	20.38	20.40	20.39	20.39	20.37	20.35	20.36	20.38	20.41	20.46	20.54	20.64	20.73	20.82	20.63	20.65	20.67
Kapuskasing TS	T5/T6	106.50	95.85	14.72	14.62	14.55	14.49	14.40	14.35	14.27	14.21	14.12	14.03	13.98	13.95	13.92	13.92	13.96	14.01	14.07	14.12	13.80	13.76	13.72
Kirkland Lake TS	T12/T13	57.60	51.84	40.90	40.82	40.79	40.79	40.75	40.77	40.77	40.79	40.75	40.68	40.68	40.69	40.71	40.73	40.83	40.95	41.08	41.20	40.92	40.93	40.94
North Bay TS	T1/T2	64.10	57.69	33.17	31.67	30.16	30.68	31.26	31.83	32.39	32.98	33.53	34.05	34.61	35.20	35.82	36.45	37.10	37.75	38.41	39.06	38.78	39.26	39.74
Ramone TS	T1	20.90	18.81	13.76	13.85	13.93	14.01	14.16	14.29	14.42	14.78	14.90	15.00	15.12	15.26	15.41	15.57	15.73	15.89	16.05	16.21	16.33	16.48	16.62
Timmins TS	T2/T4	113.10	101.79	54.22	54.26	54.38	54.55	54.68	54.89	55.05	55.25	55.35	55.41	55.58	55.77	55.98	56.20	56.55	56.93	57.32	57.70	57.38	57.58	57.77
Dymond TS	T3/T4	62.00	55.80	39.70	39.66	39.66	39.72	39.75	39.84	39.88	39.94	39.93	39.90	43.63	43.70	43.78	43.89	44.08	44.30	44.52	44.73	45.25	45.62	45.99
Trout Lake	T3/T4	209.50	188.55	101.32	100.30	99.38	102.68	103.31	104.03	104.54	105.14	105.90	106.44	107.40	108.19	109.03	110.05	111.22	112.43	113.63	115.89	114.88	115.74	116.59
Calstock DS	-	-	-	8.76	8.75	8.77	8.79	8.80	8.83	8.86	8.91	8.92	8.92	8.95	8.97	9.00	9.01	9.06	9.11	9.17	9.23	9.18	9.21	9.24
CochraneMTS	-	-	-	12.77	12.69	12.63	12.57	12.50	12.44	12.37	12.31	12.25	12.17	12.12	12.08	12.05	12.02	12.02	12.02	12.03	12.03	11.83	11.79	11.74
Cochran West DS	-	-	-	3.71	3.72	3.72	3.73	3.74	3.76	3.76	3.77	3.78	3.78	3.79	3.80	3.82	3.84	3.86	3.89	3.91	3.94	3.91	3.92	3.94
Fauquier DS	-	-	-	2.22	2.23	2.24	2.25	2.26	2.28	2.28	2.29	2.30	2.31	2.32	2.33	2.35	2.37	2.39	2.41	2.43	2.45	2.44	2.45	2.46
Herridge Lake DS	-	-	-	4.00	4.01	4.02	4.03	4.05	4.07	4.08	4.10	4.11	4.12	4.13	4.15	4.17	4.19	4.22	4.26	4.29	4.32	4.30	4.32	4.34
Hoyle DS	-	-	-	8.88	8.88	8.89	8.91	8.93	8.96	8.97	9.00	9.01	9.01	9.03	9.05	9.08	9.12	9.17	9.22	9.28	9.33	9.27	9.30	9.32
Iroquois Falls DS	-	-	-	5.50	5.48	5.46	5.44	5.42	5.40	5.38	5.36	5.34	5.31	5.30	5.29	5.28	5.28	5.28	5.29	5.30	5.31	5.23	5.22	5.21
Laforest Road DS	-	-	-	13.52	13.53	13.56	13.60	13.64	13.69	13.73	13.77	13.80	13.81	13.86	13.91	13.96	14.02	14.11	14.21	14.31	14.41	14.32	14.37	14.42
Mattawa DS	-	-	-	5.16	5.17	5.19	5.21	5.23	5.26	5.27	5.29	5.31	5.32	5.34	5.36	5.39	5.42	5.46	5.50	5.54	5.58	5.55	5.58	5.60
Monteith DS	-	-	-	3.00	3.01	3.02	3.04	3.05	3.07	3.08	3.10	3.11	3.12	3.13	3.15	3.17	3.19	3.22	3.25	3.28	3.31	3.29	3.31	3.33
Moosonee DS	-	-	-	14.63	14.63	14.65	14.69	14.72	14.77	14.81	14.85	14.87	14.88	14.92	14.96	15.01	15.06	15.15	15.24	15.34	15.43	15.34	15.38	15.43
Shiningtree DS	-	-	-	4.62	4.61	4.60	4.60	4.60	4.60	4.60	4.61	4.60	4.59	4.59	4.59	4.60	4.60	4.62	4.63	4.65	4.67	4.63	4.63	4.63
Smooth Rock Falls DS	-	-	-	1.98	1.98	1.98	1.98	1.98	1.99	1.99	1.99	1.99	1.99	2.00	2.00	2.00	2.01	2.02	2.03	2.04	2.05	2.03	2.04	2.04
Temagami DS 2	-	-	-	1.80	1.81	1.82	1.84	1.85	1.86	1.87	1.89	1.90	1.91	1.92	1.93	1.95	1.96	1.98	2.01	2.03	2.05	2.04	2.06	2.07
Verner DS	-	-	-	6.06	6.06	6.06	6.07	6.08	6.10	6.09	6.10	6.10	6.10	6.10	6.12	6.13	6.16	6.19	6.22	6.26	6.29	6.24	6.25	6.26
Warren DS	-	-	-	7.53	7.52	7.52	7.53	7.53	7.55	7.54	7.54	7.53	7.53	7.53	7.54	7.55	7.58	7.61	7.65	7.68	7.72	7.65	7.66	7.67

Table A.3: North & East of Sudbury Region – Summer Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Summer Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																			
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	48.40	43.56	14.80	15.18	15.34	15.50	15.64	15.81	15.93	18.48	18.70	18.83	18.99	19.17	19.37	19.70	19.97	20.26	20.55	20.83	21.63	22.02	22.41
Hearst TS	T4	32.90	29.61	12.50	12.63	12.59	12.56	12.51	12.48	12.43	12.39	12.34	12.28	12.26	12.24	12.24	12.26	12.30	12.36	12.41	12.46	12.25	12.24	12.22
Kapuskasing TS	T5/T6	94.20	84.78	36.17	36.03	35.95	35.92	35.85	35.83	35.70	35.64	35.53	35.41	35.38	35.39	35.43	35.54	35.75	35.98	36.21	36.42	35.76	35.76	35.76
Kirkland Lake TS	T12/T13	47.30	42.57	26.02	25.92	25.87	25.84	25.78	25.75	25.72	25.72	25.66	25.59	25.56	25.54	25.52	25.51	25.56	25.63	25.69	25.76	25.51	25.49	25.47
North Bay TS	T1/T2	61.70	55.53	14.98	13.88	12.78	13.21	13.65	14.09	14.53	14.97	15.39	15.81	16.23	16.67	17.14	17.61	18.09	18.58	19.07	19.56	19.40	19.77	20.14
Ramone TS	T1	18.30	16.47	4.96	4.99	5.01	5.03	5.08	5.13	5.18	5.32	5.36	5.40	5.44	5.48	5.54	5.60	5.65	5.71	5.77	5.83	5.87	5.92	5.98
Timmins TS	T2/T4	104.20	93.78	33.45	33.39	33.38	33.43	33.43	33.48	33.49	33.54	33.52	33.48	33.52	33.59	33.68	33.79	34.01	34.26	34.50	34.74	34.31	34.37	34.44
Dymond TS	T3/T4	54.00	48.60	25.93	25.83	25.77	25.76	25.72	25.71	25.65	25.63	25.56	25.48	26.77	26.78	26.80	26.86	26.98	27.13	27.27	27.41	27.31	27.41	27.52
Trout Lake	T3/T4	186.60	167.94	66.13	64.94	63.85	66.78	67.14	67.58	67.79	68.10	68.46	68.76	69.30	69.83	70.42	71.18	72.08	73.03	73.97	75.31	74.44	75.00	75.55
Calstock DS	-	-	-	3.76	3.75	3.75	3.75	3.75	3.75	3.76	3.78	3.78	3.77	3.77	3.78	3.78	3.79	3.81	3.83	3.85	3.88	3.84	3.85	3.85
CochraneMTS	-	-	-	9.99	9.90	9.83	9.77	9.68	9.62	9.53	9.46	9.39	9.31	9.25	9.21	9.17	9.15	9.15	9.16	9.17	9.17	8.94	8.89	8.84
Cochran West DS	-	-	-	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.57	2.57	2.57	2.57	2.57	2.58	2.59	2.61	2.63	2.65	2.67	2.63	2.63	2.64
Fauquier DS	-	-	-	1.92	1.93	1.93	1.93	1.94	1.95	1.95	1.95	1.95	1.95	1.96	1.97	1.98	1.99	2.01	2.03	2.05	2.06	2.04	2.05	2.05
Herridge Lake DS	-	-	-	1.65	1.65	1.65	1.65	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.67	1.68	1.68	1.70	1.71	1.73	1.74	1.72	1.72	1.73
Hoyle DS	-	-	-	4.47	4.47	4.46	4.46	4.46	4.47	4.46	4.47	4.46	4.45	4.46	4.46	4.47	4.49	4.52	4.55	4.57	4.60	4.54	4.55	4.56
Iroquois Falls DS	-	-	-	4.96	4.93	4.90	4.87	4.84	4.81	4.78	4.75	4.71	4.68	4.66	4.64	4.63	4.63	4.63	4.64	4.65	4.66	4.55	4.53	4.51
Laforest Road DS	-	-	-	11.04	11.02	11.02	11.03	11.03	11.05	11.04	11.05	11.04	11.02	11.04	11.06	11.09	11.14	11.21	11.29	11.38	11.46	11.30	11.32	11.34
Mattawa DS	-	-	-	4.37	4.36	4.37	4.38	4.38	4.39	4.39	4.40	4.40	4.40	4.41	4.42	4.43	4.46	4.49	4.53	4.57	4.60	4.54	4.55	4.57
Monteith DS	-	-	-	1.91	1.91	1.91	1.92	1.92	1.93	1.93	1.93	1.94	1.94	1.94	1.95	1.96	1.97	1.99	2.01	2.03	2.05	2.02	2.03	2.04
Moosonee DS	-	-	-	4.97	4.96	4.95	4.96	4.96	4.96	4.96	4.97	4.97	4.96	4.97	4.97	4.98	4.99	5.02	5.05	5.09	5.12	5.06	5.06	5.07
Shiningtree DS	-	-	-	2.43	2.42	2.41	2.41	2.40	2.40	2.39	2.39	2.38	2.37	2.37	2.37	2.37	2.36	2.37	2.38	2.39	2.40	2.36	2.36	2.36
Smooth Rock Falls DS	-	-	-	1.64	1.64	1.63	1.63	1.63	1.63	1.63	1.63	1.62	1.62	1.62	1.62	1.62	1.62	1.63	1.64	1.65	1.66	1.63	1.63	1.63
Temagami DS 2	-	-	-	0.98	0.98	0.98	0.99	0.99	1.00	1.00	1.01	1.01	1.01	1.02	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.07	1.08	1.08
Verner DS	-	-	-	4.04	4.03	4.02	4.02	4.01	4.01	3.99	3.98	3.97	3.96	3.96	3.96	3.97	3.98	4.01	4.03	4.06	4.08	4.01	4.01	4.01
Warren DS	-	-	-	5.02	5.00	4.99	4.98	4.97	4.97	4.94	4.93	4.91	4.89	4.89	4.89	4.89	4.90	4.93	4.96	4.98	5.01	4.92	4.91	4.91

Table A.4: North & East of Sudbury Region – Summer non-Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Summer Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																				
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	48.40	43.56	23.02	23.61	23.86	24.10	24.33	24.59	24.78	28.74	29.08	29.28	29.53	29.82	30.13	30.63	31.06	31.52	31.96	32.40	33.64	34.24	34.85
Hearst TS	T4	32.90	29.61	14.79	14.95	14.89	14.86	14.80	14.77	14.70	14.66	14.60	14.53	14.50	14.49	14.48	14.50	14.55	14.62	14.68	14.74	14.50	14.48	14.46
Kapuskasing TS	T5/T6	94.20	84.78	64.77	64.52	64.36	64.32	64.18	64.15	63.93	63.82	63.61	63.40	63.35	63.37	63.45	63.64	64.01	64.43	64.84	65.21	64.03	64.03	64.02
Kirkland Lake TS	T12/T13	47.30	42.57	27.37	27.27	27.21	27.18	27.11	27.08	27.05	27.05	26.99	26.91	26.88	26.86	26.85	26.83	26.89	26.96	27.03	27.09	26.83	26.81	26.79
North Bay TS	T1/T2	61.70	55.53	18.22	16.87	15.55	16.06	16.60	17.14	17.67	18.20	18.72	19.22	19.74	20.28	20.84	21.42	22.00	22.60	23.19	23.78	23.59	24.04	24.49
Ramone TS	T1	18.30	16.47	7.20	7.24	7.27	7.31	7.38	7.45	7.51	7.72	7.78	7.83	7.89	7.96	8.04	8.12	8.21	8.29	8.38	8.46	8.52	8.60	8.68
Timmins TS	T2/T4	104.20	93.78	36.64	36.57	36.56	36.61	36.61	36.67	36.68	36.74	36.72	36.67	36.72	36.79	36.89	37.01	37.25	37.52	37.79	38.05	37.58	37.65	37.72
Dymond TS	T3/T4	54.00	48.60	30.08	29.97	29.90	29.89	29.83	29.83	29.76	29.74	29.66	29.56	31.06	31.06	31.09	31.16	31.30	31.47	31.64	31.79	31.68	31.80	31.93
Trout Lake	T3/T4	186.60	167.94	77.61	76.21	74.93	78.37	78.80	79.31	79.55	79.92	80.35	80.69	81.33	81.95	82.65	83.54	84.59	85.71	86.81	88.38	87.36	88.01	88.67
Calstock DS	-	-	-	6.96	6.94	6.93	6.94	6.93	6.94	6.96	6.99	6.99	6.98	6.98	6.99	7.00	7.01	7.05	7.09	7.13	7.18	7.11	7.12	7.13
CochraneMTS	-	-	-	12.44	12.33	12.24	12.16	12.06	11.98	11.87	11.79	11.69	11.59	11.53	11.47	11.42	11.40	11.40	11.41	11.42	11.42	11.14	11.08	11.01
Cochran West DS	-	-	-	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.85	2.85	2.84	2.85	2.85	2.86	2.87	2.89	2.92	2.94	2.96	2.91	2.92	2.92
Fauquier DS	-	-	-	2.57	2.57	2.57	2.58	2.59	2.59	2.60	2.60	2.60	2.61	2.61	2.62	2.64	2.65	2.68	2.70	2.73	2.75	2.72	2.73	2.74
Herridge Lake DS	-	-	-	2.24	2.24	2.24	2.25	2.25	2.26	2.26	2.26	2.26	2.26	2.26	2.27	2.28	2.29	2.31	2.33	2.35	2.36	2.33	2.34	2.35
Hoyle DS	-	-	-	6.36	6.35	6.34	6.35	6.35	6.35	6.35	6.35	6.34	6.33	6.34	6.35	6.36	6.39	6.42	6.47	6.51	6.54	6.46	6.47	6.48
Iroquois Falls DS	-	-	-	5.47	5.43	5.40	5.37	5.34	5.31	5.27	5.23	5.20	5.16	5.14	5.12	5.11	5.10	5.11	5.12	5.13	5.14	5.02	5.00	4.98
Laforest Road DS	-	-	-	13.27	13.25	13.24	13.26	13.26	13.28	13.27	13.28	13.27	13.25	13.26	13.29	13.33	13.38	13.47	13.57	13.67	13.77	13.58	13.60	13.63
Mattawa DS	-	-	-	5.18	5.18	5.18	5.19	5.20	5.21	5.21	5.22	5.22	5.22	5.23	5.24	5.26	5.29	5.33	5.37	5.42	5.46	5.39	5.40	5.42
Monteith DS	-	-	-	2.24	2.24	2.24	2.25	2.26	2.26	2.26	2.27	2.27	2.27	2.28	2.29	2.30	2.31	2.34	2.36	2.38	2.40	2.37	2.38	2.39
Moosonee DS	-	-	-	8.69	8.67	8.66	8.67	8.66	8.67	8.68	8.69	8.69	8.67	8.68	8.69	8.71	8.73	8.78	8.83	8.89	8.94	8.84	8.85	8.86
Shiningtree DS	-	-	-	3.02	3.00	2.99	2.99	2.98	2.97	2.97	2.97	2.96	2.95	2.94	2.94	2.94	2.93	2.94	2.95	2.96	2.98	2.93	2.93	2.93
Smooth Rock Falls DS	-	-	-	1.93	1.92	1.92	1.92	1.91	1.91	1.91	1.91	1.90	1.90	1.90	1.90	1.90	1.90	1.91	1.93	1.94	1.95	1.92	1.92	1.92
Temagami DS 2	-	-	-	2.65	2.65	2.66	2.68	2.69	2.70	2.71	2.72	2.73	2.74	2.75	2.77	2.79	2.81	2.84	2.87	2.90	2.93	2.90	2.92	2.93
Verner DS	-	-	-	4.56	4.55	4.54	4.54	4.53	4.53	4.52	4.51	4.49	4.48	4.48	4.48	4.49	4.50	4.53	4.56	4.58	4.61	4.53	4.53	4.53
Warren DS	-	-	-	5.57	5.55	5.53	5.53	5.51	5.51	5.48	5.47	5.45	5.43	5.42	5.42	5.42	5.44	5.47	5.50	5.53	5.55	5.46	5.45	5.45

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Appendix B:

Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)	Supply Circuits
1.	Ansonville TS	230/115	A9K A94N A5H A4H P91G A93I A8K
2.	Crystal Falls TS	230/44	H23S H24S
3.	Dymond TS	115/44	D4Z D3K D2L W71D
4.	Hearst TS	115/27.6	F1E
5.	Hunta SS	115	H7T A5H A4H H9K H6T D2H D3H
6.	Kapuskasing TS	230/115/28	H9K L21S K38S F1E
7.	Kirkland Lake TS	115/44	A8K A9K D3K K2 K4
8.	Little Long SS	230/44	L20D L21S
9.	Moosonee SS	115	T7M T8M M3K M9K
10.	North Bay TS	230/44	L5H
11.	Otter Rapids SS	115	T7M T8M R21D D6T
12.	Otto Holden TS	230/115/14	L5H D5H H4Z H23S H24S
13.	Pinard TS	500/230/115	L20D H22D R21D D3H D501P D4 D6T D23G D2H
14.	Porcupine TS	500/230/115	P91G P15T P7G D501P P13T P502X
15.	Ramore TS	115/27.6	A9K
16.	Spruce Falls TS	230/115/14	F1E K38S
17.	Timmins TS	115/27.6	H7T T2R H6T P15T T61S P13T
18.	Trout Lake TS	230/44	H24S W71D
19.	Widdifield SS	230	H23S H24S W71D

Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	A4H/A5H	Ansonville TS	Hunta SS	115
2.	A8K/A9K	Ansonville TS	Kirkland Lake TS	115
3.	D2H/D3H	Pinard TS	Hunta SS	115
4.	H6T/H7T	Hunta SS	Timmins TS	115
5.	P13T/P15T	Porcupine TS	Timmins TS	115
6.	T7M/T8M	Otter Rapids SS	Moosenee SS	115
7.	D2L	Dymond TS	Crystal Falls TS	115
8.	H9K	Hunta SS	Kapuskasing TS	115
9.	K2	Kirkland Lake TS	Radial	115
10.	K4	Kirkland Lake TS	Radial	115
11.	L1S	Martindale TS	Crystal Falls TS	115
12.	L5H	Crystal Falls TS	Otto Holden TS	115
13.	D3K	Dymond TS	Kirkland Lake TS	115
14.	P7G	Porcupine TS	Radial	115
15.	T61S	Timmins TS	Radial	115
16.	F1E	Kapuskasing TS	Hearst TS	115
17.	T2R	Timmins TS	Radial	115
18.	D23G	Pinard TS	Radial	230
19.	H22D	Pinard TS	Radial	230

20.	H23S/H24S	Martindale TS	Otto Holden TS	230
21.	K38S	Kapuskasing TS	Spruce Falls TS	230
22.	L20D	Pinard TS	Little Long SS	230
23.	L21S	Kapuskasing TS	Little Long SS	230
24.	P91G	Porcupine TS	Ansonville TS	230
25.	R21D	Otter Rapids SS	Radial	230
26.	W71D	Dymond TS	Widdfield SS	230
27.	P502X	Porcupine TS	Hanmer TS	500
28.	D501P	Porcupine TS	Pinard TS	500

Appendix C: Voltage Performance Analysis at Dymond TS

To address the on-going voltage issue due to operation of SC11& SC12 Capacitor banks at Dymond TS under N-1-1 contingency, Hydro One can de-rate the capacitor bank between 14-16MX. The capacitor banks can only be physically de-rated in the steps of 3MX.

Following table shows a PSSE simulation result with both capacitors de-rated to 15MX. (*Hydro One 2022 Winter Base case used for simulation purpose).*

Bus	Contingency														
	N-0					D3K O/S					D3K O/S +W71D				
		24+24 MX Caps		15+15 MX Caps			24+24 MX Caps		15+15 MX Caps			24+24 MX Caps		15+15 MX Caps	
	No Cap	ON	% Change	ON	% Change	No Cap	ON	% Change	ON	% Change	No Cap	ON	% Change	ON	% Change
Dymond TS 220	243.89	246.62	1.12	245.59	0.69	244.44	248.25	1.56	246.80	0.96					
Dymond TS 115	123.49	125.67	1.77	124.84	1.10	124.05	127.08	2.44	125.92	1.50	117.51	131.96	12.30	125.76	7.03
Dymond TS 44	46.35	47.11	1.63	46.82	1.02	46.55	47.59	2.25	47.19	1.39	44.28	49.37	11.50	47.15	6.47
Temagami 115	123.41	124.93	1.22	124.35	0.76	123.98	126.06	1.68	125.27	1.04	119.78	129.21	7.88	125.19	4.52

Capacitor bank switching under the studied scenario is infrequent due to the N-1-1 condition and voltage change limits shall take this into consideration. Sizing the capacitor banks between 14-16MX is shown to reduce the voltage change to reasonable limits based on the in frequent nature of the occurrence. This reduction allows for reactive support at Dymond TS to remain at a level that can still help with normal operations during non-contingency scenarios or system changes such as load growth. Simulation results will continue to be studied to correctly size the capacitor banks.

Appendix D: List of LDC's

Sr. No.	Local Distributor Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX/DX
2.	North Bay Hydro	DX
3.	Northern Ontario Wires Inc.	TX/DX
4.	Hearst Power Distribution Co.	DX
5.	Greater Sudbury Hydro Inc.	DX

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Town of Hearst
2	Town of Kapuskasing
3	Town of Smooth Rock Falls
4	Town of Cochrane
5	Town of Foleyet
6	Town of Iroquois Falls
7	Town of Kirkland Lake
8	Town of Englehart.
9	Township of Black River
10	Township of Matheson
11	Township of East Ferris
12	City of North Bay
13	City of Temiskaming Shores
14	City of Timmins
15	Municipality of West Nipissing

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor

PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



Renfrew Region Integrated Regional Resource Plan

December 22, 2022

Connecting Today.
Powering Tomorrow.

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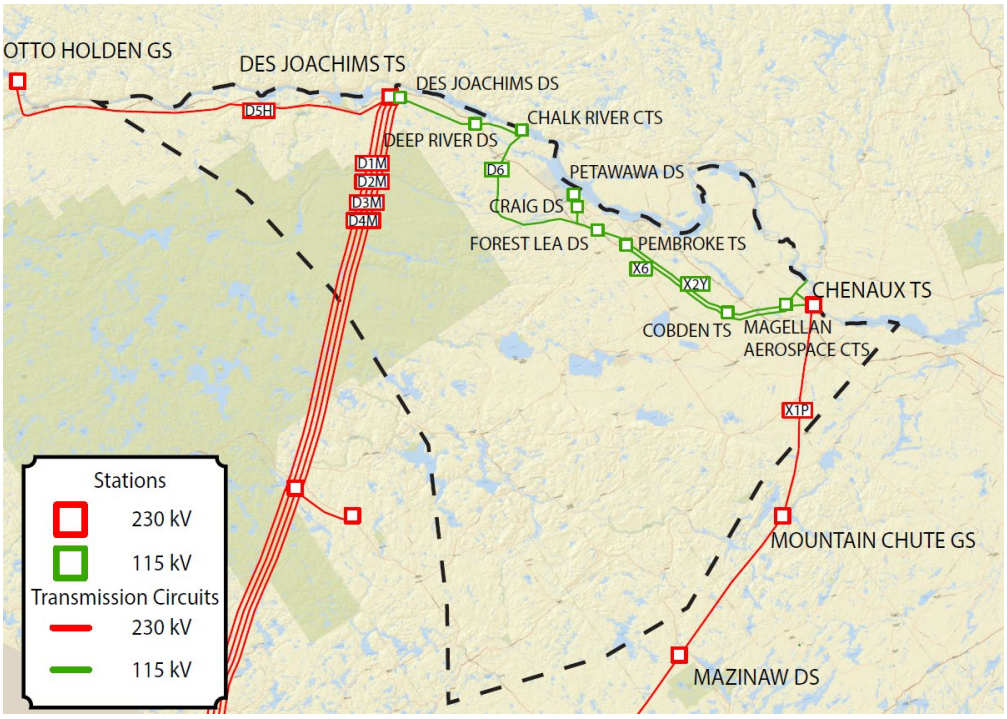
List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DG	Distributed Generation
DS	Distribution Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

This Integrated Regional Resource Plan (IRRP) for the Renfrew region addresses the regional electricity needs over the study period, i.e., from 2021 to 2042. The Renfrew region is located in Eastern Ontario with the majority of the population residing along the Ottawa river. It is bounded by two hydro generating stations, Des Joachims in the west and Chenaux in the east. The Renfrew region, shown in Figure 1, includes five Indigenous and Metis communities and 18 municipalities with a total population of approximately 100,000 people.

Figure 1 | Renfrew Region Map



The purpose of this IRRP is to document the findings and actions required to address the transmission system issues in the region. The IRRP is one part of the overall planning process and this report is the final product of this stage. The regional electricity planning process was formalized by the Ontario Energy Board (OEB) in 2013, and it requires transmitters, distributers, and the Independent Electricity System Operator (IESO) to carry out regional planning activities for the 21 electricity planning regions across Ontario at least once every five years. This is the first time that issues have been identified in Renfrew that require further regional coordination and, as a result, this is the first IRRP for the Renfrew region.

The region has historically had low growth, however, the electricity demand is slowly reaching the capacity of the transmission system. Specifically, there have been station capacity issues identified in the Pembroke, Petawawa, and Laurentian Valley areas. The scope of this IRRP is centered around addressing these issues and the Technical Working Group has taken this opportunity to engage on a broader scale with municipalities, large electricity customers, and other relevant stakeholders in order to understand some of the electricity trends that are affecting the region.

Through public webinars, stakeholder feedback, and individual engagements a number of trends impacting the region's future electricity demand have been identified. Several communities are seeing larger migrations from urban centers and are preparing for residential developments. The majority of existing residential areas do not have air conditioners and also utilize gas heating both of which when installed and converted will contribute to peak energy consumption in the summer and winter, respectively. Lastly, the impact of electrification, which is being felt across the province, could further constrain the transmission system that has historically seen flat growth.

This IRRP report summarizes upcoming power system capacity, reliability, and end-of-life asset replacement issues and recommends specific investments to address the most imminent issues. This IRRP also recommends near-term activities to manage longer-term requirements. The next planning cycle is scheduled to be initiated in 2026. Annual monitoring of potential issues will provide additional input on when the next regional planning cycle should be initiated.

The report is organized as follows:

- A summary of the recommended plan for the Renfrew region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- A background of the Renfrew region is presented in Section 4;
- The development and methodology of creating the 20-year long-term forecast is presented in Section 5;
- The electricity issues for the Renfrew region are presented in Section 6;
- Options, alternatives, and recommendations to address the issues are presented in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8;
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Renfrew region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC).

This IRRP identifies three planning horizons: near-term (year 1 to 5), medium-term (year 6 to 10), and long-term (year 11 to 20) from the base year (2020). These planning horizons reflect the inverse relationship between the length of time and demand certainty (in that the longer the outlook, the less certain it is), lead time for electricity resource development, and planning commitment required. This IRRP identifies and recommends specific projects for implementation in the near-term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions.

This IRRP also identifies possible long-term electricity needs, some of which may advance to the near- or medium-term for a high growth scenario. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to commit specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time or so the Technical Working Group can respond in a timely manner, if a high growth scenario were to materialize.

2.1 Near- to Medium- Term Plan

Recommended Actions

1. **Build new station at Pembroke, finalize scope during Regional Infrastructure Plan (RIP) period**

The existing Pembroke Transformer Station (TS) supplies the City of Pembroke. Two Local Distribution Companies (LDC) supply customers from Pembroke TS, Hydro One Distribution and Ottawa River Power Corporation (ORPC), as an embedded customer to Hydro One Distribution. The station has an existing 1 MW station capacity issue that is forecast to increase to 14 MW, in the summer, over the study period. A new station, targeting an in-service date of 2027 has been identified as the preferred option to address the need. Both a High Voltage Distribution Station (HVDS) and a standard dual-element spot network (DESN) transformer station were considered as options.

Both would meet the long-term forecast and each have their benefits and risks. A standard DESN station is preferred from a reliability perspective and would better prepare the area to accommodate long-term needs, but comes at an increased cost. The Technical Working Group recommends that further analysis be conducted during the RIP stage of regional planning to refine costs and benefits and confirm the additional cost of a DESN station is warranted.

2. **Perform a 2 MW load transfer from Forest Lea Distribution Station (DS) to Craig DS**

Forest Lea DS is located in Laurentian Valley and currently has a 1 MW station capacity issue. There is an existing tie-point on the distribution system between Forest Lea DS and Craig DS that can be used for load transfer. The Technical Working Group recommends this tie-point be utilized to transfer 2 MW of load from Forest Lea DS to Craig DS. This action is estimated to take 1-2 years to complete, targeting an in-service date of 2025. Further, if additional capacity is needed in the future the Technical Working Group recommends installing transformer fan cooling and Supervisory Control and Data Acquisition (SCADA) monitoring at Forest Lea DS to increase the station limit by an additional 4 MW.

3. **Build a new HVDS at Petawawa DS**

Petawawa DS supplies both the town of Petawawa and a large institutional customer, with the large customer representing the majority of the load supplied from the station. Due to upcoming development on the customer's site and forecast growth for the town of Petawawa, the station capacity is forecasted to be exceeded in 2029. Further, through the engagement process a growth scenario was developed to reflect significant load increase due to fuel switching in the long-term. The Technical Working Group recommends to build a new HVDS near Petawawa to meet the forecast demand growth. The expected in service year for the new station is 2027.

2.2 Long- Term Plan

Recommended Actions

1. **Monitor the load on the Des Joachims sub-system**

Through discussions with the stakeholders in the region, the Technical Working Group developed two growth scenarios, primarily driven by two separate large scale projects. If both projects materialize the Des Joachims sub-system will require upgrades. If only one project materializes, a capacitor installed at the end of the line will improve the limit of the system sufficiently to meet the forecast demand. Due to the uncertainty and long-term nature of the projects, the Technical Working Group recommends continuing to monitor the load growth on the sub-system and install a capacitor in the Petawawa region to increase the load meeting capability of the sub-system when deemed necessary.

3. Development of the Plan

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

The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified issues and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which identifies recommendations to meet issues requiring coordinated planning; and
4. A Regional Infrastructure Plan, led by the transmitter, which provides further details on recommended wires solutions

More information on the regional planning process and he IESO's approach to regional planning can be found in Appendix B – Development of the Plan.

In addition to regional planning process, there are bulk planning and distribution planning processes. Distribution system planning is for system at 44 kV and lower, while bulk and regional planning are for higher voltages. Furthermore, regional planning focuses more on a particular, local part of the grid, while bulk planning reviews electricity transfers across the province. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.1 Renfrew IRRP Development

Development of the Renfrew IRRP was initiated in 2021 with the release of the Needs Assessment report. This product was prepared by Hydro One (Transmission) with participation from the IESO, Hydro One (Distribution), and ORPC. Screening for issues was carried out to identify issues that may require coordinated regional planning. The subsequent Scoping Assessment Outcome Report, which was prepared by the IESO, recommended that an IRRP should be developed to address previously identified and new needs in this region due to the potential for coordinated solutions. In 2021, the Technical Working Group was formed to develop a finalized Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the region, and recommend actions to address them.

4. Background and Region Overview

4.1 Region Overview

The Renfrew region is home to Indigenous communities including: Algonquins of Pikwakanagan, Algonquins of Ontario (AOO Consultation Office), Huron Wendat, MNO Ottawa Region Métis Council, and MNO High Land Waters Métis Council. A full list of Indigenous communities that were invited to participate in the regional planning engagements can be found in Section 8.5. The region is also comprised of the following communities: Township of Admaston/Bromley, Township of Bonnechere Valley, Township of Brudenell, Lyndoch, and Raglan, Township of Greater Madawaska, Township of Head, Clara, and Maria, Township of Horton, Township of Killaloe, Hagarty, and Richards, Township of Laurentian Valley, Township of Madawaska Valley, Township of McNab/Braeside, Township of North Algona Wilberforce, Township of Whitewater Region, Town of Arnprior, Town of Deep River, Town of Laurentian Hills, Town of Petawawa, Town of Renfrew, and the City of Pembroke.

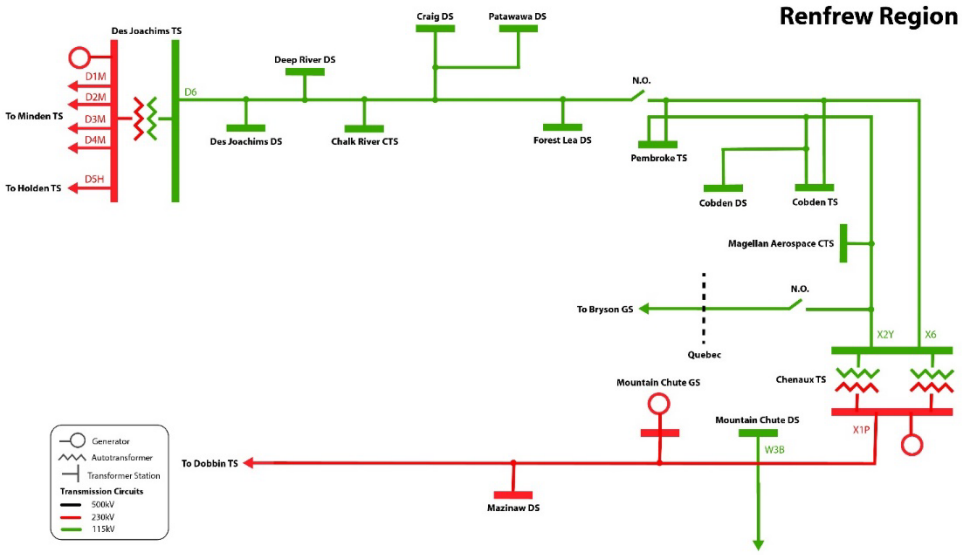
Hydro One Distribution is the main LDC for the region with Ottawa River Power Corp. embedded at Pembroke TS. ORPC is responsible for managing the distribution system for the central Pembroke area. The Hydro One portion of the station is predominantly industrial based. The ORPC portion of the load is largely residential loads. Pembroke is also unique in the fact that it has a tie to the Brookfield generator in Quebec and has been importing energy from the generator since 1893. The generator was established in Pembroke at the same time as the lumber mill and allowed for the first street lighting in Canada. The ownership and management of the generator has changed hands many times but it remains a core characteristic of the city's electrical supply.

Petawawa is the next largest municipality in the region and is served by Craig TS, Craig DS, and Petawawa DS. An industrial customer makes up a significant portion of the Petawawa DS load. The region is also home to two transmission connected customers in Chalk River Nuclear Laboratories and Magellan Aerospace. The majority of the remaining Renfrew region is made up of townships with predominantly residential loading.

4.2 Electrical System

Two hydro electric generation stations supply either end of the transmission system. Power is stepped down from 230 kV to 115 kV at Des Jaochims TS and Chenaux TS. The Des Joachims sub-system consists of 115 kV transmission circuit D6 while the Chenaux sub-system is supplied by the X2Y and X6 transmission circuits. A normally open point is found between Pembroke TS and Forest Lea DS which separates the two sytems under normal operations but can be closed in order to supply the 115 kV system during planned and unplanned outages from either Des Joachims TS or Chenaux TS. The region has two transmission connected customers: Chalk River Nuclear Laboratories and Magellan Aerospace. Figure 2 shows the electric system for Renfrew.

Figure 2 | Single Line Diagram of Renfrew Electric System



4.3 Previous Planning Activities

The most recent cycle of regional planning for the Renfrew region began with a Needs Assessment, carried out by Hydro One, that was published in May of 2021. The Needs Assessment developed a 10 year forecast and identified several needs in the region. Two end-of-life asset issues were addressed: refurbishment of Chenaux T3/T4 Auto transformers and 115 kV switchyard, and the refurbishment of the D6 line from Des Joachims TS to Petawawa DS. Finally, the Needs Assessment identified the station capacity need at Pembroke TS and recommended that the next stage of regional planning, the Scoping Assessment, should determine whether further regional planning coordination is required.

The Scoping Assessment began immediately following the Needs Assessment and was published in August of 2021. This step in the process is lead by the IESO and includes one public webinar to present the Technical Working Group's recommendation on the next steps. Through deliberation it was decided that further coordination and assessing the possibility of non-wires alternatives (NWA) to address the capacity issue at Pembroke TS was necessary which moved the Renfrew region to the IRRP stage.

4.4 Scope of Work

There are several key steps to an IRRP that are taken in order for the Technical Working Group to be able to come to a consensus on what the ultimate recommendations will be for each issue. First is the development of a planning forecast. The Technical Working Group is tasked with analyzing historical demand and then projecting anticipated demand over a 20-year period while taking into account the effect of generation, conservation and demand management, and extreme weather. The IRRP for the Renfrew region produced non-coincident planning forecasts which serve as an aid in identifying transmission system issues.

The Needs Assessment identified a station capacity issues at Pembroke TS but following the completion of the planning forecast several other issues were found. The scope of this IRRP includes station capacity issues at Pembroke TS, Forest Lea DS, Petawawa DS, and examines the Load Meeting Capability (LMC) of both the Des Joachims and Chenaux sides of the transmission system. Details regarding each of these issue is outlined in the Section 6 – Transmission System Issues.

The next steps are then to identify suitable solutions for each of the issues which are covered in the options analysis in Section 7. The IRRP considers wires, non-wires alternatives, including energy efficiency solutions, and accesses each based on cost, feasibility, and timing. Stakeholders are consulted throughout the planning process in the form of individual engagements as well as three public webinars. Finally, recommendations are provided which outline the best course of action as agreed upon by all members of the Technical Working Group.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in a region. In order for the Technical Working Group to plan for the future transmission system issues of a region, a 20- year planning demand forecast is developed. This section outlines the demand forecast methodology, discusses historical electricity demand trends, development of the planning demand forecasts as well as the expected contributions of conservation and demand management (CDM) and distributed generation (DG) towards reducing the peak demand in the region. By taking all of these factors into consideration the planning demand forecast is developed and is used to plan the transmission grid such that the grid can operate reliably and economically in the long-term. In addition to this, the final sections will examine higher growth scenarios and their impact on the region's transmission system.

5.1 Demand Forecast Methodology

The goal of creating a 20-year forecast is to understand how electricity demand will change in the region, on a station by station basis, in order to understand which parts of the electricity system will require further planning decisions. The planning forecast serves as a reference with the understanding that true, actualized demand may be higher or lower. In order to develop the planning forecast it is important to consider how to treat past electricity demand. Naturally demand fluctuates hour by hour, day by day, and seasonally so the basis of the forecast is annual peak demand. The reference forecast is based on the annual peak as this is the highest demand that the electricity system is expected to experience in the year and must be able to handle in accordance with planning criteria.

The planning forecast is divided into three time horizons: near-, medium-, and long-term. The near-term (one to five years) has the highest degree of certainty and any issues are typically met using regional transmission or distribution solutions. The medium- (five to ten years) and long-term (ten to twenty years) issues will also examine non-wires alternatives such as generation and CDM solutions. In addition to this, a summer and a winter forecast can be developed to account for regions that experience peaking in both seasons. For the Renfrew region both a summer and winter non-coincident forecast were produced.

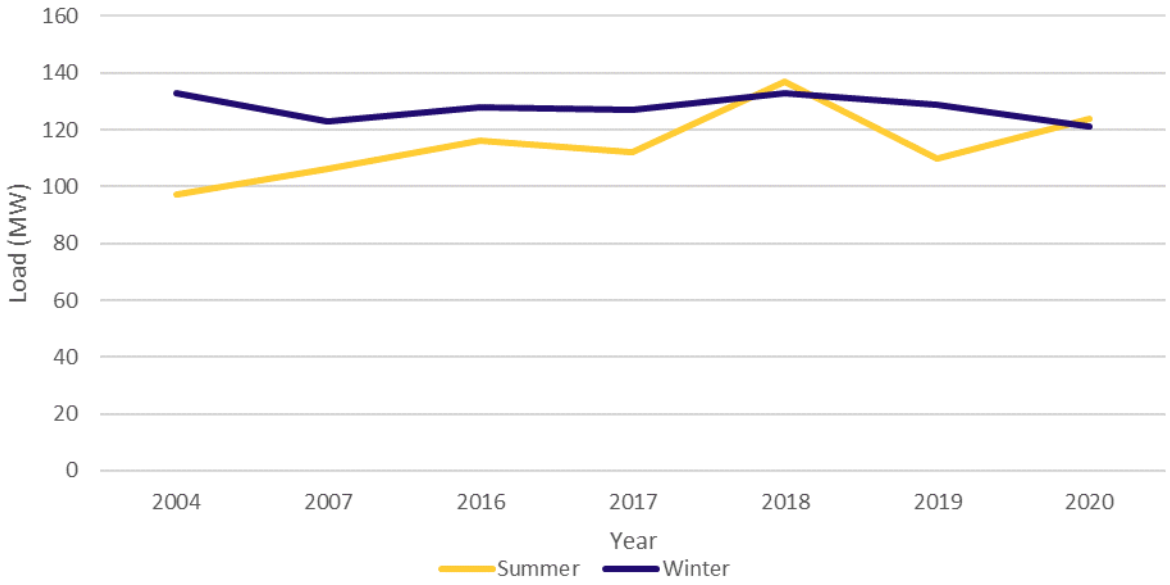
The process of developing the planning forecast starts with the development of the starting points. These consider several factors including historical load, weather, and generation at each of the stations. Using these starting points, distributors develop a 20-year gross demand forecast by accounting for known customer connections, predicted growth in population, and other electricity considerations that planners are privy to. Then, the forecast accounts for the effects of CDM and DG by subtracting them from the demand to produce a Reference Forecast. This is then adjusted for extreme weather which is represented by the hottest year in thirty years, as this will likely be seen over the course of the planning horizon.

Additional details on the demand outlook assumptions can be found in Appendix A.1 - Methodology and Assumptions for Demand Forecast as well as Appendix A.5 for the forecasts themselves. The demand outlook was used to assess any growth-related transmission system issues in the region.

5.2 Historical Electricity Demand

The Renfrew region has historically been a winter peaking region but has seen two of the past five years reach a higher demand in the summer. Going further back to the mid-2000s Figure 3 shows that as a whole the region has seen little growth in peak coincident demand in general. In fact, it appears as though winter demand has slightly decreased while summer demand has been consistently increasing. The region is predominantly made up of residential loads while the larger municipalities such as Pembroke and Petawawa have larger industrial customers.

Figure 3 | Renfrew Historical Coincident Demand



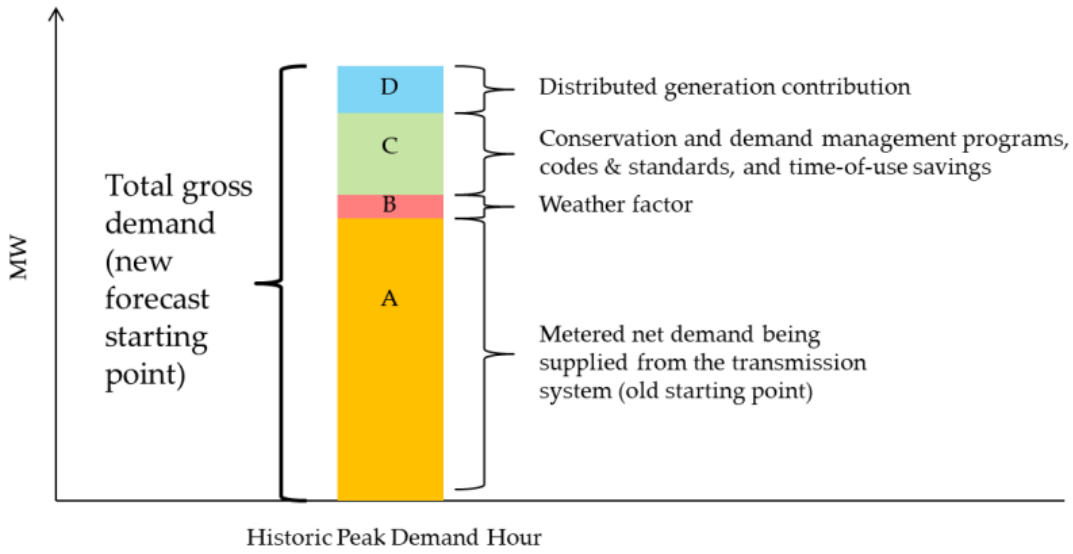
Based on the historical trend it is might be thought that the next twenty years will continue to see little to no growth. However, it is precisely the summer forecast's gradual increase that is telling of trends that could have a significant effect. The ratings of the power system electrical equipment are lower in the summer than in the winter because the natural ambient air cooling is not present and higher temperatures tend to further constrain the equipment's electrical capabilities. The Technical Working Group learned that a vast majority of the residential customer do not have air conditioners. AC units are one of the most impactful contributors to peak loads as they are typically used on the hottest days while the system is seeing its largest demand. Further, residential customers are also mainly using gas heating which means fuel-switching could also increase the winter demand over the next twenty years.

5.3 Gross Demand Forecast Starting Point

The purpose of the starting point is to allow LDCs to forecast their growth from a common place. Gross is used as it is a better approximation of true demand. The starting points are developed by first examining the past five years of historical hourly peak data for each station. For the Renfrew region the base year chosen was 2020 as the IRRP was started in 2021. The hourly demand data for each of the five years is adjusted for normal and extreme weather which is done by taking a weighted average of the 30 years of daily max temperature for the region. The daily peaks for temperature are found for all five years and graphed against daily peak consumption. Certain portions of the data are filtered out to ensure proper correlation is established between temperature and load including outliers, holidays, and weekends. A linear regression is performed to establish a line of best fit and the 90th percentile represents extreme temperature while to 50th percentile is normal temperature.

Typically, the effects of DG and CDM are taken into account as well in order to produce the gross starting point. In the case of Renfrew this was done by identifying the DG in the area and applying a contribution factor which varies by technology type, season of use, and region. The effects of CDM are typically analysed by reviewing the historical demand management programs, codes & standards, and time-of-use savings data available. Figure 4 shows the makeup of the starting point. As mentioned, LDCs then forecast the gross demand for each station based on their own methodologies.

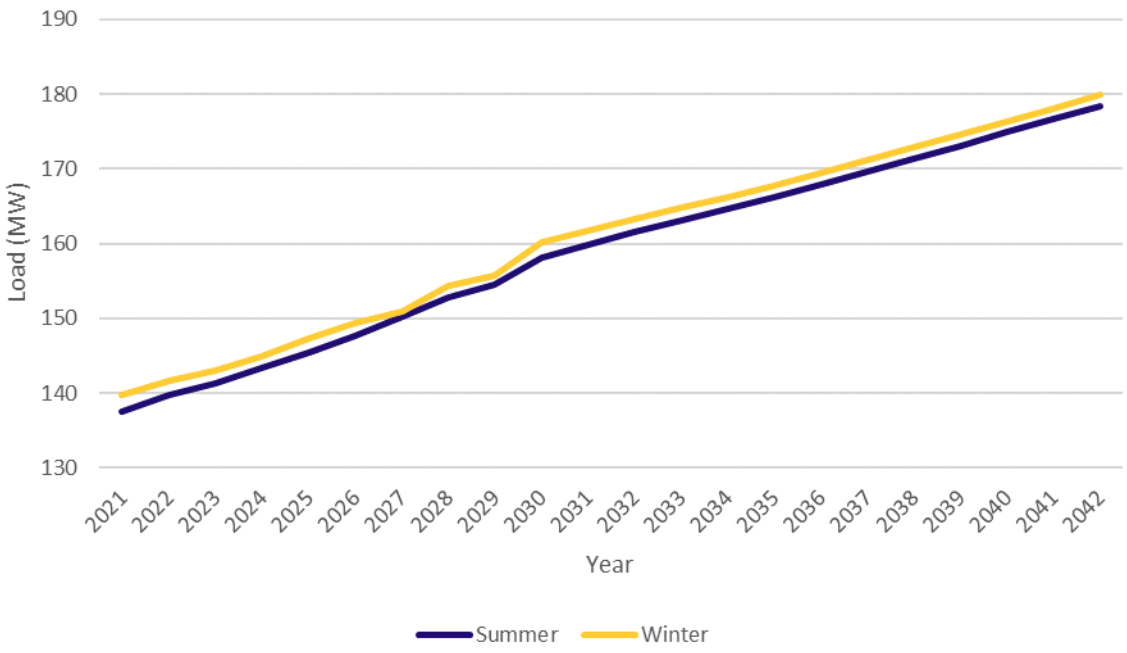
Figure 4 | Load Unbundling to Establish a Gross Demand Starting Point for Forecasting



5.4 Gross Demand Forecast

The gross demand forecast for the 20 year planning period is developed by each LDC. In the case of Renfrew, Hydro One Distribution developed the forecast for all stations with the exception of Pembroke TS which was jointly developed with the embedded LDC ORPC. The LDCs have better insights into the load growth supplied by the distribution stations through their customer connections, management of the station assets, and engagements with electricity customers. The purpose of the gross demand forecast is to serve as a reference which means only load growth that is committed or has a strong chance of materializing is to be considered. Figure 5 shows the summer and winter gross demand forecasts.

Figure 5 | Renfrew Region Non-Coincident Gross Median Demand



5.5 Contribution of Conservation on Forecast

CDM helps in meeting Ontario's electricity needs by reducing demand. This is achieved through a mix of codes and equipment standards amendments as well as CDM program-related activities.

Demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers. Program-related activities include the Save on Energy programs being implemented as part of the 2021-2024 CDM framework.

For the Renfrew region, the total forecast conservation savings at the time of summer peak are shown in Table 1 for a selection of the forecast years. These savings are subtracted from the gross median demand forecast as described in Section 5.4. Additional information is provided on Appendix B.

Table 1 | MW Savings from Conservation and Demand Management

Year	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040	2042
Summer Savings (MW)	2	4	6	8	10	12	13	14	14	14	14

5.6 Contribution of Distributed Generation on Forecast

In addition to conservation resources, DG in the Renfrew region is also forecasted to offset peak demand requirements. The resources that were included in the DG forecast reflect resources that have contracts with the IESO as a result of previous procurement programs, such as the FIT and microFIT programs. In the Renfrew region, the contracted DG resources are all solar projects.

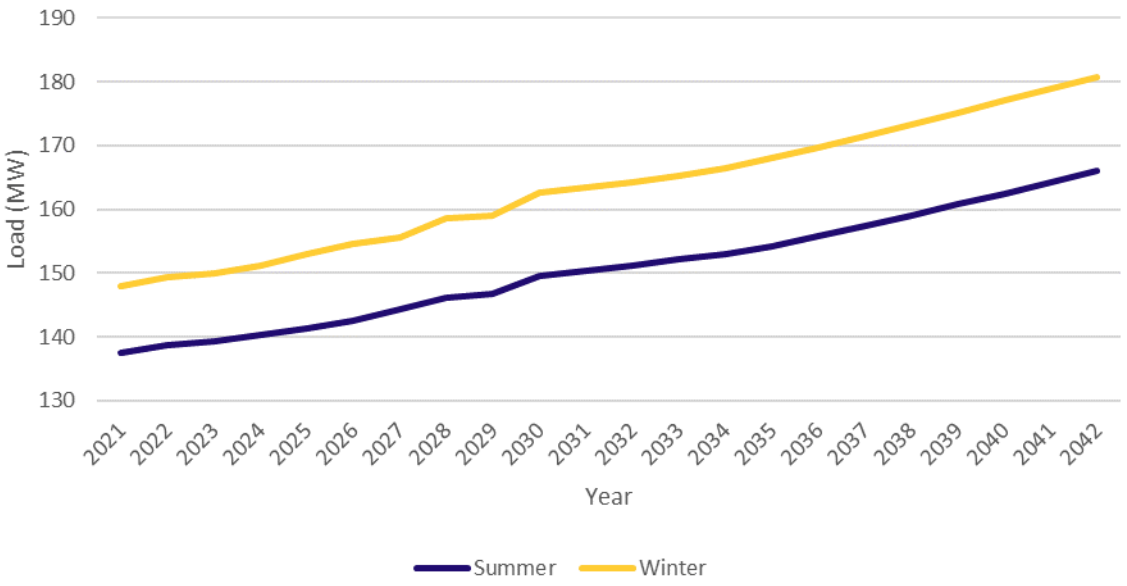
The effective capacity, i.e., the MW output at the time of regional peak, was determined at a resource level, and the data was aggregated at a station level in order to put together a forecast specifying the estimated peak demand reduction due to DG output. From 2021 to 2042, the expected annual peak demand contribution of contracted DG in the Renfrew region is 1.7 MW. The DGs included in the Renfrew IRRP are connected from the following stations:

- Deep River
- Des Joachims
- Cobden
- Pembroke

5.7 Planning Demand Forecast

In order to determine whether transmissions system issues exist it is important to consider the net demand for each station. The net demand represents the peak load level that the transmission system actually experiences and needs to serve. The final net demand forecast, adjusted for extreme weather, for the Renfrew region can be seen in Figure 6. The growth seen here is consistent with the electricity trends that have been noted throughout the report. The planning forecast for each of the stations in the region can be found in Appendix A.5. The planning forecast is used to determine where the issues in a region are and the Technical Working Group ensured the accuracy of the forecast by meeting with stakeholders in those areas to inquire about specific electricity plans.

Figure 6 | Renfrew Region Non-Coincident Extreme Weather Planning Demand Forecast



5.8 Sensitivity Scenario: Higher Growth Forecast

The concept of sensitivity is an important consideration for the planning process. It refers to the idea of stressing a system or examining alternative scenarios. The previous sections have dealt with a reference scenario which is akin to a middle-of-the-road path. It has a higher degree of certainty and by nature discounts extreme growth or extreme decline. Growth scenarios are examined when there is a trend or large project not considered in the reference forecast. Two such scenarios were identified during the planning process. Through discussions with stakeholders it was discovered that two prominent electricity customers in the Renfrew region have tentative plans to increase their load consumption on the order of 20 MW each. The customers are on the Des Joachims sub-system so this IRRP examined one growth scenario where a single increase takes place as well as a scenario where both increases take place. These scenarios occur in the long-term and due to their uncertainty will not have formal recommendations, however, the IRRP will provide insight into how the transmission system can be modified to accommodate this potential growth.

5.9 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain station with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. These profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6. Transmission System Issues

Based on the demand outlook, system capability, application of provincial planning criteria, and the transmitter's identified end-of-life asset replacement issues, the Renfrew IRRP Technical Working Group determined transmission system issues in the near-, medium-, and long-term. This section describes the capacity issues in the Renfrew region. No end-of-life or reliability issues were identified as part of this IRRP cycle but the methodology is still described below.

6.1 Transmission System Issues Methodology

Based on the application of ORTAC and NERC TPL 001-4 Standard, the Technical Working Group identified transmission system issues related to local or regional reliability requirements for the following categories:

- **Station Capacity Issues** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Issues** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Replacement Issues** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement issues identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement issues identified in the medium- to long-term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term issues should reflect the potential for the need date to change as condition information is routinely updated.

- **Load Security and Restoration Issues** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC. No load security and restoration issues were identified as part of this IRRP.

6.2 Near- to Medium-Term Needs

6.2.1 Station Capacity Issues

Station Capacity Issues have been identified for Pembroke TS, Forest Lea DS, and Petawawa DS.

6.2.1.1 Pembroke TS Capacity Issue

Pembroke TS is owned by Hydro One Transmission and managed by Hydro One Distribution while Ottawa Power River Corp is an embedded customer and LDC. Pembroke TS has three distribution feeders that supply both LDC loads. Hydro One supplies Pembroke DS and Greenwood DS as well as other larger commercial and industrial customers while ORPC utilizes two of the distribution feeders to supply seven of their own distribution stations throughout the core of the city. The distribution feeders that supply the core part of the city are also tied with the Brookfield generator from Pontiac Hydro, the details of the relationship with the generator can be found in section 4.1.

The planning forecast confirms and refines the capacity issue at Pembroke TS. Based on the load growth from the demand forecast the issue will grow to approximately 14 MW in the summer and 12 MW in the winter. The summer loading is more constraining as the equipment ratings in the summer are lower. The Technical Working Group met with key industrial customers to inquire about future plans and confirmed the accuracy of the planning demand forecast.

Figure 7 | Summer Non-Coincident Demand Forecast for Pembroke TS

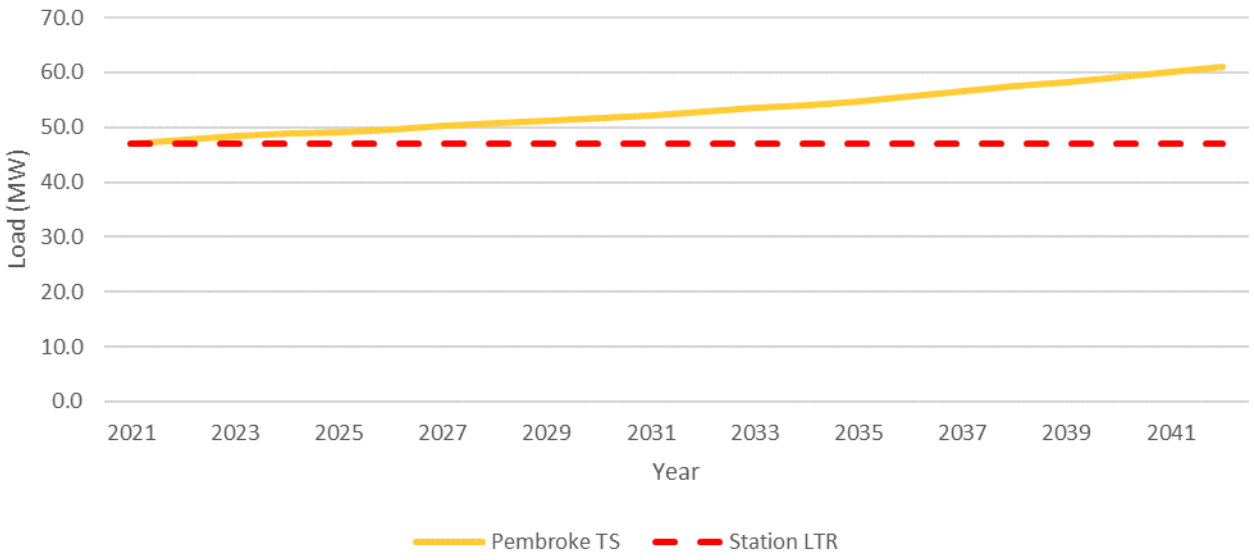
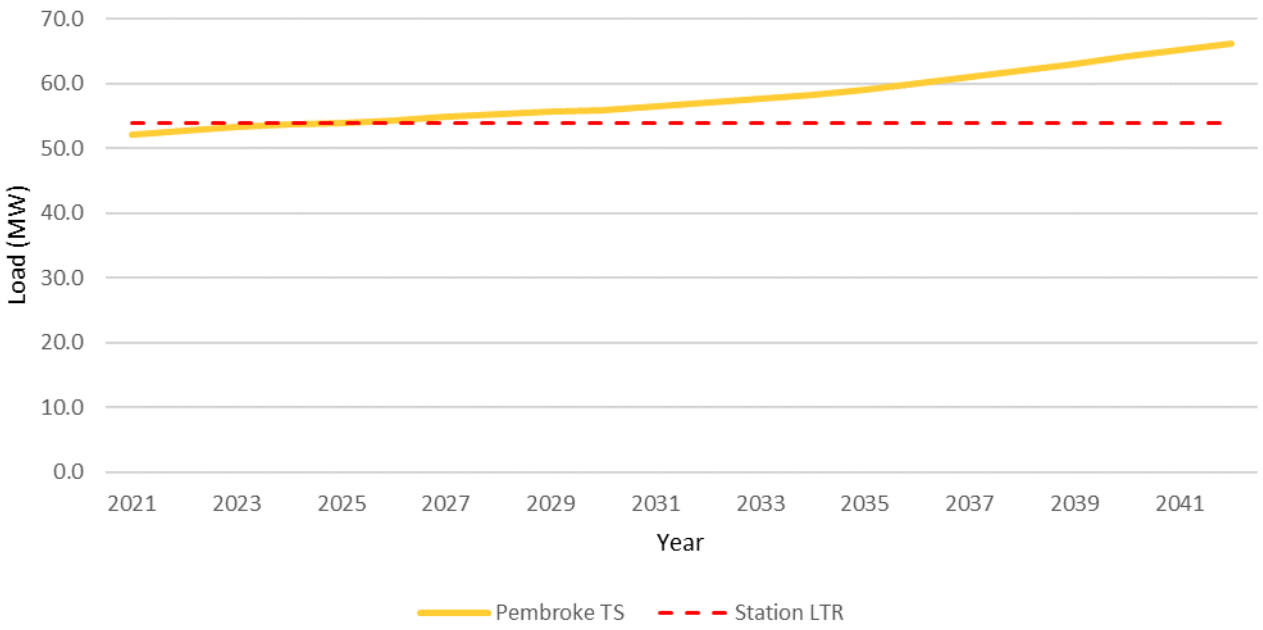


Figure 8 | Winter Non-Coincident Demand Forecast for Pembroke TS



6.2.1.2 Forest Lea DS Capacity Issue

Forest Lea DS is located in Laurentian Valley Hills, just outside the city of Pembroke. It is near the end of the circuit D6, close to Petawawa DS and Craig DS. The station is owned by Hydro One Distribution and has two 7.5 MVA, 115 kV to 13.4 kV, stepdown transformers that were installed in 1974. They are in good working condition and have not been targeted for replacement or refurbishment in a capital program as of the publishing of this report. The station's peak demand currently exceeds its LTR in the summer by approximately half a megawatt and will increase to nearly a full megawatt by 2042 as seen in Figure 10. In the winter, the station is expected to reach its LTR by 2025 and exceed that rating by just over half a megawatt by 2042 as seen in Figure 9.

Figure 9 | Summer Non-Coincident Demand Forecast for Forest Lea DS

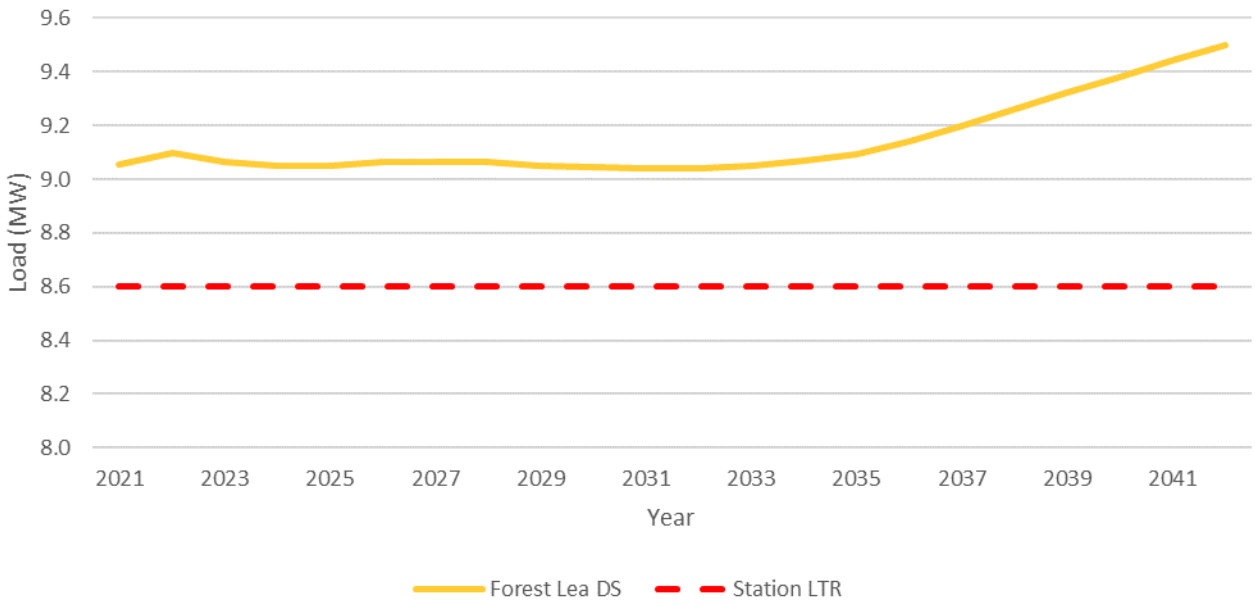
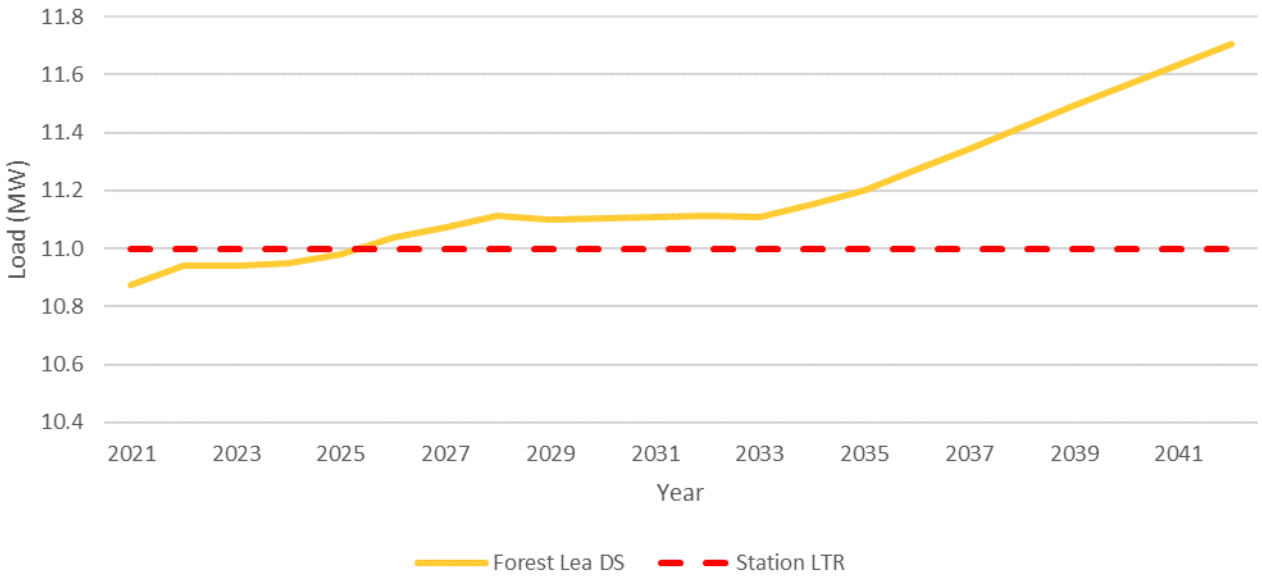


Figure 10 | Winter Non-Coincident Demand Forecast for Forest Lea DS



6.2.1.3 Petawawa DS Capacity Issue

Petawawa DS is supplied by circuit D6 and is located at the end of the circuit alongside Craig DS. The station is owned by Hydro One Distribution and has two 7.5 MVA, 115 kV to 13.4 kV, stepdown transformers that were installed in 1976. They are in good working condition and have not been targeted for replacement or refurbishment in a capital program as of the publishing of this report. The station's load is predominantly made up of one large industrial customer with the rest being the town of Petawawa. Two outreach meetings were held with the customer to finalize the planning forecast and the outcomes of the discussions made it clear that there is both medium- and long-term plans for further electricity consumption. The final forecast can be seen in Figure 11 which includes the medium-term expansion project. The station is anticipated to reach its limit by 2030 in the summer and based on the latest forecast will be within its winter rating. Further, the engagement also revealed a very sizeable heating load at the industrial customer which will need to be converted as part of the Canadian Net-Zero Emissions Accountability Act. This development is one of the basis for the growth scenarios developed as part of this regional plan and further details can be found in Section 6.3. It is considered a growth scenario as opposed to part of the planning forecast due to the uncertainty of the size and exact timing of the project.

Figure 11 | Summer Non-Coincident Demand Forecast for Petawawa DS

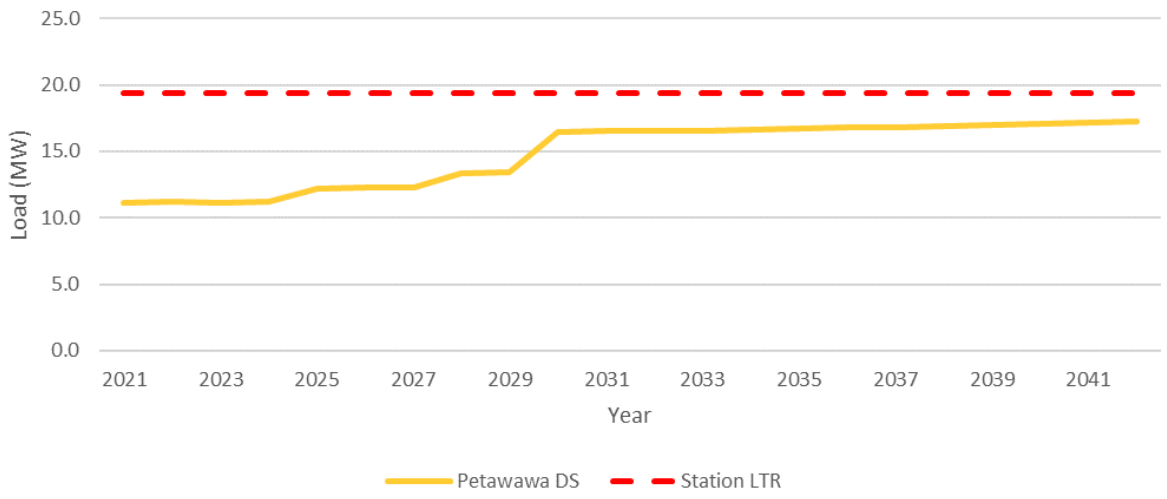
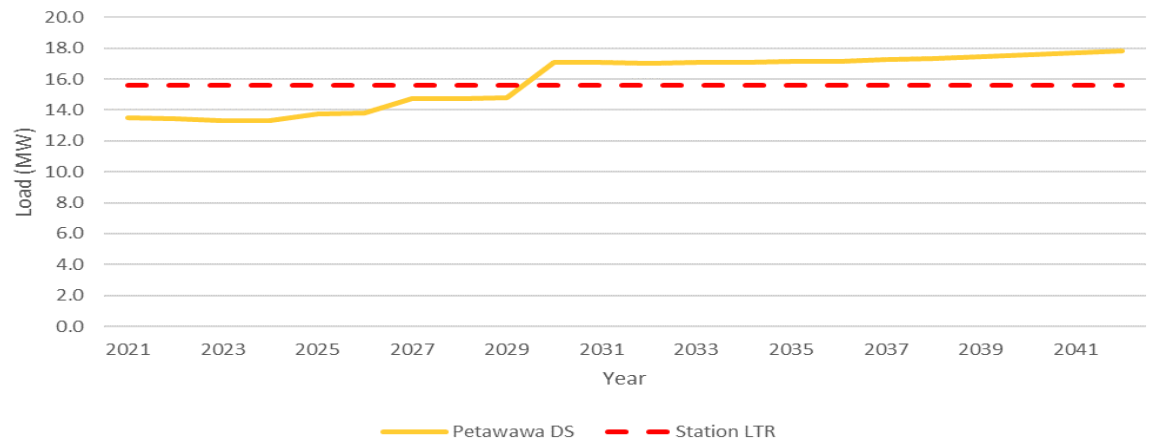


Figure 12 | Winter Non-Coincident Demand Forecast for Petawawa DS



6.3 Long-Term Needs

6.3.1 Supply Capacity Issues

6.3.1.1 Des Joachims Sub-System Capacity Issue

The Renfrew electricity system is comprised of two sub-systems, the Des Joachims and Chenaux sub-systems. The Des Joachims sub-system refers to the transmission line D6 and the generating station in the Western part of the Renfrew Region called Des Joachims TS while the Chenaux sub-system refers to the transmission lines X2Y and X6 and associated stations. As part of the planning process the LMCs are determined for the relevant parts of the transmission system. It was found that there are no long-term issues under the planning forecast for the Chenaux sub-system. Growth scenarios were developed for the Des Joachims sub-system and long-term issues were identified. With one element out and a contingency to a generator at Des Joachims TS, under peak coincident demand and low generation conditions, there is a voltage change violation at end-of-line stations such as Petawawa DS, Forest Lea DS, and Craig DS on the Des Joachims sub-system. That LMC is approximately 80 MW as seen in Figure 13.

Figure 13 | Des Joachims Side Summer Coincident Load Forecast



7. Options and Recommendations

This section describes the options considered and recommendations to address the issues in the Renfrew Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wires" options and can include things like local utility scale generation, distributed energy resources, demand response, or energy efficiency.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. The IESO utilized a screening approach to assess which needs would be best suited to a detailed assessment for non-wires options, this is first described in Section 7.2. Section 7.3 covers the options and recommendations for meeting the near- to medium-term issues, and is followed by Section 7.4 which discusses the options and recommendations for the long-term. The summary and next-steps is found in in Section 7.5.

7.1 Options Considered in IRRPs

Wires options are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc.) of each need. These options are developed through discussions with the Technical Working Group. These wire options consider the capital cost of the line and stations plus the energy cost associated with the unserved energy profile.

The high-level cost estimates for wires options are provided by the transmitter, Hydro One. The RIP, following the IRRP, will perform additional detailed analysis and refine these cost estimates before implementation work begins. The IESO will continue to participate in the Technical Working Group during the RIP and revisit these recommendations if costs estimates differ significantly.

To select a non-wire options an hourly load profile is first created as described in Section 5.9. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need.

Cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. The use of new natural gas-fired generation is considered in the economic analysis for illustrative purposes to represent the lowest cost of generation. The use of energy storage such as a lithium nickel manganese cobalt oxide (NMC) batteries is also considered as it becomes competitive due to declining technology costs and the expectation of increasing carbon prices in line with federal policy. Conservation demand management (CDM) are also non-wires alternatives that can be considered based on regional availability.

For all of the above options, the system capacity value if applicable is "credited" back to arrive at the net cost to meet local reliability needs. This is done to ensure a level playing field comparison between resources that provide capacity and wires options that address the local need but do not provide system capacity benefits.

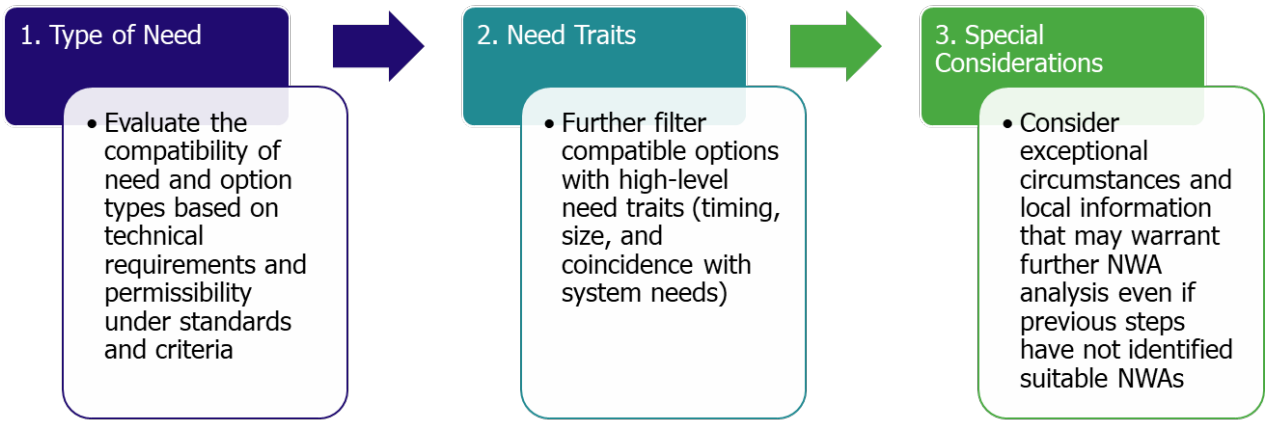
Both the upfront capital and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs ($/kW-yr) over the lifespan of the asset in question (for Renfrew a 45-year lifespan is assumed for the station infrastructure) for each option. The net present value (NPV) of these levelized costs are the primarily basis through which options are compared below. Unless stated otherwise, the costs are net present values and in 2021 CAD dollars. The list of assumptions made in the economic analysis can be found in Appendix C.

7.2 Screening Options

As explained in Section 7.1, different options can be developed to meet local needs during an IRRP based on the needs requirement. Options are then evaluated to recommend the most cost-effective and technically feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 14.

Figure 14 | IRRP Screening Mechanism



Note that the screening mechanism only acts as a guideline; many other considerations for its application in the Renfrew IRRP are described in the following sections.

7.2.1 Non-Wires Options for the Capacity Needs

In general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be connected downstream of the limiting step-down transformer.

7.2.1.1 Pembroke TS

As described previously in Section 6.2.1.1, there are forecast station capacity needs at Pembroke TS. Since the capacity need at Pembroke TS is existing today, and grows to 14 MW and 12 MW in the summer and winter, respectively, a DR solution was screened out as prior years' auction indicates there isn't sufficient DR potential in the east zone for 16 MW for both summer and winter seasons.

7.2.1.2 Petawawa DS

As described in Section 6.2.1.2, there is a forecast station capacity need at Petawawa DS. Due to consideration of the growth scenario, a DR solution was screened out. Further, in 2042 there will be a station capacity need at Petawawa DS 47% of the time in July, which is not a good candidate for DR. Lastly, CDM was screened out as the station supplies one large industrial customer which greatly reduces the available programs and initiatives.

7.2.1.3 Forest Lea DS

For Forest Lea DS, all options except transmission-connected generation were developed in further detail.

7.2.1.4 Des Joachims Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Des Joachims sub-system, the need was only forecast to emerge under the growth scenario. To focus non-wires alternative analysis on the needs emerging under the reference forecast, only wires options were evaluated.

7.2.1.5 Summary of Screening Outcomes

Table 2 | Results of Renfrew IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Pembroke TS	Wires, DG, CDM	Transmission-connected generation, DR
Station capacity	Petawawa DS	Wires, DG	Transmission-connected generation, DR, CDM
Station capacity	Forest Lea DS	Wires, DR, DG, CDM	Transmission-connected generation
Supply capacity	Des Joachims Sub-system	Wires	Transmission-connected generation, DR, DG, CDM

7.3 Options for Meeting Near- to Medium-Term Issues

7.3.1 Options for Meeting Pembroke TS Station Capacity Need

Pembroke TS supplies both Hydro One Distribution and ORPC load. The embedded ORPC load is supplied from two of the existing feeders. These feeders provide both a normal and back up supply to seven ORPC owned distribution stations throughout the core of the city. The feeders mentioned distribute power at a voltage of 44 kV which is stepped down at the DS. The station LTR is currently exceeded by 1 MW and this is forecast to increase to 14 MW, in the summer, over the course of the 20 year forecast.

7.3.1.1 Transmission Options

Two feasible wires options were considered:

- Building a new HVDS, or
- Building a new DESN station, or "TS".

These options differ both in the capacity they are capable of offering and the secondary, or distribution voltage, available.

The HVDS would be built by converting the existing Pembroke DS to an HVDS. It would be connected to only one of the two transmission circuits that currently supply Pembroke TS, X2Y or X6. An HVDS would provide 18 MW of capacity at a cost $13M (NPV), which includes $11M (NPV) for building the station and at a least an additional $2M (NPV) for distribution costs. Due to configuration of the existing system, the HVDS would be used to supply existing load, freeing up space for new load on Pembroke TS. The new HVDS would supply existing ORPC load which would split the ORPC distribution system into two distinct sub-systems: the existing system and a new radial system. The existing system utilizes the two feeders from Pembroke TS with ties between them to improve reliability and flexibility during planned outages and contingencies. Further, ORPC and Hydro One Distribution utilize different voltages which will require further analysis and cost in order to implement the HVDS solution.

Maintaining two separate systems with different levels of reliability could prove to be an operational challenge and any growth beyond the forecast would likely necessitate the expansion of this new less reliable radial 12 kV system in the future, once the capacity is exceeded. As the HVDS would only have one upstream transmission supply, this also represents a decrease in reliability over the LDC's existing supply arrangement at Pembroke TS. From a capacity standpoint, this option leaves 2 MW of remaining capacity at the new HVDS and 2 MW of remaining capacity at Pembroke TS at the end of the 20 year forecast period, which would not be sufficient to accommodate a high growth scenario.

The other option is to build a new DESN station, or TS, near the existing Pembroke TS, connected to both the X2Y and X6 circuits. It would cost approximately $28M (NPV) to build the station. Transferring existing load to the new station is estimated to have negligible cost, as no new feeders would need to be constructed. While the new supply station would be rated for 47 MW, the station will only be able to supply up to 36 MW of load due to upstream transmission constraints on 115 kV circuits. By transferring 6 MW of Greenwood DS load and 12 MW of Hydro One Distribution load to the new TS, ORPC will be able to supply their 20 year forecasted growth using their existing distribution system. This leaves 18 MW of capacity at the new TS and 4 MW of capacity at the existing TS. Compared to the HVDS option, the TS option provides higher levels of reliability, consistent with what the LDCs currently experience and provide today, as it is a dual supply station, maintains ORPC's current distribution configuration which provides back-up supply, and provides 22 MW of spare capacity for the future versus 4 MW. These additional benefits would come at an incremental cost of $15M (NPV) compared to the HVDS option.

7.3.1.2 Non-wires Options

The non-wires alternative options considered for Pembroke TS were distributed generation and additional energy efficiency. For the distributed generation option gas generation and storage were evaluated. Solar and wind were not considered due to a lack of alignment between their typical production profiles and the hourly need requirement. The gas generation option was based on costs for a 16 MW reciprocating engine located in eastern Ontario. A 93% effective capacity for system benefit was assumed in the analysis.

This option was estimated to cost of $47M (NPV). The storage option required 16 MW of capacity and 10.3 hours of storage. This option was estimated to cost $96M (NPV). The development of cost for the storage option assumed a 10 MW capacity battery with 10 hr reservoir would be installed in 2026, with an additional 6 MW installed in 2035.

Lastly, analysis of the potential for additional energy efficiency, on top of the already committed CDM programs, reveals there is the potential for approximately 6 MW of additional savings over the 20 year forecast at a cost of $31M (NPV) by 2038. This option would be insufficient to meet the need requirement of 10 MW by 2038.

7.3.1.3 Recommendations

Building a new TS in the Pembroke area will maintain current levels of reliability, will allow ORPC to continue growing their system under the current methodologies and level of distribution reliability, and allows for a substantial amount of new capacity for flexibility in meeting long-term demand compared to the HVDS option. However, this comes at an increased upfront cost for the capacity. While the technical challenges and reliability limitations associated with the HVDS are considerable, the Technical Working Group has decided the difference in cost warrants a more detailed study of the costs of the proposed HVDS connection and distribution impacts in the RIP to confirm the additional cost associated with the TS solution is warranted. The targeted in-service date for a new station in Pembroke is 2027.

7.3.2 Options for Meeting Petawawa DS Station Capacity Need

Petawawa DS supplies the town of Petawawa and a large institutional customer. The majority of the load, an upwards of 80%, is consumed by the customer. Engagements with the customer have revealed that there are developments planned for expanding several buildings on their campus which led the Technical Working Group the revise the draft forecast. The forecast now estimates the station will be overloaded in the near-term by approximately 2-3 MW.

7.3.2.1 Transmission Options

There were several wires options identified to provide the additional capacity. First, the transformers at the station could be upgraded to a larger size which would add only 3 MW of incremental capacity to the station rating. This comes at a cost of approximately $5M (NPV). Alternatively, a new HVDS could be built at a cost of approximately $10M (NPV) and would add an additional 18 MW of incremental capacity. The working group also examined the feasibility of conducting a load transfer to Craig TS but, as that station does not have a significant amount of spare capacity, it was deemed that load transfer is not suitable in this case.

The upgrade of the transformers would meet the forecast demand but offer no spare capacity. A new HVDS, however, is $5M more expensive but provides significantly more capacity and allows for flexibility to meet the challenge presented in the growth scenarios.

7.3.2.1 Non-wires Options

From a non-wires alternative perspective, a number of options were considered but only a generation option was developed as it fit the nature of the need profile. The generation option evaluated was a simple cycle gas turbine (SCGT) facility for the 2 MW need. This comes at a cost of $11M in net-present value. Wind and solar resource options were not evaluated as the load requirement does not match their production profiles. Based on comparison of the costed gas generation option to the lower cost wires options, a storage solution was not evaluated as it would be higher cost than the gas option.

7.3.2.3 Recommendations

Building a new HVDS for the Petawawa DS station capacity need is recommended. The targeted in-service date for the new HVDS is 2027. This solution will provide ample capacity to meet the immediate planned growth in demand from the institutional customer as well as provide flexibility in the future as the customer converts their gas heating load. This is the most cost effective solution that ensures capacity for the long-term growth of Petawawa.

While comparable on a cost basis, the options of incremental energy efficiency and replacement of existing station transformers would provide insufficient margin of available capacity in the area to manage the high growth scenarios at Petawawa DS, resulting in the electricity system potentially limiting the ability of customers to electrify in a manner consistent with their plans or policies.

7.3.3 Options for Meeting Forest Lea DS Station Capacity Need

Forest Lea DS has a station limit of 8.6 MW in the summer and is currently over that limit but will only exceed it by 1 MW in the 20 year forecast.

7.3.3.1 Transmission Options

A number of wires solutions were considered, including distribution load transfers to nearby stations, improving the ratings of the existing station transformers and building a new HVDS. First, the possibility of transferring load to a nearby station was explored for both existing ties with Pembroke DS and Craig DS. A 1 MW load transfer to Craig DS can be done with minimal work resulting in a capital cost of only $50k (which is equal to $55k (NPV)). A transfer to Pembroke DS, although technically feasible, would currently result in a further overload of the upstream Pembroke TS. Depending on the solution executed for the Pembroke station capacity issue it could be possible to offload Forest Lea DS but for these reasons transferring load to Craig DS is favourable.

There are two options for upgrading the capacity of Forest Lea station: upgrading the transformers or installing fan cooling and a SCADA monitoring system to the existing transformers. The former option adds 10 MW of capacity for a capital cost of $4.5M ($4.4M NPV) while the latter provides 4 MW at a capital cost of $0.6M ($0.6M NPV).

Building a new HVDS for the Forest Lea area is also possible and would add 18 MW of load at a capital cost of $12M ($11.7 M NPV). However, this option provide capacity that far exceeds what would be required, even under consideration of a high growth scenario.

7.3.3.2 Non-wires Options

For the need at Forest Lea DS, demand response, distributed generation (storage), and incremental energy efficiency were evaluated. The demand response option is based on prior capacity auction potential of an additional 1 MW in the area to meet the need and the 2018-2021 costs from capacity auctions. The effective capacity for demand response is 69% and is based on the summer effective capacity in the 2022 APO. This option comes at a cost of $1M (NPV). The storage option examined is a 1 MW battery with a 4-hour battery life and a cost based on National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). This resource option is estimated to cost $1.6M (NPV). Lastly, analysis of the potential for additional system cost effective energy efficiency, on top of the already committed CDM programs, reveals there is approximately 1 MW of achievable potential over the 20 year forecast at a cost of $6.1M (NPV) by 2038. However, due to the small amount of load supplied by Forest Lea DS there is a higher degree of uncertainty associated with realizing these additional savings given the top-down estimate approach and there is no margin of potential additional savings when compared to the identified need.

7.3.3.2 Recommendations

Since the need at Forest Lea DS is existing and is only expected to grow to just over 1 MW in the long-term it is recommended that the 2 MW load transfer to Craig TS be executed. The targeted date for this load transfer is 2026.

In the event of further load growth beyond the reference forecast, it is recommended that the upgrade to fan cooling at the station and the installation of SCADA monitoring be implemented to allow for an additional 4 MW limit increase.

7.4 Options for Meeting Long-Term Issues

7.4.1 Options for Meeting the Des Joachims Sub-System Capacity Issue

During the course of the engagement stage of the IRRP two growth scenarios were identified for the Des Joachims Sub-system. Each scenario signifies approximately 20 MW of additional growth in the form of a large scale energy project. If one of these events were to take place it would bring the sub-system to its LMC. At this level of loading, and other assumptions, there would be voltage issues at the end of the line at stations like Forest Lea DS and Petawawa DS. The LMC can be improved to 90 MW by installing shunt capacitors at the end of the transmission line (D6). By examining the two growth scenarios outlines, growth scenario 1 being an additional 20 MW and growth scenario 2 being an additional 40 MW, the current LMC will be violated by both scenarios while the improved LMC can handle growth scenario 1 but not growth scenario 2.

7.4.1.1 Transmission Options

Installing capacitor banks at one of these stations would improve the LMC by approximately 10 MW. This means that for the more aggressive load growth scenario the Des Joachims sub-system would be 10 MW over what the system can adequately supply. In this scenario a future cycle of regional planning would need to examine options including a new transmission line.

7.4.1.2 Recommendations

As both growth scenarios are in the mid- to long-term and have a fair amount of uncertainty it is recommended that the Planning Technical Working Group continues to monitor the state of the projects and triggers the capacitor upgrade if a need were to arise ahead of the next planning cycle.

7.5 Summary of Actions and Next Steps

Table 3 | Summary of Actions and Next Steps

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
Pembroke Station Capacity	Hydro One Transmission	Build a new station; conduct further analysis during the RIP period to finalize decision between new TS or HVDS	2027
Forest Lea Station Capacity	Hydro One Distribution	Transfer 2 MW of load from Forest Lea DS to Craig DS using existing tie	2025-2026
Petawawa Station Capacity	Hydro One Distribution	Build a new HVDS transformer station at Petawawa	2027
Des-Joachims Sub-System System Supply	IESO	Monitor load growth in the area and wait to trigger investment	N/A

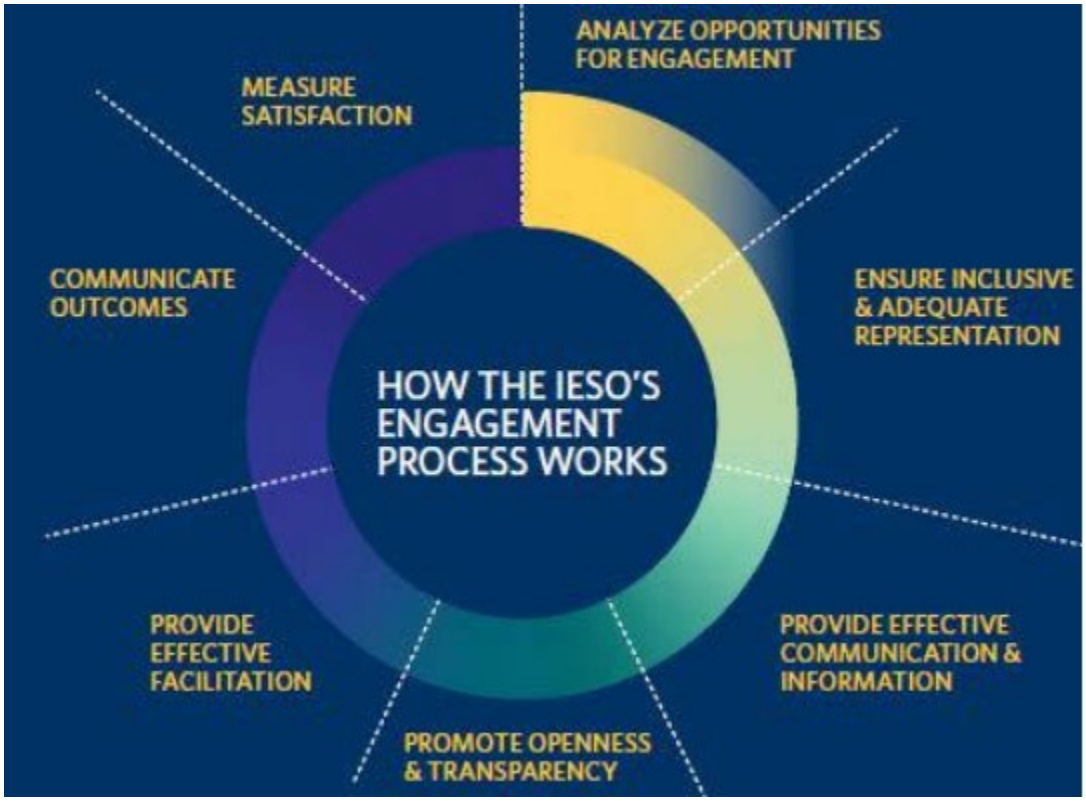
8. Engagement

The engagement process is critical to the development of the IRRP. Identifying, interacting, and collaborating with stakeholders in the region allows for the collection of knowledge and input which directly shapes how the plan is developed. Engagement is conducted in various forms and the details of the process as well as the feedback heard for the Renfrew region is described in this section.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP[1]. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 15 | IESO's Engagement Principles



[1] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

8.2 Developing an Engagement Plan for Renfrew

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region. As part of the engagement process, it is important to seek out information and input on the region's electricity needs and growth plans. This helps to ensure that the IRRP captures the most accurate and up-to-date information.

Creating the engagement plan for this IRRP involved:

- Discussions to help inform the engagement approach for the planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact on this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to feedback throughout the engagement process;
- Regular communication with interested communities, rights-holders and stakeholders by e-mail or through the IESO weekly Bulletin;
- Public Webinars;
- Targeted one-on-one outreach with specific stakeholders and communities to ensure that their identified needs are addressed.

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Renfrew Region. An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft Renfrew Scoping Assessment Outcome before it was finalized. A public webinar was held in July 2021 to provide an overview of the regional electricity planning process and seek input on the high level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021 which identified the need for a coordinated regional planning approach to develop the first IRRP for the Renfrew Region.

Following the finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the Renfrew Region to ensure that all interested parities were made aware of this opportunity for input.

Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses and other stakeholders and written feedback was collected over a 21-day comment period following each webinar.

The three stages of engagement invited input on:

1. The draft engagement plan, electricity demand forecast and early identified needs to set the foundation of this planning work.
2. The defined electricity needs for the region and high level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

The first Webinar centered around presenting the draft demand forecast as well as preliminary issues identified in the region. Input was requested on major electricity demand projects that may not have been captured in the forecast as well as any ideas about the development of the engagement plan. The second Webinar presented a completed forecast, list of issues, as well as a slate of wires and non-wires alternatives options for each issue. At this point the public was asked to provide input on the options to help shape the recommendations. The final Webinar presented the recommendations found in Section 7 and feedback on the final outcome was requested.

One-on-one outreach to communities, and stakeholders, including the largest electricity customers, located where stations that were over or close to their Long-Term Rating was influential in informing updates to the long-term forecast and ultimately to the report recommendations. Discussions addressed long-term energy plans as electricity customers' expansion and/or decommissioning plans.

Comments received during this engagement were primarily focused on ensuring that the growth plans of communities and large electricity users have been considered and accounted for in the IRRP work as well as the type of solutions addressing those needs. Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Renfrew Region subscribers, municipalities and communities as well as to the members of the East Ontario Regional Electricity Network.

Based on the discussions through the Renfrew IRRP engagement initiative, a key priority is to ensure that the IRRP and recommended actions align with the accelerated demand for housing in the region as well as can prepare to accommodate potential large scale increase in electricity needs by two large customers in the area. These insights have been valuable to the IESO in understanding how the region is growing to ensure an accurate electricity demand forecast, determination of needs and recommendation of solutions to ensure the adequacy and reliability of supply over the long-term.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Renfrew Region IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on local planning and development activities related to electricity to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, other opportunities for broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around anticipated growth in specific municipalities in the region. New insights on notable residential growth, in particular in exurban areas, was identified through discussions with the Town of Petawawa, City of Pembroke, Town of Laurentian Valley, and the Town of Deep River, which is reflected in the demand forecast and associated IRRP recommendations.

8.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Renfrew, the IESO invited Indigenous communities located in or near the Renfrew region to participate in webinars that were held on July 21, 2021, February 9, 2022 and November 1, 2022. These communities included: Alderville, Algonquins of Ontario (AOO Consultation Office), Algonquins of Pikwakanagan, Curve Lake, Hiawatha, Mississaugas of Scugog Island, the Metis Nation of Ontario Ottawa Region Metis Council, and the Metis Nation of Ontario High Land Waters Metis Council. The Huron-Wendat Nation, now located in Wendake, Quebec, was also invited due to their historical presence in southern Ontario and their interest in archaeological resources. The IESO also invited the Haudenosaunee Chiefs Confederacy Council to the July and November 2022 webinars upon being informed of their interest in Renfrew.

Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective option after it has engaged with stakeholders and Indigenous communities, and publishes those recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement those solutions require immediate action, the IESO may provide those recommendations ahead of the publication of a planning report, such as through a hand-off letter to the lead local transmitter in the region, for example.

As part of the overall transmission development process, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts

to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then need to apply to the OEB for approval through a Leave to Construct hearing, and only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

9. Conclusion

The Renfrew IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2042, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends a load transfer from Forest Lea DS to Craig DS on the order of 2 MW. Further, it is recommended to build a new HVDS near Petawawa DS to help meet both the near term expected expansion work as well support future anticipated larger scale fuel-switching initiatives. Lastly, it is recommended that further analysis is conducted during the RIP period to choose between building a new HVDS or new TS in the city of Pembroke in order to select the most prudent investment. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group continues to monitor the development of the two large scale energy projects that have been identified in the region. The size and timing of the projects will determine when and where further action will need to be taken. Installing a capacitor will likely be sufficient to accommodate one of the two scenarios but both will require a more robust solution which will be developed by the Technical Working Group.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

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Renfrew

REGIONAL INFRASTRUCTURE PLAN

July 13, 2023

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

With support from:

Company
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Ottawa River Power Corporation (ORPC)

Disclaimer

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

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

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

EXECUTIVE SUMMARY

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

The participants of the Renfrew Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process. Hydro One, as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Renfrew region was initiated with Needs Assessment (NA) and the report was published in May 2021 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in August 2021 and December 2022, respectively, by the Independent Electricity System Operator (IESO).

The Renfrew RIP provides a consolidated summary of needs and recommended plans for the region over a study period of 2022-2042 based on available information. In this regional planning cycle, plans are recommended for the near to medium-term needs. The needs for the longer term were assessed but due to uncertainties in the load growth, long-term needs will be monitored and further reviewed in next regional planning cycle.

I. Following Major projects were completed during the last ten years:

- Chenaux TS: 230/115 kV, T3 & T4 Autotransformers replaced with new 75/100/125 MVA units along with regulators TR3 and TR4, 115kV oil circuit breakers 4X6 and 4X2Y, completed in 2021.

II. Following Major projects are underway:

- 115kV D6 Circuit: Complete line refurbishment of 76.8 km Line section between Des Joachims TS and Petawawa/Craig DS, planned in-service date in 2025.

III. New needs identified during the second cycle regional planning:

a. Asset Renewal for Major HV Transmission Equipment

- No new major HV Transmission Asset renewal identified.

b. Station Capacity

- Pembroke TS: Currently exceeding summer station LTR.
- Forest Lea DS: Currently exceeding summer station LTR.
- Petawawa DS: Update on need as identified in IRRP.

c. Transmission Line Capacity

- No new Transmission Line capacity identified.

d. System Reliability, Operation and Load restoration

- No System Reliability, Operation and Load restoration issues identified.

e. Long term needs

- Des Joachims sub-system supply capacity: Monitor load growth in the area.

The major infrastructure investments in this second cycle recommended by the TWG in the Renfrew Region over the near, medium and long-term period are given in Table 1 below, along with their planned in-service date and estimate for planning purposes.

Table 1. Renfrew Region - Recommended Plans over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Renfrew region is located in Eastern Ontario with the majority of load along the Ottawa river. For electrical planning purposes this region includes eighteen municipalities including the towns of Arnprior, Deep River, Laurentian Hills, Petawawa and Renfrew. As well as the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke. Figure 1-1 represents the Renfrew Region Map.

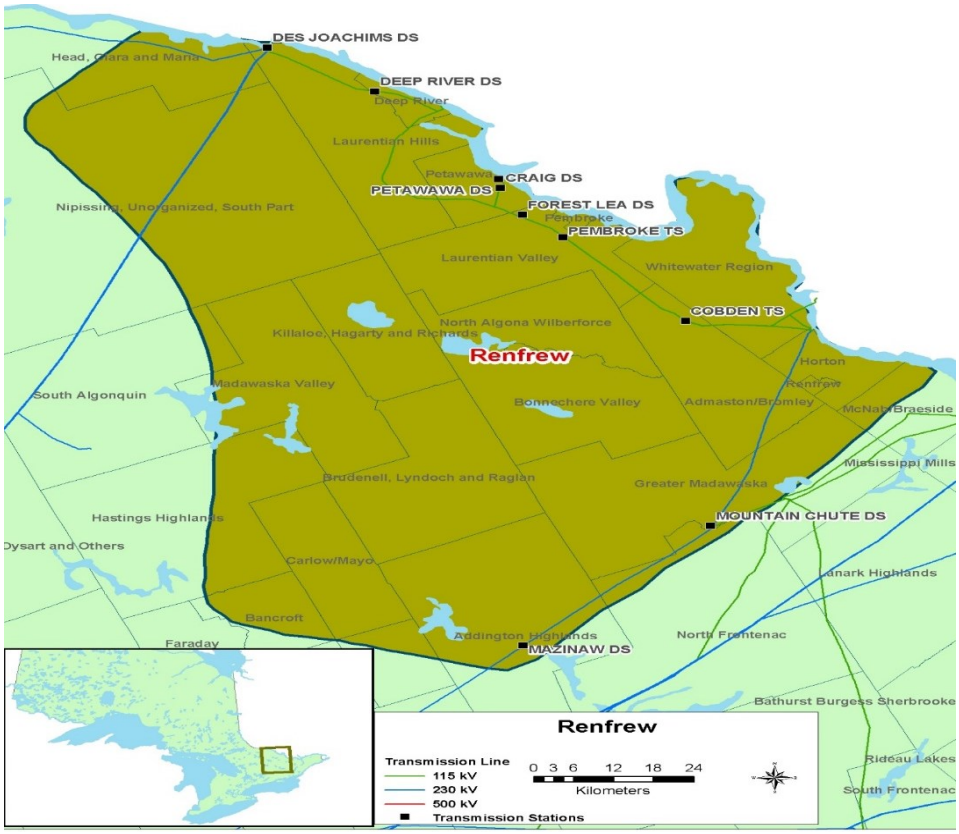


Figure 1-1 Renfrew Region Map

1.1 Objectives and Scope

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the study period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Renfrew IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) assess, and document which of the needs that,

a. can be addressed directly between the customer and transmitter along with a recommended plan, and;
b. require further regional coordination and identification of LDCs to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs,

a. are local in nature,
b. require limited investments in wires (transmission or distribution) solutions, and;
c. do not require upstream transmission investments.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. The approach is either a RIP,

which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region were identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.
The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

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

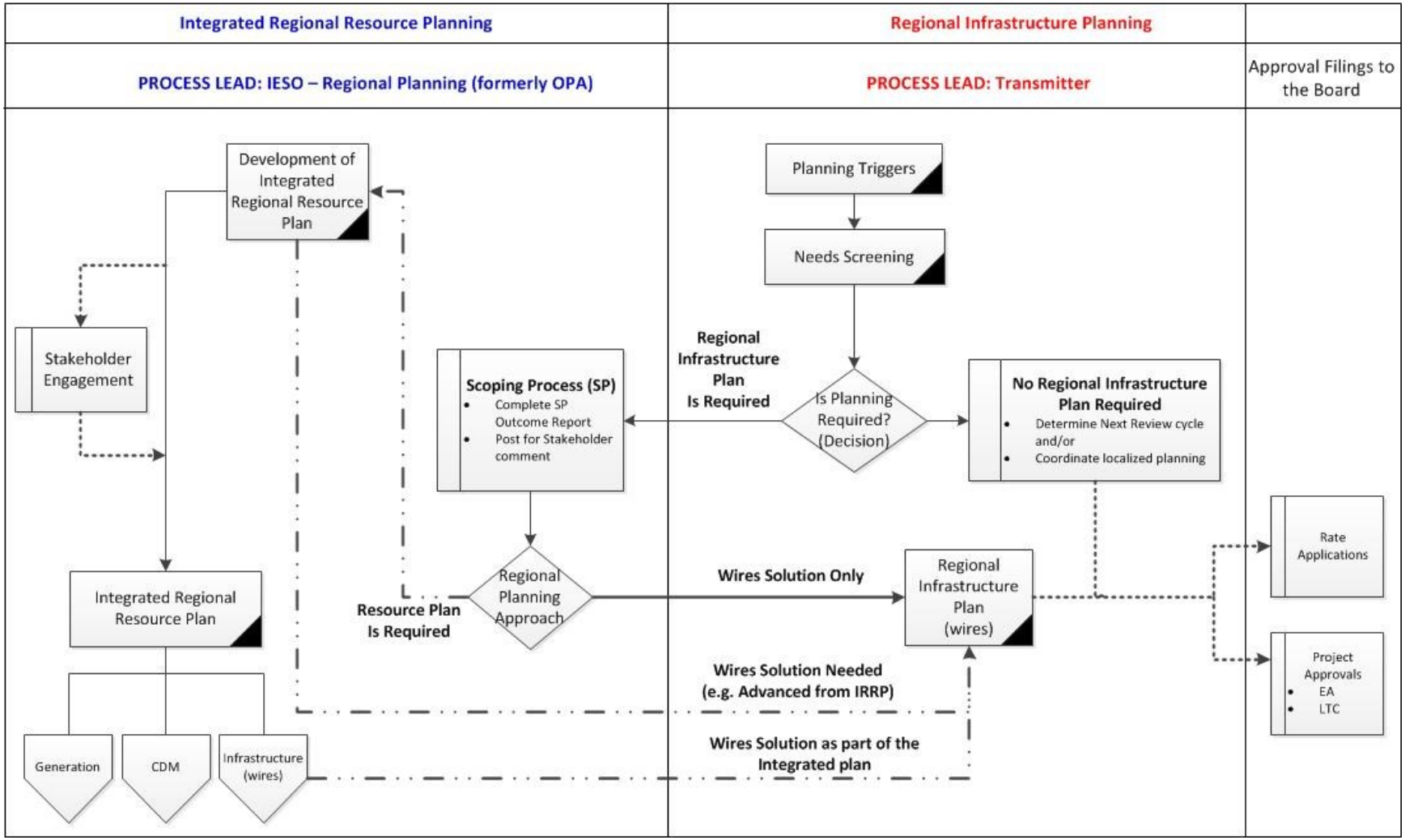


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four-step process (see **Error! Reference source not found.**) as follows:

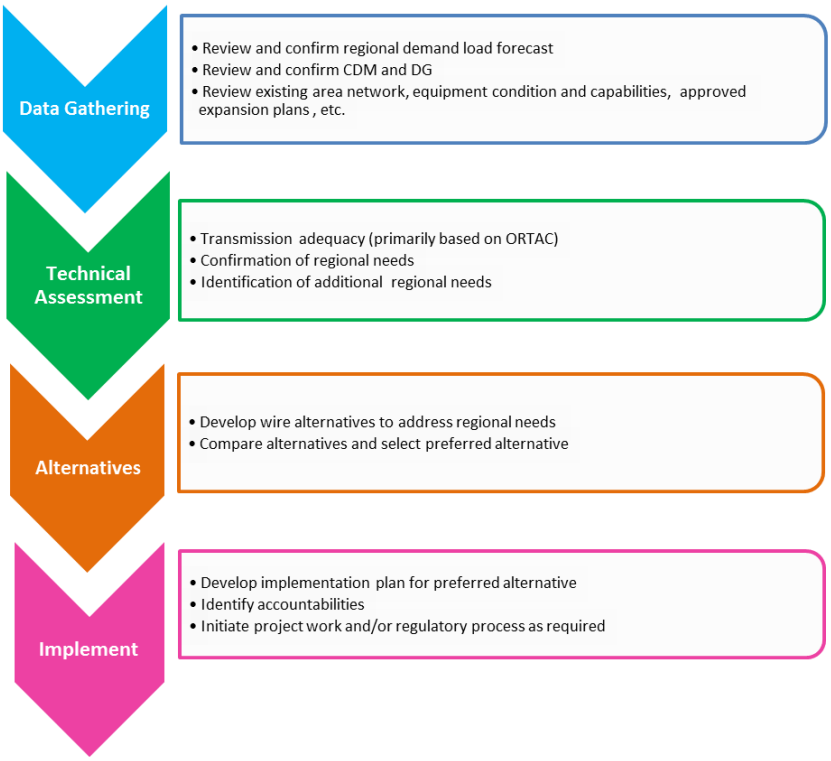


Figure 2-2 RIP Methodology

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was adopted for this RIP, with the exception of Petawawa DS.
    - Review and confirm electrification, other growth scenarios, etc. which effects the projects recommended in in previous stages.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

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

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

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

3. REGIONAL CHARACTERISTICS

THE RENFREW REGION IS LOCATED IN EASTERN ONTARIO WITH THE MAJORITY OF LOAD ALONG THE OTTAWA RIVER. THE ELECTRICITY SUPPLY TO THE REGION IS PROVIDED THROUGH ONE 230KV CIRCUIT X1P AND THREE 115 KV RADIAL CIRCUITS: D6, X6 AND X2Y. THE 115KV CIRCUITS ARE SUPPLIED BY 230/115 KV AUTOTRANSFORMERS AT CHENAUX TRANSFORMER STATION (TS) FROM THE EAST AND DES JOACHIMS TS FROM THE WEST. A NORMALLY OPENED 115KV SWITCH AT PEMBROKE TS ISOLATES THE EAST AND THE WEST SIDES OF THE REGION.

The Renfrew region is bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the South. The distribution system in this region consists of voltage levels 44 kV and 12.5 kV. The main generation facilities in the Renfrew region are Chenaux Generation Station (GS) of 143.7 MW, Mountain Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW

Hydro One Networks Inc. (Distribution) is the main LDC in the area. Other LDCs supplied from electrical facilities in the Renfrew region include Ottawa River Power Corporation and Renfrew Hydro Inc., both are embedded into Hydro One's distribution system. Renfrew Hydro Inc. customers are being fed from Stewartville TS which is part of the Greater Ottawa Regional Planning. As such, Renfrew Hydro Inc. has not been included as part of this NA.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1.

- Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y
- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Customer Transformer Station (CTS-1).
- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.
- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Customer Transformer Station (CTS-2)
- Bryson GS from Hydro Quebec can be radially connected to Renfrew region via X2Y, when required.
- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region.

The circuits and stations of the area are summarized in the Table 2-1 below:

Table 1-1: Transformer Station and Circuits in the Renfrew region

115kV circuits	230kV circuits	Transformer Stations	Generation Stations
D6, X6 and X2Y	X1P	Des Joachims TS*, Des Joachims DS, CTS-1, Deep River DS, Chalk Craig DS, Petawawa DS, Forest Lea DS, Pembroke TS, Cobden TS, Cobden DS, CTS-2, Chenaux TS*, Mountain Chute DS and Mazinaw DS.	Mountain Chute GS (170.2MW) Des Joachims GS (432.5MW) Chenaux GS (143.7MW)

*Stations with Autotransformers installed

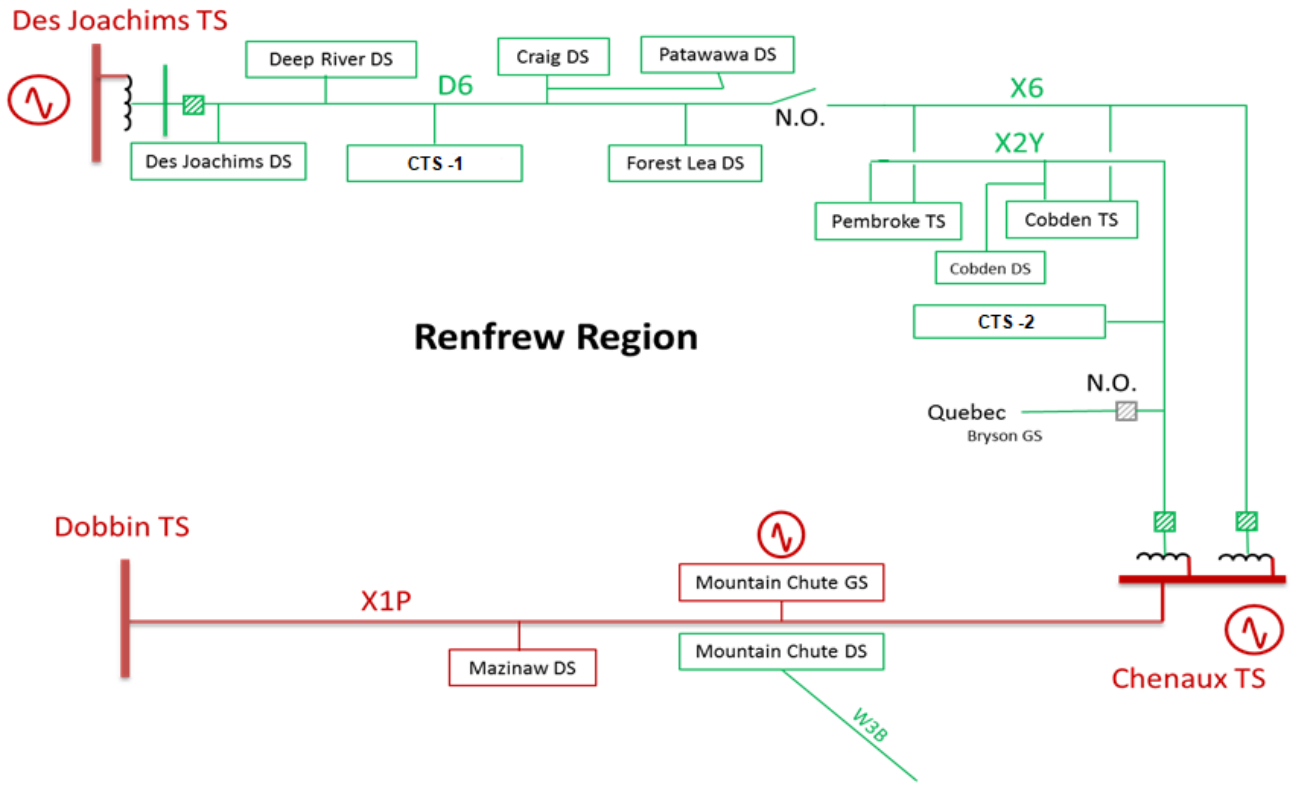


Figure 3-1 Renfrew Region Single Line Diagram

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

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE RENFREW REGION.

A list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Renfrew region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner(TAO) in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Chenaux TS Autotransformer Replacement (2021): The 230/115 kV T3/T4 Autotransformers were replaced by new 75/100/125 MVA units along with associated facilities.

II. Following Major projects are underway:

1. 115kV D6 Line refurbishment (2025): This project is currently underway and includes complete refurbishment of 76.8km line between Des Joachims TS and Petawawa/Craig DS due to its condition assessment.

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

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The TWG adopted the IRRP load forecasts for this RIP as no material change was identified, with the exception of Petawawa DS. At Petawawa DS, the load increased abnormally in June 2020 due to generator refurbishment work at a customer facility connected to Petawawa DS which resulted in adding about 3.1 MW to station peak. The load returned to its normal value after the work was completed in July 2020. The updated load forecast for Petawawa DS considers the updated actual peak load recorded in 2021.

The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight on the future load growth and was considered during IRRP load forecast development. During the study period, the load in the Renfrew region is expected to grow at an average annual rate of approximately 1.5% in summer from 2022 to 2042. The assessment is based on both summer and winter peak loads.

Figure-5-1 & 5-2 shows the Renfrew region extreme summer & winter weather non-coincident load forecast from 2022 to 2042. The load forecast from the Renfrew region IRRP was adopted as agreed to by the TWG, except for Petawawa DS. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident forecast for the individual stations in the region is available in Appendix E and is used to determine any need for station capacity relief in the region.

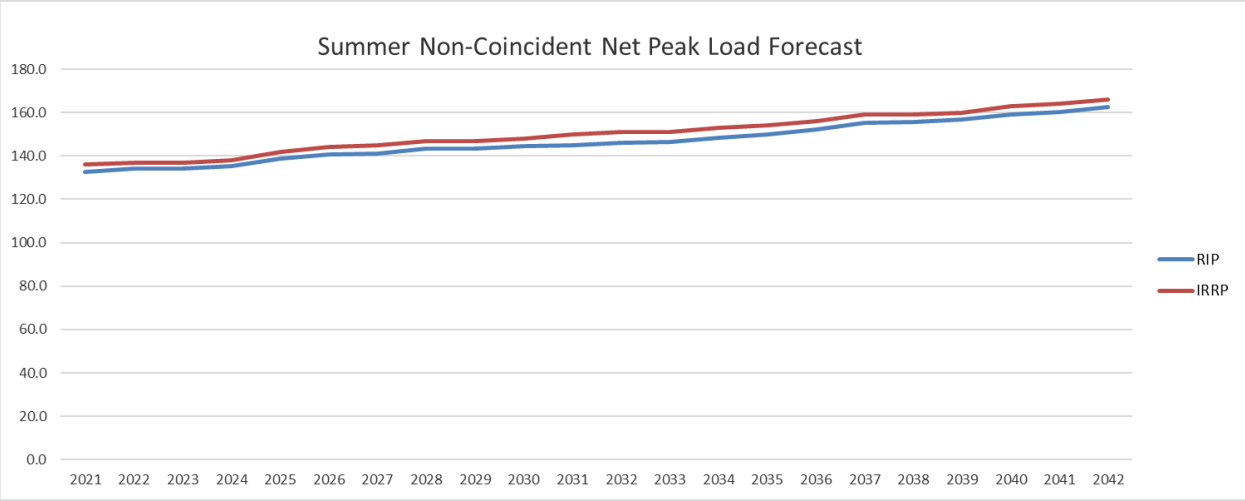


Figure 5-1 Renfrew Region Non–Coincident Net Summer Peak Load Forecast

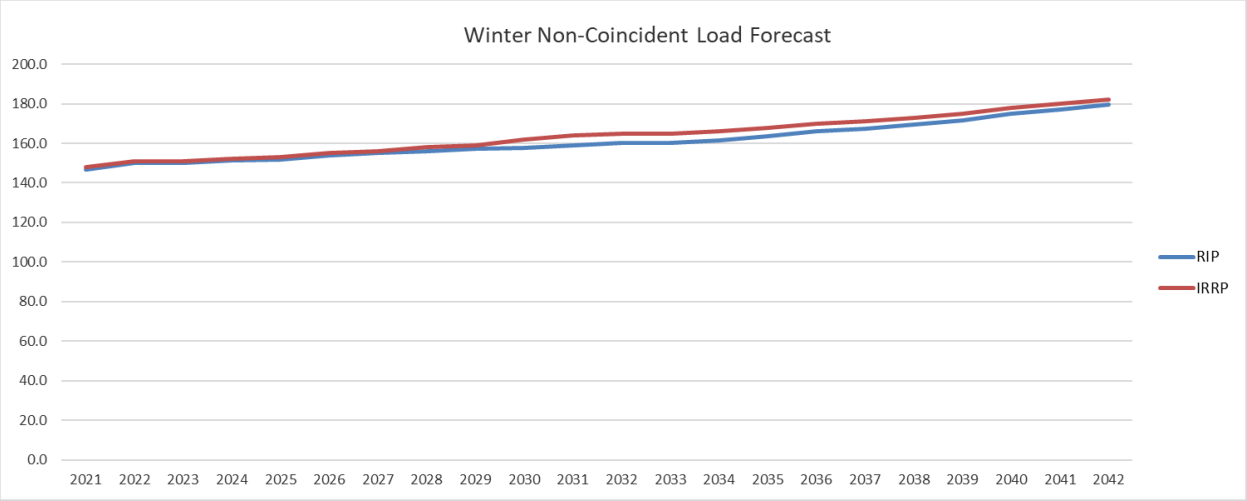


Figure 5-2 Renfrew Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2042.
- LDCs reconfirmed load forecasts up to 2042 in the area are the same as the IRRP(except for Petawawa DS).
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE RENFREW REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Renfrew region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- Renfrew region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- Renfrew region Second cycle Integrated Regional Resource Plan Report, Completed in December 2022 by the IESO

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near, mid and long-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the Renfrew Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service.

Sections 6.1- 6.5 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 Station Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transformer Stations within the Renfrew region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 6-1 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 6-1 Renfrew Region – Station capacity needs

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2022 Loading (MW) (Summer/Winter)	Need Date
1	Pembroke TS	47/57 MW	48/53 MW	Current
2	Forest Lea DS	8.6/11.6 MW	9/11 MW	Current
3	Petawawa DS	16.3/20.2 MW	10/10 MW	*

* Identified during IRRP phase but was eliminated in RIP following the load forecast update for Petawawa DS.

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Transmission Line Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Renfrew region. It was determined that all Transmission Lines are within the thermal limits of the circuits and within the voltage range as per ORTAC over the study period adequate over the study period for the loss of a single 230/115 kV circuit in the Region.

6.3 Asset Renewal for Major HV Transmission Equipment

Hydro One is the only Transmission Asset Owner (TAO) in the Renfrew region. Hydro One facilities in the region that will require replacement over the near-medium -term period as listed in Table 6-2 below.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Table 6-2 Renfrew Region - Planned Replacement Work

Station/Circuit	Need Description	Planned ISD
D6	Complete 76.8kM line refurbishment between Des Joachims TS and Petawawa/Craig DS	2025

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

6.5 Long Term Needs

During IRRP phase, a long-term supply capacity issue has been identified under high growth scenarios in the Des Joachims sub-system. The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region.
The options and preferred solution to address this need is discussed further in Section 7 of the report.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE RENFREW REGION.

The electrical infrastructure needs for the Renfrew Region are summarized in Table 7-1. These needs include those previously identified in the NA and IRRP for the Renfrew region. All estimated costs included in the alternative analysis are considered as planning estimates and are used for comparative purposes only.

Table 7-1 Renfrew Region – Near, Medium- and Long-Term Needs

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Station Capacity Needs			
Pembroke TS	Station has exceeded its summer LTR	Current	7.1.1
Forest Lea DS	Station has exceeded its summer LTR	Current	7.1.2
Petawawa DS	Station was expected to exceed its summer LTR	*	7.1.3
Long Term Needs			
Des Joachims sub-system	Supply capacity issue in long-term under high growth scenario	2034	7.5.1

* Identified during IRRP phase but was eliminated in RIP following the load forecast update.

7.1 Station Capacity Needs

A station capacity assessment was performed over the study period 2022-2042 for the 230kV and 115kV transforming stations in the Renfrew region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following station capacity needs have been identified in the during the study period:

7.1.1 Pembroke TS – 115kV

Pembroke TS supplies Hydro One Dx while ORPC is an embedded LDC. It is a 115/44 kV Transmission Station (TS) with two 25/33/42 MVA (T1/T2) transformers supplied by circuits X2Y & X6 with a summer and winter LTR of 47 MW and 57 MW, respectively.

Pembroke TS has three distribution feeders which supplies Hydro One Distribution, with ORPC as an embedded LDC on two feeders. This station has exceeded its normal supply capacity in 2019 and TWG has agreed that a wires solution is required to address this need.

The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Build a new HVDS:
A new HVDS would be built near Pembroke TS. An HVDS would provide 18 MW of capacity at an approximate cost of $14M, which includes $11M for building the station and at a least an additional $3M for distribution costs. The new HVDS would be connected to 115kV circuit X6 as during contingency it is less limiting than X2Y as the overall circuit have a higher thermal rating compared to X2Y. The Pembroke DS load, which is expected to be 6 MW, will be transferred to the new HVDS, therefore freeing up capacity for new load on Pembroke TS. The remaining capacity of new HVDS would also be able to supply an additional 12MW of new load at 12kV in the area. Although connecting a HVDS to one circuit is less reliable than a TS connected to both circuits as it does not provide full redundant supply, there is an existing transmission 115kV switch at Cobden TS that can be used to tie X2Y and X6 to restore the load on the new HVDS for in case of a fault East of Cobden TS. All of ORPC load is currently supplied by the existing two 44kV feeders from Pembroke TS. Due to the current distribution configuration of the ORPC system, future ORPC load from the new HVDS will require further modifications at ORPC's operating system within its service territory.

From a capacity standpoint, this option would be able to supply all the forecasted load in area for the long term.

Alternative 3 – Build a new Transmission Station (TS):
Build a new TS consisting of two 115/44 kV 25/33/42 MVA step-down transformers near the existing Pembroke TS, connected to both the X2Y and X6 circuits. This would cost approximately $30M. The new supply station will be able to supply 47 MW, which is more than sufficient for the 20-year load forecast, including Pembroke TS long term growth. Similar to the HVDS option, 115kV circuit X2Y is more limiting and during a contingency situation, the thermally limiting sections on X2Y will prevent the new TS from supplying the full 47 MW station capacity.

Recommendation:
Both alternatives 2 and 3 addresses the need for additional capacity at Pembroke TS during normal operations. However, building a new TS is significantly more expensive than building a new HVDS and will also require an additional cost for transmission line upgrades to utilize the full station capacity. Building a new HVDS which is a less costly alternative, has its own operational limitations and complications for ORPC. As the assessment of both alternatives are very complex, further discussion between Hydro One Tx and the impacted LDCs is required. Both Hydro One Dx and ORPC will continue to explore these two options to determine the most feasible solution to address the capacity need at Pembroke TS.

7.1.2 Forest Lea DS – 115kV

Forest Lea DS is located in Laurentian Valley Hills, outside the city of Pembroke. It is connected at the tail end of the circuit D6, after Petawawa DS and Craig DS. This station is owned and operated by Hydro One Dx. Forest Lea DS is a 115/13.4 kV Step down station and is radially supplied by circuit D6 it has two 7.5/11 MVA (T1/T2) transformers with a summer LTR of 8.6 MW and winter LTR of 11.1 MW.

This station has already exceeded its normal supply capacity but will only increase by slightly over the station LTR at the end of the study period. The TWG has agreed that a solution is required to address this need.
The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Load Transfer:
Through existing Dx interties, there is a possibility of transferring load to the Pembroke DS and Craig DS. TWG confirmed that a 1 MW load transfer to Craig DS can be done with minimal work with a capital cost of only $50k. A transfer to Pembroke DS, is also technically feasible, but would result in a further overload of the upstream Pembroke TS and the outcome of the preferred solution for Pembroke TS station capacity issue could affect the load transfer. In light of all these reasons, load transfer at Craig DS is preferred.

Alternative 3 – Upgrading the supply capacity:
The capacity of Forest Lea station can be upgraded using two methods which are:
i) Upgrading the transformers to add 10 MW of capacity for a capital cost of $4.5M or,
ii) Installing fan cooling and SCADA monitoring system to the existing transformers to add 4 MW at a capital cost of $0.6M.

Alternative 4 – Building new HVDS:
It is also possible to build a new HVDS for the Forest Lea area which will add 18 MW of load at a capital cost of $12M. This option will provide a higher capacity, which is not required at this moment, even under consideration of a high growth scenario.

Recommendation:
The need of station capacity at Forest Lea DS is current, but the expected load growth is very low. The load at this station is only expected to grow to slightly over 1 MW in the long-term. Hence, load transfer to Craig TS is considered as the most appropriate as well as cost effective alternative. TWG recommends and agrees to transfer 2 MW load to Craig DS. The expected completion date for this load transfer is 2026.

7.1.3 Petawawa DS – 115kV

Petawawa DS supplies the town of Petawawa and a large customer. The majority of the load i.e., 80% of the total load, is consumed by this large customer. The station is radially supplied by D6 and is located at the end of the circuit, right after Craig DS. It has two 115/13.4 kV Step down 7.5/10/13 MVA (T1/T2) transformers with a summer LTR of about 16 MW and winter LTR of 20 MW.

As per the IRRP Load Forecast the station reaches its summer LTR in 2030 and hence recommended to build a new HVDS transformer station at Petawawa with in-service date of 2027. During the RIP phase it was observed that the load increased abnormally in June 2020 due to generator refurbishment work at the customer's facility in Petawawa DS and resulted in the net load increase by 3 MW at the station. This work was completed in July 2020. As the load displacement generation is permanently operating, the net load at the station returned to its normal value resulting in a net load of approximately 9.8 MW during the year 2021. Hence, the Load Forecast for

Petawawa DS was updated in the RIP, and the 2022 load was determined by considering the actual load in 2021. The updated load forecast yields a lower Net Load at the end of study period.

Recommendation:
Since the elevated load forecast was updated for actual value, the load at Petawawa DS remains below the summer/winter (16.3/20.2 MW) LTRs for the long-term forecast. However, during the IRRP phase the customers in this area have indicated some possible future expansion and heating load conversion under Canadian Net-Zero Emissions Accountability Act that was considered in a high load growth scenario. Hence, for now it is recommended to defer this need as no additional capacity is required at this station for the short to medium term, but the TWG will continue to monitor the future high load growth scenario and trigger regional planning earlier if and when demand arises at the station.

7.2 Transmission Line Capacity Needs

All line and equipment load shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2022-2042 for the 230kV and 115kV Transmission line circuits in the Renfrew region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, no new Transmission line capacity needs were identified in the region during the study period.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.
No new major HV Asset Renewal Needs were identified in the region during the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2022-2042 to cater

this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

7.5 Long Term Considerations

7.5.1 Des Joachims sub-system – Supply capacity issue

The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region and ends at Petawawa DS and Forest Lea DS in the east. During IRRP, two high growth scenarios (i.e., increase in load by 20MW & 40MW) were identified as a part of the engagement process for the Des Joachims sub-system. The LMC of Des Joachims sub-system is approximately 80MW and under high growth scenarios, with one element out and a contingency to a generator at Des Joachims TS, under peak coincident demand and low generation conditions, voltage change violations are identified at the stations connected to the end of D6 circuit.

Alternative 1 - Maintain Status Quo:
The need is identified in the medium to long-term, and both high load growth scenarios have fair amount of uncertainties. Monitor the current load growth in the area and maintain status quo until next regional planning cycle.

Alternative 2 – Capacitor banks:
Installing capacitor banks at either Craig DS, Petawawa DS or Forest Lea DS will improve the LMC by approximately 10 MW and can support the first high growth scenario i.e., a load growth of over 20 MW.

Alternative 2 – Transmission options:
For the more aggressive load growth scenario, i.e., load growth of over 40MW, the support provided by capacitor banks will not be enough and there will be a need to construct new transmission line in the area.

Recommendation:
The need is identified in the mid to long-term, and in light of uncertainties of the load growth in the sub-system. Hence, for now it is recommended that TWG will continue to monitor the future high load growth scenario and if required can proceed with the capacitor upgrade if and when need arises.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE RENFREW REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near, medium and long-term are provided in Table 8-1 below, along with their planned in-service dates and estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

9. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Independent Electricity System Operator, Renfrew region IRRP Cycle-2 (December, 2022)

[6] Independent Electricity System Operator, Renfrew region Scoping Assessment Cycle-2 (August, 2021)

[7] Hydro One Networks Inc., Renfrew region Needs Assessment Cycle-2 (May 2021)

APPENDIX A. RENFREW REGION - STATIONS

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Cobden DS (T3)	115/12.5	X2Y
2.	Cobden TS (T1/T2)	115/44	X2Y/X6
3.	Craig DS (T1/T2)	115/12.5	D6
4.	Deep River DS (T1/T2/T3)	115/12.5	D6
5.	Des Joachims DS (T1)	115/12.5	D6
6.	Forest Lea DS (T1/T2)	115/12.5	D6
7.	Mazinaw DS (T1/T2)	230/12.5	X1P
9.	Pembroke TS (T1/T2)	115/44	X2Y/X6
10.	Petawawa DS (T1/T2)	115/12.5	D6

APPENDIX B. RENFREW REGION - TRANSMISSION LINES

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Des Joachims DS to Pembroke TS	D6	115
2	Chenaux TS to Pembroke TS	X6	115
3	Chenaux TS to Pembroke TS	X2Y	115
4	Dobbin TS to Chenaux TS	X1P	230

APPENDIX C. RENFREW REGION - DISTRIBUTORS

Sr. no.	Name of LDC
1	Hydro One Networks Inc.(Distribution)
2	Ottawa River Power Corporation (ORPC)

APPENDIX D. RENFREW REGION - MUNICIPALITIES

Sr. no.	Name of Municipality
1	Town of Arnprior
2	Town of Deep River
3	Town of Laurentian Hills
4	Town of Petawawa and Renfrew
5	Township of Admaston/Bromley
6	Township of Bonnechere Valley
7	Township of Brudenell
8	Township of Lyndoch and Raglan
9	Township of Greater Madawaska
10	Township of Head
11	Township of Clara and Maria Horton
12	Township of Killaloe
13	Township of Hagarty and Richards
14	Township of Laurentian Valley
15	Township of Madawaska Valley
16	Township of McNab/Braeside
17	Township of North Algona Wilberforce and Whitewater Region
18	City of Pembroke

APPENDIX E. RENFREW REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.2	7.3	7.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Cobden DS	Tx	T3	N/A	N/A	9.4	Load	7.1	7.2	7.3	7.3	7.4	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.8	7.8	7.9	8.9	8.9	8.9	8.9	8.9	8.9
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	47.8	Load	23.9	24.1	24.3	25.5	25.7	25.9	26.1	26.3	26.4	26.6	26.8	27.0	27.1	27.2	27.3	28.3	28.3	28.3	28.3	28.3	29.3
						DG	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
						CDM	0.4	0.6	0.8	1	1.2	1.4	1.6	1.8	1.9	2.1	2.3	2.5	2.6	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
						Net	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	24	24	24	24	24	25
Craig DS	Tx	T1/T2	B1B2	N/A	19.9	Load	14.3	14.4	14.5	15.6	15.7	15.9	16.0	16.1	16.2	16.3	16.4	16.5	17.6	17.6	17.7	17.7	17.7	17.7	18.7	18.7	18.8
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.3	0.4	0.5	0.6	0.7	0.9	1	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8
						Net	14	14	14	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17
Deep River DS	Tx	T1/T2/T3	N/A	N/A	8.6	Load	8.2	8.3	8.3	8.4	9.5	9.5	10.6	10.7	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1	1	1	1	1	1	1	1
						Net	8	8	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Des Joachims DS	Tx	T1	N/A	N/A	9.4	Load	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Forest Lea DS	Tx	T1/T2	BY	N/A	8.6	Load	9.1	9.2	9.3	9.4	9.4	9.5	9.6	9.7	9.7	9.8	9.9	9.9	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1	1	1	1	1	1	1	1	1.1
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Mazinaw DS	Tx	T1	BY	N/A	6.9	Load	3.1	3.1	3.1	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
						Net	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mountain Chute DS	Tx	T1	BY	N/A	8.6	Load	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	47	Load	48.5	48.6	49.9	50.2	51.5	51.7	52.9	53.1	54.5	54.7	55.9	56.1	57.2	58.2	59.3	60.3	60.3	61.3	62.4	63.4	64.4
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.3	0.4	0.7	1	1.3	1.5	1.7	1.9	2.3	2.5	2.7	2.9	3	3	3.1	3.1	3.1	3.1	3.2	3.2	3.2
						Net	48	48	49	49	50	50	51	51	52	52	53	53	54	55	56	57	57	58	59	60	61
Petawawa DS	Tx	T1/T2	BY	N/A	16.3	Load	10.5	10.9	11.3	11.6	11.9	12.3	12.6	12.9	13.2	13.6	13.9	14.2	14.4	14.8	15.1	15.3	15.6	15.8	16.2	16.3	16.6
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.5	0.7	0.9	1	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2	2.1	2.1	2.1	2.1	2.2	2.1	2.1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

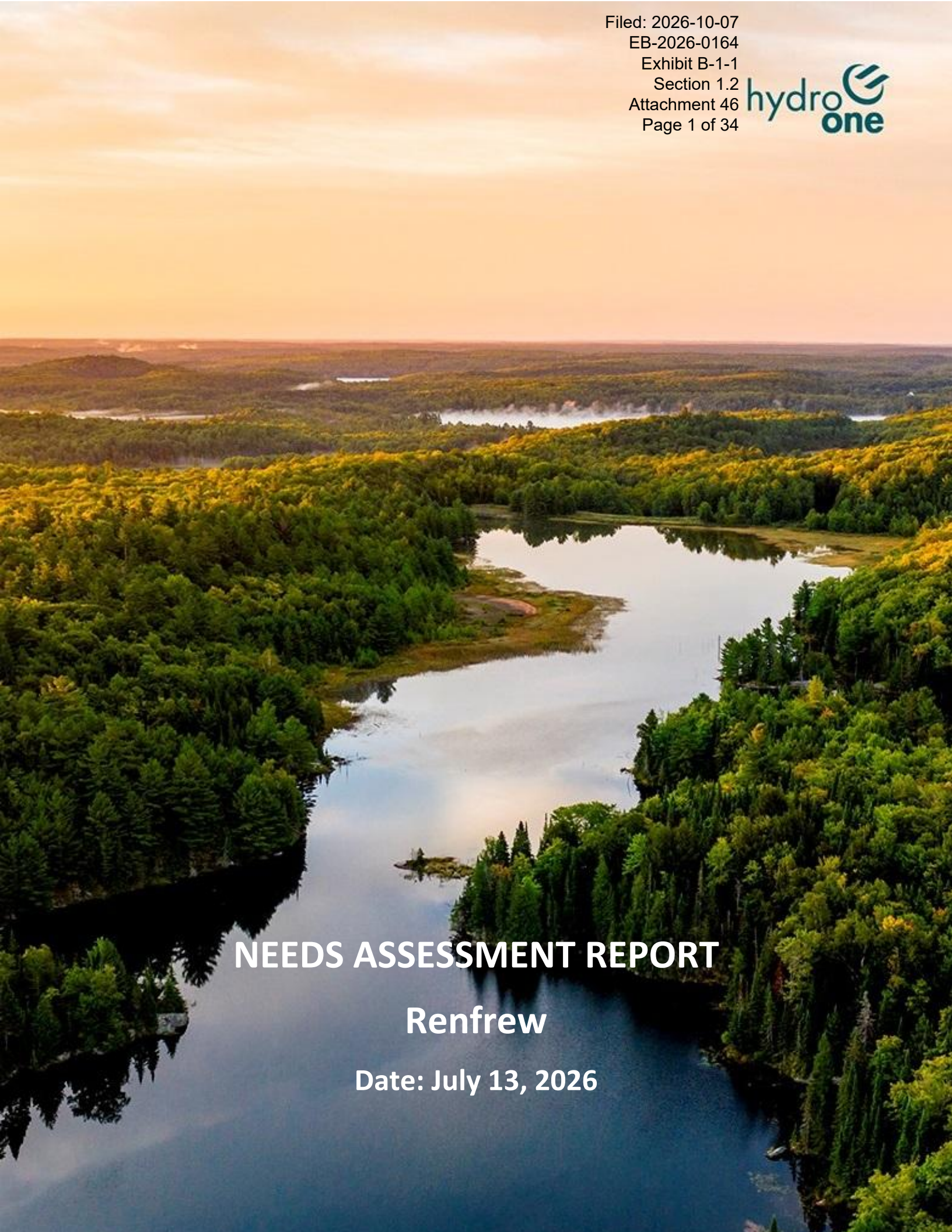
Winter Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	9.0	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.3	10.3	10.2	10.2	10.2	10.2	10.2	10.2
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cobden DS	Tx	T3	N/A	N/A	12	Load	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.5	8.5	8.5	8.5	8.5
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	54.7	Load	25.4	25.6	25.7	25.8	25.9	26.0	26.1	26.3	26.5	26.6	27.8	27.9	28.0	28.1	28.1	28.1	29.1	29.1	29.1	29.1	30.2
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.3	1.4	1.6	1.7	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2
						Net	25	25	25	25	25	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	28
Craig DS	Tx	T1/T2	B1B2	N/A	23.2	Load	12.1	12.2	12.2	12.3	13.3	13.4	13.4	13.5	13.6	13.7	13.7	13.8	13.9	14.9	14.9	14.9	14.9	14.9	14.9	15.9	16.0
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1
						Net	12	12	12	12	13	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
Deep River DS	Tx	T1/T2/T3	N/A	N/A	11.6	Load	10.1	10.2	10.2	10.3	11.3	11.4	12.4	12.5	12.5	12.6	12.6	12.7	12.7	12.7	12.8	12.8	12.8	12.8	12.8	12.8	12.8
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
						Net	10	10	10	10	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Des Joachims DS	Tx	T1	N/A	N/A	12	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.2**	**3.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4	4	4	4
Forest Lea DS	Tx	T1/T2	BY	N/A	11.6	Load	**11.1**	**11.2**	**11.2**	**11.3**	**11.3**	**11.4**	**11.4**	**11.5**	**11.6**	**11.6**	**11.7**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**12.8**	**12.8**	**12.9**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
						Net	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12
Mazinaw DS	Tx	T1	BY	N/A	9.3	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**5.3**	**5.3**	**5.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mountain Chute DS	Tx	T1	BY	N/A	11.6	Load	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	57	Load	**53.1**	**53.2**	**54.5**	**54.8**	**55.0**	**56.2**	**56.3**	**57.6**	**57.9**	**59.1**	**59.3**	**60.5**	**60.6**	**61.6**	**62.5**	**63.6**	**64.6**	**65.6**	**66.5**	**67.5**	**68.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.5	0.8	1	1.2	1.3	1.6	1.9	2.1	2.3	2.5	2.6	2.6	2.5	2.6	2.6	2.6	2.5	2.5	2.5
						Net	53	53	54	54	54	55	55	56	56	57	57	58	58	59	60	61	62	63	64	65	66
Petawawa DS	Tx	T1/T2	BY	N/A	20.2	Load	**10.2**	**10.5**	**10.8**	**11.0**	**11.3**	**11.5**	**11.8**	**12.0**	**12.3**	**12.6**	**12.9**	**13.1**	**13.4**	**13.7**	**13.9**	**14.1**	**14.4**	**14.6**	**14.9**	**15.2**	**15.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1	1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

APPENDIX F. LIST OF ACRONYMS

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



NEEDS ASSESSMENT REPORT

Renfrew

Date: July 13, 2026

Needs Assessment Report

Renfrew

Date: July 13, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: Renfrew Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Renfrew Region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on the best available information throughout the planning process.

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Executive Summary

REGION Renfrew Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: May 15, 2026 **END DATE:** July 13, 2026

The second Regional Planning cycle for the Renfrew Region was completed in July 2023 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report).

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in January 2026 for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

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

The Technical Working Group (TWG) comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and operational concerns.
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Table 1: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.

Table 2: Needs that Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden TS T1/T2	Projected to reach capacity in 2033 under summer High growth scenario.
Transmission Capacity Needs		
2	115 kV D6	Projected to reach capacity in 2031 under summer high growth scenario.
3	115 kV X2Y	Projected to reach capacity limits at the end of study period (2035) during X6 contingency and summer high growth scenario.
System Reliability, Operation and Load restoration Needs		
4	115 kV D6 – Voltage Performance	Voltage issues identified in 2035 for normal summer forecast and in 2031 for High growth summer forecast
5	X2Y Load Restoration	Projected to exceed thermal ratings of X2Y when complete load of Cobden TS needs to be restored under X6 contingency in 2029 under normal growth scenario and 2028 under high growth scenario.

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Ottawa River Power Corporation (ORPC)

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Renfrew Region was completed in July 2023 with the publication of the Regional Infrastructure Plan ("RIP") Report (RIP Report). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the Renfrew Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

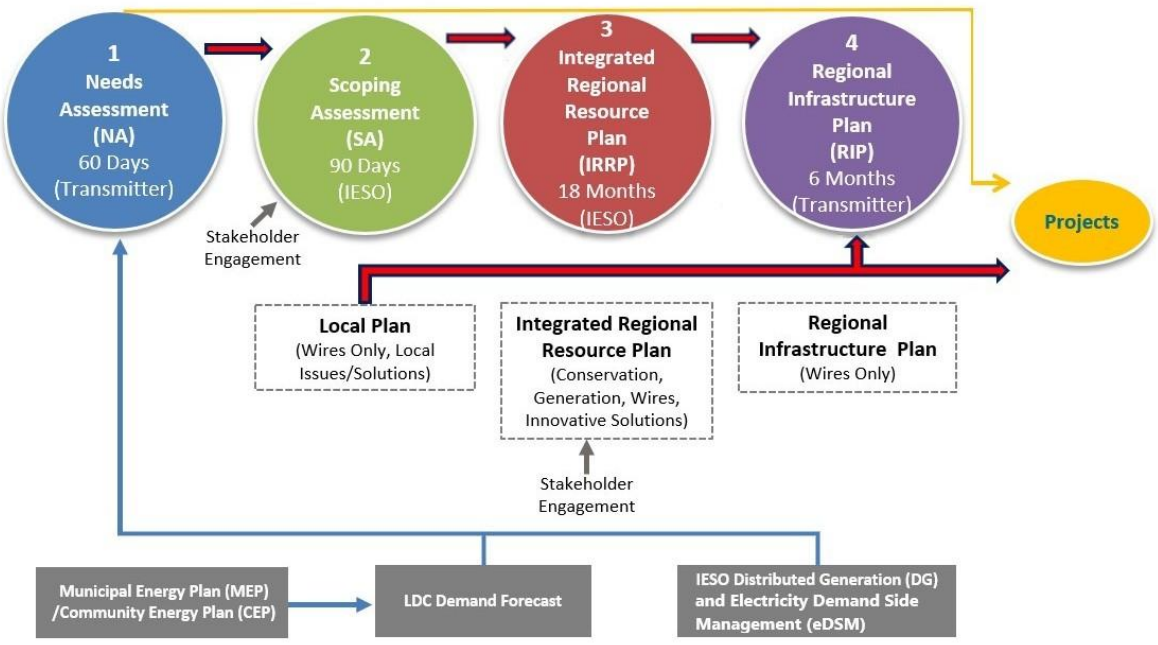


Figure 1: Regional Planning Process

This report was prepared by Renfrew TWG, led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 3.

Table 3: Renfrew Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator (IESO)
3	Hydro One Networks Inc. (Hydro One Dx)
4	Ottawa River Power Corporation (ORPC) (embedded to Hydro One Dx)

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the Renfrew region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Renfrew region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Renfrew region is located in Eastern Ontario with the majority of the load along the Ottawa river. For electrical planning purposes this region includes eighteen municipalities including the towns of Arnprior, Deep River, Laurentian Hills, Petawawa and Renfrew. As well as the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke. The geographical boundaries of the Renfrew region are shown in Figure 2 below.

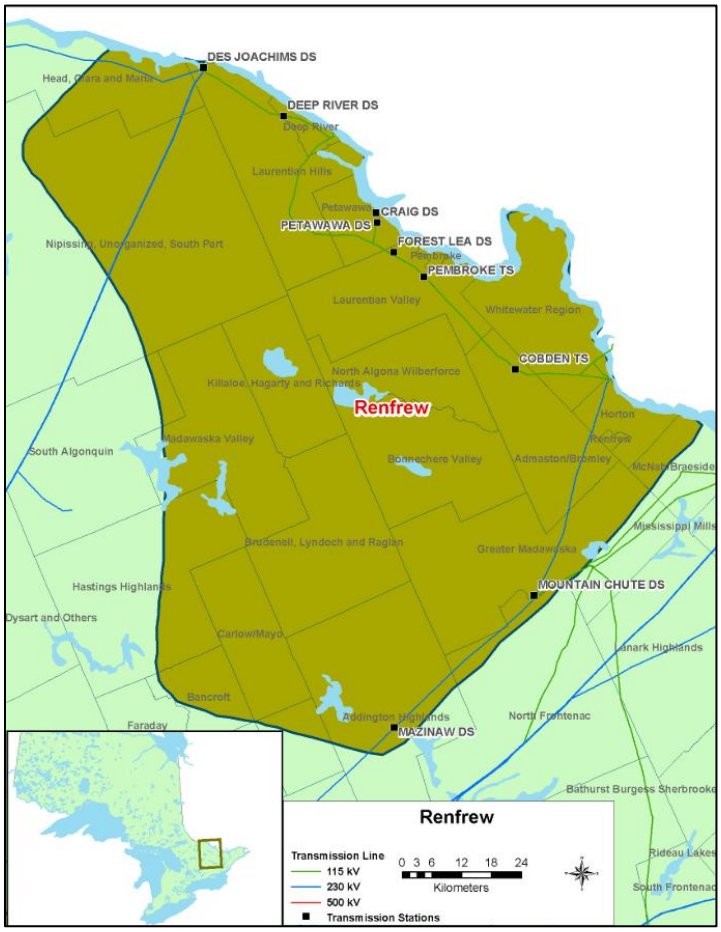


Figure 2: Map of Renfrew Regional Planning Area

The Renfrew region is located in Eastern Ontario, with most of its load concentrated along the Ottawa River. It is bounded by Des Joachims TS to the west, Chenaux TS to the east, and the 230 kV circuit X1P to the south. Electricity supply is provided through one 230 kV circuit (X1P) and three 115 kV radial circuits (D6, X6, and X2Y), with the 115 kV system fed by 230/115 kV autotransformers at Chenaux TS from the east and Des Joachims TS from the west. A normally open 115 kV switch at Pembroke TS separates the eastern and western portions of the region.

The distribution system in the Renfrew region operates at 44 kV and 12.5 kV. The main generation facilities in the area include Chenaux Generation Station (143.7 MW), Mountain Chute Generation Station (170.2 MW), and Des Joachims Generation Station (432.5 MW).

Hydro One Networks Inc. (Distribution) is the main LDC in the area. Other LDCs supplied by electrical facilities in the Renfrew region include Ottawa River Power Corporation and Renfrew Hydro Inc., both are embedded into Hydro One's distribution system. Renfrew Hydro Inc. customers are being fed from Stewartville TS, which is part of the Greater Ottawa Regional Planning. As such, Renfrew Hydro Inc. has not been included as part of this NA.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3.

• Chenaux TS is a major 230 kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230 kV bus. The station connects to the bulk system via a single 230 kV circuit X1P. Two autotransformers step down the voltage to 115 kV to supply two radial circuits X6 and X2Y.

• The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Customer Transformer Station (CTS-2).

• Des Joachims TS is the other major 230 kV transformer station in the Region. There are 432.5 MW of hydraulic generation connecting to the 230 kV bus. The station interconnects to the Bulk Electric System (BES) via five 230 kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115 kV to supply one radial circuit D6.

• The 115 kV circuit D6 from Des Joachims TS 115 kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and CTS-1

• Bryson GS from Hydro Quebec can be radially connected to Renfrew region via X2Y, when required.

• The 230 kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew region: Mountain Chute GS (with hydraulic generation of 170.2 MW) and Mazinaw DS.

• Mountain Chute DS, a 115 kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region.

The circuits and stations of the area are summarized in Table 4 below:

Table 4: Transmission Station and Circuits in the Renfrew Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
D6, X6, and X2Y	X1P	Des Joachims TS*, Des Joachims DS, Deep River DS, Chalk Craig DS, Petawawa DS, Forest Lea DS, Pembroke TS, Cobden TS, Cobden DS, Chenaux TS*, Mountain Chute DS, Mazinaw DS, CTS-1, CTS-2	Mountain Chute GS (170.2MW) Des Joachims GS (432.5MW) Chenaux GS (143.7MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of the Renfrew region is shown in Figure 3 below.

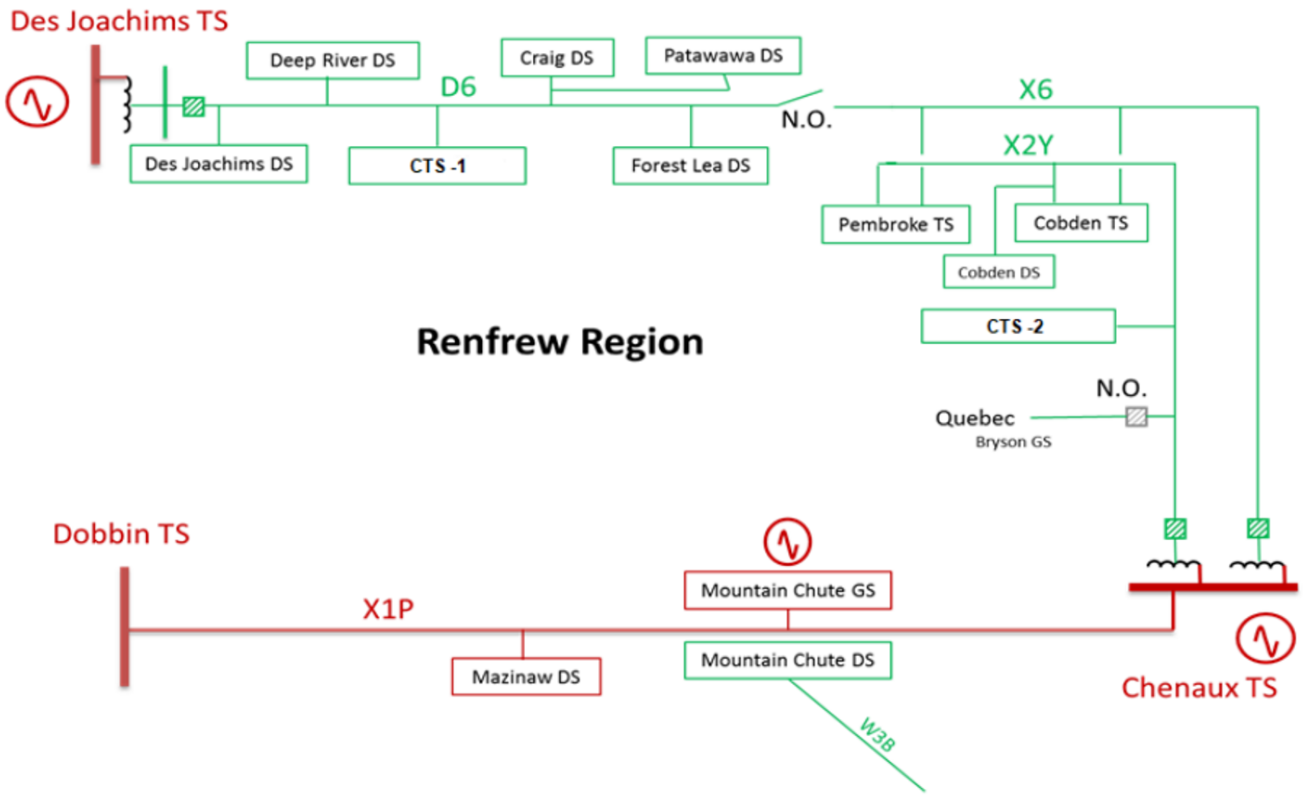


Figure 3: Renfrew Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for Renfrew region NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- Renfrew 10-year summer and winter Load Forecasts for all supply stations inclusive of inputs provided by the municipalities.

  However, sensitivity analysis is undertaken which captures uncertainties via different growth scenarios.

- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and

- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the Renfrew.

- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Load forecast data was requested from industrial customers in the region, and

- This assessment is based on summer and winter peak loads. Three forecasts were developed, i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

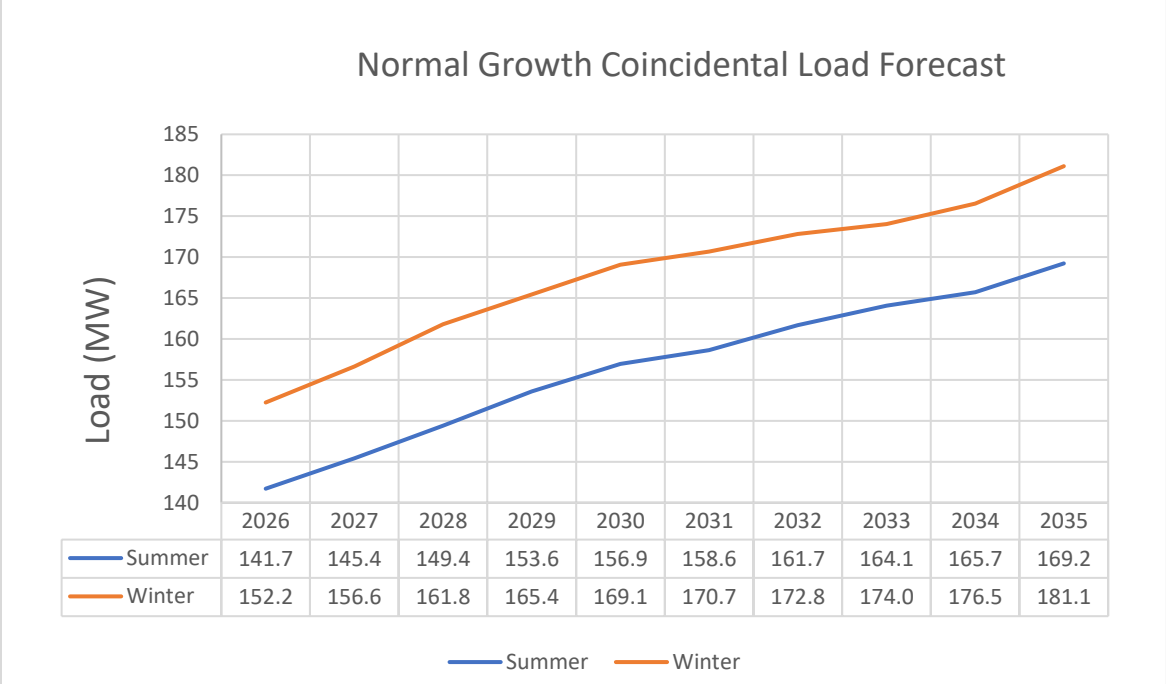
- The study period for this Needs Assessment is 2026-2035.
- The Region is winter peaking; however, system performance was assessed under both summer and winter peak load conditions, including studies for summer peak loads.
- System studies and reported results are based on N-1 (single contingency) conditions, meaning the system is assessed to remain within applicable thermal, voltage, and stability limits following the loss of any one credible transmission element, with the system otherwise in the base configuration.
- No import from Quebec from Bryson CGS.
- Transmission adequacy is assessed based on the system's ability to supply forecast coincident peak demand with all elements in service while maintaining equipment loading within continuous ratings and voltages within normal range, and with one element out of service while maintaining circuit loading within long-term emergency (LTE) ratings and transformer loading within their applicable summer 10-Day Limited Time Rating (LTR).
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day LTR of a single transformer at that station.
- Normal planning supply capacity for distribution stations is determined by the Hydro One summer Peak Loading Limit (PLL) at the station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the Renfrew region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided an Electricity Demand Side Management ("eDSM") , and Distributed Energy Resources ("DER") forecast for the Renfrew region. The region's

extreme summer/winter coincident peak gross load forecasts for each station were prepared in accordance with the Load Forecast Guidelines published by the OEB RPPAG. The LDC load forecast growth rates were calculated (including expected growth, committed customers load etc.) and applied to the actual 2025 summer/winter peak extreme weather corrected loads. The extreme summer/winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage eDSM and then by the amount of effective new DER capacity provided by the IESO for that station. It is to be noted that as contracts for existing DER resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DER resources, and an increase in net demand. This extreme summer/winter weather corrected net load forecast for the individual stations in the Renfrew region is given in Appendix A. The graphical representation of the regional net coincidental load growth for both summer and winter season over the study period is shown in Figure 4 below.



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	141.7	145.4	149.4	153.6	156.9	158.6	161.7	164.1	165.7	169.2
Winter	152.2	156.6	161.8	165.4	169.1	170.7	172.8	174.0	176.5	181.1

Figure 4: Renfrew Region Coincident Load Forecast

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

No new Asset renewal needs were identified during the study period.

6.2.4. System Reliability and Operational Issues:

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

During the studies TWG identified system operational issues on 115 kV D6 line. Under high growth scenarios there are voltage issues observed at end of line stations for Petawawa DS, Forest Lea DS and Craig DS during normal all in-service condition.

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

7. NEEDS

This section describes emerging new needs identified in the Renfrew Region and/or updates on previously identified needs since the completion of previous Regional Planning cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. Pembroke TS T1/T2 – A station capacity need was identified in the previous regional planning cycle. However, based on updated detailed LTR studies with recent loading profile at the station the LTR of the station have been updated and this need no longer exists within the short-term planning cycle due to higher LTR ratings than the value used in the previous regional planning cycle.
2. Forest Lea DS – A load transfer need was identified in the previous regional planning cycle. However, based on the revised PLL, this need no longer exists, as the updated PLL is higher than the value used in the previous regional planning cycle.
3. 115 kV D6 Line Refurbishment - The existing HONI 115 kV circuit D6 will be partially relocated and will reduce the length of the line section between CTS-1 and Petawawa JCT from 38.9 km to 30.7 km and therefore will reduce the overall D6 circuit length from 90.8 km to 82.7 km. The project is expected to be completed in December 2027.
4. Des Joachims T6 Autotransformer- Due to asset condition Replacement of autotransformer T6 with standard 125 MVA 239/121-13.9 kV autotransformer completed in June 2026.

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

All near and mid-term needs that are discussed as a part of this report are summarized in Table 5 below.

Table 5: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update	NA Report Section
Asset Renewal Needs		
115 kV D6 Line	Complete 76.8 km line refurbishment between Des Joachims TS and Petawawa/Craig DS	7.1.1
Station Capacity Needs		
Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.	7.2.1
Cobden TS T1/T2	Projected to reach capacity in 2033 under summer High growth scenario.	7.2.2

Transmission Line Capacity Needs		
115 kV D6	Projected to reach capacity in 2031 under summer high growth scenario.	7.3.1
115 kV X2Y	Projected to reach capacity limits at the end of study period (2035) during X6 contingency and summer high growth scenario.	7.3.2
System Reliability, Operation and Load Restoration Needs		
115 kV D6 – Voltage Performance	Voltage issues identified in 2035 for normal summer forecast and in 2031 for High growth summer forecast	7.4.1
X2Y Load Restoration	Projected to exceed thermal ratings of X2Y when complete load of Cobden TS needs to be restored under X6 contingency in 2029 under normal growth scenario and 2028 under high growth scenario.	7.4.2

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and the TWG identified no new asset renewal needs for major HV transmission equipment over the next 10 years in the Renfrew Region.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The asset renewal assessment considers the following options for "right sizing" the equipment:

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

Table 6: Major HV Transmission Assets Planned for Replacement in Renfrew Region in next 10 years

Station/Circuit	Need Description	Planned ISD
115 kV D6	Complete 76.8 km line refurbishment between Des Joachims TS and Petawawa/Craig DS	2027

7.1.1 115 kV D6 Line Refurbishment

The 115 kV D6 is a single circuit transmission line that connects Des Joachims TS to Pembroke TS along the Ottawa River in the Laurentian Hills area. Based on asset condition assessment, the circuit was identified for refurbishment and expected to be completed by end of 2027. The planned in-service date for the project is in end of 2027.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2026-2035 for the 230kV and 115kV Transforming stations in the Renfrew Region using either the summer or winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Cobden DS – T3

Cobden DS is located in the eastern part of the Renfrew region and is supplied by the 115 kV X2Y circuit, with provision to be supplied by X6 under contingency conditions. The station has one transformer, T3, with a summer PLL of 8.9 MW, and supplies load to Hydro One Distribution.

Based on the load forecast, Cobden DS is expected to exceed its summer PLL in 2029. Winter loading is forecast to remain within limits throughout the study period. Under the high-growth scenario, the projected summer need date advances to 2028.

The TWG recommends that the identified station capacity needs be addressed through coordinated planning between Hydro One Transmission and Hydro One Distribution. In the near term, feasible mitigation measures should be evaluated, including load transfers, transformer upgrades, and the implementation of SCADA-based fan monitoring to maximize the utilization of existing assets. The TWG further recommends continued monitoring of station loading and demand growth trends, with the objective of developing an appropriate longer-term solution through the Local Planning process when capacity reinforcement is required.

7.2.2 Cobden TS – T1/T2

Cobden TS is an important supply point for customers in and around the Cobden area. The station is supplied by X2Y and X6 circuits and is equipped with two 42 MVA transformers, T1 and T2 with a summer and winter LTR of 41.6 MW and 49.3 MW respectively.

Under the normal load forecast, no station capacity need has been identified at Cobden TS over the study period. However, sensitivity analysis indicates that under the summer high-growth forecast, Cobden TS is expected to exceed its summer LTR in 2033. Given that this need only materializes under the high-growth sensitivity scenario, TWG recommends continued monitoring of actual load growth at the station and revisiting the capacity need in the next phase of regional planning.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2026-2035 for the 230kV and 115kV Transmission line circuits in the Renfrew Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified during the study period:

7.3.1 115 kV D6

The 115 kV Des Joachims subsystem is supplied from Des Joachims TS through 115kV circuit D6 and serves load eastward toward Petawawa DS, Craig DS and Forest Lea DS. Circuit D6 forms a critical supply path in the western Renfrew area, and prior regional planning has recognized the importance of this corridor in maintaining reliable supply to communities including Laurentian Hills, Deep River, Petawawa and Laurentian Valley. As outlined in section 7.1.1 Hydro One's D6 refurbishment project, involving

approximately 76.8 km of 115 kV transmission line between Des Joachims TS and Pembroke TS, was initiated to address end-of-life assets and support continued reliability of supply in the area this refurbishment with larger standard conductors have increased the load meeting capability of the circuit from 50.9 MW to 93.9 MW. Adequacy studies were completed for the Des Joachims subsystem under both a normal growth forecast and a high growth sensitivity with the new conductors are shown in Figure 5 below

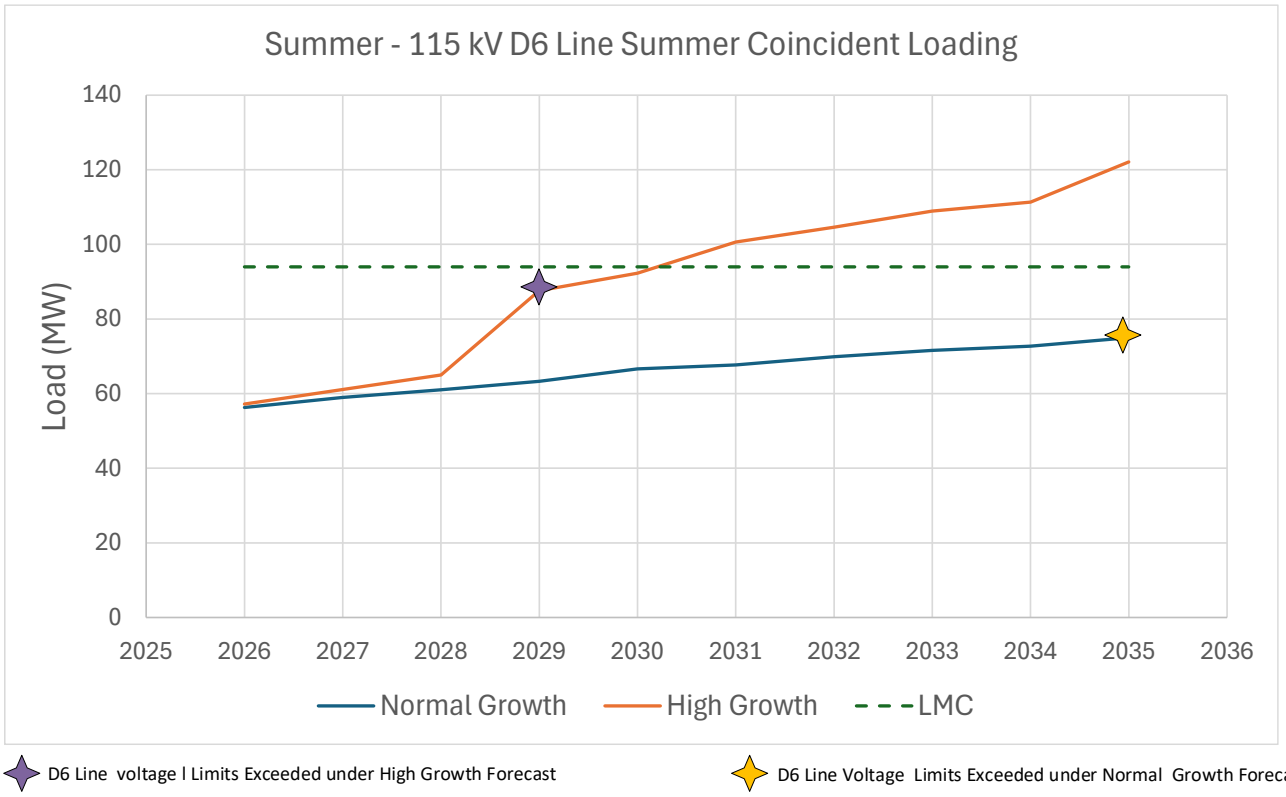


Figure 5: 115 kV D6 Loading

Normal Growth Scenario

Under the normal growth scenario, the 115 kV Des Joachims subsystem is expected to remain thermally adequate over the study period. The D6 line refurbishment project provides sufficient capacity to accommodate the forecast load growth on the subsystem. However, while no thermal capacity concerns were identified, the studies indicate that voltage performance becomes a limiting factor in the later years of the study period. In particular, stations located toward the remote end of Circuit D6, including Petawawa DS, Craig DS and Forest Lea DS, were found to experience voltage levels below the applicable ORTAC minimum voltage criteria. As a result, the subsystem is considered adequate from a line-loading perspective under normal growth, but voltage support or other mitigation measures will be required in the longer term to maintain acceptable voltage performance at the end-of-line stations.

High Growth Scenario

Under the high growth scenario, the adequacy of the 115 kV Des Joachims subsystem becomes more constrained. This sensitivity was developed to reflect increased connection interest along Circuit D6 and assumed 50% higher load growth than the normal forecast, along with potential new transmission-connected load with a high certainty score. Study results indicate that, under this higher load outlook, Circuit D6 exceeds its thermal capability beginning in the 2031 summer forecast year. In addition to the thermal limitation, voltage violations are also observed at the remote stations connected to D6, including Petawawa DS, Craig DS and Forest Lea DS in 2029. These results indicate that the subsystem would not be adequate under the high growth scenario without additional reinforcement or mitigation.

Further studies in next phase should be undertaken to develop solutions (including non-wires alternatives).

7.3.2 115 kV X2Y

X2Y is a 58 km, 115 kV circuit located northwest of the Greater Ottawa area and electrically associated with the Renfrew regional supply area. The circuits provide connection and/or supply to Pembroke TS, Chenaux TS, Cobden TS, Cobden DS, CTS-2, and Bryson CGS in Hydro-Québec. X2Y has an LTE rating of 91.0 MVA and 102.8 MVA in summer and winter respectively.

Under the normal growth forecast the X2Y remains within its thermal limits but under the high growth forecast X2Y approaches its thermal limits under X6 contingency at the end of study period.

TWG recommends studying this need in the next phase of the regional planning for long-term solution for the X2Y limiting section. If the total loading at Pembroke TS, Cobden TS, and Cobden DS exceeds the thermal rating of the limiting X2Y section before solutions are implemented, then operating measures can be deployed in the interim to alleviate the limit.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been carried out, considering the net coincident load forecast and the loss of one element over the study period 2026-2035 to cater for this need**.** Based on the results, the following needs have been identified during the study period:

7.4.1 Voltage Performance of 115 kV D6

A series of system studies were conducted to evaluate the voltage performance of the 115 kV D6 circuit under various operating conditions and long-term load growth assumptions.

Under the 2035 normal growth scenario and 2029 high growth scenario the analysis shows that the pre-contingency voltage on D6 violates ORTAC limits. Specifically, the voltage on the affected sections of

D6 falls below the minimum ORTAC limit of 113 kV, indicating inadequate voltage performance in this scenario.

TWG recommends further review of this need in the next phase of regional planning.

7.4.2 X2Y Load Restoration

Under normal configuration, Cobden TS is supplied from X6 and X2Y, with the low-voltage bus tie normally open. Following an X6 contingency, restoration of the full Cobden TS load requires manual closure of the LV tie switch. This restoration configuration transfers additional load onto X2Y, resulting in the circuit exceeding its LTE rating in the near term.

When restoring the load of Cobden TS from X2Y under X6 contingency the need is expected to emerge in 2029 under the normal summer growth scenario and advance to 2028 under the high-growth scenario whereas for the winter time the need is expected to emerge in 2028 for both normal and high growth scenarios. Accordingly, the restoration need is considered a near- to medium-term transmission loading need, depending on the growth scenario. As load loss is less than 150 MW for the contingency, it will be restored within 8 hours as per load restoration criteria in section 6.2.4

TWG recommends further review of this need in the next phases of regional planning.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Renfrew region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%. The High Growth scenario incorporates EV scenarios, includes consideration of potential additional demand from electrification as well as anticipated large industrial and commercial customers expected to connect in the near to mid-term.

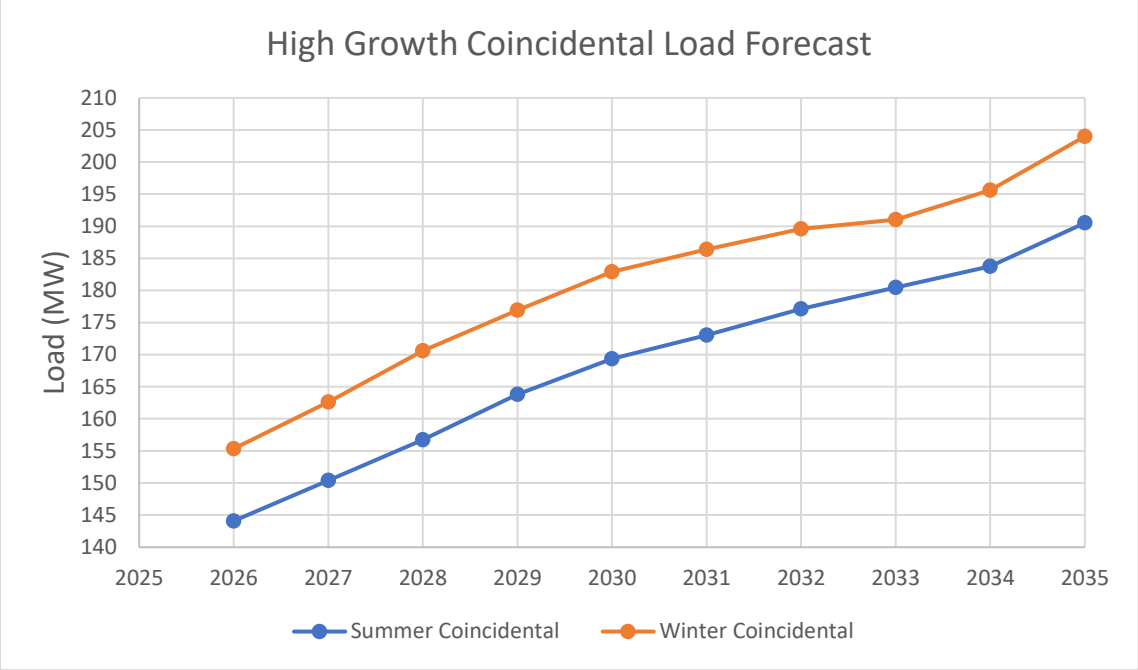


Figure 6: High Growth Forecast for existing station

The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 7: Impact of Sensitivity Analysis on Station/Line capacity Needs in the Region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Cobden DS	2029	2028	-
2	Cobden TS T1/T2	-	2033	-
3	115 kV D6 Line	-	2031	-
4	115 kV X2Y Line	-	~2035	-
5	Voltage Performance of 115 kV D6	2035	2031	-
6	X2Y Load Restoration	2029	2028	-

9. CONCLUSION AND RECOMMENDATION

The Needs Assessment has considered N-1 contingency scenarios to identify needs in the area. The next phases will include a revised forecast and additional outage/contingency analysis beyond what was assessed here. These studies may find further limits on the system's ability to supply additional load. Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs that Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.

Table 9: Needs that Require Further Regional Coordination

#	Need Location	Need Description
Station Capacity Needs		
1	Cobden DS	Projected to reach capacity in 2029 under normal growth summer forecast and in 2028 under summer High growth scenario.
2	Cobden TS T1/T2	Projected to reach capacity in 2033 under summer High growth scenario.
Transmission Line Capacity Needs		
3	115 kV D6	Projected to reach capacity in 2031 under summer high growth scenario.
4	115 kV X2Y	Projected to reach capacity in 2035 under summer high growth scenario.
System Reliability, Operation and Load restoration Needs		
5	115 kV D6 – Voltage Performance	Voltage issues identified in 2035 for normal summer forecast and in 2031 for High growth summer forecast.
6	X2Y Load Restoration	Projected to exceed thermal ratings of X2Y when complete load of Cobden TS needs to be restored under X6 contingency in 2029 under normal growth scenario and 2028 under high growth scenario.

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Ottawa River Power Corporation (ORPC)

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

10. REFERENCES

[1] Hydro One, RIP Report – Renfrew Region (Second cycle) , published in July, 2023

[2] Independent Electricity System Operator, IRRP Report (Second Cycle) , published in December 2022

[3] Hydro One, NA Report – Renfrew Region (Second cycle) , published in May, 2021

[4] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 6.0 September 10, 2025)

[5] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[6] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: Renfrew Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Station Name	Summer LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	8.9	8.4	8.6	8.8	9.0	9.0	9.0	9.1	9.1	9.2	9.3
Cobden TS	41.6	30.8	32.4	34.4	35.2	35.4	35.6	36.6	37.0	37.3	37.8
Craig DS	28.5	16.7	17.4	18.2	18.9	19.7	20.0	20.1	20.2	20.4	20.6
Deep River DS	16.4	9.7	9.9	10.2	10.3	10.3	10.3	10.3	10.3	10.4	10.4
Des Joachims DS	8.9	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Forest Lea DS	16.4	10.2	10.5	10.7	10.8	11.0	11.1	11.3	11.4	11.6	11.7
Mazinaw DS	6.6	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.3	4.3
Mountain Chute DS	8.2	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS	59.9	49.6	49.8	49.2	50.4	50.7	50.9	51.2	51.7	52.1	52.5
Petawawa DS	28.5	11.6	12.7	13.5	14.7	15.9	15.9	15.9	15.9	16.0	16.1
CTS-1		8	8	8.5	9	10	10.75	12.25	13.5	14	16
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		155.7	160.0	164.4	169.2	173.0	174.8	177.8	180.4	182.1	185.7

Table A.2: Renfrew Region – Winter Non-Coincident- Normal Growth Net Load Forecast

Station Name	Winter LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	11.4	7.3	7.6	7.7	7.8	7.9	7.9	8.0	8.0	8.1	8.2
Cobden TS	49.3	29.2	30.7	32.8	33.5	33.6	33.7	33.8	34.0	34.2	34.6
Craig DS	28.5	13.0	13.7	14.6	15.3	16.1	16.4	16.5	16.6	16.7	17.0
Deep River DS	22.1	10.5	10.7	11.1	11.2	11.2	11.2	11.2	11.3	11.3	11.4
Des Joachims DS	11.4	4.0	4.0	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1
Forest Lea DS	22.1	9.0	9.3	9.5	9.6	9.9	10.0	10.1	10.3	10.4	10.6
Mazinaw DS	8.8	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	4.0	4.0
Mountain Chute DS	11.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pembroke TS	67.5	54.3	54.6	54.9	55.0	55.2	55.4	55.7	55.0	56.3	57.7
Petawawa DS	28.5	11.6	12.7	13.5	14.8	16.1	16.1	16.1	16.1	16.1	16.3
CTS-1		8.0	8.0	8.5	9.0	10.0	10.8	12.3	13.5	14.0	16.0
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		154.8	159.3	164.6	168.3	172.1	173.7	175.9	177.1	179.6	184.2

Table A.3: Renfrew Region Summer Non-Coincident – High Growth Net Load Forecast

Station Name	Summer LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	8.9	8.5	8.9	9.3	9.5	9.6	9.7	9.8	9.9	10.0	10.2
Cobden TS	41.6	31.7	34.2	37.3	38.7	39.2	39.7	41.0	41.7	42.4	43.3
Craig DS	28.5	17.2	18.4	19.7	21.0	22.4	23.0	23.3	23.6	24.0	24.4
Deep River DS	16.4	9.8	10.2	10.7	10.9	11.0	11.0	11.1	11.2	11.3	11.4
Des Joachims DS	8.9	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0
Forest Lea DS	16.4	10.5	10.9	11.3	11.5	11.9	12.1	12.4	12.7	13.0	13.3
Mazinaw DS	6.6	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6
Mountain Chute DS	8.2	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Pembroke TS	59.9	52.8	53.3	52.7	54.7	55.3	56.0	56.6	57.4	58.2	59.0
Petawawa DS	28.5	12.1	14.0	15.2	17.5	19.7	19.8	19.8	19.9	20.1	20.3
CTS-1		8.0	8.0	8.5	9.0	10.0	11.5	13.0	14.0	15.0	19.0
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		161.4	168.7	175.7	183.9	190.3	194.2	198.5	202.0	205.5	212.5

Table A.4: Renfrew Region –Winter Non- Coincident – High Growth Net Load Forecast

Station Name	Winter LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Cobden DS	11.4	7.4	7.9	8.2	8.4	8.5	8.6	8.7	8.8	8.9	9.0
Cobden TS	49.3	30.0	32.4	35.4	36.6	37.0	37.3	37.6	38.0	38.4	39.1
Craig DS	28.5	13.5	14.7	16.1	17.3	18.7	19.3	19.5	19.8	20.1	20.5
Deep River DS	22.1	10.7	11.1	11.6	11.8	11.9	12.0	12.1	12.2	12.3	12.4
Des Joachims DS	11.4	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3
Forest Lea DS	22.1	9.3	9.7	10.1	10.3	10.7	11.0	11.2	11.5	11.8	12.1
Mazinaw DS	8.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3
Mountain Chute DS	11.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1
Pembroke TS	67.5	58.1	58.6	59.2	59.7	60.2	60.7	61.2	60.3	62.5	64.8
Petawawa DS	28.5	12.1	14.0	15.3	17.7	19.9	20.0	20.1	20.2	20.4	20.6
CTS-1		8.0	8.0	8.5	9.0	10.0	11.5	13.0	14.0	15.0	19.0
CTS-2		3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Net Demand		160.9	168.4	176.6	183.2	189.4	192.9	196.1	197.6	202.3	210.7

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Cobden DS (T3)	115/12.5	X2Y
2	Cobden TS (T1/T2)	115/44	X2Y/X6
3	Craig DS (T1/T2)	115/12.5	D6
4	Deep River DS (T1/T2/T3)	115/12.5	D6
5	Des Joachims DS (T1)	115/12.5	D6
6	Forest Lea DS (T1/T2)	115/12.5	D6
7	Mazinaw DS (T1/T2)	230/12.5	X1P
8	Pembroke TS (T1/T2)	115/44	X2Y/X6
9	Petawawa DS (T1/T2)	115/12.5	D6

Appendix C: List of Transmission Lines

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Des Joachims DS to Pembroke	D6	115
2	Chenaux TS to Pembroke TS	X6	115
3	Chenaux TS to Pembroke TS	X2Y	115
4	Dobbin TS to Chenaux TS	X1P	230

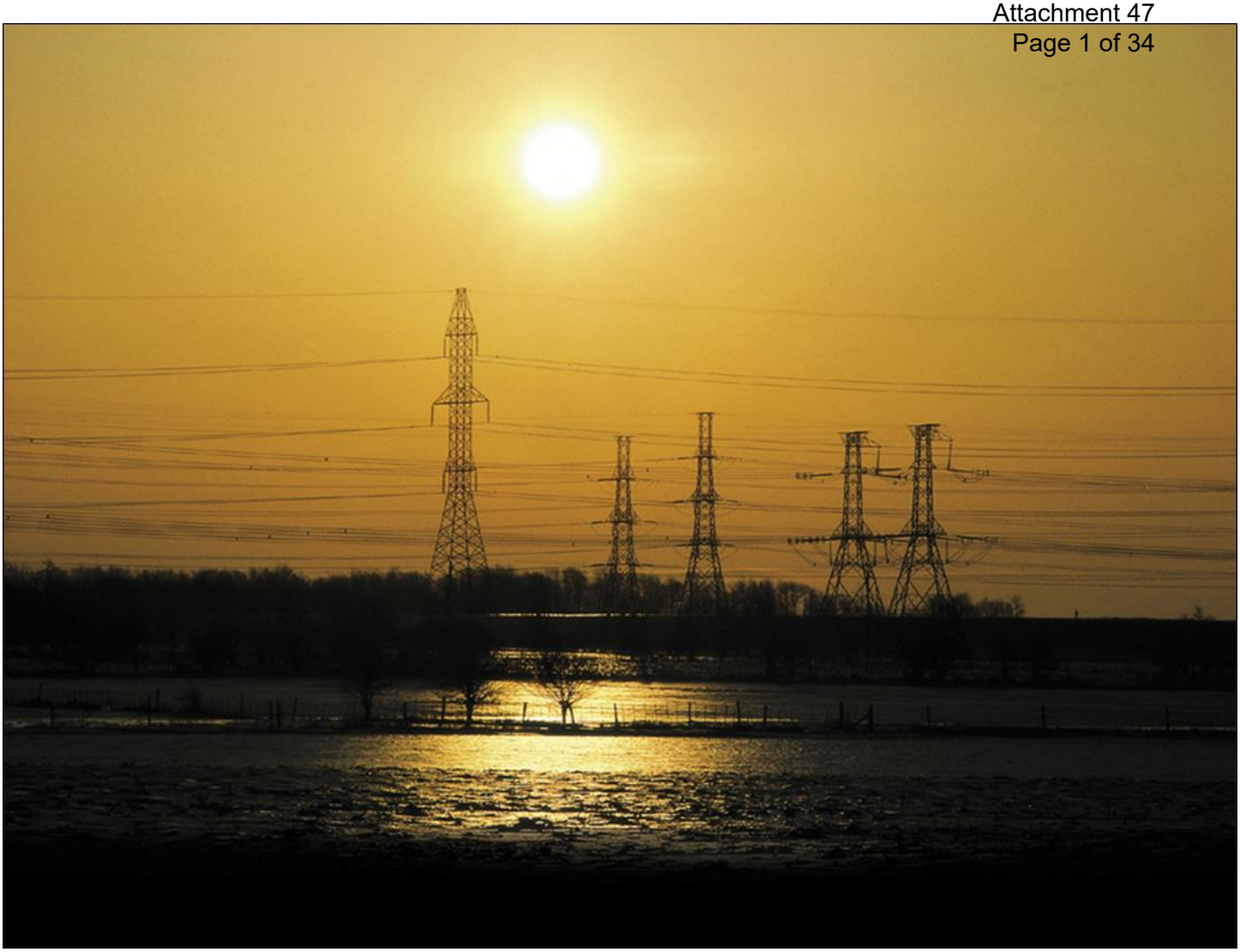
Appendix D: List of Municipalities in the Renfrew Region

No.	Name of Municipality
1	Town of Arnprior
2	Town of Deep River
3	Town of Laurentian Hills
4	Town of Petawawa and Renfrew
5	Township of Admaston/Bromley
6	Township of Bonnechere Valley
7	Township of Brudenell
8	Township of Lyndoch and Raglan
9	Township of Greater Madawaska
10	Township of Head
11	Township of Clara and Maria Horton
12	Township of Killaloe
13	Township of Hagarty and Richards
14	Township of Laurentian Valley
15	Township of Madawaska Valley
16	Township of McNab/Braeside
17	Township of North Algona Wilberforce and Whitewater Region
18	City of Pembroke

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resources
DS	Distribution Station
eDSM	Electricity Demand Side Management
EV	Electric Vehicle
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IPL	International Power Lines
IRRP	Integrated Regional Resource Plan
kV	Kilo Volt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation

Acronym	Description
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PLL	Planned Loading Limit
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RPPAG	Regional Planning Process Advisory Group
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TAO	Transmission Asset Owner
TS	Transformer Station
TWG	Technical Working Group



St Lawrence

Regional Infrastructure Plan

March 7, 2022

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Cooperative Hydro Embrun Inc.
Hydro One Networks Inc. (Distribution)
Rideau St Lawrence Distribution Inc.

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group ("TWG"). The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the Regional Planning Technical Working Group.

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

EXECUTIVE SUMMARY

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

The participants of the Regional Infrastructure Plan ("RIP") Technical Working Group included members from the following organizations:

- Cooperative Hydro Embrun Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Rideau St Lawrence Distribution Inc.

The first cycle of RP process was completed in April 2016 with the publication of the Needs Assessment ("NA") Report. As no further regional coordination or planning was required, the NA recommended that the needs be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous NA report as well as new asset replacement/refurbishment needs identified in the St. Lawrence Region, the 2nd Regional Planning cycle for the St. Lawrence region was triggered in Q3 2021 beginning with the NA phase. This NA report was completed in Sept. 2021 and did not identify any needs requiring further coordinated regional planning.

This RIP is the final phase of the second cycle of the St. Lawrence regional planning process, and is developed based on the information and recommendations in the previous NA report.

The major infrastructure investment recommended for the St. Lawrence Region over the near and mid-term planning horizon is provided in the Table 1 below, along with a description of the investment, its planned in-service date, and budgetary estimate for planning purposes.

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

Stations / Lines Project	Investment	Planned I/S Date	Cost[1] ($M)
L22H	Replacement of conductor, shieldwire, insulator and tower work	2026	64

[1] These costs are budgetary estimates for planning purposes unless otherwise specified.

The St. Lawrence TWG recommends that:

- Hydro One and relevant LDC(s) continue with the implementation of infrastructure investments listed in Table 1 above;
- As no other needs have been identified in the region, the TWG will assess the St. Lawrence region during the next regional planning cycle.

The next regional planning cycle for the St. Lawrence Region must be triggered within five years, beginning with the NA phase. It is expected that the next NA will start in Q3 2026. However, the next regional planning cycle can be started earlier if required to address any new emerging needs.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE ST LAWRENCE REGION BETWEEN 2021 AND 2032.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") that consists of Hydro One, Cooperative Hydro Embrun Inc., Hydro One Networks Inc. (Distribution), Rideau St Lawrence Distribution Inc., the Independent Electricity System Operator ("IESO"), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The St Lawrence region is located in southeastern Ontario bordering the St Lawrence River. The region starts at the Gananoque in the West and extends to the inter-provincial boundary with Quebec in the East. Electrical supply to the Region is provided from four 230 kV and three 115 kV step-down transformer stations. The approximate boundaries of the St Lawrence Region are shown below in Figure 1-1.

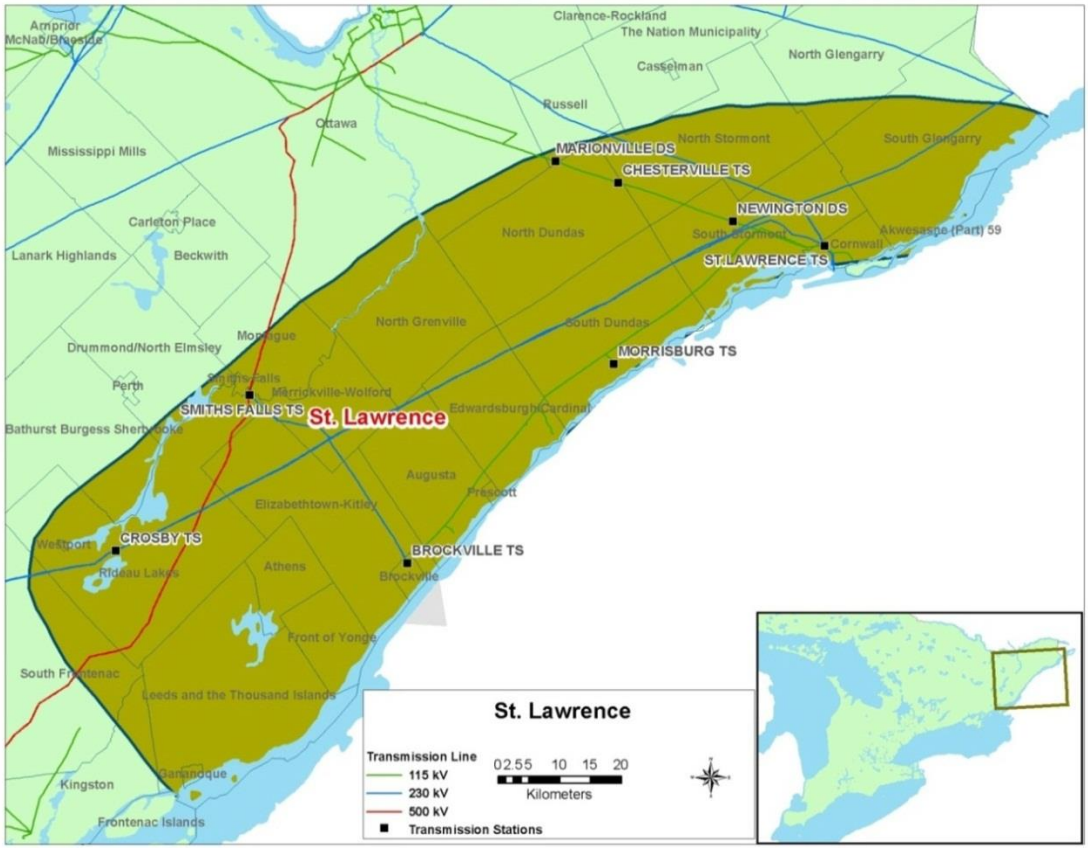


FIGURE 1-1: ST LAWRENCE REGION MAP

1.1. Objectives and Scope

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

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage transmission equipment requiring replacement over the near and mid-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases; and,
- Discussion of any other major transmission infrastructure investment plans over the planning horizon.

1.2. Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1. Overview

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

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

2.2. Regional Planning Process

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

The following describes the process in general, considering all four phases of the study.

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the TWG determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

The RIP phase is the fourth and final phase of the regional planning process and involves discussion of previously identified needs and plans, identification of any new needs that may have emerged since the start of the planning cycle, and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

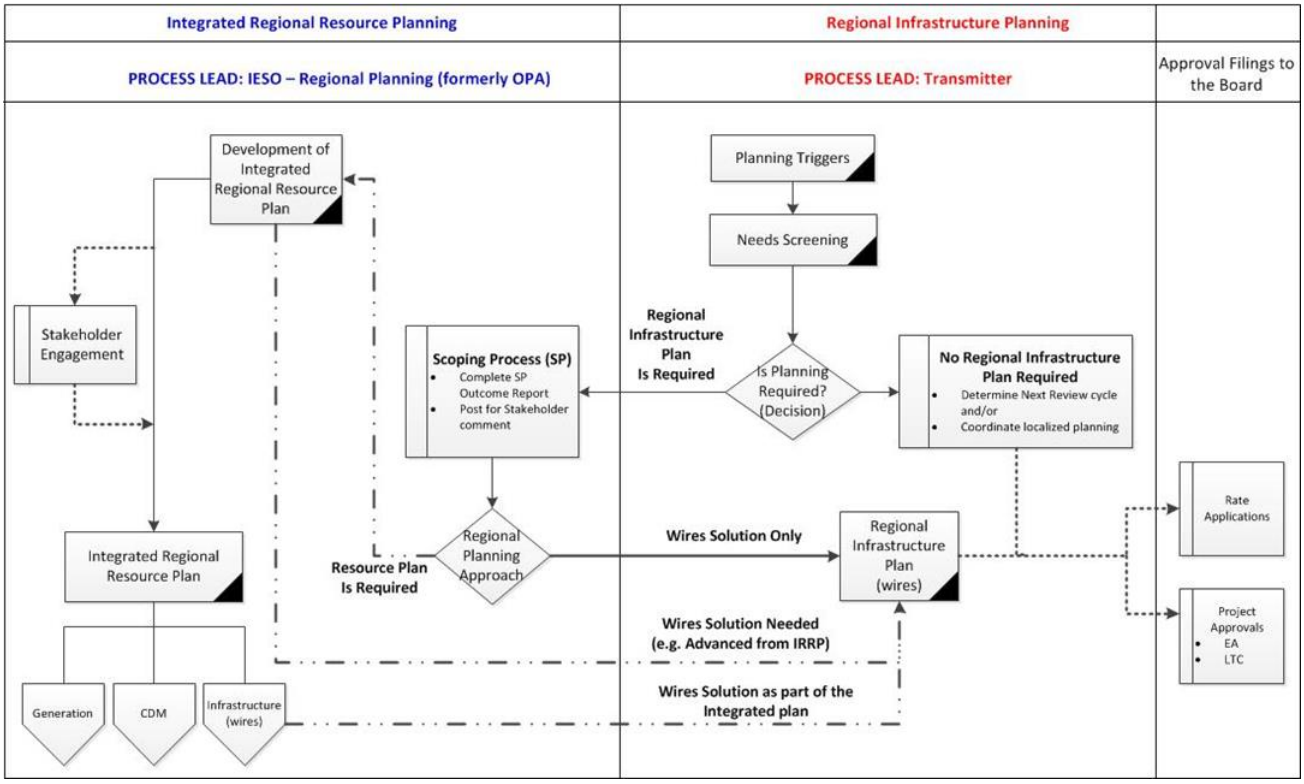


FIGURE 2-1: REGIONAL PLANNING PROCESS FLOWCHART

2.3. RIP Methodology

The Needs Assessment did not identify any needs requiring further coordinated regional planning. As such this RIP report summarizes the information and recommendations in the previous NA report.. The following discusses the RIP process in general.

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

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Technical Working Group to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending

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

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

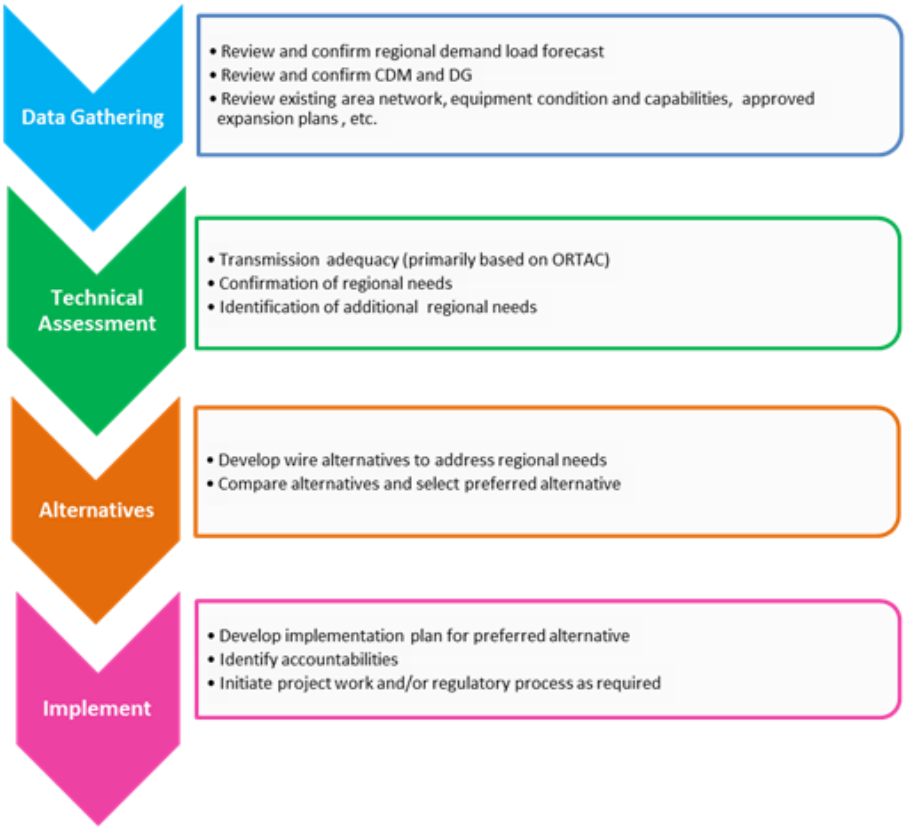


FIGURE 2-2: RIP METHODOLOGY

3. REGIONAL CHARACTERISTICS

THE ST LAWRENCE REGION IS LOCATED IN SOUTHEASTERN ONTARIO BORDERING THE ST LAWRENCE RIVER. THE REGION STARTS AT THE GANANOQUE IN THE WEST AND EXTENDS TO THE INTER-PROVINCIAL BOUNDARY WITH QUEBEC IN THE EAST.

The St Lawrence Region is connected to the Greater Ottawa Region through 230kV circuits L24A and B31L. Circuit B31L also provides an interconnection between the Provinces of Ontario and Quebec. In addition, 115kV circuit L2M also connects St Lawrence to the Greater Ottawa Region, however this connection is normally open and is only used for load transfers between the two areas in case of system need. The Region is also connected to the Peterborough to Kingston Region through 230kV circuits L20H, L21H, and L22H. The existing facilities and interconnection of the Region are summarized below and depicted in the single line diagram shown in Figure 3-1 and 3-2.

St Lawrence TS is the major transmission station for the region and connects to the main source of supply for the area, Saunders GS via four 230kV circuits. All the 230kV and 115kV circuits listed above connect at St Lawrence TS. Also connecting to the 230kV yard of the station are two International Power Lines (IPL). These IPLs connect Ontario to the State of New York and power exchange across the IPLs are regulated using two phase shifting transformers. The station also has two 230kV/115kV 250MVA autotransformers to connect the 230kV and 115kV networks.

There is a total of seven transformer stations in the area to supply load customers. There are also two industrial customer stations and a customer owned generating station. The stations are broken down into the following categories:

1. **St Lawrence 230 kV Area:** The transformer stations in this area are supplied by the St Lawrence TS to Hinchinbrook TS 230kV transmission lines. In addition, St Lawrence TS DESN is also supplied from the 230kV. The following stations are included:
    - Brockville TS
    - Crosby TS
    - Smith Falls TS
    - St Lawrence TS

    Figure 3-1 shows additional 230kV circuits connected to St Lawrence TS. These circuits were not part of the St Lawrence regional planning scope of work for the following reasons:

    - L24A, B31L: These circuits do not supply stations included in the St Lawrence area.
    - S25L, S26L, S30L, S32L: These circuits connect to OPG Saunders generating station.
    - L33P, L34P. These circuits are International Power Lines that connect Ontario to the State of New York.

2. **St Lawrence 115 kV Area:** The transformer stations in this area are supplied 115kV circuits. The circuits are radial from St Lawrence TS. The 115kV area also includes two industrial customer stations and a customer owned generating station. The following load customer stations are included:
    - Chesterville TS
    - Morrisburg TS
    - Newington DS

    The industrial station and generating stations are also included in the study area, however the study focuses on the regional needs and load customer station.

    Figure 3-2 shows an additional 115kV circuit, L5C. This circuit is normally not supplying load station included in this region. It is a backup supply for the City of Cornwall. This circuit is not included in the scope of the St Lawrence regional planning.

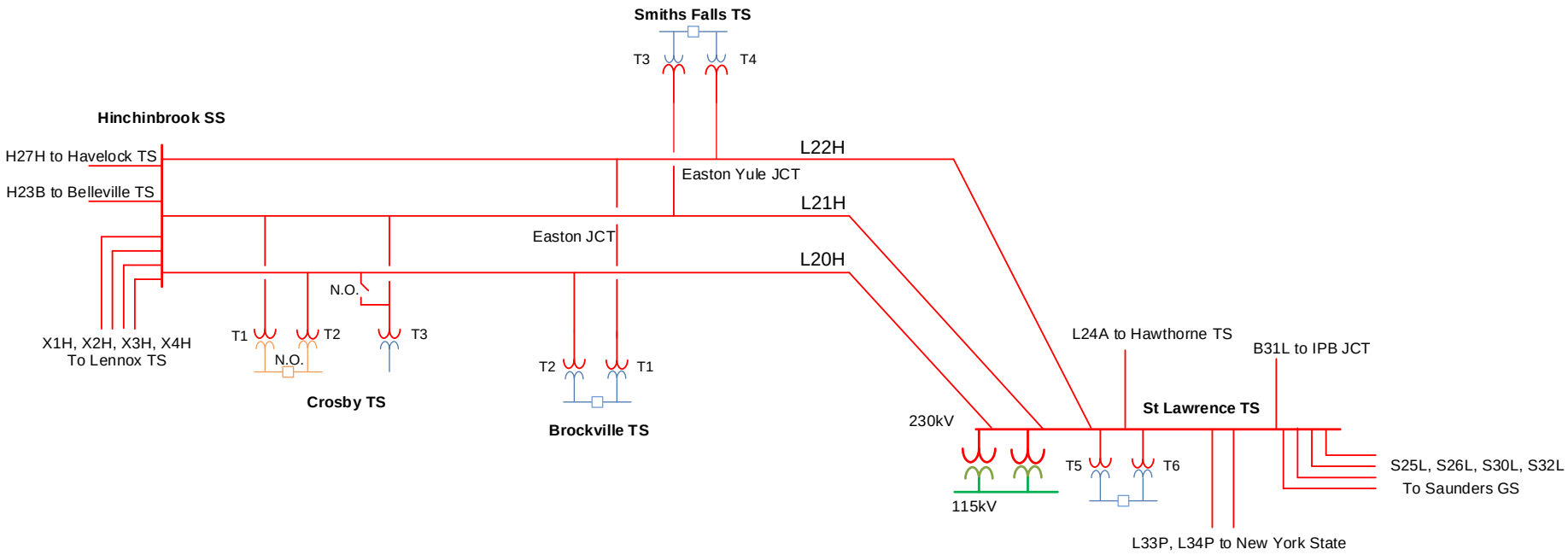


FIGURE 3-1: SINGLE LINE DIAGRAM OF THE ST LAWRENCE REGION 230KV TRANSMISSION NETWORK

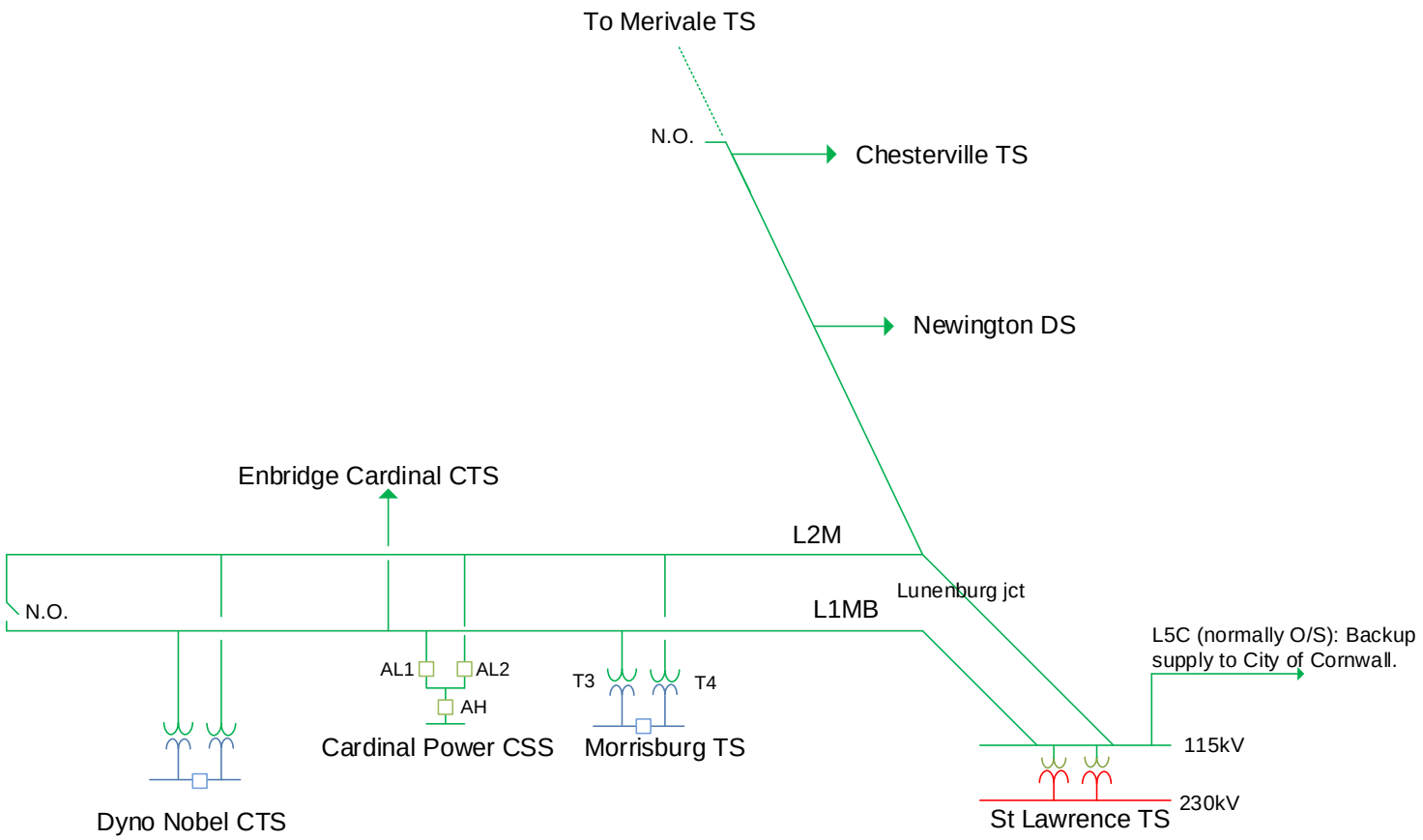


FIGURE 3-2: SINGLE LINE DIAGRAM OF THE ST LAWRENCE REGION 230KV TRANSMISSION NETWORK

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

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

A summary and description of the major projects completed over the last 10 years is provided below:

- Chesterville TS (2014): Replaced 25/33/42 MVA, 115/44 kV step down transformers with new 25/33/42 MVA, 115/44 kV – replaced existing transformers with similar units to address asset condition.

A summary and description of the major transmission project currently underway is provided below. This project was initiated as a result of transformer failure and was agreed to by Hydro One, IESO, the New York Power Authority and New York Independent System Operator.

- St Lawrence Phase Shifting Transformers (2023) – replace failed phase shifting transformer PS33 and its companion PSR34. These transformers are used to regulate the power exchanged over the Ontario-New York interconnection at St Lawrence TS.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1. Load Forecast

The electricity demand in the St Lawrence Region is anticipated to grow by about 7.5% over the next ten years (2022-2032). Figure 5-1 shows the St Lawrence Region's planning load forecast (winter net, non-coincident extreme weather corrected peak) developed during this NA phase.

This load forecast, along with the summer forecast, was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity.

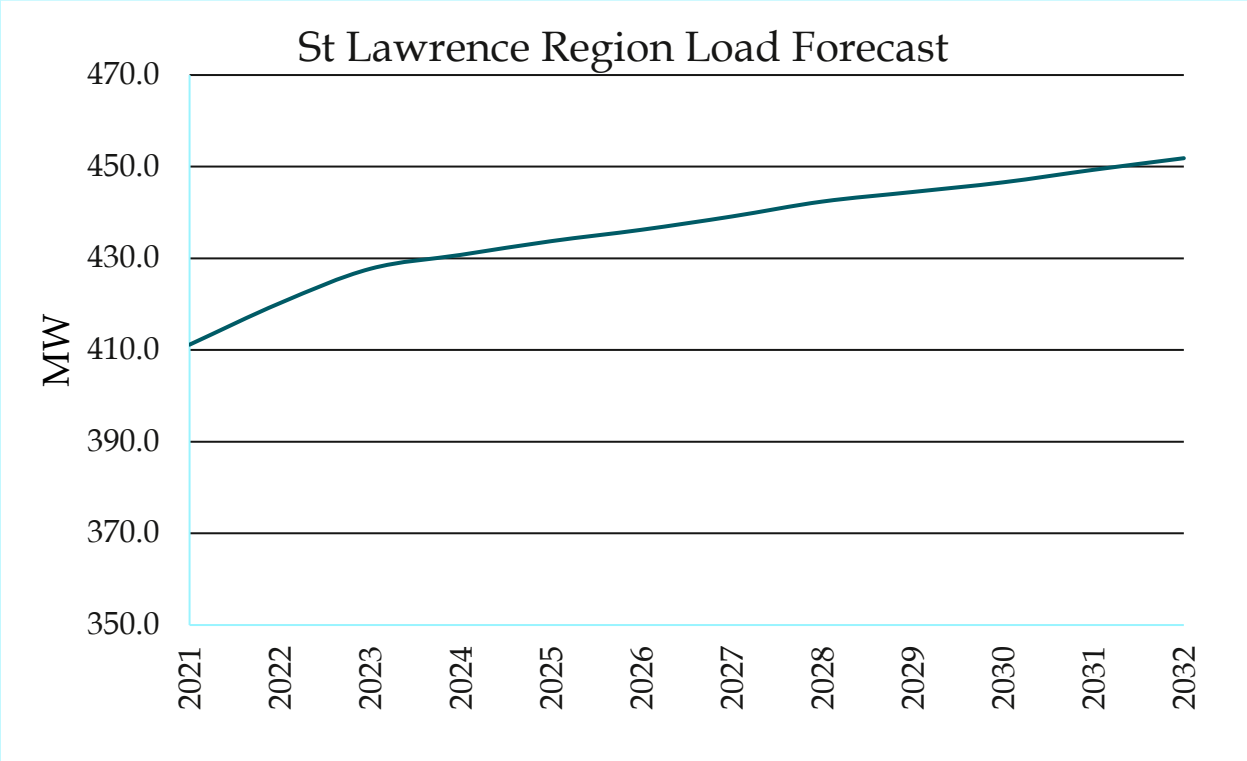


FIGURE 5-1: ST LAWRENCE REGION LOAD FORECAST

The regional-coincident load forecast represents the total peak load of the 7 step-down transformer stations in the St Lawrence Region. The Region's peak winter load is forecasted to increase from 420 MW in 2022 to 452 MW by 2032.

The load forecast for St Lawrence RIP is provided in Appendix D. The load forecast for this RIP was prepared by adjusting the actual 2019/2020 summer and winter peak loads applying an extreme weather correction factor and then applying growth rates derived from the LDCs' forecast. This forecast was further adjusted taking into account the impact of CDM and DGs

provided by the IESO. The forecasts shown in Appendix D show a reduction in DG output in the long term of the forecast. This is due to the uncertainty of DG contribution as contracts begin to expire. The forecast is showing the impact assuming the DG remains in operation or stop operation.

The Needs Assessment focuses on a 10 year period. However, a 20 year forecast was completed to review trends of the load over the long term.

Hydro One has also researched to find community energy plans in the region. No energy plans have been identified that would impact the assessment undertaken as part of this report. The TWG will monitor and take them into consideration as they are developed.

5.2. Study Assumptions

The following assumptions are made in the NA report.

- The study period is based assessments is 2021-2032.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Generating station Saunders GS was assumed to generate at its average 98% of time dependable hydro generation level which is 467MW for winter and 511MW for summer.
- No power exchanges on the Ontario Eastern interconnections.
- Load forecast data was requested from industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
- The Region is winter peaking so this assessment is based on winter peak loads. However sensitivity analysis was also done using summer peak loads
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE ST LAWRENCE REGION OVER THE PLANNING PERIOD (2021-2032).

During this regional planning cycle, the Needs Assessments was completed for the St Lawrence Region. No needs requiring further coordinated regional planning were identified, therefore those findings are presented here.

6.1. 230 kV Transmission Facilities

The three 230 kV transmission circuits considered in the St Lawrence Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system through the Peterborough to Kingston Region. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (please refer to Figure 3-1):

a) St Lawrence TS to Hinchinbrook TS 230 kV circuits L20H, L21H, and L22H supplies Brockville TS, Crosby TS, and Smith Falls TS

The RIP review of the current load forecast shows that based on the forecasted station loadings, all the above three (3) 230 kV transmission lines are expected to be adequate over the study period under normal and N-1 supply condition.

As discussed in previously Section 3, St Lawrence TS is connected to Saunders generating station, to the State of New York through two IPLs, and to the Province of Quebec through circuit B31L (Beauharnois generating station). As a result of these connections, many operating scenarios and system conditions can influence the flows on circuits L20H, L21H, and L22H. These scenarios are evaluated under Bulk planning and are not part of the scope of the Needs Assessment. However, it should be noted that there is a generation rejection scheme in place that can runback Saunders GS and/or Beauharnois GS under post-contingency conditions. This scheme ensures that the St Lawrence to Hinchinbrook TS lines are not overloaded under peak summer conditions.

6.2. 230/115 kV Autotransformer Facilities

The 230/115 kV autotransformers at St Lawrence TS supplying the Region are within their ratings and are adequate to supply the forecasted load over the study period.

6.3. 115 kV Transmission Facilities

The St Lawrence Region contains two 115 kV circuits. These 115 kV circuits serve three transformer stations, two industrial customers, and connect a customer owned generating station. The 115kV circuits supplying the Region are adequate over the study period for the loss of a single 115kV circuit in the Region under the study assumptions of the Needs Assessment.

6.4. Step-Down Transformer Station Facilities

There are 7 step-down transformer stations within the St Lawrence Region. These stations are listed with the load forecast in Appendix D. There are also two transmission-connected industrial customer transformer stations.

The region is winter peaking. The stations winter and summer peak non-coincident load forecasts are given in Table D-1 and D-2 in Appendix D.

All the transformer stations in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next regional planning cycle.

Depending on the load growth and the future decisions on contracts for distributed energy resources connected to the station, the capacity of some stations could reach their limit in the long term (10+ years). The TWG will continue to monitor the load growth at the stations and will re-evaluate the capacity during the next planning cycle.

6.5. System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

6.6. 115kV System

The distributed energy resources (DER) connected to the 115kV stations of the area and the 115kV generating station have resulted in the following, identified in the Cardinal Power G3 Expansion SIA/CIA [3, 4]:

a) Reverse Power Flow at Morrisburg TS and Dyno Nobel CTS

At Morrisburg TS, under light load condition with high output for DER and 115kV connected generation, a reverse power flow issue was identified. This situation occurs if one of the line breakers at Cardinal Power has an inadvertent opening (IBO). This IBO results in all of Cardinal Power's generation being sent to one line, which causes reverse power at Morrisburg TS beyond its maximum limit. Additional generation connection has been restricted at Morrisburg TS to manage the reverse power flow at the station.

Under the same conditions mentioned above, an IBO at Cardinal Power can also result in power flow through the Dyno Nobel CTS transformers to exceed their rating.

For Morrisburg TS and Dyno Nobel CTS transformer loading issues, Cardinal Power run back scheme is triggered to reduce the flows to within equipment ratings as it was outlined in the SIA and CIA [3, 4]. No further action is recommended within the scope of this regional planning.

b) L2M/L1MB

Under light load condition and with all distributed generation in the area and the Cardinal Power generation at maximum output the section of the L1MB/L2M line between St Lawrence to Lunenburg JCT can be loaded beyond its short time emergency (STE) rating for loss of either circuit [3,4].

To manage the situation, Morrisburg TS has been restricted to accept new generation connection. In addition, there is Cardinal Power's runback scheme which will reduce the plant output following the loss of either circuit and hence reduce the post-contingency loading on either of the L1MB/L2M lines. However, since the lines could be loaded beyond their STE, measures such generation re-dispatch is implemented by the IESO as per the Cardinal Power G3 Expansion studies [3, 4].

6.7. Other Needs Identified during Regional Planning

6.7.1. Asset Renewal for 230 kV circuit L22H

Hydro One identified the need for refurbishment of 230kV circuit L22H between Easton JCT and Hinchinbrooke North JCT within the 10-year planning horizon. The need is based on asset condition assessment. In general, asset condition assessment is based on a range of considerations such as equipment deterioration due to aging infrastructure and other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards.

Asset renewal work for L22H is summarized in Table 6-1 below.

TABLE 6-1: ST LAWRENCE REGION – PLANNED ASSET REPLACEMENT WORK

Stations / Lines Project	Details	Timeframe
Circuit L22H	A total of 65 km of 230 kV circuit L22H between Easton JCT X Hinchinbrook North JCT has been identified for refurbishment. The work includes the replacement of conductors, shieldwire, insulators and refurbishment of lattice steel structures.	2026

No other major high-voltage transmission equipment in the St Lawrence region has been identified for replacement at this time.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE ST LAWRENCE REGION IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

7.1. Asset Renewal for 230 kV circuit

7.1.1. Description

As indicated in Section 6.1, L22H is expected to be adequate over the study period under normal and N-1 contingency conditions, including the section planned for refurbishment.

A total of 65 km of 230 kV circuit L22H between Easton JCT X Hinchinbrook North JCT requires refurbishment. The work includes the replacement of conductors, shieldwire, insulators and refurbishment of lattice steel structures.

The TWG recommends that refurbishment of L22H between Easton JCT X Hinchinbrook North JCT does not require further regional coordination. The implementation and execution plan for this need will be coordinated by Hydro One and affected LDCs. However, as part of IESO-led Bulk Planning Studies, IESO and Hydro One will work together to determine if conductor upgrade is required for the line section in the L22H refurbishment plan.

7.2. Needs Identified in Previous Cycle

7.2.1. Delivery Point Performance at Chesterville TS

The past Needs Assessment had identified that the target delivery point performance had been missed due to momentary outages (due to severe weather patterns). Hydro One was to review the delivery point performance of the station to determine if corrective actions were required. From the review of performance of the delivery point, no corrective actions were identified. Hydro One will continue to monitor the delivery point.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE ST. LAWRENCE REGION.

The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon are provided in Table 8-1 below.

TABLE 8-1: RECOMMENDED PLANS IN ST. LAWRENCE REGION OVER THE NEXT 10 YEARS

Stations / Lines Project	Details	Timeframe
L22H	Refurbishment of 65 km of the circuit between Easton JCT X Hinchinbrook North JCT	2026

The TWG recommends that:

- Hydro One and LDCs to continue with the implementation of infrastructure investments listed in Table 8-1 above while keeping the TWG apprised of project status;
- No other needs have been identified and further assessment of the St. Lawrence region will be undertaken by the TWG in the next regional planning cycle.

9. REFERENCES

[1] Needs Assessment Report – St Lawrence – April 2016
[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
[3] Cardinal Power 15MW Plant Expansion SIA (2011-432)
[4] Cardinal Power 15MW Plant Expansion CIA

10. APPENDIX A. STATIONS IN THE ST LAWRENCE REGION

Station*	Voltage (kV)	Supply Circuits
Brockville TS	230 kV	L20H/L22H
Chesterville TS	230 kV	L2M
Crosby TS (T1/T2)	230 kV	L20H/L21H
Crosby T3	230 kV	L21H
Morrisburg TS	230 kV	L1MB/L2M
Newington DS	230 kV	L2M
Smith Falls TS	230 kV	L21H/L22H
St Lawrence TS	230 kV	Transformers connected at 230kV switchyard

11. APPENDIX B. TRANSMISSION LINES IN THE ST LAWRENCE REGION

Location	Circuit Designations	Voltage (kV)
St Lawrence TS – Hinchinbrook TS	L20H, L21H, L22H	230 kV
St Lawrence TS – Brockville TS	L1MB	115 kV
St Lawrence TS – Brockville TS – Merivale TS	L2M	115 kV

12. APPENDIX C. DISTRIBUTORS IN THE ST LAWRENCE REGION

Distributor Name	Station Name	Connection Type
Cooperative Hydro Embrun Inc	Chesterville TS	Dx
Hydro One Distribution	Brockville TS	Tx
	Chesterville TS	Tx
	Crosby TS	Tx
	Morrisburg TS	Tx
	Smith Falls TS	Tx
Rideau St Lawrence.	Brockville TS	Dx
	Morrisburg TS	Dx

13. APPENDIX D. ST LAWRENCE REGION LOAD FORECAST

TABLE D1: ST LAWRENCE NON-COINCIDENT WINTER LOAD FORECAST

Station		LTR (MW)	Type	Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)				
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2033	2035	2037	2039
Brockville TS	T1/T2	166.2	Load	125.3	130.2	134.6	138.1	140.8	141.9	143.2	144.5	145.7	146.9	148.0	150.2	152.6	154.9	157.2
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.5	-45.3	-45.3	-45.3
			CDM	0.8	1.8	2.8	3.6	4.2	4.4	4.6	4.7	5.2	5.5	5.6	5.8	7.1	6.8	6.4
			NET	124.5	128.4	131.8	134.5	136.7	137.5	138.6	139.8	140.5	141.4	142.4	144.9	190.8	193.4	196.0
			NET_DG	124.5	128.4	131.8	134.5	136.7	137.5	138.6	139.8	140.5	141.4	142.4	144.4	147.1	149.6	152.2
Chesterville TS	T1/T2	61.5	Load	39.5	39.8	40.1	40.4	40.6	40.9	41.2	41.4	41.7	41.9	42.1	42.6	43.0	43.4	43.8
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.4
			CDM	0.3	0.5	0.8	1.0	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.6	1.6	1.5	1.4
			NET	39.2	39.2	39.3	39.3	39.4	39.6	39.9	40.1	40.2	40.3	40.5	40.9	41.6	42.1	42.8
			NET_DG	39.2	39.2	39.3	39.3	39.4	39.6	39.9	40.1	40.2	40.3	40.5	40.9	41.5	42.0	42.4
Crosby TS	T1/T2	65.6	Load	13.8	13.9	14.0	14.1	14.2	14.3	14.4	14.5	14.6	14.7	14.8	15.0	15.2	15.4	15.6
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.1	0.2	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5
			NET	13.7	13.7	13.7	13.8	13.8	13.9	14.0	14.1	14.1	14.2	14.3	14.4	14.7	14.9	15.1
			NET_DG	13.7	13.7	13.7	13.8	13.8	13.9	14.0	14.1	14.1	14.2	14.3	14.4	14.7	14.9	15.1
Crosby TS	T3	75.0	Load	22.7	23.0	23.2	23.4	23.6	23.7	24.0	24.2	24.3	24.5	24.7	25.1	25.4	25.8	26.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.2	0.3	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	1.0	0.9	0.9	0.8
			NET	22.6	22.6	22.7	22.8	22.9	23.0	23.2	23.4	23.5	23.6	23.8	24.1	24.5	24.9	25.3
			NET_DG	22.6	22.6	22.7	22.8	22.9	23.0	23.2	23.4	23.5	23.6	23.8	24.1	24.5	24.9	25.3
Morrisburg TS	T3/T4	127.2	Load	56.3	59.1	62.0	62.6	63.2	63.7	64.4	65.0	65.7	66.3	66.8	68.1	69.3	70.6	71.9
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.3	-11.3	-11.3	-11.3
			CDM	0.4	0.8	1.3	1.6	1.9	2.0	2.1	2.1	2.3	2.5	2.5	3.1	2.9	2.8	2.6
			NET	55.9	58.3	60.8	61.0	61.3	61.8	62.3	62.9	63.4	63.8	64.3	76.4	77.8	79.1	80.6
			NET_DG	55.9	58.3	60.8	61.0	61.3	61.8	62.3	62.9	63.4	63.8	64.3	65.5	66.8	68.2	69.6
Newington DS	-	13.5	Load	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
			NET	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
			NET_DG	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Smiths Falls TS	T3/T4	176.4	Load	114.1	117.4	119.7	120.4	121.1	121.9	122.7	123.6	124.4	125.1	125.8	127.3	128.7	130.1	131.5
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.8	1.6	2.5	3.1	3.6	3.8	4.0	4.0	4.4	4.7	4.8	4.9	4.6	4.4	4.2
			NET	113.3	115.8	117.2	117.3	117.5	118.1	118.8	119.5	120.0	120.4	121.0	122.4	124.1	125.7	127.4
			NET_DG	113.3	115.8	117.2	117.3	117.5	118.1	118.8	119.5	120.0	120.4	121.0	122.4	124.1	125.7	127.4
St. Lawrence TS	T5/T6	183.5	Load	40.1	40.4	40.7	40.9	41.1	41.3	41.5	41.8	42.0	42.1	42.3	42.7	43.0	43.3	43.7
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.3	0.5	0.8	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.7	1.5	1.5	1.4
			NET	39.8	39.8	39.9	39.8	39.9	40.0	40.2	40.4	40.5	40.6	40.7	41.0	41.5	41.9	42.3
			NET_DG	39.8	39.8	39.9	39.8	39.9	40.0	40.2	40.4	40.5	40.6	40.7	41.0	41.5	41.9	42.3

TABLE D2: ST LAWRENCE NON-COINCIDENT SUMMER LOAD FORECAST

Transformer Station		LTR (MW)	Type	Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)				
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2033	2035	2037	2039
Brockville TS	T1/T2	145.6	Load	97.3	101.4	105.2	108.0	110.2	111.2	112.1	113.1	114.0	114.9	115.8	117.6	119.5	121.3	123.2
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-4.5	-4.6	-49.5	-49.5
			CDM	0.5	1.6	2.8	3.7	4.4	4.6	5.0	5.1	5.3	5.3	5.2	5.2	4.8	6.4	6.4
			NET	96.8	99.8	102.4	104.3	105.9	106.5	107.1	107.9	108.8	109.6	110.6	117.0	119.3	164.3	166.3
			NET_DG	96.8	99.8	102.4	104.3	105.9	106.5	107.1	107.9	108.8	109.6	110.6	112.6	114.9	116.7	118.6
Chesterville TS	T1/T2	50.0	Load	36.1	36.6	37.0	37.2	37.3	37.6	37.9	38.1	38.4	38.6	38.8	39.2	39.6	40.0	40.3
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-3.0	-3.0	-3.2
			CDM	0.2	0.6	1.0	1.3	1.5	1.6	1.7	1.7	1.8	1.8	1.7	1.7	1.7	1.6	1.6
			NET	35.9	36.0	36.0	35.9	35.9	36.0	36.2	36.4	36.6	36.8	37.1	37.6	40.9	41.3	42.0
			NET_DG	35.9	36.0	36.0	35.9	35.9	36.0	36.2	36.4	36.6	36.8	37.0	37.5	38.0	38.5	38.9
Crosby TS	T1/T2	57.6	Load	12.0	12.1	12.3	12.3	12.4	12.5	12.6	12.7	12.8	12.9	13.0	13.1	13.3	13.4	13.6
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-3.0	-3.0	-3.0
			CDM	0.1	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
			NET	11.9	11.9	11.9	11.9	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.6	15.6	15.8	16.0
			NET_DG	11.9	11.9	11.9	11.9	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.6	12.8	12.9	13.1
Crosby TS	T3	75.0	Load	21.6	21.9	22.2	22.4	22.5	22.7	22.9	23.1	23.3	23.4	23.6	23.9	24.3	24.6	24.9
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-4.1	-5.5	-5.5	-5.5
			CDM	0.1	0.4	0.6	0.8	0.9	0.9	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.1	1.1
			NET	21.5	21.5	21.6	21.6	21.6	21.7	21.9	22.0	22.2	22.3	22.5	26.9	28.6	29.0	29.3
			NET_DG	21.5	21.5	21.6	21.6	21.6	21.7	21.9	22.0	22.2	22.3	22.5	22.9	23.3	23.7	24.0
Morrisburg TS	T3/T4	115.2	Load	48.7	51.3	53.9	54.4	54.9	55.4	55.9	56.5	57.0	57.5	58.1	59.2	60.3	61.4	62.4
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-6.8	-6.8	-6.8
			CDM	0.2	0.8	1.4	1.8	2.2	2.3	2.5	2.6	2.6	2.7	2.6	2.5	2.6	2.6	2.6
			NET	48.5	50.5	52.5	52.5	52.7	53.0	53.4	54.0	54.4	54.9	55.5	56.7	64.5	65.6	66.7
			NET_DG	48.5	50.5	52.5	52.5	52.7	53.0	53.4	54.0	54.4	54.9	55.5	56.7	58.0	59.1	60.1
Newington DS	-	13.5	Load	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
			NET	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2
			NET_DG	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2
Smiths Falls TS	T3/T4	154.9	Load	92.9	95.8	97.9	98.5	99.0	99.7	100.4	101.1	101.7	102.3	102.9	104.1	105.3	106.4	107.6
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-2.8	-7.9	-11.0	-11.2	-11.2
			CDM	0.5	1.5	2.6	3.3	3.9	4.2	4.4	4.6	4.7	4.8	4.7	4.7	4.5	4.4	4.4
			NET	92.4	94.3	95.3	95.1	95.1	95.5	95.9	96.5	97.0	97.6	100.9	107.2	111.7	113.2	114.4
			NET_DG	92.4	94.3	95.3	95.1	95.1	95.5	95.9	96.5	97.0	97.6	98.3	99.7	101.2	102.4	103.6
St. Lawrence TS	T5/T6	168.1	Load	33.3	33.6	33.9	34.1	34.2	34.4	34.6	34.8	35.0	35.1	35.3	35.6	35.9	36.1	36.4
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-2.9	-8.3	-8.3	-9.7
			CDM	0.2	0.5	0.9	1.2	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7
			NET	33.1	33.1	33.0	32.9	32.9	33.0	33.1	33.2	33.4	33.5	33.7	36.8	42.5	42.8	44.4
			NET_DG	33.1	33.1	33.0	32.9	32.9	33.0	33.1	33.2	33.4	33.5	33.7	34.1	34.5	34.8	35.0

14. APPENDIX E. LIST OF ACRONYMS

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



NEEDS ASSESSMENT REPORT

St. Lawrence

Date: March 30, 2026

Needs Assessment Report

St. Lawrence

Date: March 30, 2026

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: St. Lawrence Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the St. Lawrence and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on the best available information throughout the planning process.

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

Executive Summary

REGION St. Lawrence Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: January 30, 2026 **END DATE:** March 30, 2026

The second Regional Planning cycle for the St. Lawrence Region was completed in March 2022 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report).

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in December 2025 for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. The NA for the St. Lawrence Region was advanced to align with high growing electricity demand in the region. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

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

The Technical Working Group (TWG) comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and operational concerns.
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Table 1: Needs that Do Not Require Further Regional Coordination

	Need Location	Need Description
Asset Renewal Needs		
1	St. Lawrence TS	115kV Breaker Replacement
2	Brockville TS	T1/T2 renewal based on asset condition assessment
System Reliability and Operation Needs		
1	Brockville TS	Installation of new LV Capacitor bank to mitigate the voltage issues on 44 kV bus

Table 2: Needs that Require Further Regional Coordination

	Need Location	Need Description
Station Capacity Needs		
1	Chesterville TS T1/T2	Projected to reach capacity in 2035 under normal growth and in 2033 under High growth scenario
2	Brockville TS T1/T2	Projected to reach capacity in 2032 under High Growth Scenario
Transmission Capacity Needs		
1	L2M	Projected to reach capacity in summer 2034, and in 2031 under Summer High Growth Scenario for the loss of L1MB
2	LxH	Under certain generation patterns and dispatch scenarios, some sections of the circuit may result in overloads based on existing loading condition.
System Reliability and Operation Needs		
1	Voltage on L2M	Voltage issues identified for High Growth Scenarios under L1MB contingency in mid-term.
2	L20H/L22H	Load Restoration
3	L2M/L1MB	Load Restoration

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Cooperative Hydro Embrun Inc.
- Rideau St. Lawrence Distribution Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

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1. INTRODUCTION

The second cycle of the Regional Planning process for the St. Lawrence Region was completed March 2022 with the publication of the Regional Infrastructure Plan ("RIP") Report (RIP Report). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the St. Lawrence Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

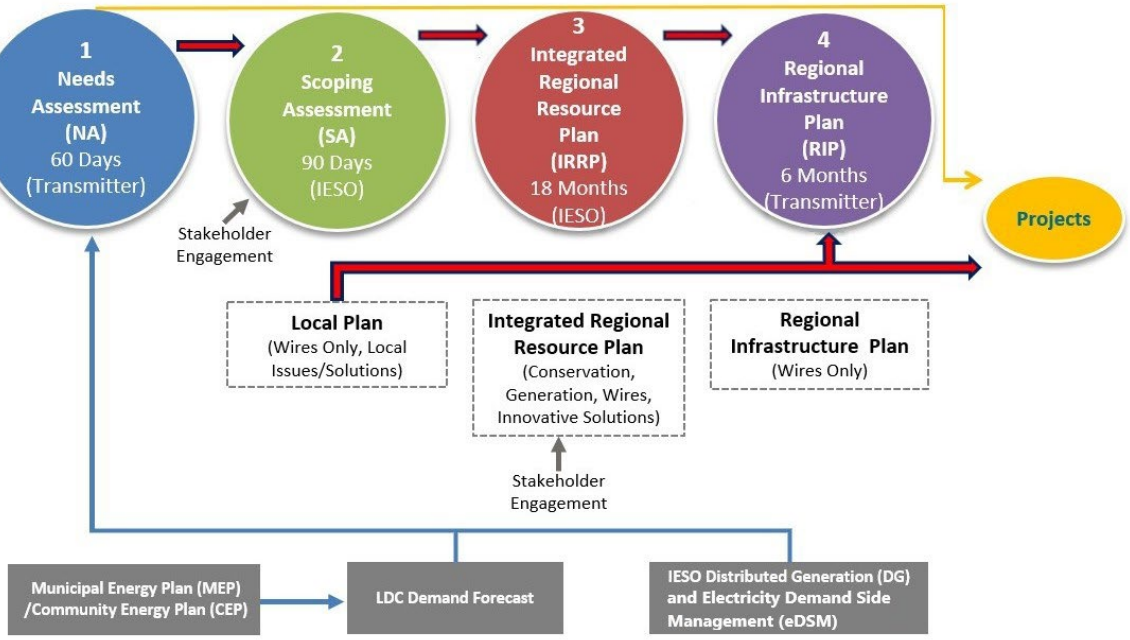


Figure 1: Regional Planning Process

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

Table 3: St. Lawrence Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator (IESO)
3	Hydro One Networks Inc. (Hydro One Dx)
4	Cooperative Hydro Embrun Inc. (embedded to Hydro One Dx)
5	Rideau St. Lawrence Distribution Inc. (embedded to Hydro One Dx)

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. The NA for the St. Lawrence Region was advanced to align with high growing electricity demand in the region

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the St. Lawrence region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The St. Lawrence Region covers the southeastern part of Ontario bordering the St. Lawrence River. The region starts east of Gananoque and extends to the inter-provincial boundary with Quebec in the East. The western part of the region is supplied by Hydro One owned stations connected to the 230 kV network. The remainder of the region is supplied from Hydro One stations connected to the 115kV network except for St. Lawrence TS, which is supplied from 230kV.

The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region. The geographical boundaries of the St. Lawrence region are shown in Figure 2 below.

Note : Map shows the approximate location for regional planning.

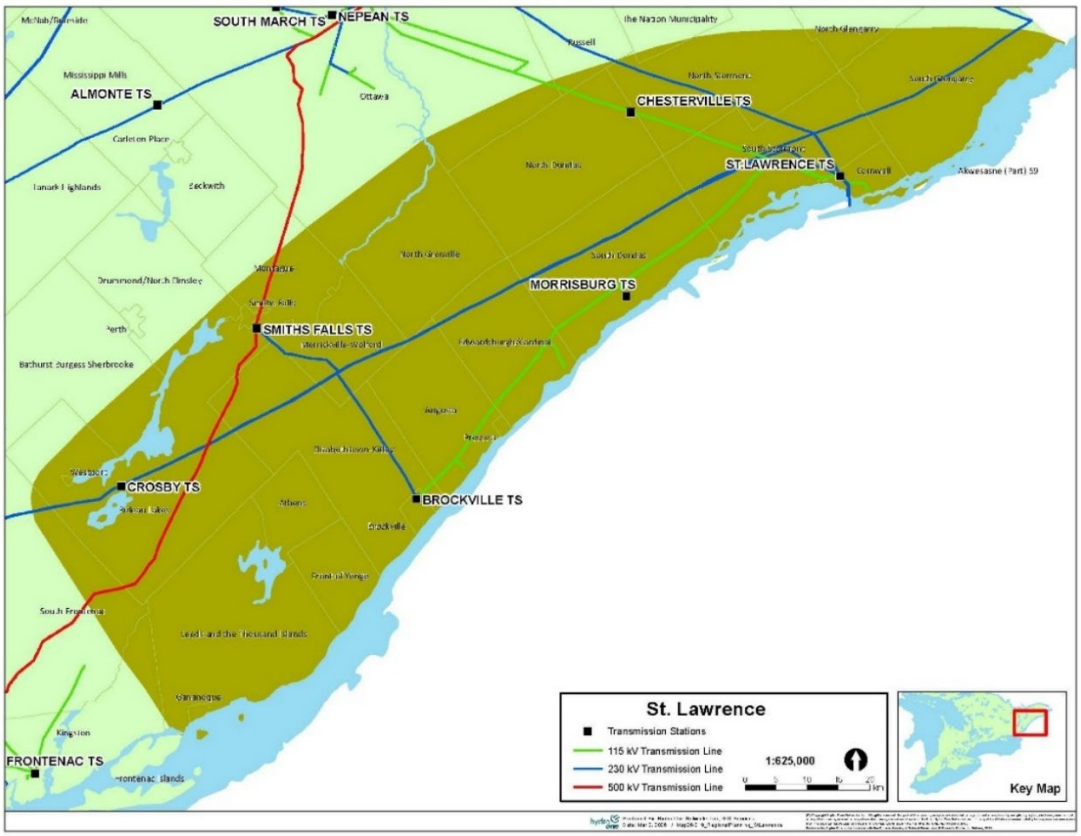


Figure 2: Map of St. Lawrence Regional Planning Area

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. The major source of supply for this region is OPG's Saunders Hydro Electric station which connects to St. Lawrence TS 230kV yard.

The St. Lawrence Region is connected to the Greater Ottawa Region through 230kV circuits L24A and B31L. Circuit B31L also provides an interconnection between the Provinces of Ontario and Quebec. In addition, 115kV circuit L2M also connects St. Lawrence to the Greater Ottawa Region, however this connection is normally open and is only used for load transfers between the two areas in case of system need. The Region is also connected to the Peterborough to Kingston Region through 230kV circuits L20H, L21H, and L22H.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2 and 3.

- St. Lawrence TS is the major transmission station for the region and connects to the main source of supply for the area, Saunders GS via four 230kV circuits. Also connecting to the 230kV yard of the station are two International Power Lines (IPL). These IPLs connect Ontario to the State of New York and power exchange across the IPLs are regulated using two phase shifting transformers. The station also has two 230kV/115kV 250MVA autotransformers to connect the 230kV and 115kV networks.

- Seven step-down transformer stations supply the St. Lawrence Area load. At 230kV: Brockville TS, Crosby TS, Smith Falls TS, and St. Lawrence TS. At 115kV: Chesterville TS, Morrisburg TS, and Newington DS.

- Two Customer Transformer Stations (CTS) are supplied in the Region from the 115kV network: CTS-1 and CTS-2 .

- Another source of supply to the area is an existing transmission connected generating station, CGS-1 with maximum output 134MW (summer) and 184MW (winter).

The circuits and stations of the area are summarized in Table 2 below:

Table 4: Transmission Station and Circuits in the St. Lawrence Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
L1MB, L2M, L5C[1]	L20H, L21H, L22H, L24A[2], B31L[2], L33P[3], L34P[3]	Brockville TS, Chesterville TS, Crosby TS, Morrisburg TS, Newington DS, Smith Falls TS, St. Lawrence TS*, CTS-1, CTS-2	Saunders GS (1056 MW) CGS-1 (184 MW)

*Stations with Autotransformers installed

[1]L5C is normally o/s and used as a backup supply for the City of Cornwall.

[2]L24A and B31L connect to St. Lawrence TS but do not have load customers connection.

[3]IPLs circuits.

The single line diagram of the 230kV Transmission Network of St. Lawrence region is shown in Figure 3 below.

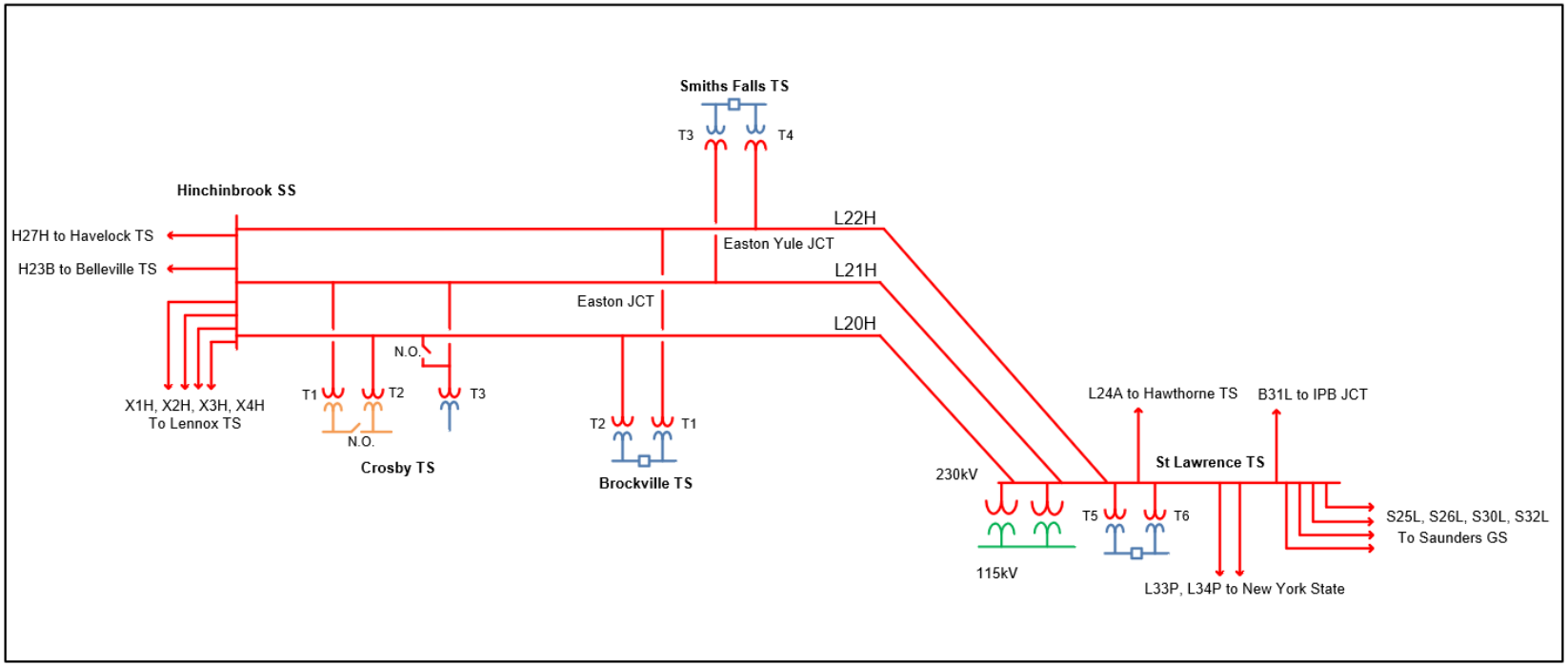


Figure 3: St. Lawrence 230kV Transmission Single Line Diagram

The single line diagram of the 115kV Transmission Network of St. Lawrence region is shown in Figure 4 below.

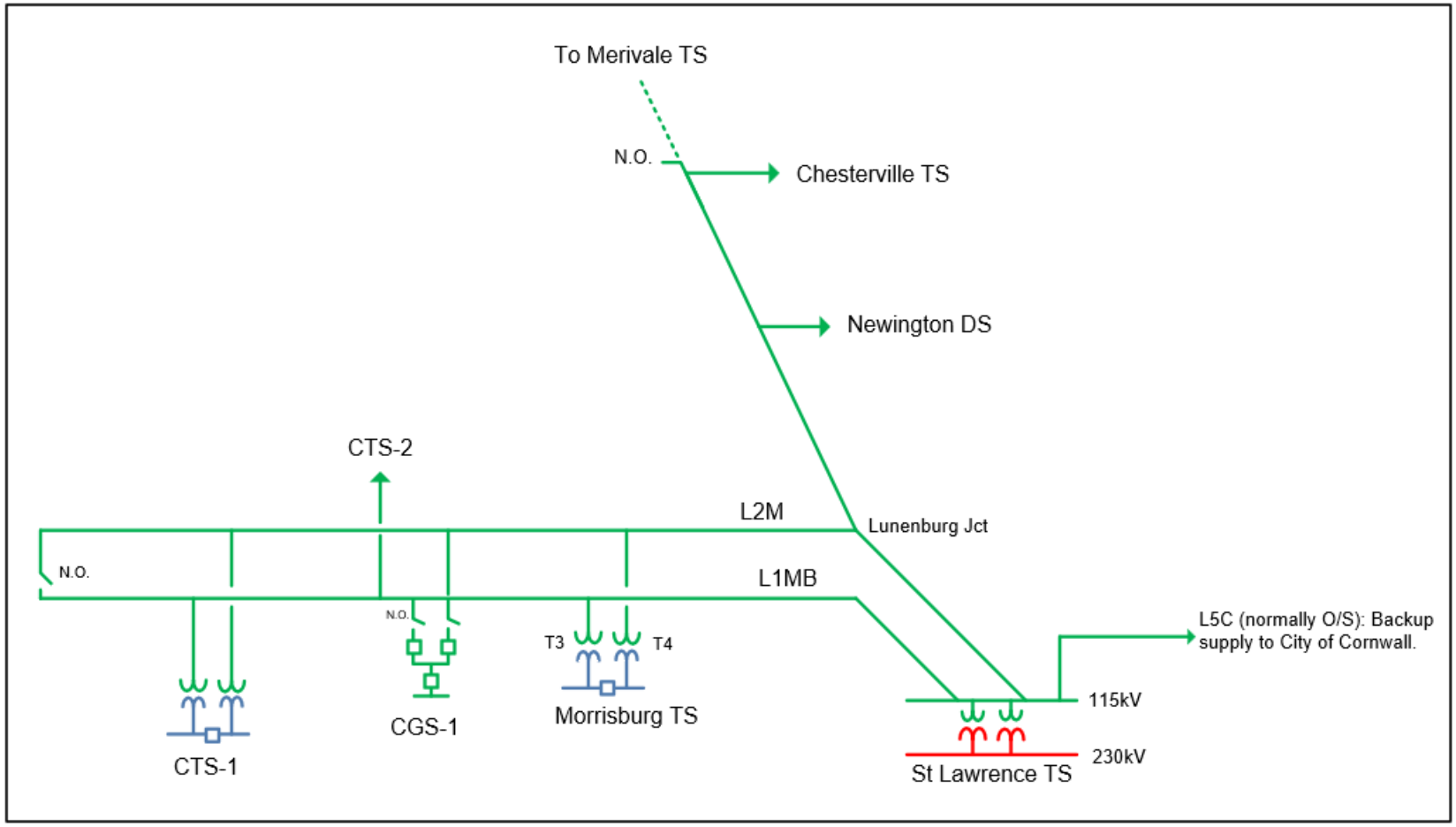


Figure 4: St. Lawrence 115kV Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the St. Lawrence NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-C.

The information provided includes the following:

- St. Lawrence 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities. Some municipalities in the region have informed us that their formal input will be provided before the end of March 2026. This information will be considered in the next phases of regional planning, i.e IRRP and RIP.

The TWG has made some assumptions and undertaken sensitivity analysis to capture uncertainties via different growth scenarios.

- Known capacity and reliability need, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the St. Lawrence.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.

- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer and winter peak loads. Three load forecasts were developed per season, i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

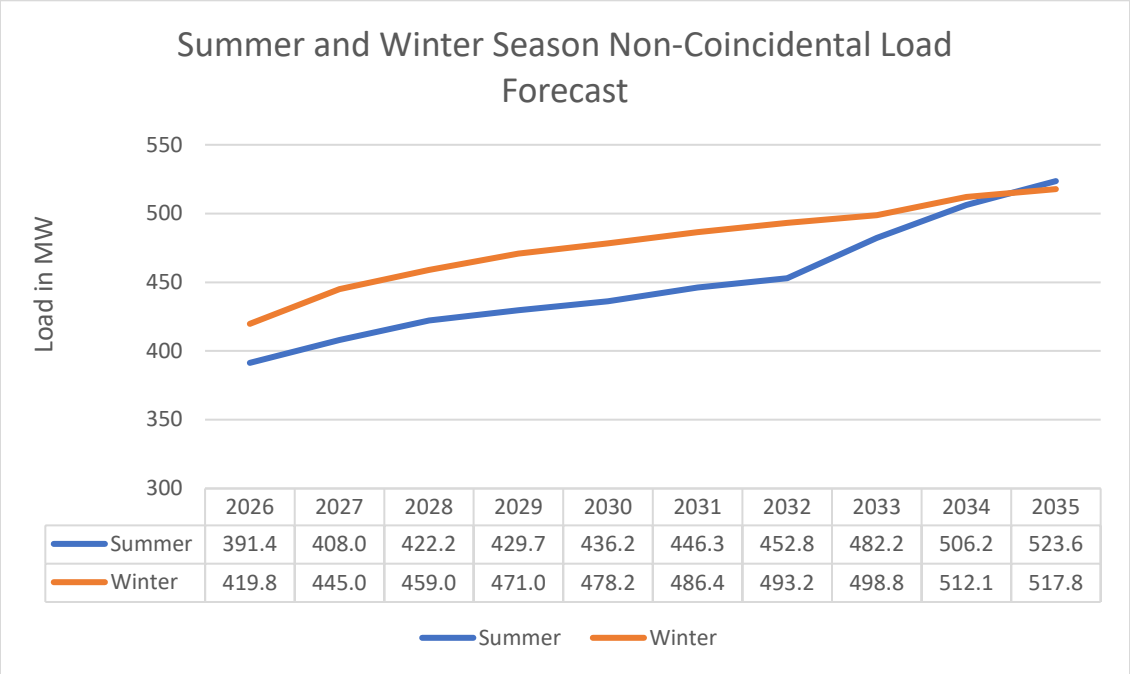
The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2026-2035.
- The Region is winter-peaking, with a projected shift toward summer peaking toward the end of the study period; therefore, this assessment considers both winter and summer peak loads.
- Line capacity adequacy is assessed by using non-coincidental peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Load forecast data was requested from industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
- Saunders Generating Station was assumed to generate at 750MW for winter and 840MW for summer.
- No import from New York at the St. Lawrence interconnection.
- No import from Quebec from Beauharnois interconnection.
- System studies and reported results are based on N-1 (single contingency) conditions, meaning the system is assessed to remain within applicable thermal, voltage, and stability limits following the loss of any one credible transmission element , with the system otherwise in the base configuration.
- CGS-1 is assumed to remain in service until its planned retirement at the end of 2034. Accordingly, it is treated as available for dispatch throughout the study period. System performance was evaluated with CGS-1 both fully dispatched and offline to establish local area limits and to assess the sensitivity of these limits to the generator's availability.
- For the purpose of this study, the Skyview BESS is assumed to discharge during peak demand hours and charge during off-peak hours. The BESS is also assumed to provide VAR support as required.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1 Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the St. Lawrence region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided an Electricity Demand Side Management ("eDSM"), and Distributed Generation ("DG") forecast for the St. Lawrence region. The region's extreme summer/winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual historical summer/winter peak extreme weather corrected loads. The extreme summer/winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage eDSM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer/winter weather corrected net load forecast for the individual stations in the St. Lawrence region is given in Appendix A. The graphical representation of the regional net non-coincidental load growth for both summer and winter season over the study period is shown in Figure 5 below.



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	391.4	408.0	422.2	429.7	436.2	446.3	452.8	482.2	506.2	523.6
Winter	419.8	445.0	459.0	471.0	478.2	486.4	493.2	498.8	512.1	517.8

Figure 5: St. Lawrence Region net Summer and Winter season Non-Coincidental Load

6.2.2 Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked

to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios is provided in section 8 of this report.

6.2.3 Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4 System Reliability, Operational and Load Restoration Issues:

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

The needs identified during this NA are discussed in section 7.4.

7. NEEDS

This section describes emerging new needs identified in the St. Lawrence Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. St. Lawrence Phase Shifting Transformers – Replaced failed phase shifting transformer PS33 and its companion PSR34. This work was completed in 2023.
2. Chesterville TS Delivery Point Performance – Chesterville TS has returned to its expected performance and is no longer delivery point outlier.

3. Circuit L22H – A total of 65 km of 230 kV circuit L22H between Easton JCT X Hinchinbrook North JCT is planned for refurbishment. As per the latest condition assessment, this circuit is considered for refurbishment in long term.

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

All near and mid-term needs that are discussed as a part of this report are summarized in Table 5 below.

Table 5: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update	NA Report Section
Asset Renewal Needs		
St. Lawrence TS	115kV breakers renewal based on asset condition	7.1.1
Brockville TS	T1/T2 transformers renewal based on asset condition	7.1.2
Station Capacity Needs		
Chesterville TS T1/T2	Projected to reach capacity in 2035 under normal growth and in 2033 under summer High growth scenario	7.2.1
Brockville TS T1/T2	Projected to reach capacity in 2032 under High Growth Scenario	7.2.2
Transmission Line Capacity Needs		
L2M	Projected to reach capacity in summer 2034 and, under Summer High growth scenario in 2031	7.3.1
LxH Circuits	No Capacity need identified for 230 kV LxH lines with NA assumptions . However, they are near their loading limits and will be studied further in next phases of regional planning cycle.	7.3.2
System Reliability and Operation Needs		
Brockville TS	Install LV Capacitor bank	7.4.1
115 kV L2M – Voltage performance	Voltage issues identified for High Growth Scenarios under L1MB contingency in mid-term.	7.4.2
L20H/L22H	Load Restoration	7.4.3
L2M/L1MB	Load Restoration	7.4.4

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and the TWG identified new asset renewal needs for major HV transmission equipment over the next 10 years in the St. Lawrence Region. They are listed in Table 6 below. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with lower ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement)
- Replacing equipment with higher ratings and built to current standards

TWG is recommending that Hydro One as a facility owner and operator of its transmission equipment, should plan to refurbish or replace aging major HV equipment and doing nothing is generally not an option due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

Table 6: Major HV Transmission Assets Requiring Replacement in St. Lawrence Region in next 10 years

Station/Circuit	Need Description	Planned ISD
St. Lawrence TS	115 kV breaker replacement based on asset condition	2034
Brockville TS T1/T2	T1/T2 transformers renewal based on asset condition	2034

7.1.1 115 kV Breakers – St. Lawrence TS

St. Lawrence TS is an important transformer stations within Hydro One's network. Located approximately 5 km northwest of Cornwall, it serves as an important node on Hydro One's 230-kV grid system, and the main supply to the 115kV system of the region through its autotransformers.

Based on asset condition assessments, the existing five (5) 115 kV oil-filled circuit breakers at St. Lawrence TS have been identified for renewal. To address this asset renewal need and maintain system reliability, Hydro One plans to replace the existing units with new SF_6 circuit breakers, along with any associated protection and control updates. The estimated in-service date for the replacement is Q4 2034.

7.1.2 Brockville TS (T1/T2)

The existing transformers 125 MVA 215.5/44 kV T1 and T2 were commissioned in 1975 and based on asset condition assessment, they are identified for replacement with like-for-like units as this is the highest rating available with a planned in-service date in 2034.

However, the station will be exceeding its LTR under summer high growth scenario in 2032 which is further discussed in section 7.2.2.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period **2026-2035** for the 230kV and 115kV transformer stations in the St. Lawrence Region using either the summer or winter peak load forecasts that were developed with input from the TWG. Based on the results, the following station capacity needs have been identified during the study period:

7.2.1 Chesterville TS (T1/T2)

Chesterville TS is located in the northern part of the St Lawrence region and is supplied from the 115 kV L2M circuit . The station provides load supply to Hydro One Distribution and the embedded Cooperative Hydro Embrun through two 42 MVA, 115.5/44 kV transformers T1 and T2.

According to the load forecast, Chesterville TS is expected to exceed its summer LTR by approximately 1 MW in 2035, while winter loading remains within LTR limits throughout the study period. Under the high-growth scenario, the projected summer needs date advances to 2033. Given that this capacity

need occurs near the end of the study horizon and under the high-growth scenario, the Technical Working Group (TWG) recommends continued monitoring of the load and revisiting this capacity need in the next phase of regional planning cycle.

7.2.2 Brockville TS (T1/T2)

Brockville TS is located within the City of Brockville and is supplied by the 230 kV L20H and L22H transmission circuits. The station provides load supply to Hydro One Distribution and the embedded Rideau St. Lawrence Distribution service area through two 125 MVA, 215.5/44 kV transformers T1 and T2. Based on asset-condition assessments, both transformers have been identified for replacement by 2034, as outlined in Section 7.1.2.

Sensitivity analysis indicates that, under the high-growth forecast, Brockville TS is expected to exceed its summer LTR by approximately 2 MW and its winter LTR by approximately 2.5 MW in 2032.

The development of an appropriate solution to address this emerging capacity need will be further assessed through the next phase of the regional planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period **2026-2035** for the 230kV and 115kV Transmission line circuits in the St. Lawrence Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. This section summarizes the findings from the analysis.

7.3.1 115 kV System Adequacy

The 115 kV system in the St. Lawrence planning region is supplied by two long transmission circuits, L2M and L1MB, which together form the backbone of supply to the area. The L2M circuit is a 167 km, 115 kV line extending from Merivale TS to St. Lawrence TS with a normally open disconnect switch at Chesterville TS that separates the Greater Ottawa and St Lawrence Regions. The St. Lawrence section of L2M is approximately 118 km supplying two sectors: northwest and southwest of St Lawrence TS. This southern sector supplies multiple downstream stations in a radial configuration including Morrisburg TS, CTS-1, CTS-2, and CGS-1. The northern sector supplies radially Chesterville TS and Newington DS. The second primary supply circuit, L1MB, is approximately 90 km in length and runs from St. Lawrence TS to CTS-1, providing supply to Morrisburg TS, CGS-1, CTS-1, and CTS-2. The long radial nature of both circuits makes voltage performance and reactive support key considerations when evaluating system adequacy, especially under higher loading conditions or reduced local generation.

The southern section of 115kV circuits described above runs parallel to Highway 401 from Cornwall to Brockville and has gathered interest due to their strategic location for new connection requests. As part of this Needs Assessment study, the capability of the system was reviewed. This section provides details on the capacity and possible options to further extend the system's capability to serve new loads.

The following scenarios evaluate system adequacy under different operating conditions, with and without generation from CGS1. The additional load capability values presented are scenario-based as the studies were done using N-1 contingency scenario. The next phases will include additional outage/contingency analysis beyond what was assessed here and may further limit the system's ability to supply additional load. The results shown are to provide an indication of the system's capability.

Scenario 1 – No MW Generation from CGS-1

Case 1 – Line Section Requires No Upgrade

Under Scenario 1, with no MW generation from CGS-1 and starting with 2026 forecast loading levels, the existing 115 kV system has the capability to support load growth up to 2034 normal summer growth forecast. This corresponds to about 32 MW of additional new load with existing reactive power (VAR) support is available. In this condition with L1MB out of service, the loading of the L2M line segment between St. Lawrence TS and Lunenburg Junction remains within limits, meaning the system can accommodate this incremental load without requiring any upgrade to L2M.

Loading beyond 2034 would require upgrades to the 115kV circuit as described below. The voltage performance of the circuit is reaching ORTAC limits, however no violations were observed. This outcome demonstrates that the existing infrastructure can continue to reliably meet the area load up to year 2034 of the normal growth forecast for the region as shown in Figure 6.

Thermal assessments for the 2035 summer normal growth scenario, with CGS-1 out of service and with no additional VAR support installed in the area, indicates that the line section between St. Lawrence TS and Lunenburg Jct. exceeds its LTE rating under L1MB contingency. Under the 2031 summer High Growth scenario, this same segment exceeds its LTE capability when subjected to L1MB contingency.

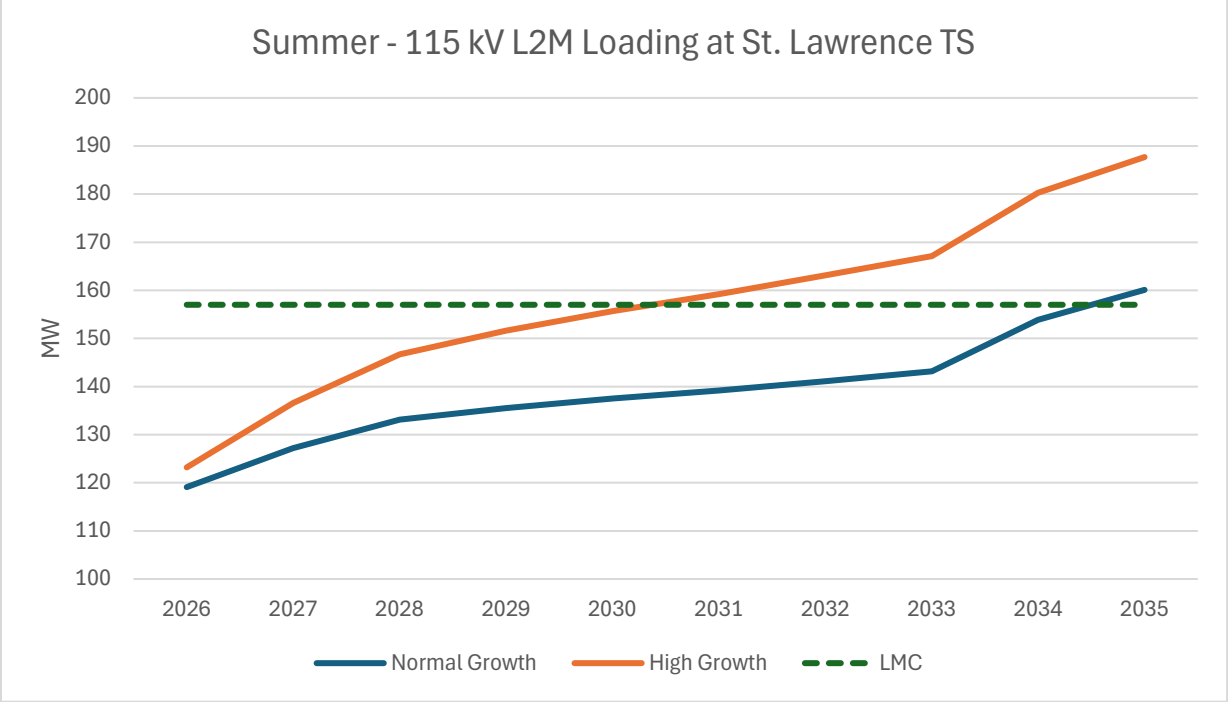


Figure 6: 115 kV L2M Loading

Case 2 – Line Section Requires Upgrade

If the line segment between St. Lawrence TS and Lunenburg Junction is upgraded and additional reactive power support is installed on the 115 kV system, the load-carrying capability increases significantly. Under this enhanced configuration, the system is capable of supporting approximately 100MW beyond the 2026 load forecast. Upgrade of the line improves its thermal capacity. When combined with increased VAR support to maintain acceptable voltage levels, the reinforced system can reliably accommodate a substantially higher level of future demand without violating planning criteria.

TWG recommends that IESO and Hydro One as a part of IRRP and RIP studies should consider options, such as, but not limited to running CGS-1 as a synchronous condenser and/or installing dynamic VAR support near Brockville area.

Scenario 2 – With MW Generation from CGS-1

When CGS-1 is generating, the power flow pattern across the 115 kV system changes, resulting in improved voltage support and reduced loading on upstream segments of L2M and L1MB. Under this scenario, the system is able to serve about 100 MW of additional load above 2026 loading from normal growth forecast without requiring any upgrades or refurbishment to the transmission lines. The presence of local generation strengthens voltages along the radial corridor, improving overall system behavior under high-load conditions. However, despite the enhanced support from CGS-1, additional reactive compensation is still needed to maintain voltage performance within acceptable limits as

demand grows. With appropriate VAR installations, the system can reliably supply higher load levels while leveraging the benefits of local generation from CGS-1.
As the identified thermal constraint occurs when CGS1 and L1MB is out of service with L2M exceeding its capacity in 2035 under normal growth, and in 2031 under high growth loading conditions, the TWG recommends

a. IESO to explore extending the contract and ensuring that CGS-1 output is available at peak hours to provide both MW and MVAR support. - or
b. Other transmission options to reinforce the 115kV to enable new connections beyond the 2034 summer normal growth forecast.
   A plan should be developed for 230 kV expansion in the mid-term as the capacity on 115 kV system is limited and load growth continues .

Further studies in next phase should be undertaken to develop solutions (including non-wires alternatives).

New connections such as Industrial/Commercial customers shall be required to install VAR support for their system.

7.3.2 230 kV – LxH circuits

The LxH circuit group comprising the 230 kV L20H, L21H, and L22H transmission circuits—extends between Hinchinbrook SS and St. Lawrence TS, forming a long-distance supply corridor approximately 160 km in length. These circuits provide the primary 230 kV supply to several key stations in the region, including Smiths Falls TS, Brockville TS, and Crosby TS. A significant portion of LxH sections have limited capacity as a result of sag limitations.

With the connection of the Skyview BESS near Easton Junction, system studies indicate that during discharge conditions under the High-Growth scenario in 2035, certain LxH line sections approach their LTE ratings. Although no thermal violations are observed under Normal-Growth and regional planning assumptions, the analysis shows that the LxH circuits have limited remaining thermal headroom for accommodating future increases in regional demand. Please refer to section 8 for further information.

St. Lawrence TS is connected to the Saunders Generating Station, to the State of New York via two interprovincial lines (IPLs), and to the Province of Quebec through circuit B31L, which is tied to the Beauharnois Generating Station. Due to these interconnections, a wide range of operating scenarios and system conditions can influence power flows on circuits L20H, L21H, and L22H. Under certain generation patterns and dispatch scenarios, these factors may result in overloads on sections of these lines based on existing loading condition.

The TWG recommends reviewing the capacity need of L20H/L21H circuits and developing mitigation options as part of IRRP and RIP phases of regional planning. Increasing capacity will help economic growth projected in the area and large load connections in the area. Please refer to section 8 for further details.

7.4 System Reliability, Operation and Load Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, and to provide a median-economic forecast for an extended period with any one transmission element out of service. A study has been conducted, considering the net non-coincident load forecast and the loss of one element over the study period **2026-2035** to cater for this need**.** Based on the results, the following line needs have been identified during the study period:

7.4.1 Brockville TS – LV Capacitor bank

As new loads are anticipated to connect in the Brockville area, the increased demand will require additional reactive power resources to maintain acceptable low-voltage (LV) performance. To support system voltage and improve power factor, there is a need to install LV capacitor banks at Brockville TS.

Study assessments indicate that Brockville TS begins to experience LV voltage decline beyond permissible ORTAC limits as loading increases after 2028 under normal growth scenario. To ensure voltage remains within allowable thresholds, TWG recommends installing 44 kV capacitor banks to meet station capability and to ensure compliance with ORTAC and TSC switching requirements at the station. The capacitor bank has been right sized (2x21.6 MVAR) based on meeting system performance and station loading.

Hydro One will proceed with implementation of this with a tentative in-service date for this project in 2029.

7.4.2 Voltage Performance of 115 kV L2M

A series of system studies were conducted to evaluate the voltage performance of the 115 kV L2M circuit under various operating conditions and long-term load growth assumptions.

Under the high-growth 2032 scenario, the analysis shows that the post-contingency voltage on L2M violates ORTAC limits only under the L1MB outage contingency. Specifically, the voltage on the affected sections of L2M falls below the minimum ORTAC limit of 113 kV, indicating inadequate voltage performance in this scenario. Results also indicate that under normal growth the voltage approaches its limits by end of the study period.

The TWG recommends further review of this need in the next phases of regional planning cycle.

7.4.3 Load Restoration for L20H/L22H

Brockville TS is supplied solely by the 230 kV L20H and L22H circuits. Loss of both circuits would result in a complete loss of supply to the station. Under the Normal Growth forecast, the projected winter peak load at Brockville TS exceeds 150 MW by the end of the study period. Under the High Growth forecast, the station load is projected to exceed 150 MW in 2033 (summer) and 2030 (winter).

In accordance with ORTAC load restoration requirements for double circuit contingencies where more than 150 MW of load is interrupted, TWG is recommending IRRP and RIP to consider building a Switching Station near Easton Jct. which can provide switching flexibility for load restoration for Brockville along with several other system benefits in the area.

7.4.4 Load Restoration for L2M/L1MB

115 kV Circuits L2M and L1MB supply Chesterville TS, Morrisburg TS, Newington DS, CTS-1 and CTS -2. The double contingency of L2M and L1MB will result in complete loss of supply to these stations. Under the Normal Growth forecast, the projected summer peak load at these stations exceeds 150 MW by the end of the study period. Under the High Growth forecast, the station load is projected to exceed 150 MW in 2030 (summer) and 2029 (winter).

In accordance with ORTAC load restoration requirements for double circuit contingencies more than 150 MW of load may be interrupted. The TWG will review this need as part of next phases of regional planning cycle.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the St. Lawrence region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG conducted a sensitivity analysis by applying ±50% growth adjustments to the Normal Growth forecast to establish the High Growth and Low Growth scenarios. The High Growth scenario incorporates EV scenarios, includes consideration of potential additional demand from electrification as well as anticipated large industrial and commercial customers expected to connect in the near to mid-term.

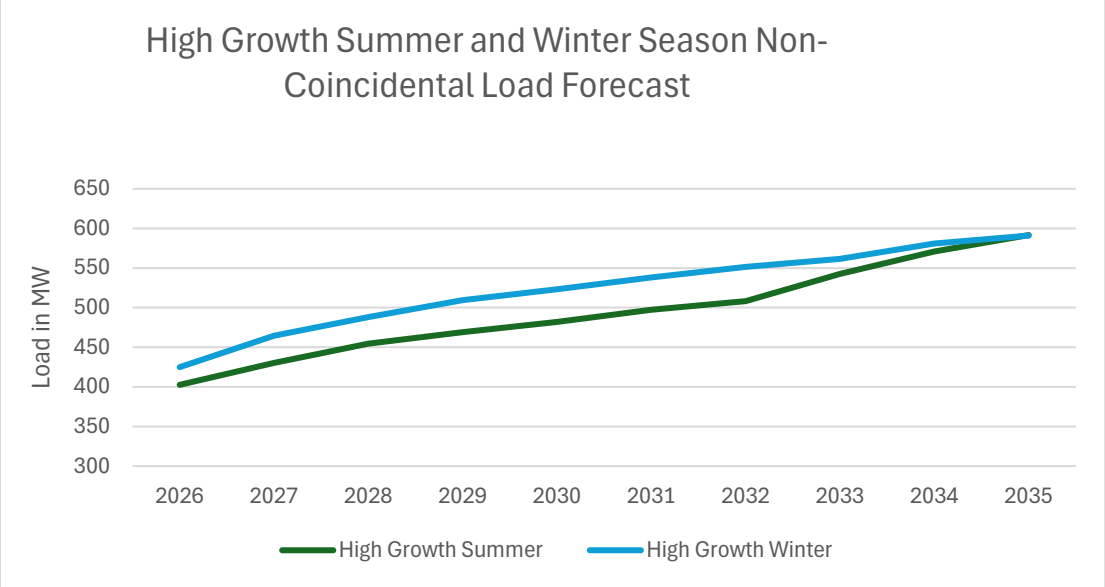


Figure 7: High Growth Forecast for existing stations.

Given further input is expected from municipalities on electricity demand, the TWG has reviewed the system capability as per study assumptions for growth beyond the NA load forecast and the findings are shown below. This additional input will be further considered in next phases of regional planning cycle.

Following is the capacity based on currently available information

a. On 115 kV system, approximately 40 MW capacity would be available (beyond the existing station's high growth forecast) to serve new industrial/commercial customers subject to upgrade described in section 7.3.
b. On 230 kV system, approximately 90 MW capacity is currently available for industrial/commercial customers (beyond the existing station's high growth forecast). Capacity beyond 90 MW will require upgrade to 230 kV circuits as described in 7.3 and system reinforcement such as switching station as described in section 7.4.

Note : - Some of the municipal information was not available and will be updated in the next phase of regional planning

The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 7: Impact of Sensitivity Analysis on Station/Line capacity Needs in the Region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Chesterville TS T1/T2	2035 (Summer)	2033 (Summer)	-
2	Brockville TS T1/T2	-	2032 (Summer) 2032 (Winter)	-
3	L2M	2034 (Summer)	2031 (Summer)	-

The sensitivity analysis identified the additional capacity needs during study period. These needs will be assessed again during the next phases of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Needs Assessment has considered N-1 contingency scenarios to identify needs in the area. The next phases will include a revised forecast and additional outage/contingency analysis beyond what was assessed here. These studies may find further limits on the system's ability to supply additional load.

9.1 Regional Needs

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
1	St. Lawrence TS	115 kV breaker replacement based on asset condition
2	Brockville TS	T1/T2 transformers renewal based on asset condition
3	Brockville TS	Installation of new LV Capacitor bank to mitigate the voltage issues on 44 kV bus.

Table 9: Needs that Require Further Regional Coordination

#	Need Location	Need Description
1	Chesterville TS T1/T2	Projected to reach capacity in 2035 under normal growth and in 2033 under High growth scenario
2	Brockville TS T1/T2	Projected to reach capacity in 2032 under High Growth Scenario
3	L2M	Projected to reach capacity in 2034 under Summer normal growth and 2031 under Summer High Growth Scenario
2	LxH	Under certain generation patterns and dispatch scenarios, some sections of the circuit may result in overloads based on existing loading condition.
4	Voltage on L2M	Voltage issues identified for High Growth Scenarios under L1MB contingency in mid-term.
5	L20H/L22H	Load restoration
6	L2M/L1MB	Load restoration

Note : Further input is expected from municipalities on electricity demand by end of March 2026 and will be considered in next phases of regional planning cycle which may trigger additional needs in the region.

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Cooperative Hydro Embrun Inc.
- Rideau St. Lawrence Distribution Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

9.2 Consideration for Future Growth

Given further input is expected from municipalities on electricity demand, the TWG has reviewed the system capability as per study assumptions for growth beyond the NA load forecast and the findings are shown below. This additional input will be further considered in next phases of regional planning cycle.

a. 115 kV analysis, approximately 40 MW capacity would be available (beyond the existing station high growth forecast) to serve new industrial/commercial customers subject to upgrade described in section 7.3.
   - A plan should be developed for 230 kV expansion in the mid-term as the capacity on 115 kV system is limited and load growth continues.

b. 230 kV analysis, approximately 90 MW capacity is still available for industrial/commercial customers (beyond the existing station high growth forecast). Capacity beyond 90 MW will require upgrade to 230 kV circuits as described in 7.3 and system reinforcement such as switching station as described in section 7.4.

10. REFERENCES

[1] Hydro One, RIP Report – St. Lawrence (Second cycle), published on March, 2022

[2] Hydro One, NA Report – St. Lawrence (Second cycle), published on December 20, 2022

[3] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 6.0 September 10, 2025)

[4] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[5] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. September 16, 2025)

[6] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: St. Lawrence Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Name of Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Brockville TS (T1/T2)	143.1	107.1	110.0	115.8	118.5	122.1	124.7	126.0	134.4	135.0	135.8
Chesterville TS (T1/T2)	54.9	44.8	47.6	48.0	48.4	48.8	49.3	49.9	50.5	53.4	56.3
Crosby TS (T1/T2)	55.5	12.6	12.6	12.6	12.7	12.7	12.8	12.9	13.0	13.2	17.9
Crosby TS (T3)	74.7	20.7	20.8	20.8	21.5	21.5	21.6	21.6	28.4	30.8	30.9
Morrisburg TS (T3/T4)	118.8	61.1	66.0	70.9	72.8	74.2	75.3	76.4	77.7	84.5	87.2
Newington DS	13.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Smith Falls TS (T3/T4)	155.9	102.6	107.5	109.4	110.2	111.1	116.5	117.5	127.0	133.3	134.7
St. Lawrence TS (T5/T6)	163.9	38.9	40.0	41.2	42.2	42.4	42.6	45.0	47.7	52.5	57.2
CTS-1	-	8	8	8	8	8	8	8	8	8	8
CTS-2	-	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9

Table A.2: St. Lawrence Region – Winter Non-Coincident – Normal Growth Net Load Forecast

Name of Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Brockville TS (T1/T2)	166.5	115.5	125.1	128.9	135.1	138.4	142.8	145.9	147.2	149.2	150.6
Chesterville TS (T1/T2)	62.1	45.0	48.4	49.1	49.6	50.2	50.9	51.5	52.2	53.0	54.0
Crosby TS (T1/T2)	65.6	16.8	17.0	17.1	17.2	17.3	17.4	17.5	17.7	17.8	18.0
Crosby TS (T3)	74.7	22.5	22.6	22.8	23.5	23.6	23.8	23.9	24.1	24.3	24.5
Morrisburg TS (T3/T4)	134.0	62.2	67.3	72.5	74.6	76.2	77.5	78.8	80.1	88.5	89.1
Newington DS	13.5	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2
Smith Falls TS (T3/T4)	185.3	111.2	116.9	119.6	120.8	122.1	123.6	125.0	126.5	128.2	130.1
St. Lawrence TS (T5/T6)	183.6	42.3	43.5	44.8	45.9	46.1	46.2	46.3	46.6	46.8	47.1
CTS-1	-	8	8	8	8	8	8	8	8	8	8
CTS-2	-	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1

Table A.3: St. Lawrence Region Summer Non-Coincident – High Growth Net Load Forecast

Name of Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Brockville TS (T1/T2)	143.1	111.3	116.4	126.0	131.1	137.6	142.4	145.1	155.0	156.3	157.9
Chesterville TS (T1/T2)	54.9	45.1	49.5	50.4	51.2	52.1	53.1	54.2	55.2	58.7	62.1
Crosby TS (T1/T2)	55.5	12.6	12.7	12.9	13.0	13.1	13.2	13.4	13.6	13.9	18.7
Crosby TS (T3)	74.7	20.8	20.9	21.1	22.2	22.4	22.5	22.7	29.7	32.1	32.4
Morrisburg TS (T3/T4)	118.8	64.6	72.7	81.0	84.6	87.4	89.6	91.9	94.4	102.5	105.8
Newington DS	13.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8
Smith Falls TS (T3/T4)	155.9	105.3	113.2	116.7	118.5	120.4	126.9	129.0	139.6	147.0	149.6
St. Lawrence TS (T5/T6)	163.9	39.3	41.2	43.1	45.0	45.4	45.9	48.6	51.5	56.7	61.6
CTS-1	-	8	8	8	8	8	8	8	8	8	8
CTS-2	-	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9

Table A.4: St. Lawrence Region – Winter Non-Coincident – High Growth Net Load Forecast

Name of Station	LTR (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Brockville TS (T1/T2)	166.5	115.6	130.4	136.7	147.1	153.0	160.8	166.5	169.0	172.8	175.3
Chesterville TS (T1/T2)	62.1	45.3	50.5	51.8	52.9	54.1	55.3	56.5	57.8	59.2	60.8
Crosby TS (T1/T2)	65.6	17.1	17.3	17.6	17.8	18.0	18.3	18.5	18.8	19.1	19.4
Crosby TS (T3)	74.7	22.6	22.9	23.2	24.4	24.7	25.0	25.3	25.6	26.0	26.4
Morrisburg TS (T3/T4)	134.0	65.1	73.4	82.1	85.9	89.0	91.6	94.1	96.8	106.5	107.8
Newington DS	13.5	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4
Smith Falls TS (T3/T4)	185.3	111.8	120.8	125.2	127.7	130.2	132.9	135.6	138.5	141.5	144.9
St. Lawrence TS (T5/T6)	183.6	43.2	45.2	47.2	49.2	49.7	50.0	50.4	51.0	51.4	52.0
CTS-1	-	8	8	8	8	8	8	8	8	8	8
CTS-2	-	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Brockville TS (T1/T2)	230/44	L20H, L22H
2	Chesterville TS (T1/T2)	115/44	L2M
3	Crosby TS (T1/T2)	230/27.6	L20H, L21H
4	Crosby T3	230/44	L21H
5	Morrisburg TS (T3/T4)	115/44	L1MB, L2M
6	Newington DS	115/27.6	L2M
7	Smith Falls TS (T3/T4)	230/44	L21H, L22H
8	St. Lawrence TS (T5/T6)	230/44	Transformers connect at 230kV switchyard

Appendix C: List of Municipalities in the St. Lawrence Region

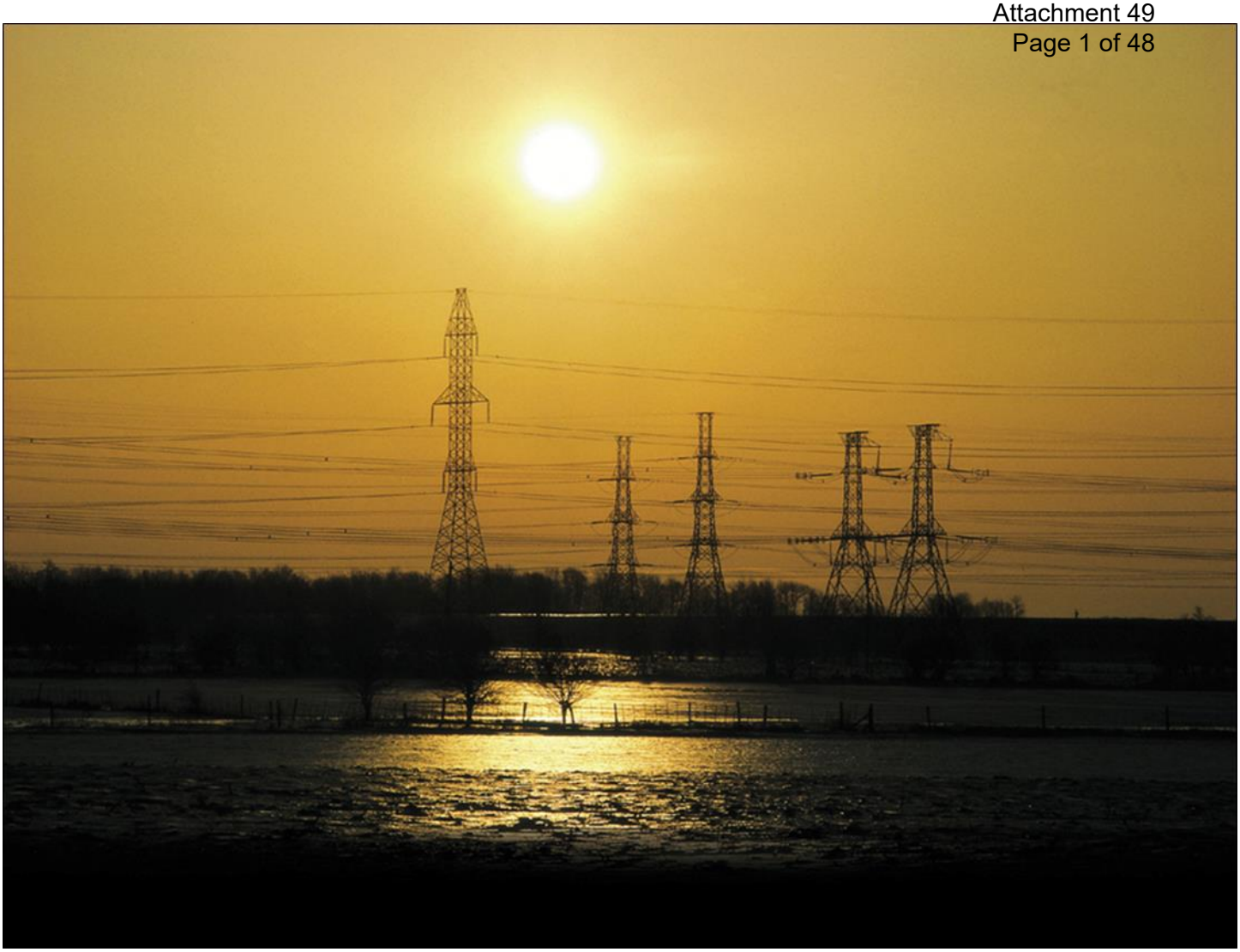
No.	Name of Municipality
1	Township of Edwardsburgh Cardinal
2	Augusta Township
3	Township of Elizabethtown-Kitley
4	Township of Front of Yonge
5	Municipality of North Grenville
6	Township of Rideau Lakes
7	City of Brockville
8	Town of Prescot
9	United Counties of Leeds and Grenville
10	Municipality of North Dundas
11	Municipality of South Dundas
12	Township of North Glengarry

13	Township of South Glengarry
14	Township of North Stormont
15	Township of South Stormont
16	Township of Elizabethtown-Kitley
17	Village of Westport
18	Township of Athens
19	City of Cornwal
20	United Counties of Prescott and Russell
21	United Counties of Stormont, Dundas and Glengarry (SDG Counties)

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	Electricity Demand Side Management
EV	Electric Vehicle
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IPL	International Power Lines
IRRP	Integrated Regional Resource Plan
kV	Kilo Volt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station

Acronym	Description
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RPPAG	Regional Planning Process Advisory Group
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TAO	Transmission Asset Owner
TS	Transformer Station
TWG	Technical Working Group



East Lake Superior

REGIONAL INFRASTRUCTURE PLAN

October 1st, 2021

hydro one

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Prepared and supported by:

Company
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Algoma Power Inc.
Chapleau Public Utilities Corporation
PUC Distribution Inc.

DISCLAIMER

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

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

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

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE SAULT STE. MARIE LP WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE EAST LAKE SUPERIOR REGION.

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

- Algoma Power Inc. ("API")
- Chapleau Public Utilities Corporation ("Chapleau PUC")
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP. ("HOSSM")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PUC Distribution Inc. ("PUC")

This RIP is the final phase of the second cycle of East Lake Superior (ELS) regional planning process, which follows the completion of the East Lake Superior Integrated Regional Resource Plan ("IRRP") in April 2021 and the East Lake Superior Region Needs Assessment ("NA") in June 2019. This RIP provides a consolidated summary of the needs and recommended plans for East Lake Superior Region over the planning horizon (1 – 20 years) based on available information.

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

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2014 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave 115kV circuit (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This project was completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway with a targeted in-service date of 2023 Q2.

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

Table 1. Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[1]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M

[1] To coordinated with IESO's 2021 Bulk Planning Study regarding Sault No.3 Circuit Overloading

8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers 'like for like' per current standard	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2 'like for like' per current standard	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M
12	Clergue TS: End of life metal clad switch gear	Replace end of life switch gear 'like for like' per current standard	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protection per current standard	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear 'like for like' per current standard	2026	$9.2M

The Study Team recommends that:

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

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE EAST LAKE SUPERIOR REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Sault Ste. Marie LP (HOSSM) on behalf of the Study Team that consists of Hydro One Networks Inc. (Transmission), Hydro One (Distribution), Algoma Power Inc. (API), PUC Distribution Inc., Chapleau Public Utilities Corporation and the Independent Electricity System Operator ("IESO"), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The East Lake Superior Region is the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south as shown in Figure 1.1 below. The region is supplied from a combination of local generation and connection to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North.

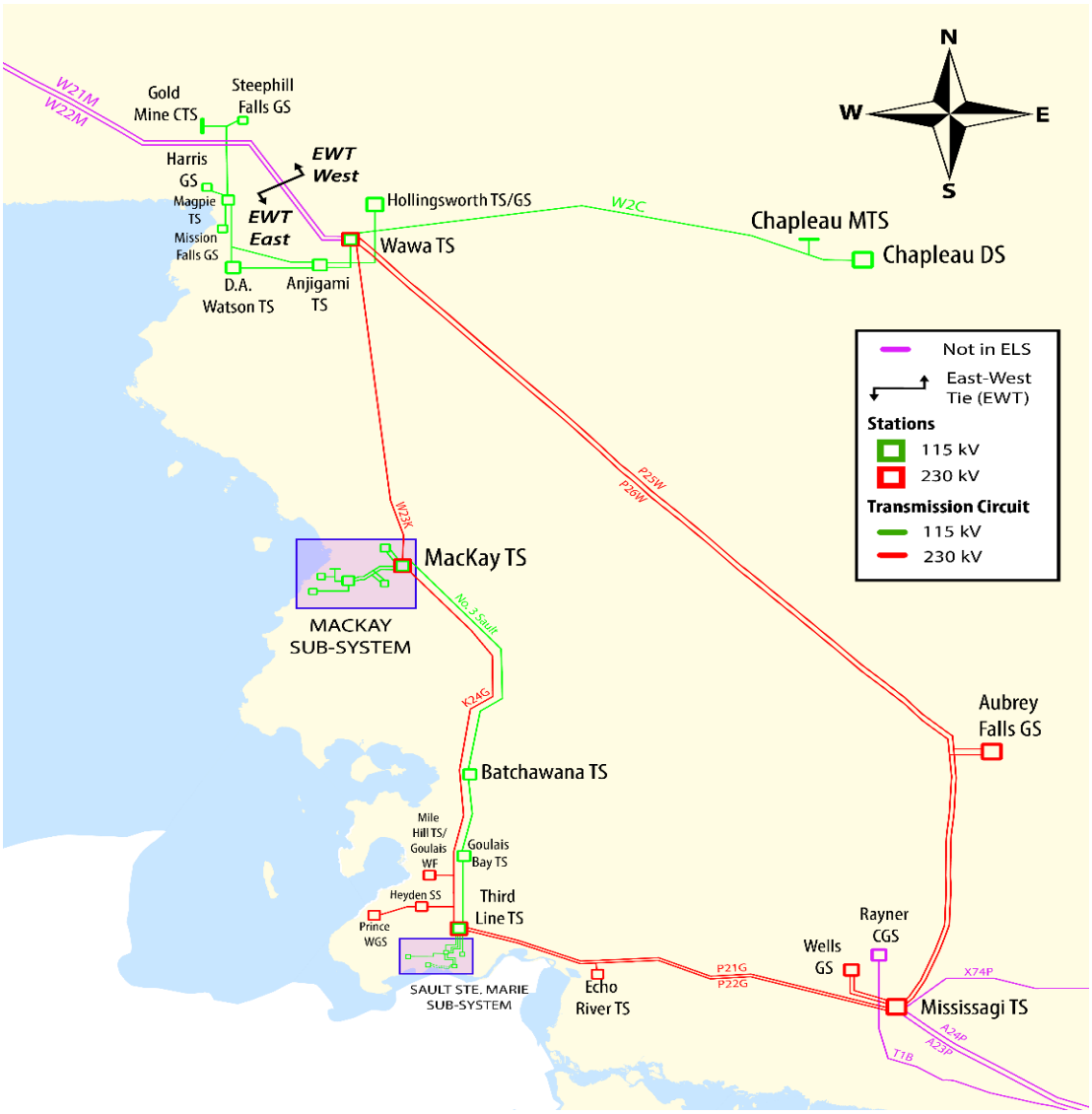


Figure 1-1: East Lake Superior Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the East Lake Superior Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [2] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company(s) ("LDC") or customer(s) and develops a Local Plan ("LP") to address them.

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

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

[2] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

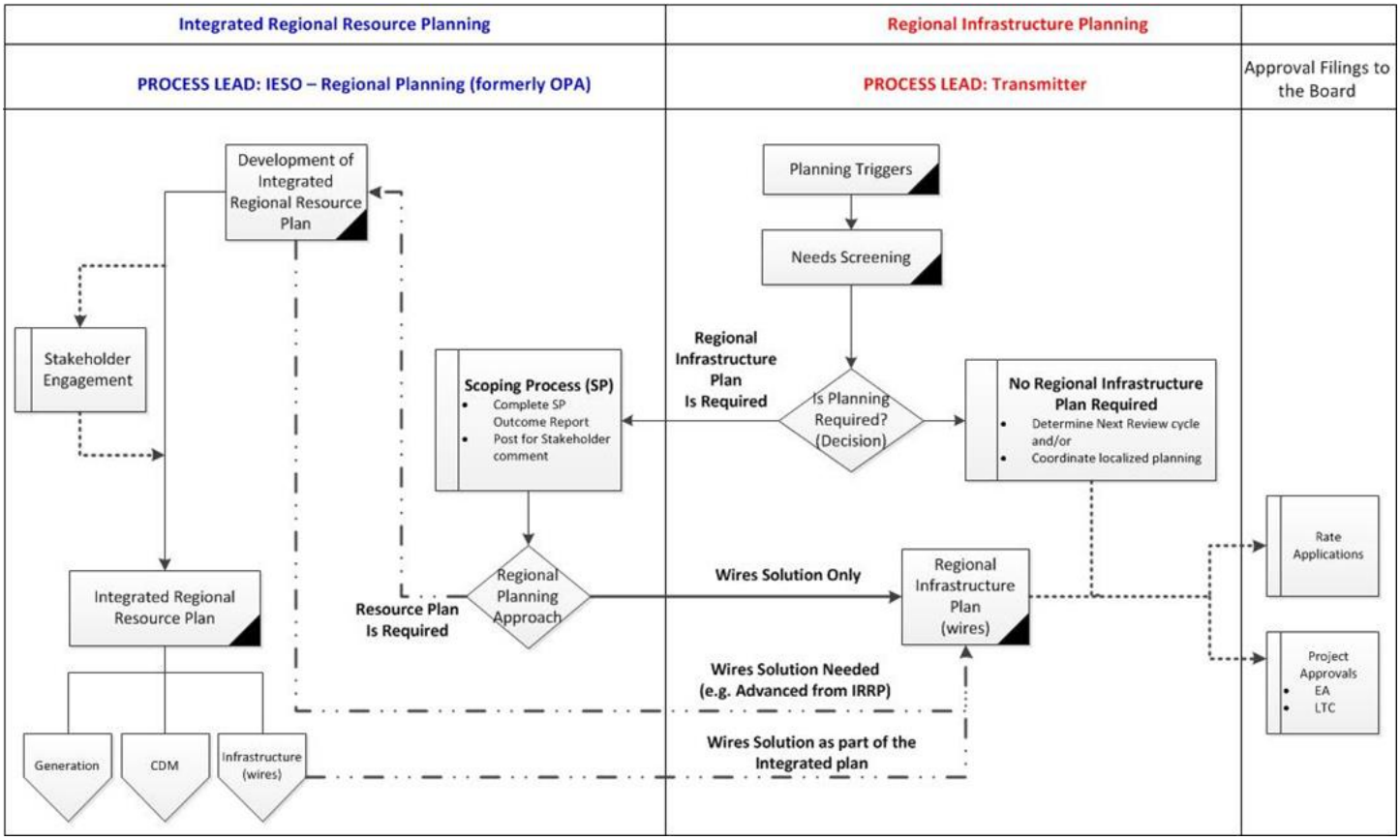


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

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

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

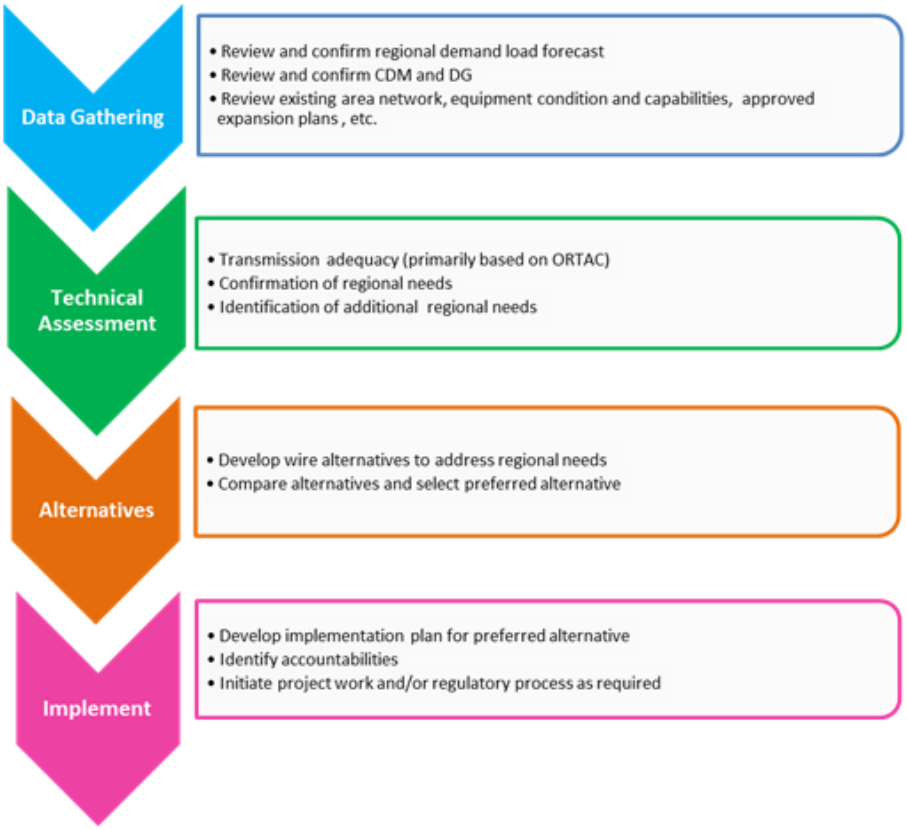


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE EAST LAKE SUPERIOR REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY TOWN OF DUBERUILVILLE AND HIGHWAY 101 TO THE NORTH AND THE TOWNSHIP OF CHAPLEAU, BRUCE MINES TO THE SOUTH AND INCLUDES THE CITY OF SAULT STE. MARIE, HIGHWAY 129 TO THE EAST, AND LAKE SUPERIOR TO THE WEST. IT CONSISTS OF THE CITY OF SAULT STE. MARIE.

The region is supplied from a combination of local generation and connections to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North. Majority of the region's electrical need is supplied through a 230/115 kV transformer station at Third Line TS. Local generation in the area consists of mainly hydroelectric and wind generation with a total installed capacity of 1039 MW in the 115 kV and 230kV networks. The East Lake Superior Region is a winter peaking region, with 2020 winter peak demand at 361MW.

PUC Distribution Inc. ("PUC") is the Local Distribution Company ("LDC") which serves the electricity demand in the City of Sault Ste. Marie. The LDC that supplies primarily rural customers – industrial, commercial, and residential customers in the aregion are API, Chapleau PUC and Hydro One Networks Inc. Distribution

Below is a description of major Transmission asset in the region:

- Third line TS is the major transmission station that connects the 115kV system within the City of Sault Ste. Marie via two 230/115kV autotransformer to the 230kV bulk electricity network.
- Mackay TS is a 230/115kV station with one 230/115kV autotransformer that connects the local 115kV network in the vicinity of Montreal River to the 230kV bulk electricity network.
- Wawa TS is a 230/115kV station with two 230/115kV autotransformer that connects the local 115kV network in the vicinity of Michipicoten River.
- 12 other Transmission stations supply the area, with 10 of them operating at 115kV, 1 operating at 230kV , 1 operating at 44kV [3]
- A total of 319 km of 230kV circuits, 232 km of 115kV circuits and 10 km of 44kV circuits interconnect transmission stations, generation customer(s), distribution customer(s) and Transmission connected load customer(s) within the region.

Table in Appendix A and B summarize Transmission station and circuits at different operating voltages and in the area. A geographical map showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-1. A single line diagram showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-2.

[3] The 44kV station and line is included in HOSSM's transmitter license and are deemed transmission asset by the OEB.

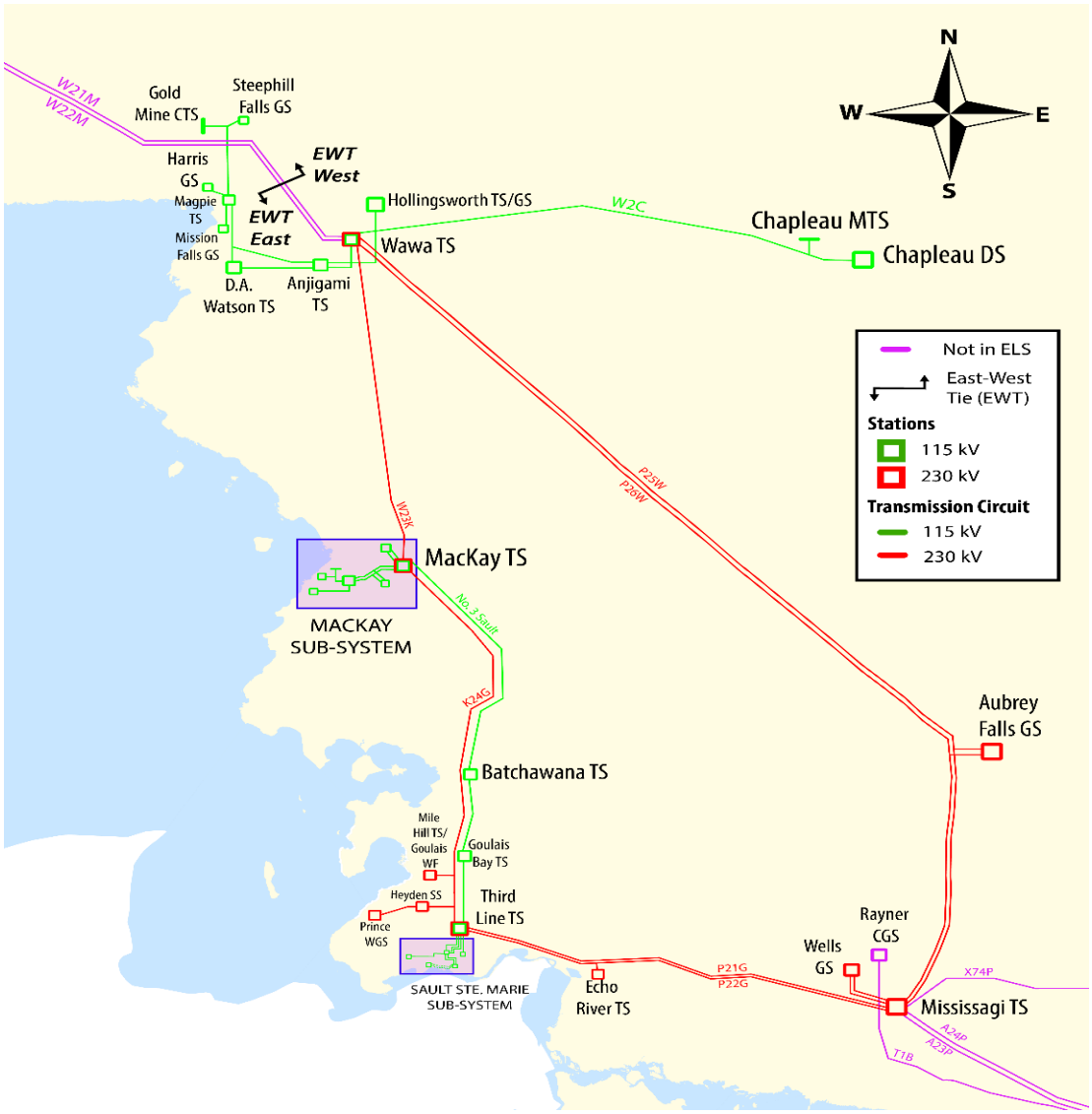


Figure 3-1: East Lake Superior Region's Transmission Network

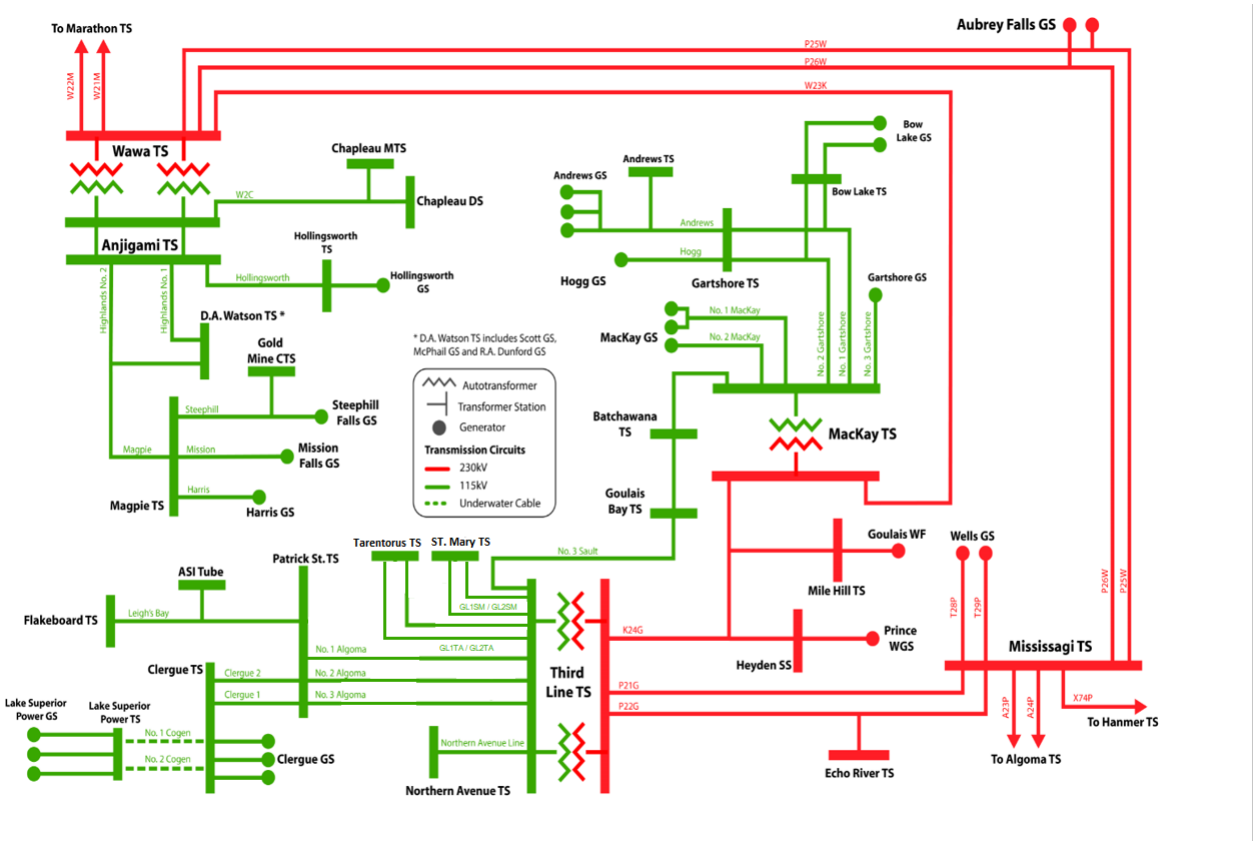


Figure 3-2: Single Line Diagram of East Lake Superior Region's Transmission Network

4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY SINCE LAST REGIONAL PLANNING

THE ESL REGIONS COMPLETED IT 1ST CYCLE REGIONAL PLANNING IN 2014. SINCE THAT TIME, SEVERAL \TRANSMISSION PROJECTS HAVE BEEN PLANNED AND/OR UNDERTAKEN BY HYDRO ONE SAULT STE. MARIE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE EAST LAKE SUPERIOR REGION.

A summary and description of the major projects completed and/or currently underway since the completion of last cycle regional planning is provided below.

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2013 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This is completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway and have a targeted in-service date of 2023 Q2.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The LDCs provided load forecasts for all the stations supplying their loads in the East Lake Superior region for the 20-year study period during the IESO led IRRP phase of regional planning. The net extreme weather corrected winter load forecast was produced by modifying the LDC forecast provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed Distributed Energy Resource (DER) that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and micro FIT program.

The electricity demand in the East Lake Superior Region is anticipated to stay flat over the next 20 years, with a peak of 348W in 2031. Figure 5-1 shows the East Lake Superior Region's Winter peak net load forecast developed during the East Lake Superior IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. The IRRP non-coincident load forecasts for the individual stations in the East Lake Superior Region is given in Appendix D, Table D-1 and Table D-2. This forecast does not included a high industrial growth or expansion scenario, which will be studied as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region

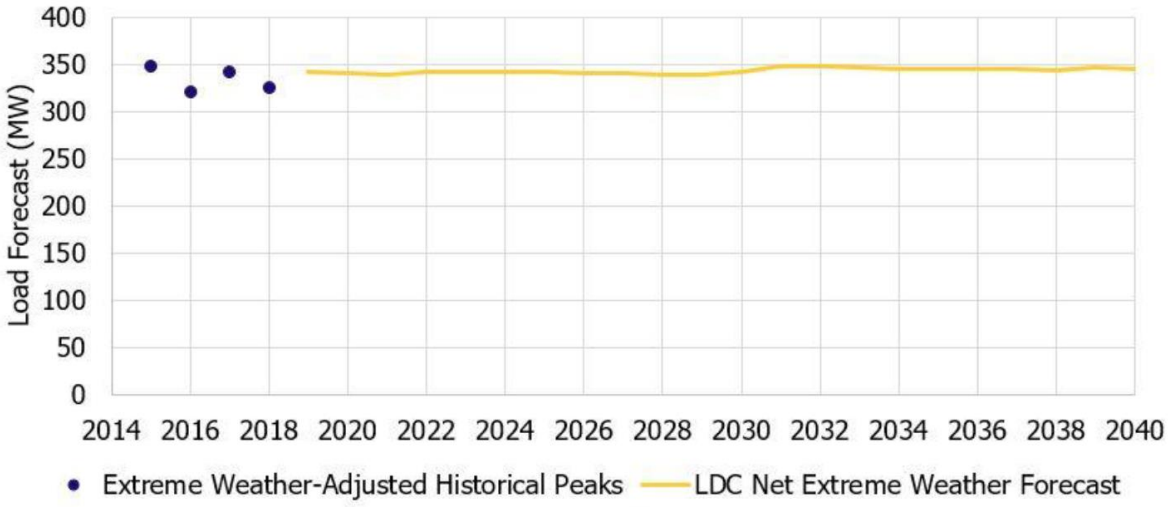


Figure 5-1: East Lake Superior Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2038.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Winter is the critical period with respect to line and transformer loadings. The assessment is therefore based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the winter 10-day Limited Time Rating (LTR).
- Autotransformers and line capacity adequacy is assessed by using coincident peak loads in the area or supplied station(s). Where a circuit is feeding radial load, the capacity adequacy is assessed by using the connected station's non-coincident peak.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- The East-West Tie Transmission Reinforcement is included in the assessment.
- Hydro-electric generation assumption is taken as the output that is coincident with the region's overall 98% dependable output. Wind generation assumption were modelled by IESO based on their summer and winter capacity contribution factors per IESO Reliability Outlook, multiplied by their peak capacity.
- Sault No.3 circuit will be refurbished and return to network configuration at 115kV.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION LINE AND TRANSFORMER STATION FACILITIES SUPPLYING THE EAST LAKE SUPERIOR REGION OVER THE PLANNING PERIOD (2019-2038). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

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

- 2019 East Lake Superior Region Needs Assessment ("NA") Report
- 2019 East Lake Superior Region Scoping Assessment ("SA") Report
- 2021 East Lake Superior Integrated Regional Resource Plan ("IRRP") and Appendices

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

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
'hot' spare transformer at Echo River TS	2023
115kV Sault No.3 circuit re-conductoring	2024

6.1 230 kV Transmission Facilities

The East Lake Superior 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1 and 3-2):

a) Mississagi TS to Third Line TS 230 kV circuits: P21G and P22G
b) Mississagi TS to Wawa TS 230 kV circuit: P25W and P26W
c) Wawa TS to Mackay TS 230 kV circuits: W23K
d) Mackay TS to Third Line 230 kV circuits: K24G

230kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single 230kV circuit in the region. Voltage concerns is observed when applying multiple contingencies on Bulk Electric System (BES) elements as per performance requirements set out in NERC TLP-001-4.

6.1.1 Voltage Concerns on following the loss of P21G and P22G

P21G and P22G are critical 230kV supply circuits that connects Third Line TS with Mississagi TS. A double circuit loss of P21G and P22G due to them being adjacent circuits on common towers, or the loss of either one circuit, followed by a contingency on the companion circuit would cause voltage decline in violation with ORTAC voltage change limits (i.e., in excess of 10%) at Third Line TS and other 115kV facilities supplied from Third Line TS throughout the planning horizon. Loss of both P21G and P22G will also result in the loss of Third Line autotransformer T1 by configuration. IESO's IRRP has determined that the voltage instability threshold for the region is reached when the GLP inflow interface exceed 230MW and both P21G and P22G are out of service.

Third line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to be armed for the loss of P21G and P22G, or the loss of T1 and T2. Currently, the IESO will direct HOSSM to arm this scheme via Hydro One's Ontario Grid Control Centre (OGCC) using manual phone call, where IESO will request arming of certain amount of load for rejection depending on prevailing system conditions. HOSSM will prioritize selection of available load blocks. IESO has expressed the need to enable remote arming of this scheme directly from IESO control room to make the arming procedure more efficient. Section 7 will discuss in more detail.

6.2 230/115 kV Autotransformers Facilities

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

a. Third Line TS 230/115 kV, 150/200/250MVA autotransformers: T1, T2
b. Mackay TS 230/115 kV, 150/200/250MVA autotransformers: T2

Loading of Third Line TS autotransformers has been identified to approach their 10-day LTR when the companion autotransformer is lost. Loading on companion autotransformer during single event contingency (N-1) would be reduced modestly beyond 2024 when the Sault No.3 circuit returns to a network at 115kV (non-radial configuration).

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is approaching its LTR limit and should continue to be monitored. Despite the fact that one of the autotransformer (T2) has been identified for end-of-life replacement by 2025, such replacement would only marginally improve supply capacity by 10MVA for Third Line's autotransformers due to LTR rating of the existing autotransformer (T1), which was put into service since 2007 and is not near End-of-Life.

6.3 115 kV Transmission Facilities

115kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single transmission element in the region. A list of circuits can be found in Appendix B. Capacity overload is observed on 115kV circuit Algoma No.1 and Sault No.3 following multiple contingencies as per performance requirements set out in NERC TLP-001-4.

6.3.1 Capacity overload on 115kV circuit Algoma No.1

A failure of breaker 214 to operate at Patrick St TS will remove Algoma No.2 and Algoma No. 3 circuits from Third Line TS to Patrick St TS by configuration. This results in thermal overload of the remaining Algoma No. 1 circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS, of which Algoma No. 1 is the lowest rated circuit out of the three. This thermal overload on Algoma No. 1 can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue which was also identified in the NA and SA report. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the Algoma No. 1 circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place. This scheme was designed as an interim solution until a more permanent solution was implemented. The IRRP has recommended a need for a more permanent solution.

6.3.2 Capacity overload of 115kV circuit Sault No.3

During an outage to either P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when No.3 Sault circuit is connected in a network configuration[4]. This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow. [5]

In addition, when one of the Third Line TS autotransformers is out of service, a Sault No.3 circuit operated as network configuration (after its proposed upgrades) helps to alleviate overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS. The risk of capacity overload on Sault No.3 circuit and area voltage decline as a result of losing both autotransformer is presently mitigated by Third line's Instantaneous Load Rejection scheme. Subjected to the outcome of IESO's 2021 Bulk Planning Study with regards to Sault No.3 overloading, the overloading may continue to be a need.

6.4 Step-Down Transformer Station Facilities

There are a total of 11 step-down transformers stations in the East Lake Superior Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations winter peak load forecast is given in Appendix D.

Table 6-2: East Lake Superior Step-Down Transformer Stations

230 kV Connected	115 kV Connected	
Echo River TS	Andrew TS	Chapleau MTS

[4] Sault No.3 circuit is currently operated radial to Mackay GS (G3) and is being refurbished as part of a sustainment project
[5] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M. By 2023, EWT tie flow will also include the flow of the new NextBridge circuits.

	Anjigami TS	Goulais TS
	Batchawana TS	Hollingsworth TS
	Clergue TS	Northern Ave TS
	Chapleau DS	St Mary CTS
	Tarentorus CTS	

Capacity of Anjigami T1 / Hollingsworth T1 & T2 are exceeded by end of 2024 based on the load forecast provided by LDC, where Hollingsworth T1 & T2 will be overload when Anjigami T1 is out of service, and vice versa. The overload is caused by loading increases on the 44kV circuit that Anjigami TS and Hollingsworth TS supply in parallel. HOSSM is working with the impacted LDC and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

6.5 Bulk Areas Need

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system outside the region. Hence, the IESO has initiated a bulk planning study for this scenario outside of the regional planning process.

Based on the reference load forecast included in the IRRP, the following bulk system need was identified and will be further coordinated with the bulk planning study described above:

- Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

Results and recommendations from the bulk planning study would be published separately. HOSSM and HONI will work with IESO to address recommendations as appropriate.

7 REGIONAL NEEDS AND PLANS

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

This section outlines and discusses electrical infrastructure needs in the East Lake Superior Region and plans to address these needs. The electrical infrastructure needs encompass both end of life replacement needs identified in the Need Assessment phase, and needs identified in section 6. A list of needs are summarized below in Table 7.1.

Table 7-1: Identified Near and Mid-Term Needs in East Lake Superior Region

Section	Facilities/Circuit	Need	Timing
7.1	Third Line TS/OGCC	Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme	Immediate
7.2	Third Line TS	End of life Protection replacement	2022
7.3	Patrick St TS, Algoma No.1 overload	Automate existing manual load curtailment scheme to meet NERC standards	Immediate
7.4	Echo River TS	Transmission Supply Reliability / End of Life 230kV Breaker replacement	2023/2024
7.5	115kV Sault No.3	Sault No.3 Structure and End of Life Conductor Replacement[6]	2024
7.6	Batchawana TS and Goulais TS	End of Life component replacement	2024
7.7	Patrick St TS	End of Life 115kV breaker replacement	2024
7.8	Third Line TS	T2 End of Life Replacement	2025
7.9	Northern Ave TS	T1 End of Life replacement	2025

[6] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

7.10	Anjigami/Hollingsworth TS	Anjigami/Hollingsworth Transformers Overload	2024
7.11	Clergue TS	End of life metal clad switch gear replacement	2026
7.12	Hollingsworth TS	End of life Protection replacement	2026
7.13	Watson TS	End of life metal clad switch gear replacement	2026

7.1 Third Line TS – Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme.

7.1.1 Description

Instantaneous Load Rejection Scheme at Third line TS are designed to respond to the loss of both P21G and P22G, or the loss of both T1 and T2. This scheme is currently armed under the direction of IESO. Upon IESO request, OGCC will manually arm the scheme and prioritized available load blocks for rejection. OGCC has established communication channels to perform arming function via Hydro One Network Management System (NMS).

7.1.2 Alternatives and Recommendation

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it will not address the manual process involved in arming of the load rejection scheme, as well as the selection of load blocks to be armed. The risk of communication delays between IESO and OGCC is not mitigated.

2. **Alternative 2 – Enable remote arming of Third Line TS Instantaneous Load rejection scheme:** Under this alternative, Hydro One will work with IESO to make necessary control points available on IESO's Energy Management System (EMS) interface such that IESO's control command can be relayed to OGCC's NMS via existing Inter-Control Centre Communication Protocol (ICCP) link, which will subsequently be relayed to Third Line's Instantaneous Load Rejection Scheme.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative because this will facilitate the automation of dispatch arming from IESO in a real-time setting, and eliminate manual communications delays between IESO and Hydro One. Further, given the ICCP infrastructure already exists, the cost to perform alternative 2 is expect to be limited to control points and status points set up in NMS and EMS respectively, as well as testing activities that can be done in both ends to ensure

functionality. The estimated cost for this upgrade is about $10,000 and is expected to in-service by end of 2021.

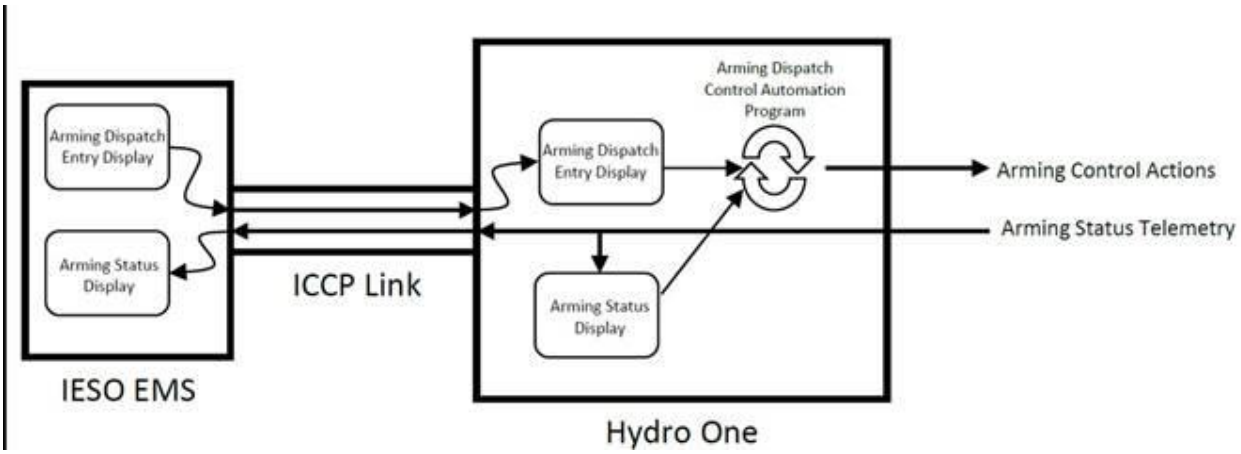


Figure 7-1: ICCP link between IESO and Hydro One.

7.2 Third Line TS – End of life Protection Replacement

7.2.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) LDC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Based on an asset condition assessment, P21G's and P22G's line protections are approaching end of life. Further, due to legacy reasons, P21G's and P22G's line protection do not meet standard physical separation requirement .

7.2.2 Alternatives and Recommendation

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

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

2. **Alternative 2 – Replace end-of-life protection as per current standard:** Under this alternative the existing end-of-life protection will be replaced with new protection relay consistent with Hydro One standard. This alternative will also implement 'A' and 'B' protection separation, which will

bring these protection be in compliance with reliability standards, addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.

The Study Team recommends Alternative 2 – replace end-of-life protection relay. The protection replacement work is expected to be complete by 2022.

7.3 Patrick St TS – Automatic Load Rejection Scheme

7.3.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on IESO IRRP findings, upon a breaker failure of breaker 214, or a contingency on either Algoma No.2 or Algoma No.3 circuit, followed by another contingency on the remaining circuit, Algoma No.1 will be overloaded beyond its STE rating during peak load. At present, a manual load shedding scheme is implemented as an interim solution until a more permanent solution is available.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the interim manual load shedding scheme need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of circuit overload during contingency and could result in equipment (overhead conductor) damage, increase public safety risk and reduce supply reliability to connected customers.

2. **Alternative 2 – Implement Automatic Load Rejection Scheme at Patrick St TS:** This alternative would implement an automatic load rejection upon the loss of Algoma No.2 and Algoma No.3 to reject load blocks and respect the existing LTE rating of Algoma No.1 circuit.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 2, consistent with recommendation from the ELS's IRRP.

7.4 Echo River TS – Install Spare 230kV Transformer (2023) and end of life 230kV breaker replacement (2024)

7.4.1 Description

Echo River TS is a 230kV load supply station. The station consists of a single 230/115/34.5kV autotransformer and a single 230kV circuit breaker (556) to supply two (2) 34.5 kV customer feeders. Historically, load at Echo River TS can be transferred to Northern Ave TS 34.5 kV feeders via the API's distribution system in case of outages at Echo River TS, such as transformer maintenance or failure.

As per the 2nd cycle of Need Assessment completed in Q2 2019 for the ELS region, it has been identified that the existing back up from Northern Ave TS can no longer provide adequate voltage support at peak load during a transformer outage at Echo River TS.

Echo River 230kV breaker 556 is a live tank minimum oil breaker, which has also been identified to be end of life and obsoleted based on asset condition assessment.

7.4.2 Alternatives and Recommendation

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

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

2. **Alternative 2 – "Cold" spare 230kV Transformer and replace end of life 230kV breaker :** install a "cold" spare in Echo River TS that is completed with new spill containment only, without 230kV and 34.5kV connection facilities and dedicated protection equipment. The spare will not normally put on potential. This alternative is not recommended as the load restoration time associated with connecting the unit and making it ready to serve load would exceed ORTAC load restoration requirement.

3. **Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker:** install a "hot" spare in Echo River TS that is completed with new 230kV and 34.5kV connection facilities, dedicated protection equipment and new spill containment systems. The spare transformer is usually on potential and ready to serve load upon switching. This alternative can significantly shorten load restoration time to respect ORTAC load restoration timeline in the event of a transformer outage due to maintenance or failure, which improves local transmission supply reliability.

The Study Team recommends Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker. The spare transformer is planned to be completed by 2023, while the breaker replacement work is planned to be completed in 2024. In lieu of replacing the breaker HOSSM will install a 230 kV circuit switcher and enable transfer trip functionality between Echo River TS and it's terminal stations.

7.5 115kV Sault No.3 Structure and Conductor Replacement

7.5.1 Description

Built in 1929, Sault No.3 is a 90 km long 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centres close to the Sault Ste. Marie area. Based on asset condition assessment, approximately 70km of the circuit's conductor from Goulais TS (str # 129) to MacKay TS is the original conductor, and has been rated between "Poor" and "Very Poor" as it has multiple component (sleeves) failures. This circuit also accounts for 39% of all line equipment related outages experienced over the 2013 – 2017 period within HOSSM's sytem. The circuit is currently de-rated as a pre-cautionary action to minimize further stress. Due to the de-rating, Sault No.3 circuit is also forced to operate in a radial

configuration to Mackay G3 to limit loading on the line. The end of life replacement work would include 'like for standard' conductor replacement and replacement of selected wood poles along the corridor as condition warrants.

HOSSM has completed the detail project defitnition work for this project. It is noted that the on-going IESO bulk system studies have considered upgrading Sault 3 to 230kV[7] as a potential solution. IESO bulk system studies is expected to be available Q4 2021. Provided that IESO's recommendation is to refurbish the line as per current plan, the project is expected to be completed by 2024.

7.5.2 Alternatives and Recommendation

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

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure of this circuit can impact the power supply to load centres close to the city of Sault Ste. Marie.

2. **Alternative 2 - Replace conductor, structures and associated End-of-Life components with Hydr One standard 115kV equipment:** Under this alternative, the existing conductor and wood pole that are assessed to be end of life will be replaced with new 115 kV rated line and structures. This alternative will also allow Sault No.3 to return to its network configuration.

The Study Team recommends Alternative 2 – the replacement of the end-of-life conductor and wood pole structures between Mackay TS and Goulais TS (str # 129) as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

7.6 Batchawana TS and Goulais – End of life Component Replacement

7.6.1 Description

Batchawana TS and Goulais Bay TS are load supply stations with single transformer to supply to the Batchawana Bay and Goulais Bay areas. Goulais Bay TS is about 30 km North of Sault Ste. Marie, while Batchawana TS is about 47 km North of Sault Ste. Marie along Hwy 17. Both are connected to 115kV No.3 Sault circuit. Figure 7-2 below shows geographical location of both station. Based on asset condition assessment, both stations are at End-of-life stage with obsoleted equipment including power transformers, protections (fuse), batteries, chargers, steel structure foundations and remote terminal units. Both stations are also built with legacy design standards and do not provide adequate clearance to today's standard. Their single transformer configuration has also made it difficult to schedule and perform maintenance.

[7] Possibly upgrading to 230kV standard and operate at 115kV until 230kV operation is needed for the bulk system.



Figure 7-2: Batchawana TS and Goulais Bay TS on 115kV circuit

7.6.2 Alternatives and Recommendation

A detailed assessment that analyzed supply options for Batchawana TS and Goulais Bay TS was carried out between HOSSM and API from 2019 -2020 to compare and evaluate supply options based on Transmission and Distribution supply reliability and performances. The assessment compared three (3) different options, they are:

- Option 1: Refurbish both Goulais Bay TS and Batchawana TS using a new 115kV, 3 –phase power transformer, with provision for a 115kV Mobile Unit substation (MUS) connection facility in each station. Transformer capacity to be sized to handle the long term peak forecast of the individual stations.

- Option 2: Consolidate Goulais Bay TS and Batchawana TS into a ‘New’ TS that is equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. The location of this ‘New’ TS would be in the vicinity of Goulais bay.

- Option 3: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS with dedicated 25kV "express feeder" between Goulais and Batchawana. This 'New' TS would be located in the vicinity of Goulais bay, and be equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. An additional 25/12.5kV unit is required on the distribution system in the vicinity of Batchawana bay to convert voltage from the incoming 25kV dedicated "express feeder" to 12.5kV in order to supply distribution sub-system in the vicinity of Batchawana bay.

Depending on the choice of distribution voltage, there are two (2) different scenarios (12.5kV vs 25kV) for each option above. Evaluation of alternatives was completed by HOSSM and API as documented in the 2021 East Lake Superior Regional Local Planning Report. As per the report's recommendation, HOSSM is proceeding with option 1 - Refurbish both Goulais Bay TS and Batchawana TS. More details related to the supply option analysis can be found in the Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020), available on Hydro One public website. Refurbishment for both stations are expected to be completed in 2024.

7.7 Patrick St TS – End of life 115kV breaker replacement

7.7.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on asset condition assessment, breaker 208, 211, 214 and 217 are minimum oil live tank breakers that are considered End of Life and obsolete.

7.7.2 Alternatives and Recommendation

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

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

2. **Alternative 2 - Replace the end-of-life breakers with new standard breakers:** This alternative involves the replacement of breaker 208, 211, 214 and 217 with new SF6 breakers in similar ratings.. This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers connected at Patrick St TS by reducing the risk of breaker failure; and reducing on-going maintenance cost associated with obsolete breaker technology.

Alternative 2 is recommended. The project is expected to be completed by 2024.

7.8 Third Line TS – T2 End of Life Replacement

7.8.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) PUC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Among the 2 autotransformers, T2 is at end of life based on asset condition assessment. Based on long term load forecast, units with similar ratings are required for the end of life autotransformer T2 replacement.

7.8.2 Alternatives and Recommendation

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

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

2. **Alternative 2 – Replace T2 with equivalent size unit as per current standard:** This alternative would replace old T2 with a unit that has equivalent rating. This is recommended alternative as it will mitigate risk of autotransformer failure due to its deteriorating conditions and maintain supply reliability of the region.

3. **Alternative 3 – Replace T2 with larger size unit:** This alternative would replace old T2 with a unit that has higher rating. This alternative is rejected as a 230/115kV autotransformer at 150/200/250MVA is currently the highest rating available based on HOSSM and Hydro One standards.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.9 Northern Ave TS – T1 End of Life Replacement

Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 is at end of life. Historically, Northern Ave TS has been used as a backup supply to Echo River TS to facilitate outages. Reliance on Northern Ave TS is expected to reduce starting 2023 as the spare unit at Echo River TS comes into service in 2023. The longer term forecast for Northern Ave TS peaks at 2.7MW.

7.9.1 Alternatives and Recommendation

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

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

2. **Alternative 2 – Replace T1 with a smaller MVA size unit as per current standard:** This alternative would replace T1 with a 'like for similar' unit that has a smaller MVA rating compared to existing T1, and would be adequate for Northern Ave's long term load forecast. This is recommended alternative as it will mitigate risk of transformer failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.10 Anjigami/Hollingsworth TS – Transformer overload.

Anjigami TS is a 115kV/44kV load supply station with a single transformer. Hollingsworth TS is a 115kV/12.5kV/44kV station that supplies load on 44kV, and connected to Hollingsworth CGS on the 12.5kV. Anjigami's and Hollingsworth's 44kV feeders are connected to each other with a 10km long 44kV line to supply LDC load on No.4 circuit. Base on LDC load forecast, load increase on 44kV system by end of 2024 would exceed transformer capacity in both Anjigami TS and Hollingsworth TS when the companion station is out of service. HOSSM is working with API and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

7.10.1 Alternatives and Recommendation

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

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the transformer capacity needs based on load forecast.

2. **Alternative 2 – Replace Anjigami T1, Hollingsworth T1 and T2 with a larger MVA size units as per current standard to handle load increases:** This alternative is considered but not recommended as both Anjigami TS and Hollingsworth TS have a limited footprint, and site expansion would be required for both sites for such upgrade. Further, due to Hollingsworth TS existing configuration, upgrades are also required on all existing 12.5kV facilities, including disconnect switches, breakers, and overhead bus work to accommodate the load increase.

3. **Alternative 3 – Build new 115/44kV 'Limer TS' that will be supplied from Hollingsworth 115kV circuit, transfer existing LDC load from existing 44kV system to 'Limer TS' :** This alternative would build a new 115/44kV station in the vicinity of Hollingsworth TS and tap off from 115kV Hollingsworth circuit to supply new loads as well as existing load that are presently supplied by Anjigami/Hollingsworth 44kV system. The new station would be similar to a DESN station with two (2) 115/44kV, 50/67/83MVA transformers as per current HONI standard, HV

and LV connection facilities such as circuit switchers and feeder breakers, modern protections and telecommunication systems to service the new load. API will re-route their 44kV feeder(s) and connect to 'Limer TS'.

Given the alternatives above, Alternative 3 is recommended because it is expected to be the most cost efficient alternatives. Compared to Alternative 2, where it will require the coordination of 2 environmental approvals at different sites for site expansion, replacement of three (3) transformer (Anjigami T1, Hollingsworth T1 and T2), and upgrade on existing 12.5kV equipment at Hollingsworth TS, Alternative 3 has a more concise scope. Building new station will also have less outage constraints when compared to upgrading existing facilities. HOSSM will continue to work with API to develop a local solution. The project is expected to be completed by end of 2024/early 2025.

7.11 Clergue TS - End of life metal clad switch gear replacement

Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on an asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is at End-of-Life and obsoleted

Based on the load forecast and expected system conditions, similar equipment ratings are required for end of life replacement.

7.11.1 Alternatives and Recommendation

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

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

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of switch gear failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

7.12 Hollingsworth TS – End of life Protection Replacement

Hollingsworth TS is a 115kV station that connects Hollingsworth Generating Station and is supplied by Hollingsworth 115kV circuit. Majority of protection relay equipment in Hollingsworth TS were in-serviced 2005. Based on asset condition assessment, the existing protection relay would approach end of life by 2025.

7.12.1 Alternatives and Recommendation

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

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

2. **Alternative 2 – Replace end of life protection with "like for like" protection relay as per current standard:** This alternative would replace identified end of life protection relays with as per current standard. This is recommended alternative as it will mitigate risk of protection relay failure due to their deteriorating conditions and maintain supply reliability to connected customers.

Alternative 2 is recommended. The project is expected to be completed by 2025

7.13 Watson TS - End of life Metal Clad switch gear replacement

DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders using metal clad switch gear. Based on an asset condition assessment, the existing minimal oil metalclad switch gear are at End of life and obsolete

7.13.1 Alternatives and Recommendation

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

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

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of equipment failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE EAST LAKE SUPERIOR REGION.

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

Table 8-1: Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life Protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[8]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M
8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M

[8] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

12	Clergue TS: End of life metal clad switch gear	Replace end of life switch	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protections	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear	2026	$9.2M

The Study Team recommends that:

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

9 REFERENCES

[1] East Lake Superior Region Needs Assessment (2019)

[2] East Lake Superior Region Scoping Assessment (2019)

[3] Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020)

[4] East Lake Superior Integrated Regional Resource Plan (2021)

[5] East Lake Superior Integrated Regional Resource Plan - Appendices (2021)

APPENDIX A. STATIONS IN THE EAST LAKE SUPERIOR REGION

Station	Voltage (kV)	Supply Circuits
Andrews TS	115/25	Andrew 115kV
Anjigami TS	115/44	High falls No.1 /Highfalls No.2
Batchawana TS	115/12.5	Sault No.3
Chapleau DS	115/25	W2C
Chapleau MTS	115kV	W2C
Clergue TS	115/12.5	Clergue No.1 / Clergue No.2
D.A. Watson TS	115/34.5	Magpie 115kV/High falls No.1 /Highfalls No.2
Echo River TS	230/34.5	P22G
Flakeboard CTS	115	Leigh's Bay 115kV
Gartshore SS	115	Gartshore No.1 / Gartshore No.2/ Gartshore No.3 / Hogg 115kV / Andrews 115kV
Gold Mine CTS (Magnacon Mine)	115	Steephill 115kV
Goulais Bay TS	115/12.5	Sault No.3
Heyden CSS	230	K24G
Hollingsworth TS	115/12.5/44	Hollingsworth 115kV
Hwy 101 SS	44	Anjigami 44kV/Limer 44kV
Mackay TS	230	K24G/W23K
Mackay TS	115	Gartshore No.1 / Gartshore No.2/ Mackay No.1/Mackay No.2/Sault No.3
Magpie SS	115	Harris 115kV/Steephill 115kV /Mission Falls 115kV/Magpie 115kV
Mile Hill CTS	230	K24G
Northern Ave. TS	115/34.5/12.5	Northern Ave 115kV
Patrick St. TS	115/34.5	Algoma No.1/No.2/No.3 , Clergue No.1 /No.2
St Mary CTS	115/34.5	GL1SM / GL2SM
Tarentorus CTS	115/34.5	GL1TA / GL2TA
Third Line TS	230	K24G/P21G/P22G
Third Line TS	115	Sault No.3, Algoma No.1/No.2/No.3, Northern Ave 115kV
Wallace Terrace CTS	115/34.5	Leigh's Bay 115kV

Wawa TS	230	P25W/P26W/W21M/W22M/W35M*/W36M*
Wawa TS	115	W2C/ Hollingsworth 115kV

*after the completion of East West Tie

APPENDIX B. TRANSMISSION LINES IN THE EAST LAKE SUPERIOR REGION

Location	Circuit Designations	Voltage (kV)
Mississagi x Third line	P21G , P22G	230
Mississagi x Wawa	P25W, P26W	230
Third line x Mackay	K24G	230
Mackay x Wawa	W23K	230
Third line x Mackay	Sault No.3	115
Third line x Patrick St.	Algoma No.1 / No.2 / No.3	115
Third line x Norther Ave	Northern Ave 115kV	115
Third line x St Mary CTS	GL1SM, GL2SM	115
Third line x Tarentorus CTS	GL1TA , GL1TA	115
Patrick st x Flakeboard CTS	Leigh's Bay 115kV	115
Patrick St. x Clergue TS	Clergue No.1 / No.2	115
Mackay GS x Mackay TS	Mackay No.1 / No.2	115
Gartshore SS x Mackay TS	Gartshore No.1 / No.2	115
Gartshore SS x Hogg CGS	Hogg 115kV	115
Gartshore SS x Andrew CGS	Andrew 115kV	115
Magpie SS x Mission Falls CGS	Mission falls 115kV	115
Magpie SS x Steephill CGS	Steephill 115kV	115
Magpie SS x Harris CGS	Harris 115kV	115
Magpie SS x DA Watson TS	Magpie 115kV	115
DA Watson TS x Wawa TS	High Falls No.1/No.2	115
Hollingsworth TS x Wawa TS	Hollingsworth 115kV	115

Anjigami TS x Hwy 101 SS	Anjigami 44kV	44
Hollingsworth TS x Hwy 101 SS	Limer 44kV	44

APPENDIX C. DISTRIBUTORS IN THE EAST LAKE SUPERIOR REGION

Distributor Name	**Station Name**	**Connection Type**
Algoma Power Inc.	Andrew TS	Tx
	Anjigami TS	Tx
	Batchawana TS	Tx
	D.A. Watson TS	Tx
	Echo River TS	Tx
	Goulais TS	Tx
	Mackay TS (115kV)	Tx
	Northern Ave TS	Tx
	Hollingsworth TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Chapleau PUC	Chapleau MTS	Tx
Hydro One Networks Inc. (Dx)	Chapleau DS	Dx
PUC Distribution	St Mary CTS	Tx
	Tarentorus CTS	Tx

APPENDIX D. EAST LAKE SUPERIOR REGION LOAD FORECAST

Table D-1: East Lake Superior Non-coincident peak Load Forecast, with the Impacts of Energy-Efficiency Savings per station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.56	1.85	1.86	1.88	1.90	1.91	1.93	1.95	1.97	1.98	2.00	2.02	2.04	2.05	2.06	2.08	2.10	2.12	2.14	2.15
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.00	8.00	9.49	9.81	10.40	10.70	10.76	10.83	10.90	10.96	11.01	11.07	11.13	11.18	11.23	11.29	11.36	11.43	11.50	11.57
Limer TS	13.18	13.74	13.81	13.88	13.99	54.00	54.00	28.62	28.65	28.68	28.70	28.76	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	4.59	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

Table D-2: East Lake Superior Forecasted Impacts of Energy-Efficiency Savings due to Codes , Standards and Funded CDM Program

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

Table D-3: East Lake Superior IRRP Forecasted DER by station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00



NEEDS ASSESSMENT REPORT

East Lake Superior

Date: October 9, 2024

Needs Assessment Report

East Lake Superior

Date: October 9, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: East Lake Superior Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the East Lake Superior region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on best available information throughout the planning process.

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Executive Summary

REGION	East Lake Superior Region (the "Region")		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE:	June 11, 2024	**END DATE:**	October 9, 2024

1. INTRODUCTION

This is the third cycle of Regional Planning for the region. The second cycle Regional Planning for the East Lake Superior ("ELS") Region was completed in October 2021 with the publication of the Regional Infrastructure Plan ("RIP") report.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous Regional Planning cycle; and,

b) Recommend which needs:

i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,

ii) do not require further regional coordination (i.e., can be addressed directly between a transmitter and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in June 2024 for the ELS Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the ELS Region NA includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),

b) Identify any new needs resulting from this assessment,

c) Recommend which need(s) requires further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and

d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between connecting transmitter and the impacted LDC(s) to develop a preferred plan

and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is ten years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The ELS region spans from Mississagi TS near Wharncliffe to Wawa TS in the township of Wawa, encompassing the city of Sault Ste. Marie. The 230 kV circuits in the Region provide electric power to the Region and facilitate power flow across the province. The 115 kV network emanating from Third Line TS supplies majority of the load in the city of Sault Ste. Marie, whereas the 115 kV network at Mackay TS connects local wind and hydro generation to the transmission network. The 115 kV system out of Wawa TS is used to supply local load and to connect local generation in the area.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), PUC-Transmission LP and Hydro One and provides input and relevant information for the ELS Region regarding capacity needs, reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and operational concerns;

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs and projects discussed in the second ELS RIP cycle have been completed.

- Providing remote arming of Third Line TS Instantaneous Load Rejection ("ILR") scheme to the IESO: completed in 2023/2024.
- Echo River TS – Install new transformer and breaker replacement: project completed in 2024.

Needs from the second ELS RIP cycle that already have a planned project are shown below.

- Third Line TS – End-of-life P21G/P22G protection replacement: planned in-service year for the project is 2027.
- Third Line TS – Autotransformer T2 replacement: planned in-service year for the project is 2027.
- Sault No.3 – End-of-life Line replacement: planned in-service year for the project is 2026.
- Batchawana TS – End-of-life components replacement: Algoma Power Inc ("API") has requested Hydro One Sault Ste. Marie ("HOSSM") to procure equipment and build the LV yard capable of operating at 25 kV in the future. The project is being executed with expected completion in Q4 2024.
- Goulais TS – End-of-life components replacement: API has requested HOSSM to procure equipment and build the LV yard capable of operating at 25 kV in the future. API has also requested for another feeder position to improve reliability within their distribution system. API and HOSSM are to continue coordination activities. Planned in-service year for the project is 2028.
- Patrick St. TS – End-of-life 115 kV breaker replacement: planned in-service year for the project is 2028.
- Northern Ave TS – End-of-life Transformer T1 replacement: planned in-service year for the project is 2030.
- Clergue TS – End-of-life Metal clad switchgear replacement: planned in-service year for the project is 2028.
- Hollingsworth TS – End-of-life protection replacement: planned in-service year for the project is 2031.
- D.A. Watson – End-of-life Metal clad switchgear replacement: planned in-service year for the project is 2031.

II. Newly identified needs or needs requiring further review

a) Asset Renewal for Major HV Transmission Equipment

- St. Mary's MTS and Tarentorous MTS – station refurbishment/upgrade

b) Transformation Capacity

- Anjigami TS and Hollingsworth TS – transformer overload due to growing demand in the load pocket.
- Third Line TS – 230/115 kV autotransformer reaches 90% of LTR upon the loss of companion unit.
- Tagona West TS – 230/115 kV autotransformer overload upon the loss of companion unit.

c) Transmission System Capacity

- Algoma No.1/ No.2/ No.3 – circuit overload after loss of any two Algoma circuits.
- Sault No. 3 – circuit overload.

d) Voltage Performance

- Voltage violation at Third Line TS after the loss of both autotransformers.

e) System Reliability, Operation and Load restoration

- Third Line TS – voltage limitations: The 115 kV bus can only be operated in a narrow range of 118 kV – 124 kV

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. Due to the nature of load inquiries in the Region, the TWG agreed to assess sensitivity scenarios by adding a large load of 200 MW at the following locations in the Region:

a. Double circuit tap to the new 230 kV circuits P23G/P24G
b. Direct connection to 230 kV bus at Tagona West TS
c. Direct connection to 230 kV bus at Mackay TS

As per the sensitivity analysis, no new needs arise due to the addition of a large load in the ELS region. However, the analysis does indicate a few emerging needs that can be monitored as the load in the region grows. Based on the analysis findings no immediate action is required.

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the Regional Planning cycle. A list of these needs is provided below.

- St. Mary's MTS and Tarentorous MTS – need is recommended for further review in the next phases of RP.
- Third Line TS – 230/115 kV autotransformer reaches 90% of LTR upon the loss of companion unit: Continue to monitor the loading of the autotransformers at Third Line TS.
- Tagona West TS – 230/115 kV autotransformer overload upon the loss of companion unit: PUC Transmission intends to implement manual load reduction with connecting load customer to mitigate the need. To be further studied as part of the System Impact Assessment ("SIA") and accordingly documented in the next phases of RP.
- Algoma No.1/ No.2/ No.3 – circuit overload after loss of any two Algoma circuits: Need can be mitigated by cross-tripping overloaded circuit using the Third Line RAS, rejecting all load at Patrick St. TS. Recommended to review refining the amount of load rejected in the next phases of RP.
- Sault No.3 – circuit overload: During an outage of P25W or P26W, a loss of K24G can result in an overload of Sault No.3. The need can be mitigated by cross-tripping Sault No.3 using Mackay Generation Rejection scheme. Recommended to review necessity of Sault No.3 cross-trip in the next phases of RP, in coordination with SIA for the new northeast bulk projects.
- Voltage violation at Third Line TS: The violations can be mitigated by using Load Rejection (LR) schemes and/or RAS at Third Line TS. Recommended to review the necessity Third Line TS LRs and RAS contingencies in the next phases of RP, in coordination with SIA for the new northeast bulk projects.
- Third Line TS – 115 kV voltage limitations: Existing voltage limit at Third Line TS 115 kV bus is restricted to operate between 118 kV - 124 kV range. Recommended to monitor need until PUC Distribution replaces existing transformers with new units equipped with ULTC at St. Mary's MTS and Tarentorous MTS.

II. Needs that do not require further regional coordination

These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

generally impact a limited number of LDCs and can be addressed directly between applicable transmitter(s) and the LDC(s) to develop a preferred local plan. The need is provided below:

- Anjigami TS and Hollingsworth TS – transformer overload: Assess solution options via a Local Plan between API and HOSSM.

All LDCs in the TWG will be participating in further Regional Planning activities.

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1. INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the East Lake Superior (''ELS'') region (the "Region") was completed in October 2021 with the publication of the Regional Infrastructure Plan ("RIP") Report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the ELS Region. The purpose of this Needs Assessment ("NA") is to:

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

A flow chart of the Regional Planning Process is shown in Figure 1 below.

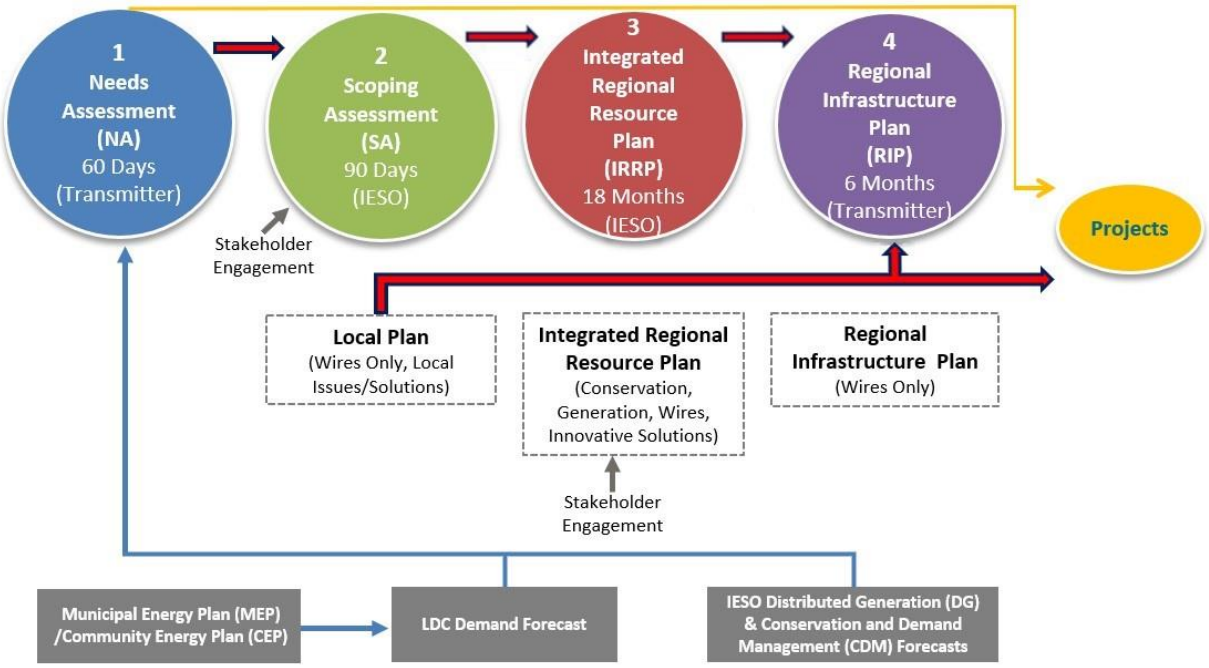


Figure 1: Regional Planning Process

This report was prepared by the ELS Technical Working Group ("TWG"), led by Hydro One Networks Inc (Transmission). The report presents the results of the assessment based on information provided by the

transmitters, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 1.

Table 1: East Lake Superior Region TWG Participants

Sr. no.	Name of TWG Participants
1	Algoma Power Inc.
2	PUC Transmission
3	PUC Distribution
4	Hydro One Transmission (HONI, HOSSM)
5	Hydro One Distribution
6	Independent Electricity System Operator

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the third Regional Planning cycle was triggered for the ELS region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the East Lake Superior region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) requires further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between the connecting transmitter(s) and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group ("TWG") may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan ("LP") and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The ELS region spans from Mississagi Transformer Station ("TS") near Wharncliffe, Ontario to Wawa TS in the town of Wawa, Ontario encompassing the city of Sault Ste. Marie and surrounding areas. The newly formed transmitter, PUC Transmission LP along with Hydro One Sault Ste. Marie ("HOSSM") and Hydro One Network Inc. are the three transmitters in the Region. Algoma Power Inc., PUC Distribution and Hydro One Distribution are the three LDCs in the Region responsible for distribution of electric power to residential, commercial and industrial customers at sub-transmission levels (69 kV and under).

The 230 kV circuits in the Region provide bulk electric power to the Region and facilitate power flow across the province. The 115 kV network emanating from Third Line TS supplies majority of the load in the city of Sault Ste. Marie, whereas the 115 kV network at Mackay TS connects local wind and hydro generation to the transmission network. The 115 kV system out of Wawa TS is used to supply local load and to connect local generation in the area.

After conclusion of the last regional planning cycle in 2021, the IESO completed bulk system studies for northeast Ontario and issued a study report in October 2022. An additional voltage study report identifying reactive requirements for northern Ontario was published in December 2023. The reports recommended the following infrastructure projects to supply growing electricity demand in Sault Ste. Marie and Timmins.

i. A new 500 kV line between Hanmer TS and Mississagi TS – Planned completion by 2029.
ii. A new 230 kV double circuit line between Mississagi TS and Third Line TS – Planned completion by 2029. The nomenclature used for the new circuits in this report is P23G and P24G and is subject to change in the future.
iii. A new 230 kV line between Porcupine TS and Wawa TS, built to operate at 500 kV in the future – Planned completion by 2030.
iv. Reactive devices identified in the voltage study:
    - One new -120 Mvar line reactor at Mississagi TS end for the new 500 kV line between Hanmer TS and Mississagi TS – Planned completion by 2029.
    - One new +/-100 Mvar STATCOM at Mississagi TS (230 kV) – Planned completion by 2029.
    - One new +/-100 Mvar STATCOM at Algoma TS – Planned completion by 2029.

In addition to the bulk reinforcement projects, the newly formed transmitter PUC Transmission, will build a new 230 kV double circuit line from Third Line TS to a new station named Tagona West TS which will

facilitate supply of electric power to the new Electric Arc Furnaces ("EAF") facility. Planned completion of the project is within the assessment study period.

The geographical boundaries of the East Lake Superior region are shown in Figure 2 below.

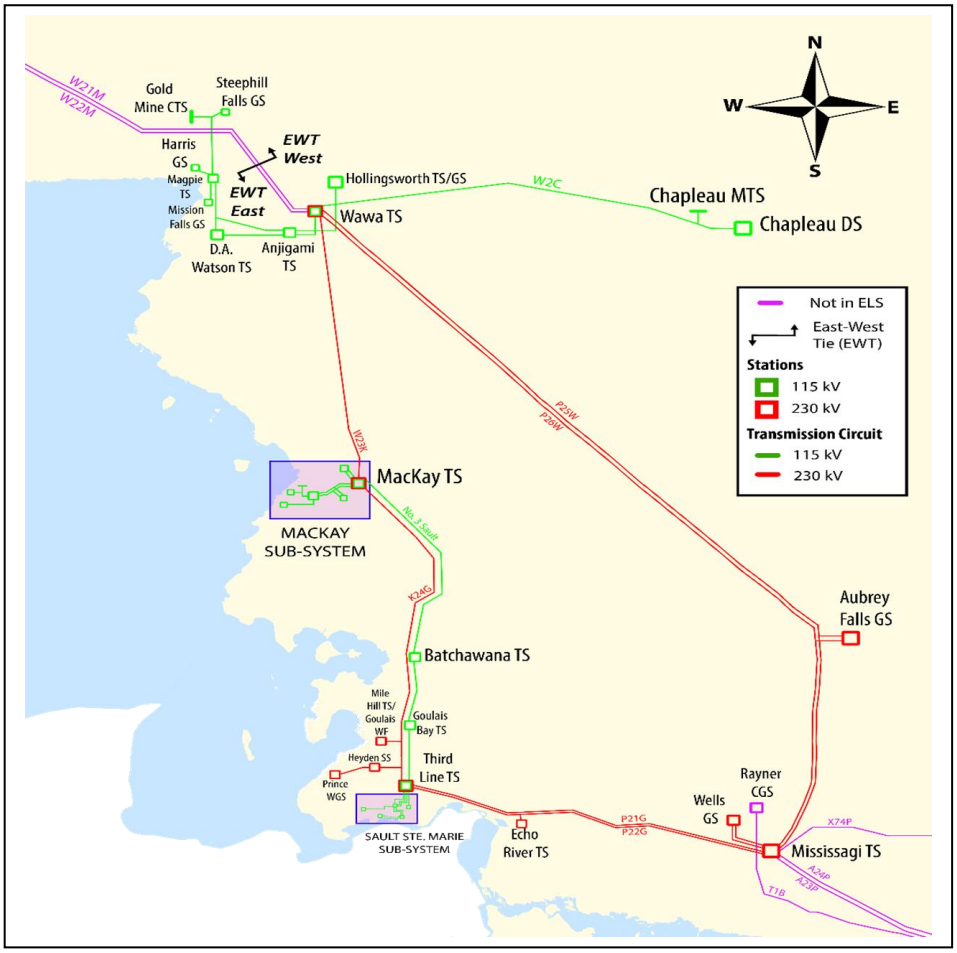


Figure 2: Map of East Lake Superior Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the ELS Region

44 kV circuits	115 kV circuits	230 kV circuits	Transformer Stations	Generation Stations
Anjigami No.1, Limer No.1	Sault No.3, Algoma No.1 / No.2 / No.3, Northern Ave 115kV, GL1SM, GL2SM, GL1TA, GL1TA, Leigh's Bay 115kV, Clergue No.1 / No.2, Mackay No.1 / No.2, Gartshore No.1 / No.2, Hogg 115kV, Andrew 115kV, Mission falls 115kV, Steephill 115kV, Harris 115kV, Magpie 115kV, High Falls No.1/No.2, Hollingsworth 115kV	P21G, P22G; P25W, P26W; K24G; W23K; **Planned ccts:** P23G, P24G; Third Line x Tagona W (double circuit)	Andrews TS, Anjigami TS, Batchawana TS, Chapleau DS, Chapleau MTS, Clergue TS, D.A. Watson TS, Echo River TS, Gartshore TS, Gartshore SS, Goulais Bay TS, Heyden CSS, Hollingsworth TS, Hwy 101 SS, Mackay TS*, Magpie TS, Northern Ave. TS, Patrick ST. TS, St. Mary's MTS, Tarentorous MTS, Third Line TS*, Wawa TS*, CTS1, CTS2, CTS3, CTS4, CTS5, CTS6 **Planned stations** Tagona West TS	Steephill Falls GS, Mission Falls GS, Harris GS, Lake Superior Power GS, Clergue GS, Prince WGS, Wells GS, Goulais WF, Gartshore GS, Mackay GS, Hogg GS, Bow Lake GS, Andrew GS, Aubrey Falls GS, Hollingsworth GS, McPhail GS, Scott GS

**Stations with Autotransformers installed*

The single line diagram of the transmission network of the ELS region is shown in Figure 3 below.

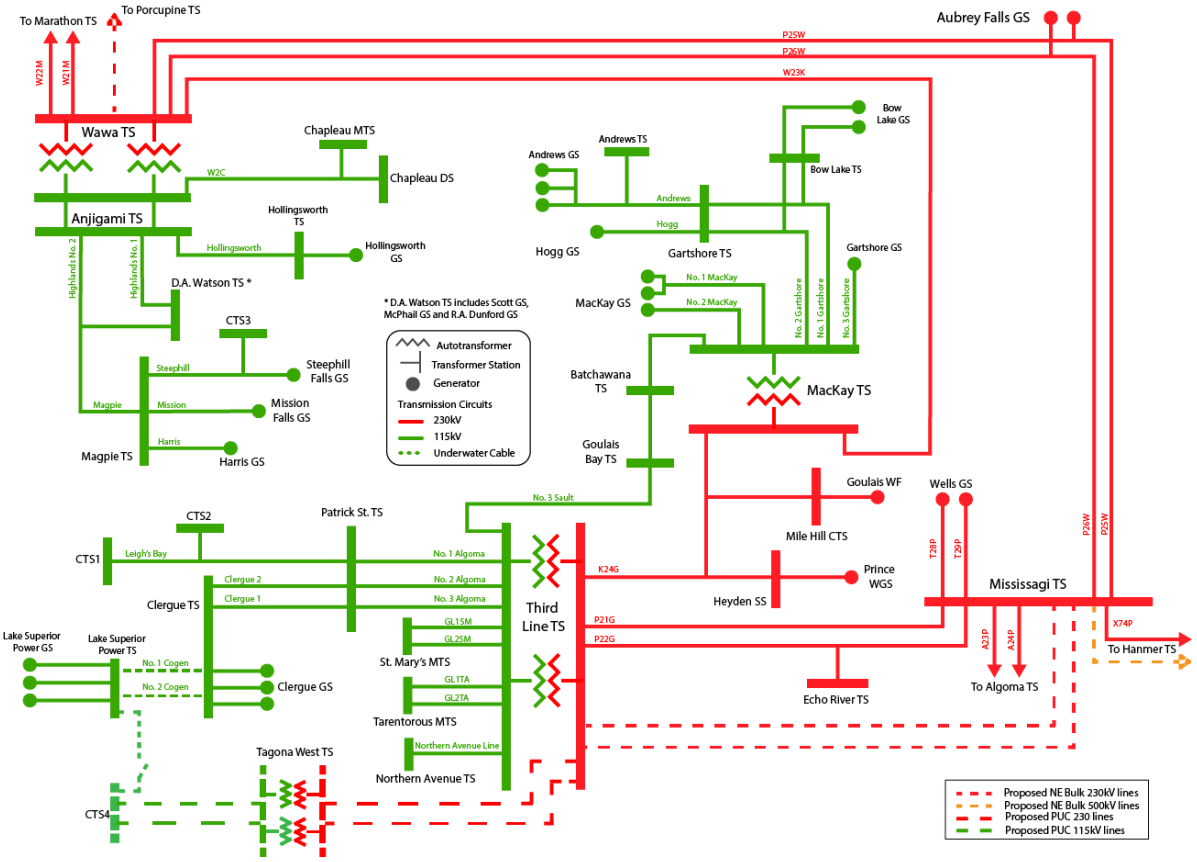


Figure 3: East Lake Superior Transmission Single Line Diagram

5. INPUTS AND DATA

The TWG participants provided information and input required for the preparation of the Needs Assessment report. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called “Load Forecast Guideline for Ontario” in October 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC’s load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix E.

The information provided includes the following:

- The ELS region 10-year Load Forecast for all supply stations is inclusive of the inputs provided by the municipalities through their MEPs & CEPs and through LDCs engagement with the municipalities and communities.

- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment.
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the ELS region.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing”.
- Load forecast data provided by LDCs and industrial customers in the region.
- 115 kV circuit Sault No. 3 is operating in network configuration between Third Line TS and Mackay TS.
- Existing load at Tarentorous MTS is assumed to be moved to the new Tagona West TS by 2030.
- This assessment is based on extreme summer and winter peak loads. The sensitivity scenario was developed by adding a large load at different locations in the region to conduct an analysis to cover unforeseen developments such as large industrial loads or higher than expected EV charging demand.

The following other assumptions are made in this report:

- The 10-year study period for this Needs Assessment is 2024-2033.
- The Region is winter peaking; however this assessment is based on summer and winter peak loads to account for equipment ratings often being more limiting in the summer.
- Line and autotransformer capacity adequacy is assessed by using coincident peak loads in the area.
- Load serving station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for Hydro One transformer stations is determined by the summer 10-Day Limited Time Rating (LTR) of a single transformer for Hydro One stations.

- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering process

6.2.1. Load forecast:

The LDCs provided their load forecast for summer and winter season for all the stations supplying their loads in the ELS region for the 10-year study period including the inputs from the municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM"), and Distributed Generation ("DG") forecast for the ELS region. The region's extreme summer/winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2023 summer and winter peak extreme weather corrected loads. The extreme summer and winter weather correction factors were provided by Hydro One. The net extreme seasonal weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, the load forecast may show a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer and winter weather corrected net load forecast for the individual stations in the ELS region is given in Appendix A. The region's extreme winter coincident net load forecast graph is provided in Figure 5. The graph shows the growth of the region within the study period of 2024 – 2033. In 2033, the Region's coincident peak is forecast to be approximately 762 MW.

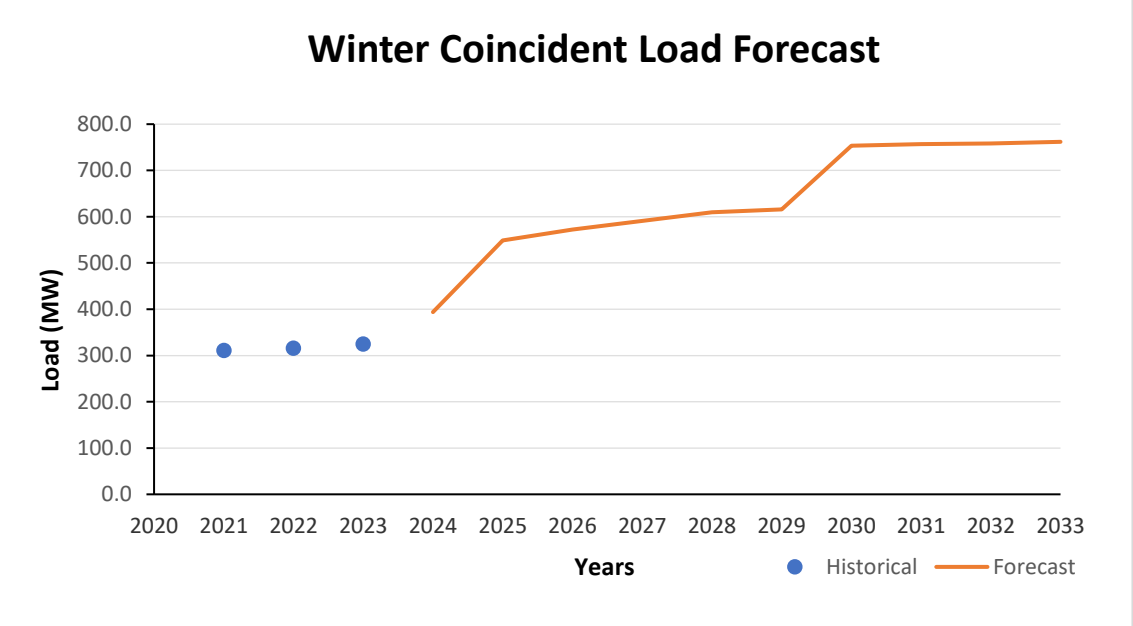


Figure 4: Winter Coincident Load Forecast

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. The NA recommendations are not necessarily linked to sensitivity scenarios; but rather the sensitivity is used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis are provided in section 8 of this report.

6.2.3. Asset renewal Needs for Major HV Equipment:

Section 7.1 lists major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV breakers, HV underground cables and overhead lines.

6.2.4. System Reliability and Operational Issues:

Relevant information regarding system reliability and operational issues in the region as feedback provided by the IESO and Hydro One Operations during the NA phase.

7. NEEDS

This section describes emerging new needs identified in the Region and/or updates on previously identified needs since the completion of previous regional planning cycle.

Needs identified and discussed in the previous regional planning cycle, along with associated projects recently completed, as well as reaffirmed needs currently in progress, are briefly outlined below with relevant updates. These will not be discussed further in the report. These projects include:

1. Providing remote arming of Third Line TS Instantaneous Load Rejection ("ILR") scheme to the IESO – completed in 2023/2024.
2. Third Line TS – End-of-life P21G/P22G protection replacement: planned in-service year for the project is 2027.
3. Third Line TS – Autotransformer T2 replacement: planned in-service year for the project is 2027.
4. Echo River TS – Install new transformer and breaker replacement: project completed in 2024.
5. Sault No.3 – End-of-life Line replacement: planned in-service year for the project is 2026.
6. Batchawana TS – End-of-life components replacement: API has requested HOSSM to procure equipment and build the LV yard capable of operating at 25 kV in the future. The project is being executed with expected completion in Q4 2024.
7. Goulais TS – End-of-life components replacement: API has requested HOSSM to procure equipment and build the LV yard capable of operating at 25 kV in the future. API has also

requested for another feeder position to improve reliability within their distribution system. API and HOSSM are to continue coordination activities. Planned in-service year for the project is 2028.

8. Patrick St. TS – End-of-life 115 kV breaker replacement: planned in-service year for the project is 2028.
9. Northern Ave TS – End-of-life Transformer T1 replacement: planned in-service year for the project is 2030.
10. Clergue TS – End-of-life Metal clad switchgear replacement: planned in-service year for the project is 2028.
11. Hollingsworth TS – End-of-life protection replacement: planned in-service year for the project is 2031.
12. D.A. Watson – End-of-life Metal clad switchgear replacement: planned in-service year for the project is 2031.

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

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
St. Mary's MTS and Tarentorous MTS – station refurbishment/upgrade	Recommended for further review in the next phases of RP.	N/A	7.1.1
Station Capacity Needs			
Anjigami TS and Hollingsworth TS – transformer overload	Assess solution options via a Local Plan between API and HOSSM.	7.10	7.2.1
Third Line TS – 230/115 kV autotransformer reaches 90% of LTR upon the loss of companion unit	Continue to monitor the loading of the autotransformers at Third Line TS.	6.2	7.2.2
Tagona West TS – 230/115 kV autotransformer overload upon the loss of companion unit	PUC Transmission intends to implement manual load reduction to mitigate the need. Recommended for further study as part of the SIA and accordingly documented in the next phases of RP.	N/A	7.2.3
Transmission Line Capacity Needs			
Algoma No.1/ No.2/ No.3 – circuit overload after loss of any two Algoma circuits	Need can be mitigated by cross-tripping overloaded circuit using the Third Line RAS, rejecting all load at Patrick St. TS.	7.3	7.3.1

	Recommended for further review in the next phases of RP.		
Sault No. 3 – circuit overload	Need can be mitigated by cross-tripping Sault No.3 upon the loss of K24G (during a P25W or P26W outage) using Mackay Generation Rejection scheme. Recommended to review necessity of Sault No.3 cross-trip in the next phases of RP, in coordination with SIA for the new northeast bulk projects.	6.3.2	7.3.2
Voltage Performance			
Voltage violation at Third Line TS	The violations can be mitigated by using Load Rejection (LR) schemes and/or RAS at Third Line TS. Recommended to review the necessity Third Line TS LRs and RAS contingencies in the next phases of RP, in coordination with SIA for the new northeast bulk projects.	6.1.1	7.4.1
System Reliability, Operation and Load restoration Needs			
Third Line TS – 115 kV voltage limitations	Existing voltage limit at Third Line TS 115 kV bus is restricted to operate between 118 kV - 124 kV range. Recommended to monitor need until PUC Distribution replaces existing transformers with new units equipped with ULTC at St. Mary's MTS.	N/A	7.5.1

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, the TWG has also identified new asset renewal needs for major equipment that are expected to be replaced over the next 10 years in the ELS Region. The list of major HV transmission equipment requiring replacement in the ELS Region is provided in table 4 in this section.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors
- Technical obsolescence due to outdated design
- Lack of spare parts availability or manufacturer support

- Potential health and safety hazards, etc.

The major equipment information shared and discussed as part of this process is listed below:

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

The Asset renewal assessment considers the following options for "right sizing" the equipment:

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

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region (New)

Station/Circuit	Need Description	Planned ISD
St. Mary's MTS and Tarentorous MTS	Station Refurbishment/Upgrade	2030

7.1.1 St. Mary's MTS and Tarentorous MTS – Station Upgrade

St. Mary's MTS and Tarentorus MTS are 115/34.5 kV transformer stations owned and operated by PUC Distribution in the city of Sault Ste. Marie. Each station is supplied by two (2) 115 kV circuits from Third Line TS, has four (4) 30 MVA, 115/34.5 kV step-down transformers and four (4) 115 kV disconnect switches. All assets in both stations are approaching end-of-life and recommended for replacement in the near to mid-term planning horizon.

PUC Distribution retained a consultant to assess alternatives for station refurbishment/upgrade for both stations. As part of the assessment, alternatives to change primary supply voltage from 115 kV to 230 kV

at Third Line TS were investigated. The assessment also investigated retiring Tarentorous MTS and moving the station load from Third Line TS to the new Tagona West TS.

The TWG recommends to further review the need in the next Regional Planning phases.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230 kV and 115 kV transformer stations in the Region using either the summer or winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following station capacity needs have been identified in the during the study period:

7.2.1 Anjigami TS and Hollingsworth TS – Transformer Overload

Anjigami TS has a 40 MVA, 115/44 kV transformer supplying a 44 kV circuit named Anjigami No.1. Hollingsworth TS has a 28 MVA, 115/11.5 kV transformer (T1), and a 28 MVA, 11.5/44 kV transformer (T2) supplying a 44 kV circuit, Limer No.1. Anjigami TS and Hollingsworth TS supply the same the load pocket. The 44 kV circuits are connected at Highway 101 SS forming a closed loop between the two stations. See figure 4 below.

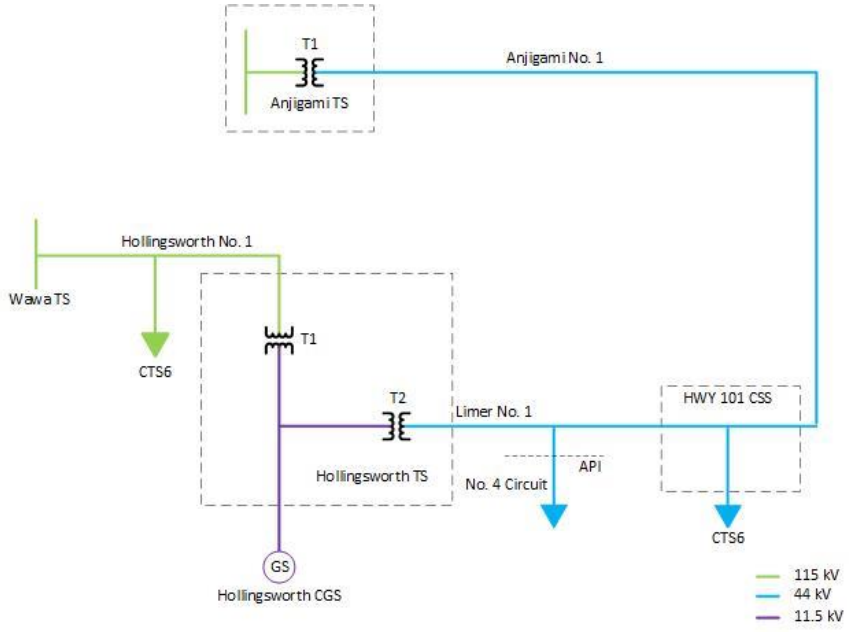


Figure 5: Anjigami TS and Hollingsworth TS - Single Line Diagram

The LDC supplied by the 44 kV circuit, API has recently experienced load growth, from 15 MW to 25 MW, in this pocket. As a result, a loss of supply from Anjigami TS results in thermal overload of both transformers and two (2) 11.5 kV disconnect switches at Hollingsworth TS, when the load exceeds 22 MW.

API will restrict their load to 22 MW to respect the thermal ratings of the equipment at Hollingsworth TS, as an interim measure. An industrial customer in the load pocket is also looking to increase their load from 1 MW to approximately 11 MW by year 2029. If all load increase materializes, a loss of supply from Hollingsworth TS will result in overload of transformer at Anjigami TS. Hence, both stations are at or approaching their maximum capacity to supply load.

A long-term solution is required to address the growing demand in the 44 kV pocket. The capacity needs are confined to customers in this 44 kV pocket. Hence, the TWG recommends further assessing potential solutions via a Local Plan between API and HOSSM.

7.2.2 Third Line TS – 230/115 kV Autotransformer Overload

Third Line TS has two (2) 250 MVA, 230/115 kV autotransformers presently supplying majority of the load in the city of Sault Ste. Marie. In the previous Regional Planning cycle, it was observed that loss of one autotransformer causes the companion autotransformer to be loaded close to its LTR thermal rating. As part of their asset renewal strategy, PUC Distribution is looking at an alternative to retire Tarentorous MTS and move load to the new Tagona West TS (section 7.1.1). If they decide to do so, the loss of an autotransformer will not result in overload of the companion unit, hence mitigating the emerging need. However, if Tarentorous MTS load is not moved to Tagona West TS, the same contingency will result in the companion autotransformer at approximately 90% LTR loading in year 2033.

In the previously RP cycle, the TWG recommended monitoring the total load supplied by autotransformers at Third Line TS. The TWG maintains the recommendation to monitor the loading of the autotransformers at Third Line TS.

7.2.3 Tagona West TS – 230/115 kV Autotransformer Overload

PUC Transmission will build a new 230/115 kV station called Tagona West TS to supply 300 MW of electric power to the new EAF facility through its 115 kV bus. Tagona West TS will connect to Third Line TS via two (2) 230 kV circuits and will have two (2) 200 MVA, 230/115 kV autotransformers that supply load to the 115 kV bus. The autotransformers will not have overload capability.

For the loss of one of the autotransformers at the new Tagona West TS the companion autotransformer will overload beyond its thermal rating under peak EAF load. PUC Transmission intends to have an agreement with their customer to manually reduce the EAF load so that it is within the thermal rating of their autotransformers under such circumstances. TWG recommends the mitigation measure to be reviewed in the SIA process and documented in the next phases of Regional Planning.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency (“LTE”) ratings with any one element out of service. Immediately following

contingencies, lines may be loaded up to their short-term emergency ("STE") ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230 kV and 115 kV Transmission line circuits in the ELS region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 Algoma No.1/ No.2/ No.3 – 115 kV Circuit Overload

Patrick St. TS is supplied by 115 kV circuits, Algoma No.1, Algoma No.2 and Algoma No.3 from Third Line TS and connects to the local generation via 115 kV circuits Clergue No.1 and Clergue No. 2. Under normal operating conditions the Algoma circuits are adequately rated to supply Patrick St. TS load. However, overloading can be observed on the Algoma circuits under contingency conditions described below.

The loss of any two Algoma circuits or a failure of circuit breaker 214 at Patrick St. TS (loss of Algoma No.2 & No.3) will result in thermal overload of the remaining Algoma circuit beyond its STE rating. Currently, this need is mitigated by manual load curtailment at Patrick St. TS, when any of the Algoma circuits are out of service. A new Third Line Remedial Action Scheme ("RAS") is being installed at Third Line TS which will (i) enable load rejection capability under weak system conditions and (ii) facilitate the connection of the new EAF facility to the transmission network. The RAS is planned to be in-service by Q1 2025. With any Algoma circuit out of service, and the subsequent loss of another Algoma circuit, the new RAS will be capable to cross-trip the remaining circuit to prevent thermal overload. This will result in all load at Patrick St. TS being rejected. This is not a desirable outcome.

Though the need can be mitigated as described above, the TWG recommends to further review in the next Regional Planning phases and develop options requiring smaller load rejection.

7.3.2 Sault No.3 – 115 kV Circuit Overload

Sault No. 3 is a 115 kV circuit between Third Line TS and Mackay TS, currently operating radially out of Third Line TS. Planned refurbishment of the circuit is underway with expected completion in 2026. After refurbishment, the circuit will operate in a network configuration, as considered in this assessment. Under normal operating conditions there is no overload observed on the circuit. During an outage of P25W or P26W, the loss of K24G (the 230 kV parallel path), may result in an overload on Sault No.3. As part of the refurbishment, the Mackay TS – No. 3 Sault 115 kV – Generation Rejection Scheme (Remedial Action Scheme) will be modified to cross-trip Sault No.3 (open circuit at Mackay TS end) for loss of K24G.

It is recommended to review the necessity of this Sault No.3 cross trip in the next phases of Regional Planning and coordinated with the ongoing System Impact Assessments for the northeast bulk projects.

7.4 Voltage Performance

At the time of this assessment there is currently three unique schemes employed at Third Line TS:

1. Third Line TS – Loss of T1/T2 or P21G/P226 GLP Instantaneous Load Rejection Scheme
   - Status based scheme
2. Third Line TS – Under Voltage Load Rejection Scheme
   - 115 kV Voltage-sensing scheme
3. Third Line TS – Northwest Load Rejection Scheme (Sault Ste. Marie portion)
   - Receives a cascaded signal from Mississagi TS for loss of 230 kV circuits P25W and P26W, A23P and A24P and loss of S22A or X74P

7.4.1 Voltage Violation at Third Line TS

Condition 1: Today, the loss of P21G and P22G will result in a severe voltage decline at Third Line TS 230 kV and 115 kV buses. When the future 230 kV circuits between Mississagi TS and Third Line TS, P23G and P24G are in-service during the study period, a loss of P21G and P22G will no longer result in voltage violations at Third Line TS. The TWG recommends that the Third Line TS – Loss of T1/T2 or P21G/P226 GLP Instantaneous Load Rejection Scheme be reviewed in the SIA for the new circuits to verify if the need to monitor for contingency of P21G and P22G remains.

Condition 2: Two (2) 230/115 kV autotransformers, T1 and T2, supply the 115 kV bus at Third Line TS. Under an outage of either autotransformer at Third Line TS, the loss of the companion autotransformer will result in a voltage collapse at Third Line TS 115 kV bus. In this assessment, the load at Tarentorous MTS was moved to Tagona West TS, thereby reducing the load on the 115 kV system at Third Line TS. Even after this relocation of load, the Third Line TS – Loss of T1/T2 or P21G/P226 GLP Instantaneous Load Rejection Scheme is still required to mitigate voltage collapse. Since load rejection is not a desired mitigation method, the TWG recommend the need for further review in next phases of Regional Planning.

It is also recommended to review the necessity of the Third Line TS – Under Voltage Load Rejection scheme in conjunction with the Third Line TS - Loss of T1/T2 or P21G/P226 GLP Instantaneous Load Rejection Scheme. Review to be conducted in the next phases of Regional Planning.

It is further recommended to review the necessity and functionality of the Third Line TS – Northwest Load Rejection Scheme (Sault Ste. Marie portion). Review to be conducted in the next phases of Regional Planning and coordinated with the ongoing System Impact Assessments for the northeast bulk projects.

7.5 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. This section

assesses operational concerns and the Load Security and Load Restoration criteria for the Region over the study period 2024-2033 to cater this need**.**

7.5.1 Third Line TS – 115 kV Voltage Limitation

The 115 kV bus at Third Line TS is restricted to operate within a narrow range of 118 kV to 124 kV. The Operations groups at the IESO and Hydro One have requested a review of the voltage range. The limitation is due to a voltage sensitive load connected to the LV bus of Tarentorous MTS and the transformers not having Under Load Tap Changers ("ULTC") to regulate the bus voltage. As part of St. Mary's MTS and Tarentorous MTS station refurbishment/upgrade, PUC Distribution has decided to replace existing transformers with unit that have ULTC to regulate the LV bus voltage. This is expected to resolve the issue. The TWG recommends continuing to monitor the voltage limitation and further assess as part of the future SIA for station refurbishment for St. Mary's MTS and Tarentorous MTS.

7.5.2 Load Security

As per ORTAC load security criteria:

Criteria #1: With all transmission facilities in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.

An outage of the largest generator, Wells G1 or G2 resulted in all equipment loading to be within continuous rating and voltages to be in normal ranges.

Criteria #2: With any one element out of service, equipment loading must be within applicable long-term emergency ratings, voltages must be within applicable emergency ranges, and transfers must be within applicable normal condition stability limits. Planned load curtailment or load rejection, excluding voluntary demand management, is permissible only to account for local generation outages. Not more than 150 MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management.

For all n-1 contingencies in the ELS region, this criterion is satisfied.

Criteria #3: With any two elements out of service, voltages must be within applicable emergency ranges, equipment loading must be within applicable short-term emergency ratings and transfers must be within applicable emergency condition stability limits. Equipment loading must be reduced to the applicable long-term emergency ratings in the time afforded by the short-time ratings. Planned load curtailment or load rejection exceeding 150 MW is permissible only to account for local generation outages. Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management.

- For a double circuit loss of the new 230 kV circuits between Third Line TS and Tagona West TS, the maximum load lost by configuration would be 380 MW in year 2033 as per this assessment. This will be the largest load lost under an n-2 contingency for the Region. [Meets criterion]

- After the loss of both autotransformers at Third Line TS, a voltage violation is averted by rejecting no more than 150 MW of load. [Meets criterion]

For all n-2 contingencies in the ELS region, this criterion is satisfied.

7.5.3 Load Restoration

The transmission system is planned with design criteria in a way to ensure that the affected loads can be restored within restoration time provided.

- All loads must be restored within approximately 8 hours.
- Load interruption greater than 150 MW, the excess amount of load greater than 150 MW needs to be restored within approximately 4 hours.
- Load interruption greater than 250 MW, the excess amount of load greater than 250 MW needs to be restored within approximately 30 minutes.

In ELS region there are radial circuits and loads that are supplied by single transformers. There can be instances where load may not be restored within 8 hours as per ORTAC criteria. A local planning report was completed for the Batchawana TS and Goulais TS in the previous RIP cycle to assess supply options. Based on the analysis conducted, having a permanent Mobile Unit Substation ("MUS") connection facility will facilitate a faster restoration time upon transformer contingency.

At Echo River TS, HOSSM in consultation with API installed a hot-spare transformer to facilitate fast restoration, upon the loss of the main load serving transformer.

At Andrews TS, HOSSM has a tentative restoration plan to mobilize a MUS nearby in the event of a transformer failure.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. Due to the nature of load inquiries in the Region, the TWG agreed to assess sensitivity scenarios by adding a large load in different pockets of the ELS region.

For the analysis, a 200 MW load is applied at the following locations:

a. Double circuit tap to the new 230 kV circuits P23G/P24G
b. Direct connection to 230 kV bus at Tagona West TS
c. Direct connection to 230 kV bus at Mackay TS

Findings

The sensitivity analysis for winter and summer loading had similar results. Reactive support is required for all connection locations assessed.

a) Double circuit tap to new P23G/P24G circuits
   - There is no need that arises from this finding.

b) Direct connection to 230 kV bus at Tagona West TS
   - Loss of either 230 kV circuit between Third Line TS and Tagona West TS will result in the companion circuit being loaded over 90% of its thermal rating (600 MVA).
   - Loss of new P23G+P24G (n-2) will result in 95-98% of LTE rating for P21G and P22G. [Summer case finding]
   - If load connects to the 115 kV bus at Tagona West TS, new autotransformers will be required. Or else the new load will exacerbate the autotransformer overload discussed in section 7.2.3.

c) Direct connection to 230 kV bus at Mackay TS
   - P25W or P26W outage and subsequent loss of K24G (n-1-1) will result in overload of Sault No.3 circuit. However, this contingency can be mitigated by Mackay TS Generation Rejection scheme.
   - Loss of new P23G+P24G (n-2) will result in 85-90% of LTE rating for P21G and P22G. [Summer case finding]
   - Loss of P25W+P26W (n-2) will result in voltage change close to 10% at the Wawa and Mackay 230 kV buses. [loads not converted to voltage-dependent model]

As per the sensitivity analysis, no new needs arise due to the addition of a large load in the ELS region. However, the analysis does indicate a few emerging needs that can be monitored as the load in the Region grows. Based on the analysis findings no immediate action is required.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 5: Needs which do not require further regional coordination

Sr.no.	Need	Recommendation
1	Anjigami TS and Hollingsworth TS – transformer overload	Assess solution options via a Local Plan between API and HOSSM.

Table 6: Needs which require further regional coordination

Sr.no.	Need	Recommendation
1	St. Mary's MTS and Tarentorous MTS – station refurbishment/upgrade	Recommended for further review in the next phases of RP.
2	Third Line TS – 230/115 kV autotransformer reaches 90% of LTR upon the loss of companion unit	Continue to monitor the loading of the autotransformers at Third Line TS.
3	Tagona West TS – 230/115 kV autotransformer overload upon the loss of companion unit	PUC Transmission intends to implement manual load reduction to mitigate the need. Recommended for further study as part of the SIA and accordingly documented in the next phases of RP.
4	Algoma No.1/ No.2/ No.3 – circuit overload after loss of any two Algoma circuits	Need can be mitigated by cross-tripping overloaded circuit using the Third Line RAS, rejecting all load at Patrick St. TS. Recommended for further review in the next phases of RP.
5	Sault No. 3 – circuit overload	Need can be mitigated by cross-tripping Sault No.3 upon the loss of K24G (during a P25W or P26W outage) using Mackay Generation Rejection scheme. Recommended to review necessity of Sault No.3 cross-trip in the next phases of RP, in coordination with SIA for the new northeast bulk projects.
6	Voltage violation at Third Line TS	The violations can be mitigated by using Load Rejection (LR) schemes and/or RAS at Third Line TS. Recommended to review the necessity Third Line TS LRs and RAS contingencies in the next phases of RP, in coordination with SIA for the new northeast bulk projects.
7	Third Line TS – 115 kV voltage limitations	Existing voltage limit at Third Line TS 115 kV bus is restricted to operate between 118 kV - 124 kV range. Recommended to monitor need until PUC Distribution replaces existing transformers with new units equipped with ULTC.

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. October 1st, 2024)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1st, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Hydro One, second cycle ELS Regional Infrastructure Plan report (Issue October, 2021)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1: ELS Region – Summer Non-Coincident Net Load Forecast – Extreme weather

Station/DESN	LTR (MW)	Historical (MW)			Summer Non-Coincident Net Forecast (MW)									
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Andrews TS	4.5	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Batchawana TS	11.3	1.7	1.3	1.5	1.7	1.8	1.8	1.9	1.9	1.9	2.1	2.0	2.1	2.1
DA Watson TS	87.8	4.4	4.6	4.1	7.0	7.2	7.4	7.7	7.9	8.2	8.3	8.6	8.8	9.1
Echo River TS	29.1	12.4	11.7	12.5	14.1	14.4	14.8	15.0	15.4	15.6	15.9	16.2	16.5	16.8
Goulais TS	13.5	4.6	4.6	4.7	6.2	6.3	6.4	6.5	6.5	6.6	6.7	6.8	6.8	6.9
Mackay TS	4.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Northern Ave TS (34.5kV)	24.0	1.8	4.2	2.6	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
Northern Ave TS (12.5kV)	5.4				2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.5
No. 4 Circuit	N/A	14.6	14.2	15.4	24.9	25.3	25.5	25.7	25.8	26.0	26.2	26.4	26.6	26.8
Chapleau DS	12.4	8.6	8.6	9.1	9.8	9.9	10.0	10.0	10.1	10.1	10.2	10.3	10.4	10.5
St. Mary's MTS	81.0	91.0	86.1	95.7	47.5	58.4	58.7	59.0	0.0	0.0	61.6	62.1	62.5	63.1
Tarentorus MTS	81.0				63.4	64.1	64.8	65.5	66.1	66.8	0.0	0.0	0.0	0.0
Tagona West TS**	180.0	N/A	N/A	N/A	0.0	0.0	0.0	0.0	60.0	70.0	45.0	47.0	48.0	50.0
Patrick St. TS	N/A	122.4	132.2	140.9	176.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Chapleau MTS	N/A	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
CTS1	N/A	14.8	15.1	15.0	15.5	15.4	15.4	15.3	15.2	15.2	15.1	15.0	15.0	15.0
CTS2	N/A	15.4	15.7	15.4	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
CTS3	N/A	8.5	8.4	9.8	15.0	13.1	13.1	15.8	15.8	15.8	15.7	15.6	15.6	15.6
CTS4	N/A	N/A	N/A	N/A	0.0	140.0	140.0	140.0	140.0	140.0	300.0	300.0	300.0	300.0
CTS5	N/A	N/A	N/A	N/A	0.0	0.0	24.0	31.7	42.8	42.8	42.8	42.8	42.8	42.8
CTS6	N/A	0.3	0.4	0.4	0.4	0.4	0.4	11.7	11.7	11.7	11.7	11.7	11.7	11.7

*** In 2030, PUC Distribution intend to relocate load from Tarentorous MTS to Tagona West TS. To be confirmed and finalized in the next phases of RP.*

Table A.2: ELS Region – Winter Non-Coincident Net Load Forecast – Extreme Weather

Station/DESN	LTR (MW)	Historical (MW)			Winter Non-Coincident Net Forecast (MW)									
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Andrews TS	4.5	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Batchawana TS	11.3	1.5	1.8	1.7	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.5	2.5
DA Watson TS	87.8	7.7	8.3	8.0	9.1	9.2	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.3
Echo River TS	29.1	14.1	15.2	15.6	16.6	16.7	16.9	17.0	17.3	17.4	17.6	17.9	18.0	18.2
Goulais TS	13.5	7.7	8.9	8.4	9.9	10.0	10.1	10.2	10.3	10.5	10.5	10.7	10.8	11.0
Mackay TS	4.5	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Ave TS (34.5kV)	24.0	2.3	2.5	2.7	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Northern Ave TS (12.5kV)	5.4				3.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
No. 4 Circuit	N/A	15.0	16.7	16.6	26.5	26.9	27.2	27.5	27.9	28.1	28.3	28.8	29.0	29.4
Chapleau DS	15.4	11.0	10.5	10.7	11.5	11.6	11.7	11.8	11.9	12.0	12.1	12.2	12.3	12.5
St. Mary's MTS	81.0	111.5	119.1	114.5	58.1	69.0	70.5	71.0	0.0	0.0	72.3	73.0	73.3	74.0
Tarentorus MTS	81.0				73.9	78.0	78.9	79.8	80.6	81.5	0.0	0.0	0.0	0.0
Tagona West TS**	180.0	N/A	N/A	N/A	0.0	0.0	0.0	0.0	70.0	75.0	60.0	62.0	63.0	65.0
Patrick St. TS	N/A	143.1	136.8	151.4	176.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Chapleau MTS	N/A	3.8	4.1	3.7	4.1	4.1	4.1	4.1	4.0	4.0	4.0	4.0	4.0	4.0
CTS1	N/A	15.2	15.9	15.3	15.9	15.8	15.8	15.7	15.6	15.6	15.5	15.5	15.4	15.4
CTS2	N/A	15.7	15.5	15.5	16.4	16.4	16.4	16.3	16.2	16.2	16.1	16.1	16.0	16.0
CTS3	N/A	9.7	9.6	10.1	11.0	11.9	11.9	12.5	12.5	12.4	12.4	12.4	12.3	12.3
CTS4	N/A	N/A	N/A	N/A	0.0	140.0	140.0	140.0	140.0	140.0	300.0	300.0	300.0	300.0
CTS5	N/A	N/A	N/A	N/A	0.0	0.0	24.0	31.7	42.8	42.8	42.8	42.8	42.8	42.8
CTS6	N/A	0.7	0.8	0.7	0.8	0.7	0.7	11.5	11.5	11.4	11.4	11.4	11.3	11.3

*** In 2030, PUC Distribution intend to relocate load from Tarentorous MTS to Tagona West TS. To be confirmed and finalized in the next phases of RP.*

Appendix B: Current Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Andrew TS	115/25	Andrew 115kV
2	Anjigami TS	115/44	Hollingsworth 115kV, High Falls No.1, High Falls No.2
3	Batchawana TS	115/12.5	Sault No.3
4	Chapleau DS	115/25	W2C
5	Chapleau MTS	115	W2C
6	Clergue TS	115/12.5	Cogen No.1, Cogen No.2, Clergue No.1, Clergue No.2,
7	DA Watson TS	115/34.5	Magpie 115kV, High Falls No.1, High Falls No.2
8	Echo River TS	230/34.5	P22G
9	Goulais Bay TS	115/12.5	Sault No.3
10	Hollingsworth TS	115/12.5/44	Hollingsworth 115kV, Limer No. 1
11	Northern Ave TS	115/34.5/12.5	Northern Ave 115kV
12	Patrick St TS	115/34.5	Clergue No.1, Clergue No.2, Algoma No.1, Algoma No.2, Algoma No.3
13	St. Mary's MTS	115/34.5	GL1SM, GL2SM
14	Tarentorous MTS	115/34.5	GL2TA, GL1TA
15	Mackay TS	115/25	Gartshore No.1, Gartshore No.2, Mackay No.1, Mackay No.2, Sault No.3

Appendix C: Current Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Mississagi x Third line	P21G, P22G	230
2	Mississagi x Wawa	P25W, P26W	230
3	Third line x Mackay	K24G	230
4	Mackay x Wawa	W23K	230
5	Third line x Mackay	Sault No.3	115
6	Third line x Patrick st	Algoma No.1 / No.2 / No.3	115
7	Third line x Norther Ave	Northern Ave 115kV	115
8	Third line x St Mary CTS	GL1SM, GL2SM	115
9	Third line x Tarentorus CTS	GL1TA, GL1TA	115
10	Patrick st x Flakeboard CTS	Leigh's Bay 115kV	115
11	Patrick st x Clergue TS	Clergue No.1 / No.2	115
12	Mackay GS x Mackay TS	Mackay No.1 / No.2	115
13	Gartshore SS x Mackay TS	Gartshore No.1 / No.2	115
14	Gartshore SS x Hogg CGS	Hogg 115kV	115
15	Gartshore SS x Andrew CGS	Andrew 115kV	115
16	Magpie SS x Mission Falls CGS	Mission falls 115kV	115
17	Magpie SS x Steephill CGS	Steephill 115kV	115
18	Magpie SS x Harris CGS	Harris 115kV	115
19	Magpie SS x DA Watson TS	Magpie 115kV	115
20	DA Watson TS x Wawa TS	High Falls No.1/No.2	115
21	Hollingsworth TS x Wawa TS	Hollingsworth 115kV	115
22	Anjigami TS x Hwy 101 SS	Anjigami No. 1	44
23	Hollingsworth TS x Hwy 101 SS	Limer No. 1	44

Appendix D: List of LDCs

No.	Name of LDC
1	Algoma Power Inc.
2	PUC Distribution
3	Hydro One Distribution

Appendix E: List of Municipalities in the ELS Region

No.	Name of Municipality
1	City of Sault Ste. Marie

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor

PPWG	Planning Process Working Group
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



East Lake Superior Integrated Regional Resource Plan

July 9, 2026

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List of Abbreviations

BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
EAF	Electric Arc Furnace
ELS	East Lake Superior
eDSM	Electricity Demand Side Management
FIT	Feed-in-Tariff
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie
IBR	Inverter-Based Resource
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LSP	Lake Superior Power
LTR	Limited Time Rating
MSR	Municipal Support Resolution
MSU	Mobile Substation Unit
MVA	Megavolt ampere
MVAr	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council

NWA	Non-Wires Alternative
OEB	Ontario Energy Board
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PLL	Planned Loading Limit
PPWG	Planning Process Working Group
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transmission Station
TWG	Technical Working Group

Executive Summary

Regional planning is a collaborative process that evaluates a range of supply resource and transmission options to ensure the electricity system remains reliable, affordable, and capable of supporting future growth. Developed with input from municipalities, Indigenous communities, utilities, and other regional stakeholders, these plans reflect the unique characteristics and needs of each planning region. The East Lake Superior region — encompassing the City of Sault Ste. Marie, the Township of Chapleau, and surrounding municipalities and districts extending from the Town of Dubreuilville in the north to the Town of Bruce Mines in the south — has a distinct electricity profile shaped largely by energy-intensive industrial activity and electrification initiatives.

Future electricity needs in the East Lake Superior region are expected to be driven primarily by industrial development and electrification initiatives rather than broad-based growth across the region. As a result, electricity system needs are localized and tied to specific areas of the system rather than widespread capacity constraints. With the inclusion of major system developments, including the 2022 Northeast Bulk Reinforcement Plan, no new medium- or long-term regional electricity needs are identified over the current planning horizon. However, a limited number of localized reliability and supply capacity needs are expected to emerge in the near term and are addressed through the recommendations in this plan.

A range of potential solutions was evaluated, including transmission and distribution reinforcements, local generation, demand-side resources, operational measures, and non-wires alternatives. The recommended approaches represent the most cost-effective and practical means of addressing identified system needs, while maintaining system reliability and ensuring infrastructure improvements are made at the appropriate time.

Implementation-Ready Actions

The following actions are recommended as near-term investments to maintain reliability and enable growth in the East Lake Superior region. Evaluated across a range of planning scenarios, these actions are considered implementation-ready and should proceed through development and implementation.

Chapleau Area – Supply Capacity
To maintain reliable electricity supply in the Chapleau area and support forecast growth, the IESO and the Technical Working Group (TWG) recommend a localized voltage support solution to address limitations on the existing supply path. Demand-side resources, including electricity Demand Side Management (eDSM), are also recommended to provide incremental support and help make the best use of existing system capacity at the lowest cost.

Chapleau DS – Station Capacity Monitoring
The TWG will continue to monitor load growth and system conditions at Chapleau Distribution Station (DS) and Chapleau DS2 to ensure the electricity system remains well-positioned to accommodate future growth. While no station capacity need has been identified under current planning assumptions, demand under higher-growth scenarios may approach available station capacity over

the longer term. Ongoing monitoring will help identify any emerging needs early and provide sufficient lead time to develop and implement appropriate solutions.

Algoma Area – Supply Reliability

To maintain reliable electricity service in the Algoma area, which is supplied by three transmission lines, a staged approach consisting of interim control actions, followed by enhancements to the existing Remedial Action Scheme (RAS)[1] is recommended. This approach addresses a contingency-driven limitation by improving the selectivity of load rejection over time, restoring compliance with planning criteria while striking a balance between operational measures and the timing of more complex and capital-intensive transmission reinforcements.

Sault Ste. Marie Area – Supply Reliability

Pursue the development and implementation of a cost-effective supply resource capable of meeting the identified reliability need. The IESO will advance this recommendation through appropriate procurement mechanisms, consistent with the performance requirements of the need. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed and capable of sustained operation for the duration of a contingency condition. This performance-based approach preserves flexibility with respect to the specific technology while providing a targeted and cost-effective solution. In addition to addressing reliability needs, such a resource can also provide broader system value through energy and capacity contributions under normal operating conditions.

Future Considerations and Optionality

In addition to implementation-ready actions, the IRRP identifies longer-term infrastructure options that could be considered if demand growth, system conditions, or supply resource availability evolve differently than currently expected. While these options are not required at this time, they inform future planning and system readiness as conditions evolve, preserving optionality and protect against overbuilding.

One such option is the potential addition of a third autotransformer at Third Line Transformer Station which is associated with the Sault Ste. Marie 115 kV system interface reliability need. While not required at this time, this investment would increase system redundancy and provide a longer-term infrastructure option should demand growth increase reliability requirements in the future.

Future infrastructure options will continue to be assessed as part of ongoing TWG reviews, considering updated demand forecasts, system performance, and the availability of supply resources.

During the preparation of this report, Hydro One Distribution identified a potential project at Chapleau Distribution Station (DS) involving the addition of a new transformer. This project is currently in the early scoping phase, with a tentative in-service timeframe of approximately 2029, and remains subject to further technical assessment, siting considerations, and internal approvals. This emerging development reinforces the need for ongoing monitoring of station capacity conditions identified in this plan.

[1] A Remedial Action Scheme or RAS is a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and MVar), tripping load, or reconfiguring the system.

As this information became available late in the study process, its potential impact on system capacity and voltage performance in the Chapleau area has not been assessed. While it may influence future system needs, the recommended plan outlined in this IRRP remains appropriate based on available information. The TWG will continue to monitor this development and assess its implications as part of the Regional Infrastructure Plan (RIP) phase or future regional planning cycles.

In addition, the ability to site new supply resources in the region is currently constrained by system conditions, including limits on inverter-based generation and congestion on key transmission elements. These constraints will be monitored and may be addressed through future planning as system conditions evolve. Where new strategic supply resources are recommended in plans, the IESO will further develop linkages to ensure procurement signals are clear to address system needs.

Implementation and Monitoring

Implementation of the recommended actions will proceed through established mechanisms, including Regional Infrastructure Plans and procurement processes, supported by continued co-ordination through the TWG.

System conditions, demand growth, and the performance of implemented solutions will be actively reviewed. Where conditions materially change, additional analysis and planning will be undertaken through future regional planning cycles to ensure continued reliability of the electricity system in the ELS region.

Conclusion

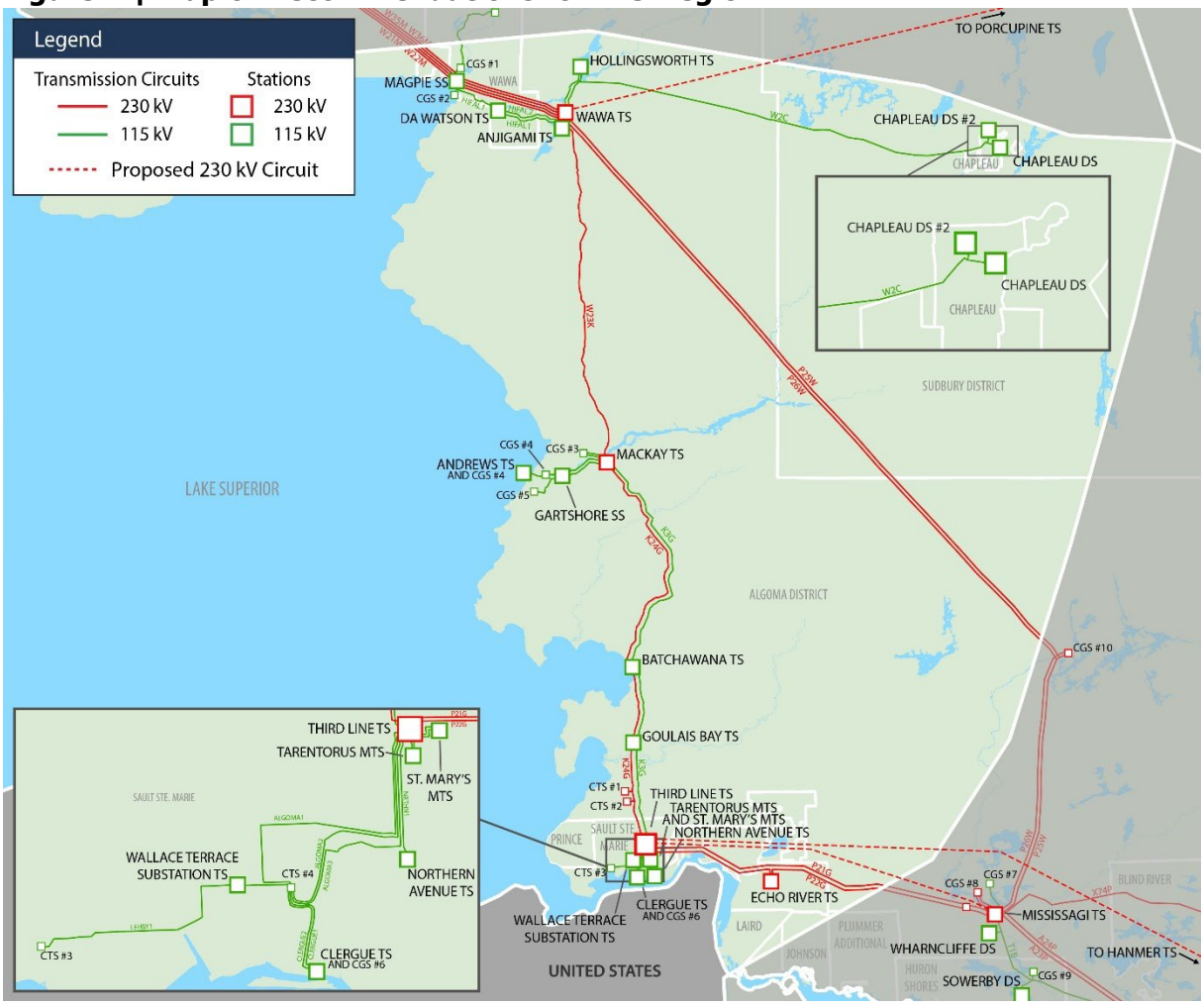
Overall, this IRRP provides a clear, proportionate, and flexible plan to address the identified electricity system needs of the ELS region. The recommended actions are designed to maintain near-term system reliability while enabling further customer and industry connections. The plan also preserves optionality to respond to future changes in demand, system conditions, and resource availability.

Table 1 | Implementation-Ready Actions

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service
Chapleau reactive power support	Transmission-side static reactive power support, with demand side measures serving as short-term supplement	Addresses voltage-limited supply capacity in the Chapleau area	Hydro One (reactive support); IESO (eDSM)	Near-term
Address Algoma 115 kV interface supply capacity need	Enhance existing RAS to support more flexible control actions; load rejection exemption framework	Mitigates contingency-driven thermal limitation at the Algoma 115 kV interface	Hydro One	Near-term

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service
Address Sault Ste. Marie 115 kV interface supply capacity need	Performance based supply solution with demand side measures	Addresses voltage instability limitations in the Sault Ste. Marie 115 kV area	IESO (lead); TWG support	Near- to mid-term
ELS region monitoring	Planning/monitoring	Preserves long-term flexibility and informs future infrastructure-based solutions	TWG	Ongoing

Figure 1 | Map of Recommendations for ELS Region



1. Introduction

1.1 Overview of Regional Electricity Planning

Regional electricity planning in Ontario is a structured process used to identify and address electricity needs at a regional level in a co-ordinated, reliable, and cost-effective manner. The regional planning process was formalized by the Ontario Energy Board (OEB) in 2013 and is carried out on a five-year planning cycle for each of Ontario's 21 planning regions. The process is undertaken collaboratively by the Independent Electricity System Operator (IESO), transmitters, and local distribution companies (LDCs) through a Technical Working Group (TWG). The IESO leads the Scoping Assessment and Integrated Regional Resource Plan (IRRP) stages of the process.

The regional planning process includes four key phases:

1. Needs Assessment (Led by the Transmitter)

The Needs Assessment is the first phase of regional planning and is led by the incumbent transmitter for the region. It evaluates the adequacy of the existing electricity system under forecast demand conditions to determine whether there are any emerging reliability or capacity concerns. The assessment applies applicable planning criteria and identifies whether electricity needs exist that may require further regional co-ordination. If no needs are identified, no further regional planning activities are required at that time.

2. Scoping Assessment (Led by the IESO)

Where needs are identified, the IESO leads a Scoping Assessment to determine the appropriate planning approach to address them. The Scoping Assessment confirms the nature and extent of the identified needs and recommends whether they should be addressed through an IRRP, a RIP, or other planning mechanisms. The Scoping Assessment also defines the geographic scope, time horizon, and level of co-ordination required.

3. Integrated Regional Resource Plan (Led by the IESO)

The IRRP is led by the IESO and developed in collaboration with transmitters, LDCs, and other members of the TWG. The IRRP assesses regional electricity needs over the near-, medium-, and long-term and evaluates a range of options to address those needs. Options considered may include transmission and distribution solutions, electricity demand-side management (eDSM), non-wires alternatives (NWAs), and generation resources. The IRRP culminates in recommended actions to address near- and medium-term needs and outlines monitoring or trigger-based approaches for longer-term needs.

4. Regional Infrastructure Plan (Led by the Transmitter)

Where the IRRP identifies transmission or distribution infrastructure solutions as recommended actions, these are carried forward into the RIP stage. The RIP is led by the transmitter and provides greater implementation detail, including preferred solution selection, siting considerations, technical

design, cost estimates, and engagement activities. The RIP supports regulatory approval and eventual construction of recommended infrastructure projects.

This IRRP represents the second cycle of regional planning for the ELS region.

1.2 Purpose of this IRRP

This IRRP assesses the reliability and adequacy of the electricity system in the ELS region over a 20-year planning horizon (from 2025 to 2044). The goal is to identify near-, medium-, and long-term needs, propose suitable options, and recommend actions to maintain a reliable and cost-effective electricity system while considering:

- projected electricity demand growth;
- infrastructure condition and capacity;
- opportunities for energy efficiency and NWAs; and
- emerging trends (e.g., electrification, distributed energy resources).

The outcome of this IRRP includes recommended infrastructure solutions, some of which will be reviewed further in the forthcoming RIP.

1.3 Description of the Area

The ELS region encompasses the City of Sault Ste. Marie, the Township of Chapleau, and surrounding municipalities and districts extending from the Town of Dubreuilville in the north to the Town of Bruce Mines in the south. Geographically, the region is surrounded by Lake Superior to the west, Highway 129 to the east, Highway 101 to the north, and St. Mary's River and St. Joseph Channel to the south, defined not only by physical geography but also by shared electricity infrastructure. The region includes the following:

- Municipalities and Townships: Town of Bruce Mines, Township of Chapleau, Hilton Township, The Municipality of Huron Shores, Township of Jocelyn, Township of Johnson, Laird Township, Township of Macdonald, Meredith & Aberdeen Additional, Township of Plummer Additional, Prince Township, City of Sault Ste. Marie, Township of St. Joseph, Tarbutt Township & Tarbutt Additional, Township of Dubreuilville, and Municipality of Wawa.
- Indigenous Communities: Batchewana First Nation, Brunswick House First Nation, Chapleau Cree First Nation, Chapleau Ojibwe First Nation, Garden River First Nation, Michipicoten First Nation, Missanabie Cree First Nation, Mississauga First Nation, Serpent River First Nation, Thessalon First Nation, Métis Nation of Ontario, Bar River Métis, and Red Sky Métis Independent Nation.
- LDCs Operating in the Region: Algoma Power Inc., Hydro One Distribution and PUC Distribution Inc.
- Lead Transmitter: Hydro One Networks Inc. Transmission (HONI), Hydro One Sault Ste. Marie (HOSSM), and PUC Transmission Inc.

Figure 2 | Overview Map of the ELS Region[3]



1.4 Demand and Infrastructure Overview

The electricity demand in the region is expected to follow a winter-peaking pattern, driven by industrial development. Average annual growth is projected at 4.8% based on winter reference scenario and 5.7% based on summer reference scenario.

Electricity is supplied through a combination of:

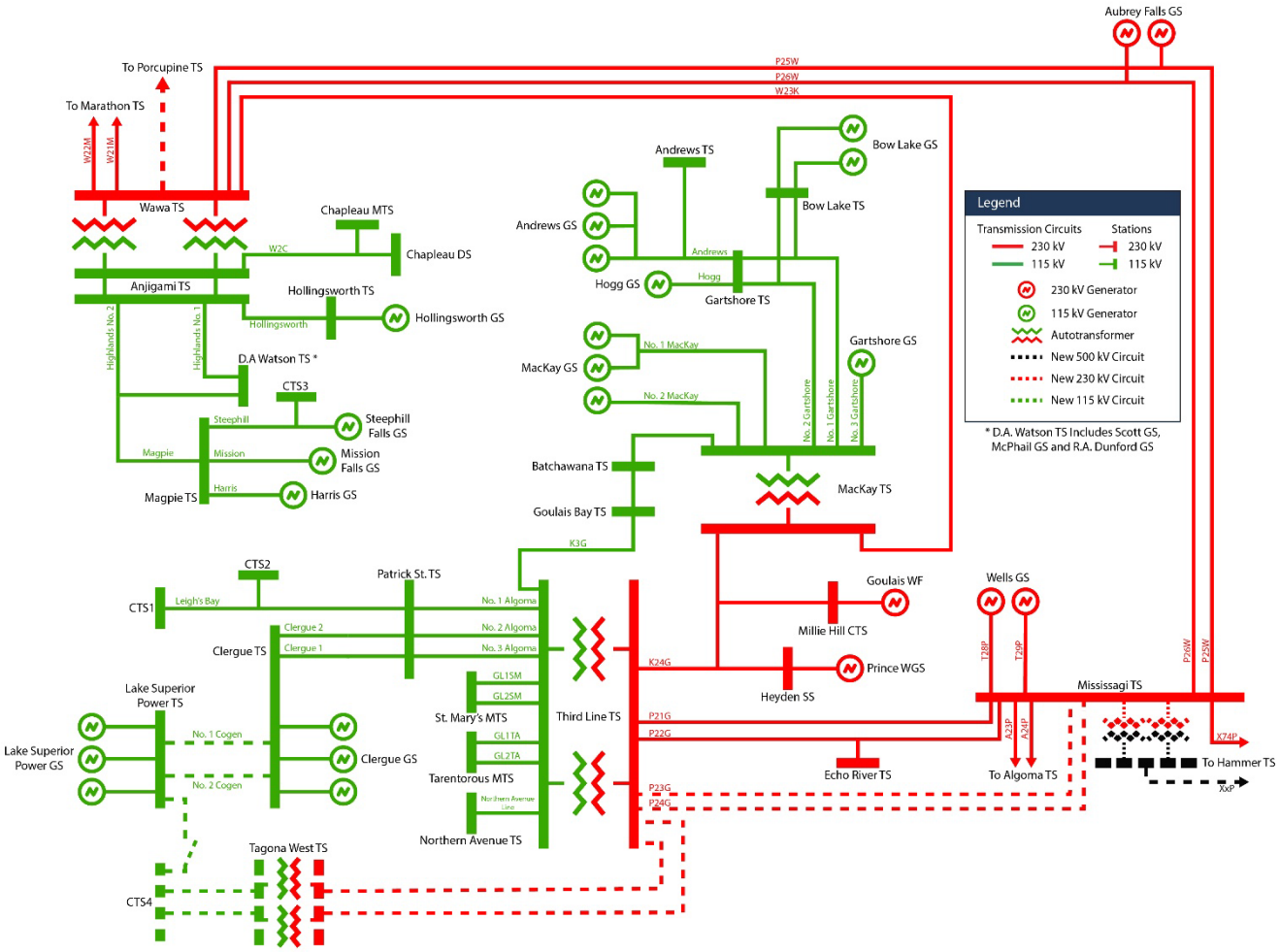
- 230 kV and 115 kV transmission infrastructure, with electrical supply provided mainly through 230/115 kV autotransformers at Third Line Transformer Station (TS), Mackay TS, and Wawa TS, as shown in Figure 2.
- Local generation, including more than 1,200 MW of hydroelectric, wind, solar, and thermal generation.

[3] IRRP regions are defined by electricity infrastructure; geographical boundaries are approximate.

Over the planning horizon, potential demand growth from industrial development, mining activity, and electrification initiatives may require the evaluation of supply options and infrastructure upgrades.

Figure 3 is a single line diagram showing major electrical infrastructure in the region.

Figure 3 | Electricity Infrastructure in the ELS Region



1.5 Organization of this IRRP

This IRRP outlines the ELS TWG's plan to continue to maintain a reliable, affordable, sustainable electricity supply to support the region. This IRRP is structured as follows:

Section 2 — Summary of the recommended plan and near-/medium-term actions

Describes the IRRP within Ontario's regional electricity planning framework and outlines how it addresses identified electricity needs through co-ordinated planning.

Section 3 Planning process and methodology

Explains the regional planning process and summarizes how the IRRP was developed, including roles, responsibilities, and key planning steps.

Section 4 — Background and context for study scope

Provides context for electricity planning in the ELS region and defines the study scope, including system assets, interfaces, and planning assumptions.

Section 5 — Electricity demand forecast

Presents the development of the regional electricity demand forecast, including historical demand, forecast methodology, and planning assumptions.

Section 6 — Identified needs and system limitations

Identifies and categorizes electricity system needs based on forecast demand and system capability, including station, supply, refurbishment, and reliability needs.

Section 7 — Options considered and recommended solutions

Evaluates options to address identified needs and presents recommended actions based on technical, economic, and reliability considerations.

Section 8 — Community and stakeholder engagement

Summarizes engagement activities undertaken to inform stakeholders and incorporate local input into the regional planning process.

Section 9 — Conclusion and next steps

Summarizes the IRRP's findings and recommendations and outlines next steps for implementation, monitoring, and future planning cycles.

Appendices provide additional detail including technical studies, demand assumptions, and supporting engagement documentation.

2. The Integrated Regional Resource Plan

2.1 Overview of the Plan

This section presents the recommended IRRP for addressing electricity needs in the ELS region over a 20-year planning horizon. The plan includes a combination of near-term actions, future optionality, and ongoing monitoring activities to address emerging needs.

The recommendations are informed by a detailed needs assessment based on system capability, forecast demand, and applicable reliability criteria. The plan reflects input from the regional TWG, local stakeholders, Indigenous communities, and the IESO's planning assessments.

Electricity needs and corresponding solutions are grouped based on geography (local, regional, or bulk system-level), timing (near-, mid-, or long-term), and need type (e.g., station capacity, supply capacity, asset condition, load security, load restoration). In this IRRP, the focus is on a limited number of localized near-term supply capacity needs, with ongoing monitoring and future optionality to respond to changing system conditions. Where relevant, needs are linked to bulk system planning efforts to support co-ordinated and efficient infrastructure development.

2.2 Needs, Solutions and Timeframe

Types of Needs

This IRRP refers to a number of different need types and corresponding solutions. These needs and their solutions include:

- Station Capacity: Load transfers, station upgrades, or new transformer stations where required. In this IRRP, no near-term station capacity need is identified.
- Supply Capacity: Transmission circuit upgrades, reactive support, controlled load interruption, remedial action schemes, or non-wires solutions, depending on the nature of the need. In this IRRP, the identified near-term needs are primarily supply capacity needs.
- End-of-Life: Like-for-like or right-sized replacement of aging infrastructure, where relevant.
- Load Security: Transmission reinforcements, reconfiguration, or other measures to reduce the amount of load interrupted following major outages.
- Load Restoration: Mobile transformers, switching arrangements, or operational measures to improve restoration following outages.

Refer to Section 6.1 for further technical details.

Classification of Needs

Three main types of needs are discussed:

- Local Needs: Specific to one facility, interface, or community.
- Regional Needs: Affect multiple customers, communities, or areas within the region.

- Bulk System Needs: Linked to upstream transmission capability or broader provincial supply and transmission considerations.

Planning Timeframes

This IRRP covers three planning timeframes:

- Near-Term Plan: 0–5 years
- Mid-Term Plan: 6–10 years
- Long-Term Plan: 11–20 years

In this IRRP, the earliest identified needs are expected to emerge in the near term, beginning around 2028. No new distinct medium- or long-term regional electricity needs are identified over the planning horizon. Needs influenced by bulk system developments are co-ordinated accordingly.

2.3 Needs and Recommendations

Based on this analysis, the ELS IRRP recommends a broad range of solutions to address identified needs. Recommendations include:

- "Implementation-ready" or near-term actions to develop infrastructure such as new and expanded transmission stations to enable reliable supply for forecast demand across the region while improving system operability to a level comparable with the rest of Ontario, and
- "Future-consideration" or long-term actions, identified to preserve longer-term optionality and serve as a backstop if near-term supply resource solutions do not materialize or if system conditions change, including higher-than-expected demand growth. These actions would be monitored and revisited through future planning cycles as conditions evolve.

Table 2 summarizes system needs and corresponding recommendations.

Table 2 | Implementation-Ready Actions for the ELS Region

Need	Recommendation	Lead Responsibility	Required By
Voltage-limited supply capacity in the Chapleau area	Implement transmission-side reactive power support, with demand-side measures (eDSM) as interim support	Hydro One (reactive support); IESO (eDSM)	Near-term
Algoma 115 kV interface supply capacity	Enhance existing RAS to support more flexible control actions; load rejection exemption framework	Hydro One	Near-term

Need	Recommendation	Lead Responsibility	Required By
Sault Ste. Marie 115 kV interface supply capacity	Develop and procure a performance-based supply solution with demand side measures	IESO (lead), TWG support	Near to mid-term
ELS region system monitoring and long-term planning	Planning and monitoring to preserve long-term flexibility and inform future infrastructure-based solutions	TWG	Ongoing

Table 3 | Future-Ready Actions for the ELS Region

Need	Recommendation	Lead Responsibility	Required By
Sault Ste. Marie 115 kV interface supply capacity	New 230/115 kV autotransformer at Third Line TS	Hydro One	To be determined

2.3.1 Chapleau Area

A supply capacity need is expected to emerge in the Chapleau area, including Chapleau Distribution Station (DS) and Chapleau DS2, which are supplied by the 115 kV W2C transmission path. This need is driven by voltage limitations under peak conditions following the retirement of local generation, which reduce the load meeting capability of the W2C path.

The recommended approach is to implement reactive support to improve voltages in the area. This would directly address the underlying voltage limitation and replace the voltage support previously provided by local generation.

Demand-side measures and distributed energy resources, including additional eDSM, were also assessed and may provide modest short-term relief during the initial years following need onset. However, consistent with regional planning assumptions regarding achievable contribution levels, these resources are considered supplementary measures only and are not sufficient to independently address the identified supply capacity need.

In addition to the needs and solutions identified above, Hydro One Distribution identified a potential project during the preparation of this report involving the addition of a new transformer at Chapleau DS to accommodate incremental load from an existing customer. This project is currently in the early scoping phase, with a tentative in-service timeframe of approximately 2029. At present, no footprint exists within the existing station, and expansion options, including development on adjacent lands, are being explored.

Due to the timing of this information and its preliminary nature, the TWG has not assessed its impact on system capacity or the identified voltage limitations in the Chapleau area. As a result, the recommended plan for the Chapleau area remains unchanged. However, this development may influence future system needs, including the timing or scope of reinforcements. The TWG recommends that this project be monitored and further evaluated as part of the RIP phase or future regional planning cycles once additional information becomes available.

2.3.2 Algoma 115 kV Interface

The Algoma 115 kV interface, consisting of the Algoma No. 1, No. 2, and No. 3 transmission lines supplying radially connected industrial load, is subject to a contingency-driven thermal limitation. Under a recognized breaker-failure or sequential outage scenario, loading on the remaining in-service circuit exceeds applicable Ontario Resource and Transmission Assessment Criteria (ORTAC) and requires mitigation.

To address this limitation, enhancement of the existing RAS has been identified as the preferred long-term solution. The enhancement will improve the selectivity of the scheme by refining tripping actions to target individual load breakers, rather than disconnecting entire circuits. This more granular control will reduce the amount of load rejected under contingency conditions while ensuring that post-contingency loadings remain within ORTAC criteria.

Given the industrial nature of the load served and the low-frequency, contingency-driven nature of the limitation, customer agreements for controlled load interruption will be maintained as an interim measure until the RAS is implemented and placed in service. This approach provides a proportionate and practical means of maintaining compliance with planning criteria while avoiding significant transmission reinforcements under relatively stable demand conditions.

2.3.3 Sault Ste. Marie 115 kV System Interface

A contingency involving the loss of both Third Line autotransformers results in voltage instability on the Sault Ste. Marie 115 kV system. Under this condition, the remaining 115 kV network is unable to reliably serve load, resulting in a supply capacity limitation.

The recommended action is to pursue a cost-effective supply solution with performance characteristics aligned with the identified reliability risk. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed after a contingency, and capable of sustained operation for the duration of the contingency condition. This performance-based framing preserves flexibility with respect to the specific technology or acquisition approach, supports transparency with communities, and allows the need to be addressed, subject to demonstrated deliverability and applicable municipal and provincial siting requirements, and all other requirements and contractual obligations of any applicable procurement mechanism. No new infrastructure is required to maintain near-term reliability following completion of planned developments, allowing time to pursue this approach. At the same time, the addition of a third autotransformer at Third Line remains a future consideration and backstop option if a suitable supply solution does not materialize or if demand grows beyond current expectations.

2.4 Ongoing Initiatives

This IRRP is supported by ongoing transmission and station projects outside the scope of the recommendations in this plan. These initiatives form part of the broader planning context for the ELS region and include:

The 2022 Northeast Bulk Reinforcement Plan, which significantly strengthens bulk supply into northeast Ontario through new 230 kV and 500 kV infrastructure to support supply to the ELS region and more broadly, into northwestern Ontario, including:

- The Hanmer TS to Mississagi TS 500 kV transmission line project;
- The Mississagi TS to Third Line TS 230 kV transmission line project;
- The Porcupine TS to Wawa TS 230 kV transmission line project; and

Ongoing asset replacement and refurbishment projects across the region, including autotransformer and station upgrades at Third Line TS, Wawa TS, Batchawana TS, and Goulais Bay TS, as well as transmission line refurbishment at Sault #3 (K3G).

2.5 Regional Context and Key Planning Assumptions

Electricity demand within the ELS region is characterized by large, project-driven load additions, primarily associated with industrial activity, resource development, and electrification initiatives. Unlike regions experiencing steady population-driven growth, demand in ELS tends to increase through distinct step-changes occurring over relatively short lead times. As a result, many identified electricity system needs are driven by system configuration, contingency performance, and planning-criteria requirements, rather than pervasive growth across the network.

This IRRP reflects the implementation or advancement of several major system initiatives that establish the reference system for this planning cycle, including:

- The Northeast Bulk Reinforcement, which significantly strengthens bulk supply into northeast Ontario through new 230 kV and 500 kV transmission facilities and additional transformation capacity.
- The staged implementation of the Algoma Steel Electric Arc Furnace (EAF) project, culminating in full reliance on transmission-supplied load following completion of planned development phases.
- Ongoing asset replacement and refurbishment projects across the region, including autotransformer and station upgrades at Third Line TS, Wawa TS, Sault #3 circuit (K3G), Batchawana TS, and Goulais Bay TS.
- New and expanding industrial and mining-related load connections, incorporated into the regional demand forecast.

Collectively, these developments materially reinforce the ELS transmission system and address or defer previously identified longer-term constraints. With the inclusion of the Northeast Bulk Reinforcement Plan and planned asset replacements, no immediate electricity system needs are identified at the beginning of the study period, and no new or distinct medium- or long-term regional electricity system needs were identified over the planning horizon.

Accordingly, this IRRP focuses on a limited number of anticipated near-term supply capacity needs, with the earliest needs emerging later in the study period, beginning around 2028.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is conducted through the regional planning process, which was formalized by the OEB in 2013. Regional planning assesses the interrelated needs of a region, which are defined by common electricity supply infrastructure over the near, medium, and long term, and results in a plan to ensure cost-effective and reliable electricity supply.

Regional plans consider the existing electricity infrastructure in an area, forecast demand growth and customer reliability, evaluate a range of potential options for addressing needs, and recommend actions to be undertaken. The process is carried out by the IESO in collaboration with the applicable transmitter(s) and LDCs.

The current regional planning process is conducted on a five-year planning cycle for each of the province's 21 planning regions and consists of four main components:

- **Needs Assessment** – Led by the applicable transmitter, the Needs Assessment screens for electricity needs in the region and determines if there are requirements for further regional co-ordination.
- **Scoping Assessment** – Led by the IESO, the Scoping Assessment determines the most appropriate planning approach for identified needs and defines the scope of any recommended planning activities.
- **Integrated Regional Resource Plan** – Led by the IESO, the IRRP proposes recommendations to meet the identified needs requiring co-ordinated regional planning.
- **Regional Infrastructure Plan** – Led by the applicable transmitter, the RIP provides further technical detail for implementing recommended wires solutions.

In addition to regional planning, there are related bulk system planning and distribution system planning activities. Bulk system planning typically considers the 230 kV and 500 kV transmission networks and examines province-wide issues, while distribution planning assesses the adequacy and reliability of the LDC's own network. Regional planning operates at the interface of these two processes. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

For the ELS region, the Needs Assessment completed in October 2024 identified several electricity system needs requiring co-ordinated regional planning. The subsequent Scoping Assessment concluded that an IRRP was the most appropriate planning approach, given the nature of the identified needs and the potential to consider a range of solutions, including NWAs. This IRRP represents the outcome of that co-ordinated regional planning effort.

3.2 IESO's Approach to Regional Planning

The IESO leads the IRRP stage of regional planning and is responsible for facilitating co-ordinated assessment of electricity system needs and potential solutions. The IESO's approach to regional planning emphasizes:

- Integrated assessment of transmission, distribution, and local resource options.
- Proportionality, ensuring that solutions are aligned with the magnitude, timing, and drivers of identified needs.
- Flexibility and optionality, preserving future decision-making where uncertainty exists.
- Transparency and engagement, enabling communities and stakeholders to understand and provide input into planning decisions.

In developing this IRRP, the IESO worked closely with the ELS TWG to assess system performance under forecast demand conditions and applicable contingencies, consistent with the ORTAC, North American Electric Reliability Corporation (NERC) standards, and Northeast Power Coordinating Council (NPCC) criteria.

A wide range of potential solutions was considered, including transmission and distribution reinforcements, local generation, demand-side resources, operational measures, and NWAs. Options were evaluated based on technical feasibility, timing, cost-effectiveness, and their ability to directly address the underlying causes of identified system needs. Preferred approaches were selected where they provided the most effective and proportionate means of maintaining system reliability.

3.3 ELS Technical Working Group and IRRP Development

The development of the ELS IRRP was supported by the ELS TWG, which serves as the primary technical forum for regional planning co-ordination. The TWG is composed of representatives from:

- the IESO;
- transmitters serving the ELS region including Hydro One Networks Inc., Hydro One Networks Sault Ste. Marie LP., and PUC Transmission LP; and
- local distribution companies operating within the region including Algoma Power Inc., Hydro One Distribution and PUC Distribution.

The TWG was responsible for:

- providing and reviewing regional demand forecast inputs and system data;
- identifying system constraints and verifying study assumptions;
- reviewing technical study results and option assessments; and
- supporting co-ordination between regional and bulk system planning activities.

Throughout the IRRP development process, the TWG met regularly to review analysis results, confirm findings, and provide input on the identification of preferred solutions. The TWG also supported

engagement activities by helping to contextualize planning issues and respond to feedback received from communities and stakeholders.

The IRRP was developed through an iterative process, with findings from the needs assessment, technical studies, and engagement activities informing successive stages of analysis. This collaborative approach ensured that the final plan reflects a shared understanding of regional electricity system conditions and provides a co-ordinated path forward for addressing identified needs in the ELS region.

4. Background and Study Scope

4.1 Background

The ELS region is supplied by the provincial transmission system and is electrically bounded by the 230 kV transmission circuits from Wawa TS to the northwest and Mississagi TS to the southeast. The study reflects forecast electricity demand, including the effects of eDSM, distributed generation, and other planning assumptions relevant to the region.

The background for this planning cycle also reflects major developments already incorporated into the reference system and planning assumptions for the region. These include transmission reinforcements associated with the Northeast Bulk Reinforcement Plan, the staged completion of the Algoma Steel EAF project, and ongoing asset replacement and refurbishment activities affecting key regional facilities. Collectively, these developments materially strengthen the regional supply context and help address or defer previously identified longer-term constraints.

4.2 Study Scope

The scope of this IRRP was established through the Scoping Assessment process and focuses on electricity system needs requiring co-ordinated regional planning within the ELS region over the planning horizon. The assessment examines system performance under forecast demand conditions, applicable reliability criteria, and credible contingency scenarios to identify limitations that may affect the region's ability to reliably serve load.

The TWG, led by the IESO and supported by transmitters and local distribution companies serving the region, prepared the demand forecast, reviewed system conditions, assessed identified needs, and considered options to address those needs. The study examined:

- Bulk system connection points and their capacity to serve regional demand.
- Interfaces such as the East West Tie West/East and its operational constraints.
- Planned projects with approved investment plans or committed in-service dates.
- Single-line diagram representation of the system for clarity on supply configuration.
- 20-year demand forecast reflecting eDSM, Distributed Generation (DG), and Distributed Energy Resource (DER) contributions.

The load-meeting capability (LMC) and reliability of the existing transmission system, considering transmission facility performance including transformer ratings, line thermal limits, load security, and restoration capability.

Establishing needs and timing with LDCs and transmitters including any identified due to end-of-life asset replacement.

Establishing options and alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as NWA including eDSM.

The assessment uses the applicable planning standards (e.g., ORTAC, NERC) and relevant asset condition data.

Consistent with the OEB's regional planning framework, this IRRP considers a broad range of potential solution types and emphasizes solutions that are technically feasible, timely, cost-effective, and proportionate to the nature and timing of the identified needs. Needs that can be addressed through local planning or asset replacement programs alone are outside the direct scope of this IRRP unless co-ordinated regional planning is required.

The scope was developed to ensure that the plan addresses all identified near-, mid-, and long-term needs in a co-ordinated and cost-effective manner. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.3 Related Bulk Planning Activities

Regional planning is informed by and co-ordinated with related bulk planning work undertaken by the IESO. This may include bulk planning studies that are underway in parallel with the IRRP, as well as completed bulk studies and associated transmission projects whose outcomes have been incorporated into the planning assumptions for the region. Where bulk transmission facilities interface directly with a regional system, the outcomes of this work can have a significant impact on regional planning decisions.

Bulk planning work may identify upstream transmission reinforcements, transformer expansions, interface upgrades, reactive compensation needs, or other system developments that affect regional supply capability, reliability, and future options. Findings and recommendations from relevant bulk planning work are incorporated into this IRRP where they affect the region.

4.3.1 Ongoing Bulk Planning Studies

Bulk planning studies underway in parallel with this IRRP form part of the broader planning context for the ELS region and may influence future supply capability, planning assumptions, and longer-term development pathways. Co-ordination between regional and bulk planning work helps ensure that assumptions remain aligned as both studies progress.

For the ELS region, the North of Sudbury Bulk Plan is particularly relevant. That work is proceeding in parallel with this IRRP and is expected to strengthen the broader transmission backbone supplying northeastern Ontario. In particular, reinforcements identified through the North of Sudbury Bulk Plan are expected to strengthen the Timmins end of the system and, in turn, support the performance and capability of the new Timmins to Wawa transmission line now under development.

As this bulk planning work nears completion on a similar timeline to the ELS IRRP, it represents an important part of the broader system context for the region and should continue to be co-ordinated with regional planning assumptions and future implementation activities.

4.3.2 Bulk Planning Outcomes Incorporated into this IRRP

This IRRP reflects the outcomes of previously completed bulk planning work that materially affects the ELS region, including the Northeast Bulk Reinforcement Plan and the Northern Ontario Voltage Study. These planning outcomes form part of the reference system and assumptions used in the regional needs assessment and options analysis.

For the ELS region, the Northeast Bulk Reinforcement Plan is particularly important because it provides upstream transmission capacity improvements that strengthen supply into northeast Ontario and improve the broader system conditions against which regional needs are assessed. The recommendations arising from the ELS study rely on upstream bulk transmission capacity that is enabled through the Northeast Bulk Reinforcement portfolio. The relevant reinforcements that support the ELS study include the new single 500 kV line between Mississagi TS and Hanmer TS (Northeast Power Line) and the new 230 kV double circuit line between Mississagi TS and Third Line TS (Northshore Link). The Northeast Bulk Reinforcement Plan supports the regional planning assumptions in this IRRP as it helps address the upstream system constraints in interfaces such as the Mississagi West/East and ensures reliable supply to the Sault Ste. Marie area. Both lines are essentially critical to supporting the load growth in the area and in providing additional capacity in the Northeast region.

Similarly, the outcomes from the Northern Ontario Voltage Study play a key role in the final recommendations in the ELS IRRP. These outcomes include system reactive compensation in Mississagi TS and Algoma TS, which have been used as an input and a study assumption into the plan. These reactive compensations inform and influence the options analysis and draft recommendations in this IRRP as they generally help improve post-contingency transient voltage performance in the region. They also benefit normal operation voltage control to reduce impact from load fluctuations. Without these devices, the options found in the IRRP would need to be reassessed to ensure that the needs in the region are fully addressed.

4.3.3 Ongoing Bulk Implementation Activities

Implementation of previously identified bulk planning outcomes is underway and forms an important part of the planning context for the ELS region. These activities are outside the direct scope of this IRRP, but they materially affect the regional supply context by strengthening upstream transmission capability and reinforcing the broader system on which the region depends.

In particular, three major transmission line projects associated with the Northeast Bulk Reinforcement are currently under development: the Northeast Power Line (Hanmer TS to Mississagi TS), the North Shore Link (Mississagi TS to Third Line TS), and the Timmins to Wawa Transmission Line (Porcupine TS to Wawa TS). Together, these projects strengthen the transmission supply to the ELS region and more broadly northeast Ontario.

These implementation activities are especially important for the ELS region because they strengthen supply into Wawa and Third Line, which are key supply points for the regional system. In combination with other system developments, they help establish the reference system against which the needs and recommendations in this IRRP have been assessed.

5. Electricity Demand Forecast

The ELS region load forecast establishes the foundation for identifying electricity system needs and developing planning options. The forecast is based on assumptions regarding population growth, economic activity, electrification trends, and other local drivers, as well as provincial planning standards and criteria. Peak demand forecasts consider both reliability requirements and the contribution from planned eDSM and DG.

The forecast development process begins with a review of historical summer and winter peak demand to establish a baseline. LDCs then provide gross demand forecasts that incorporate anticipated customer growth and connection activity. Weather correction is then applied to develop an extreme weather forecast for planning purposes. Adjustments are subsequently made to reflect the expected contributions of eDSM and DG, yielding the net planning forecast. This forecast is used to assess system adequacy and identify potential needs. In addition to annual peak demand forecasts, hourly load profiles are created to support system studies and evaluate planning options.

The forecast was developed using a 20-year planning horizon for the years 2025–2044 and consists of two components: the distribution-connected forecast and transmission connected forecast.

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the ELS region and is based on information submitted by LDCs. The regional planning process relies on LDCs to consider municipal and regional official plans and Indigenous community development plans and translate them into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities and Indigenous communities they serve.
- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This typically consists of large industrial customers that have their own transformation stations. The transmission-connected forecast is informed by direct engagement with these customers.

Either coincident or non-coincident peaks are used to develop these forecasts. The coincident peaks refer to the sum of each station's demand in the region taken at the hour when the whole region's demand is at its maximum. Meanwhile, the non-coincident peaks refer to the sum of each station's demand in the region taken at the hour where they individually peak, regardless of whether or not these peaks occur at different times.

In this plan, non-coincident peak load was assumed at each station for the region.

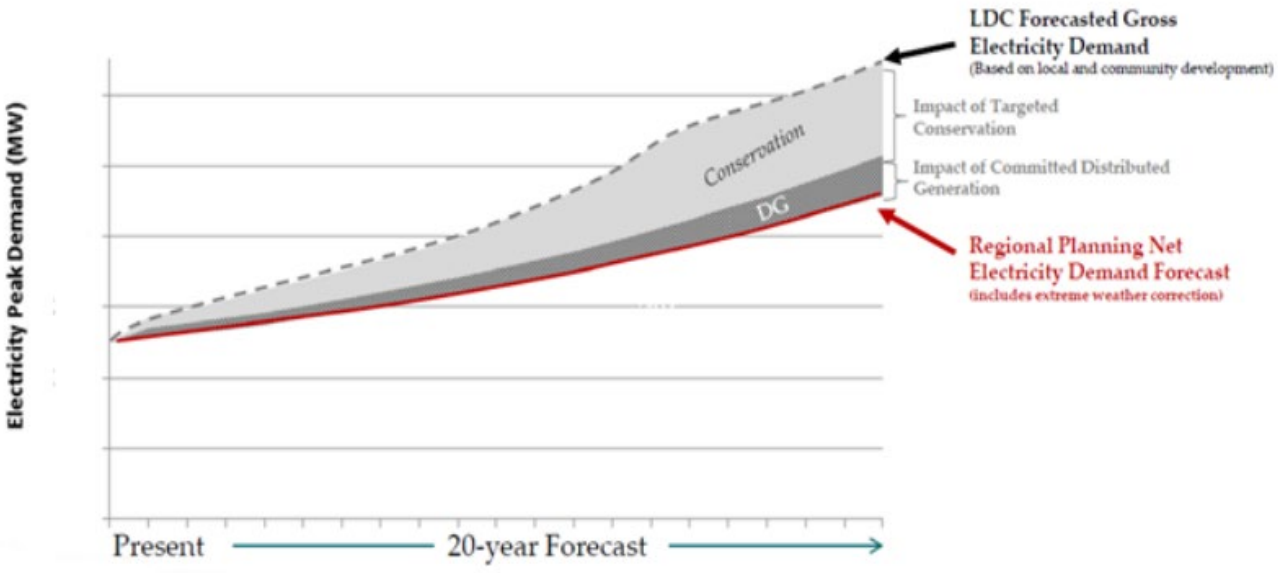
5.1 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast is shown in Figure 4. A gross demand forecast, which assumes normal weather conditions based on historical weather patterns (referred to as "normal weather"), was developed by the LDCs. This forecast was then adjusted to reflect the expected impact of extreme weather conditions for planning purposes.

Extreme weather conditions, as defined by the IESO, assume the worst observed weather over the previous 30 years. The forecast was then modified to reflect the expected peak demand impacts of provincial electricity demand side management programs and DG contracted through previous provincial programs, such as renewable Feed-In Tariff (FIT) and microFIT standard offer programs. The resulting planning demand forecast was used to assess electricity needs in the region.

The demand forecast methodology is also informed by the Load Forecast Guideline for regional planning, which was formalized by the OEB's Regional Planning Process Advisory Group. The development of the demand forecast is further explained in Appendix B.

Figure 4 | Illustrative Development of Demand Forecast

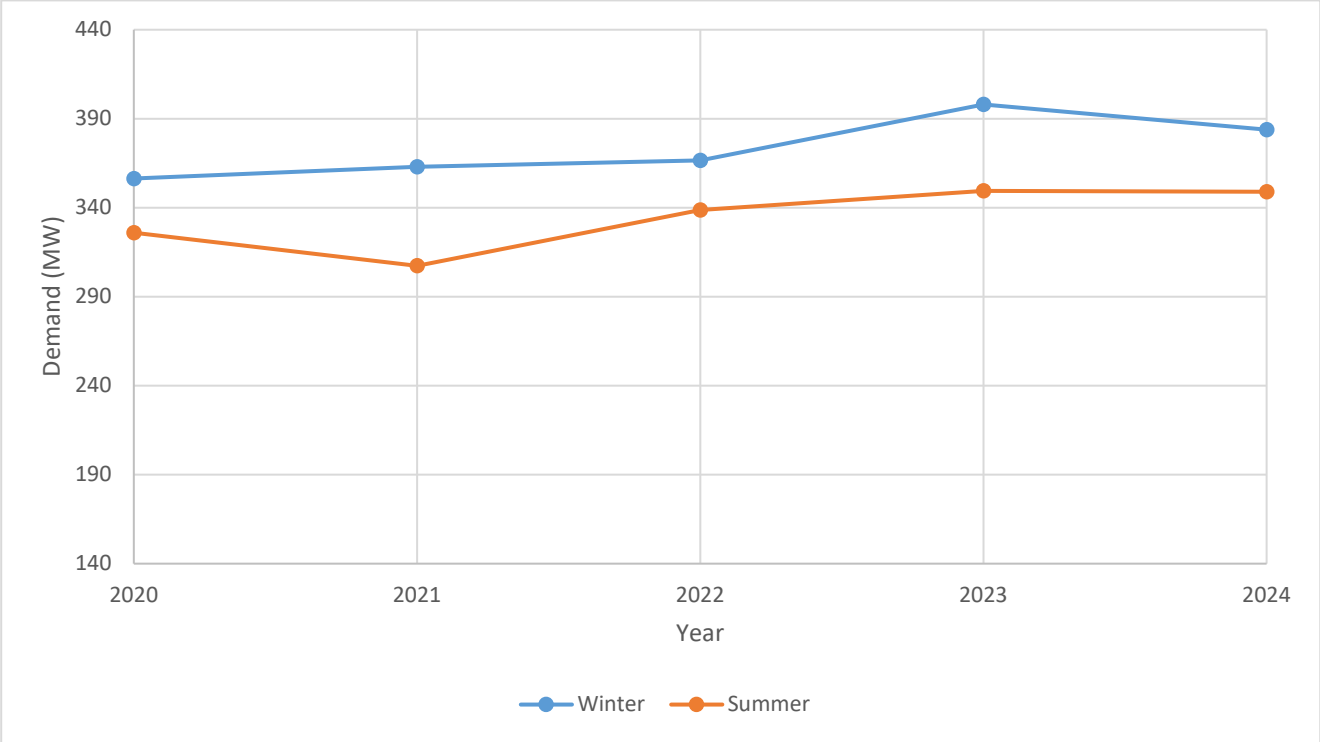


5.2 Historical Demand

Historically, the ELS region has been a winter peaking region where the peak hour for each year typically occurs in the evening, driven by electrical heating demand in the residential sector as access to natural gas is limited in the area.

The historical demand in the region for both seasons has been generally increasing, though demand has remained between 300 and 400 MW over the course of the years. Over the past five years, the demand for the region has averaged 375 MW in the winter and 335 MW in the summer. Figure 5 illustrates historical peak demand in the ELS region over the 2020 to 2024 period.

Figure 5 | Historical Peak Net Demand (2020-2024)

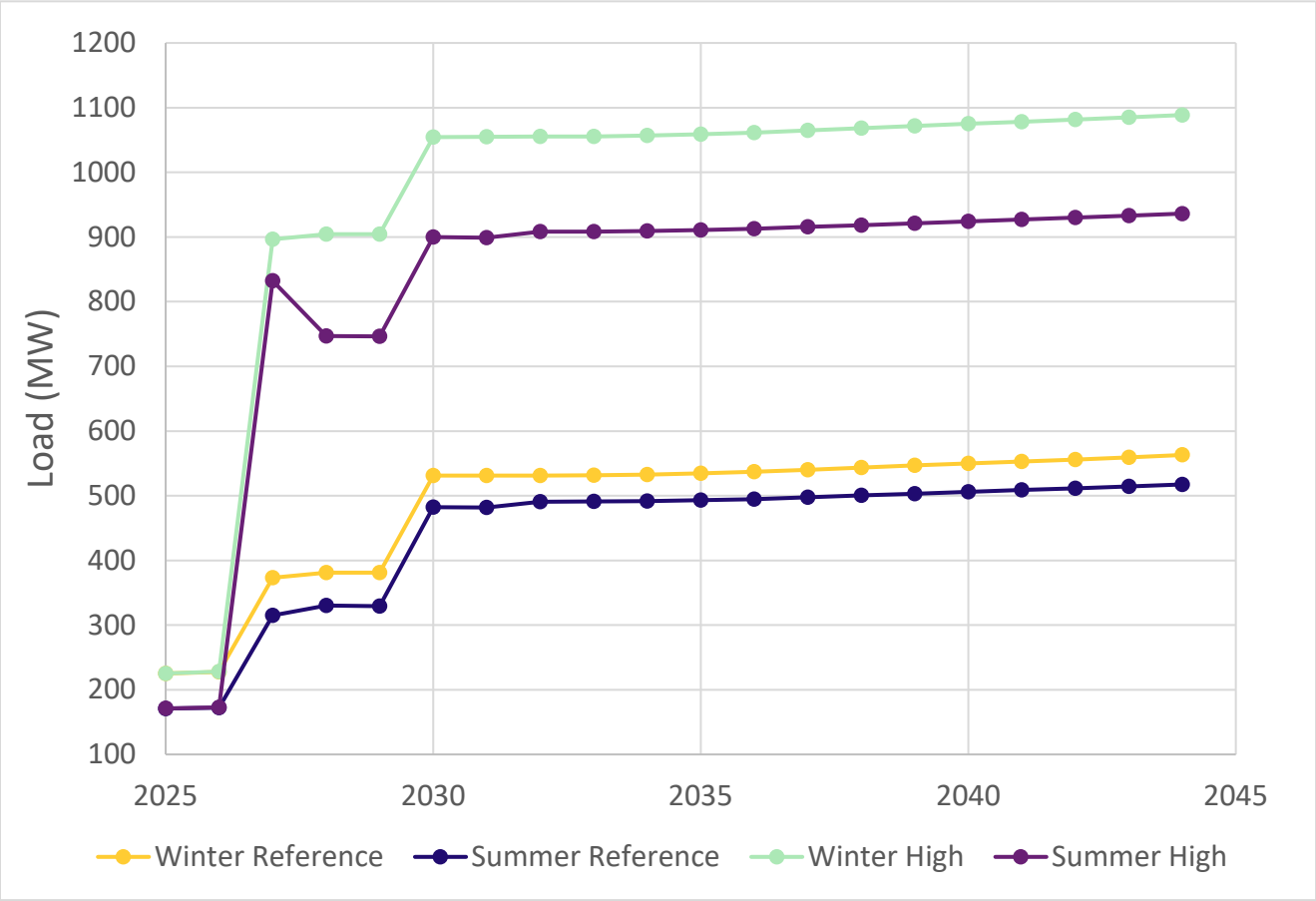


5.3 Gross Local Distribution Company Forecast

Each participating LDC prepared gross demand forecasts at the station level or at the station bus level for multi-bus stations. These forecasts account for expected changes in demand arising from efficiency improvements, rising electricity prices, and new or intensified developments. The LDC forecasts are developed based on their understanding of known local development plans and information from customer engagements. Their forecasts, however, do not include the effects of planned eDSM and DG, as they are incorporated separately by the IESO. A reference and high forecast were provided by each LDC. Additional details on each LDC's forecast methodology are provided in Appendix B.2.

The compiled distribution-connected forecasts were then adjusted to reflect extreme weather conditions. The impacts of eDSM and distributed generation were then applied separately, consistent with the forecast methodology described above. The resulting distribution-connected forecast is shown in Figure 6.

Figure 6 | Net Extreme Weather Distribution-Connected Forecast



5.4 Contribution of eDSM to the Forecast

EDSM[4] is a clean and cost-effective resource aimed to help meet the electricity needs in the province of Ontario by reducing electricity consumption and peak demand in the region. This is achieved through a combination of codes and standards amendments as well as eDSM programs, primarily the suite of Save on Energy programs, to maximize conservation results.

The reduction of demand from the codes and standards amendments is dependent on the revised codes and standards set by new or renovated buildings as well as regulation of minimum efficiency standards set by equipment used in different sectors including residential, industrial, and commercial areas.

The estimated reduction of demand due to program-related activities is based on the IESO's 2025 Annual Planning Outlook eDSM savings forecast, which is informed by the IESO's 2021–2024 CDM Framework programs, the 2025–2027 Program Plan of the new 2025–2036 eDSM Framework, existing federal programs that reduce electricity needs in Ontario and expected long-term eDSM

[4] In alignment with the language of the November 7, 2024 directive to the IESO regarding a new program framework for 2025-2036, this IRRP uses the term "Electricity Demand-Side Management" ("eDSM"), replacing "Conservation and Demand Management" used in previous IRRPs and other IESO planning documents.

program savings aligned with the current Program Plan. Following the conclusion of the 2021-2024 CDM Framework, the new 2025–2036 eDSM Framework was launched in the beginning of 2025, which expands the scale and scope of the Save-On Energy programs including launch of the Home Renovation Savings programs for residential customers and various other new incentives.

As a result, Figure 7 and Figure 8 show the total contribution of eDSM for the ELS region in the winter and summer respectively under the reference scenario, reducing the total yearly peak demand for both seasons. They are divided into three sectors including residential, commercial, and industrial.

Figure 7 | Winter Reference Peak Demand Reduction Due to eDSM

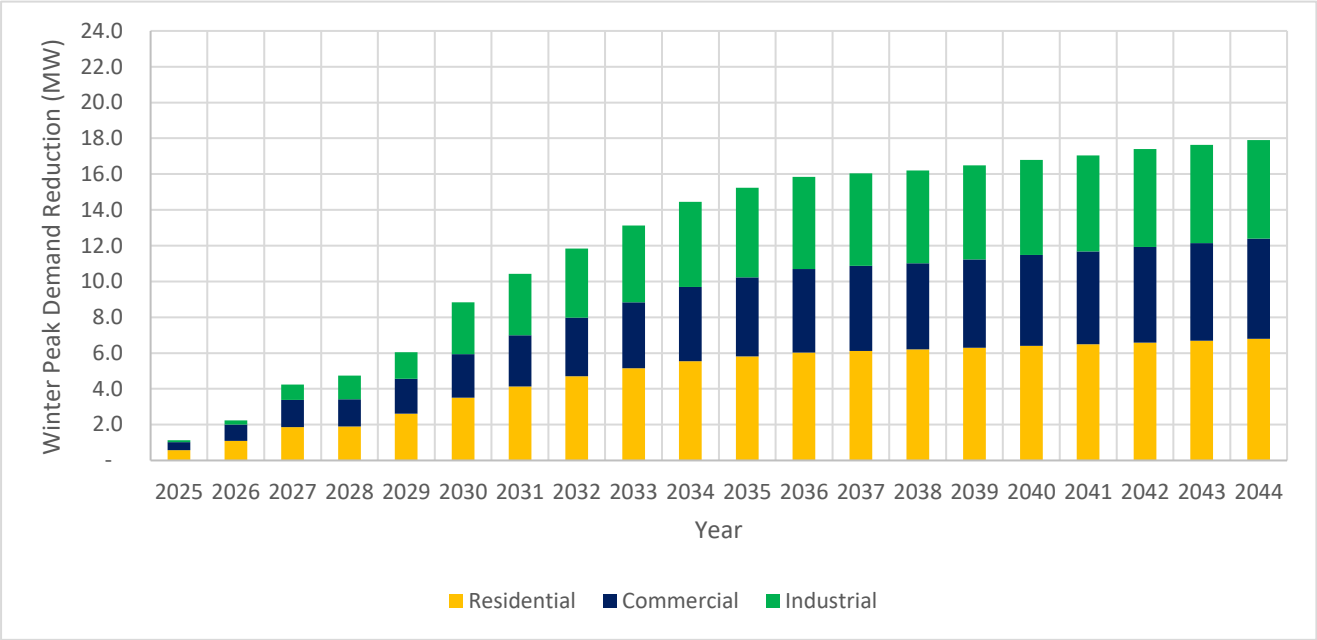
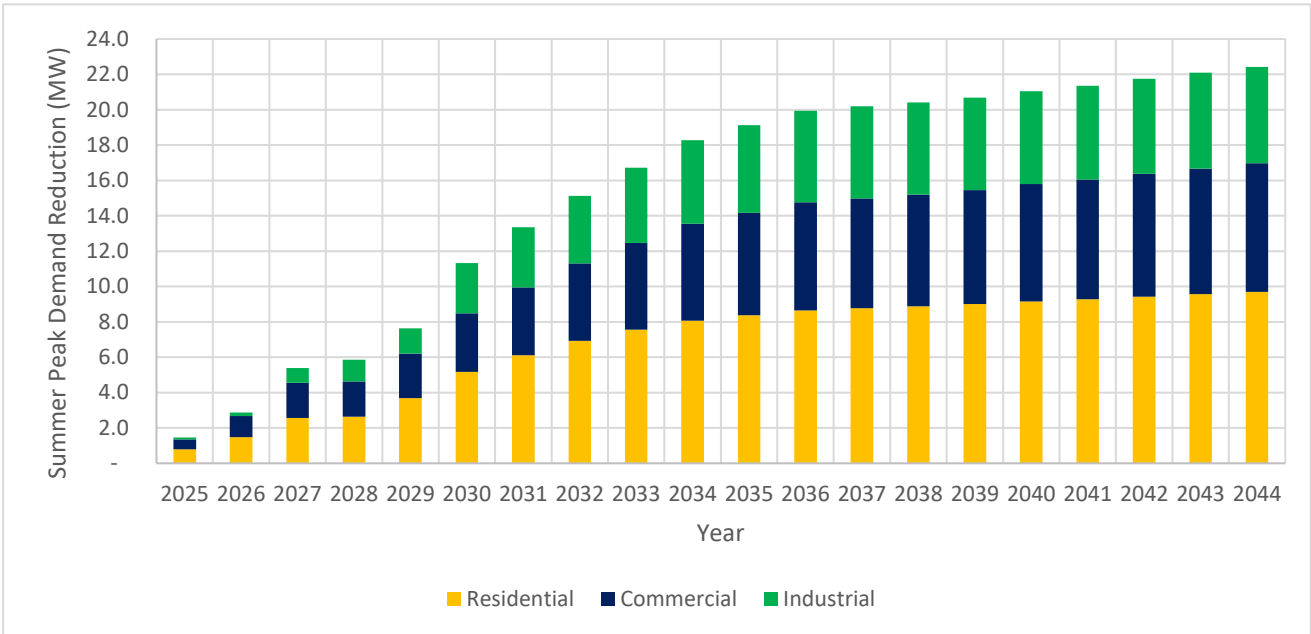


Figure 8 | Summer Reference Peak Demand Reduction Due to eDSM

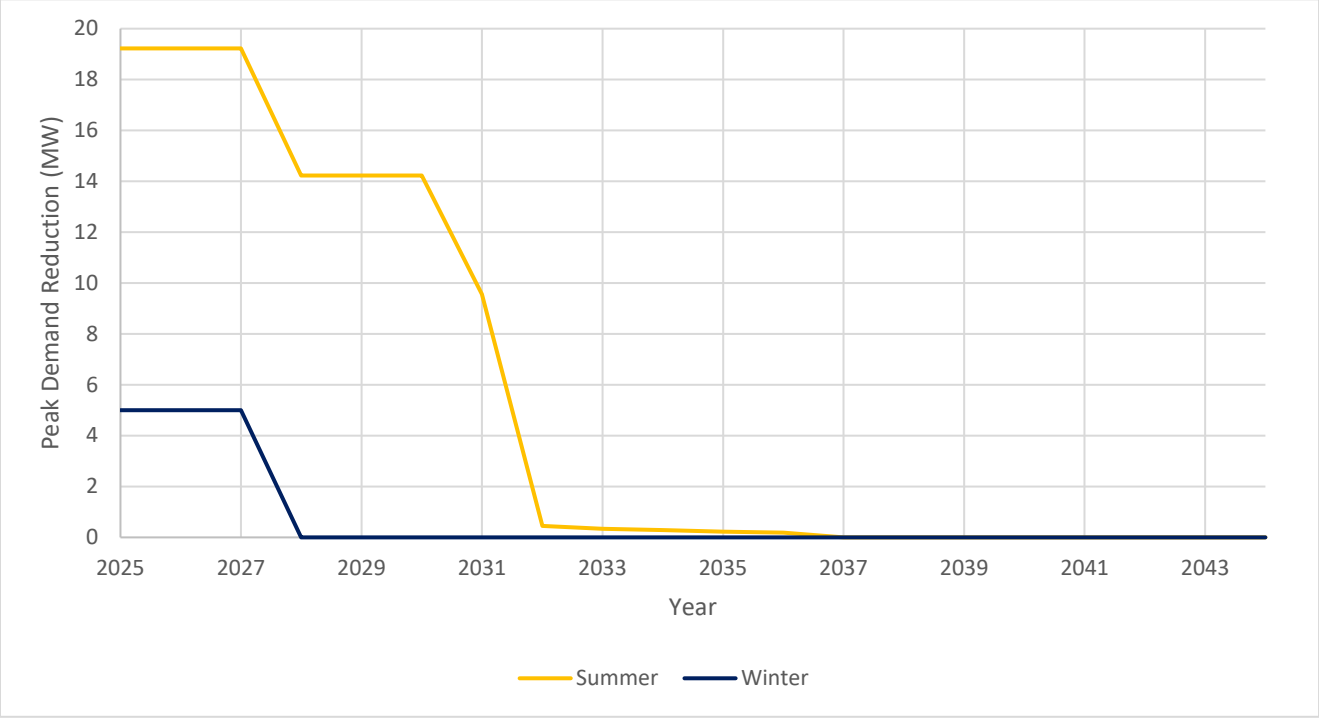


5.5 Contribution of Distributed Generation to the Forecast

Apart from eDSM resources, DG also plays a key role in reducing the electricity needs in the region. This includes resources contracted under the Ontario FIT and microFIT programs which were developed upon the introduction of the Green Energy and Green Economy Act in 2009. This act was aimed to expand renewable energy capacity across the province, encourage energy conservation and efficiency, and promote green jobs. These resources help offset peak demand requirements in regions such as the ELS region.

In Figure 9, the contribution of DG to the forecast is shown. This contribution is accounted for in the forecast, which further reduces the annual peak in addition to the contribution of eDSM. It is important to note that only facilities under contract with the IESO are accounted for and included into this forecast. As shown in Figure 9, the peak demand reduction over the years decreases. This is due to contracts expiring significantly in the middle of the next decade. The declining contribution of DG is expected to be addressed through continued implementation of the various Resource Adequacy Framework procurement mechanisms. Re-contracting of existing resources will be prioritized through upcoming windows of the Medium-Term Request for Proposals (RFP), the annual Capacity Auction and new procurement initiatives, such as the Local Generation Program. Repowering of existing resources reaching end of useful life is also being explored through the Long-Term RFP. If additional supply is required, procurement of new resources will be implemented.

Figure 9 | Peak Demand Reduction Due to DG

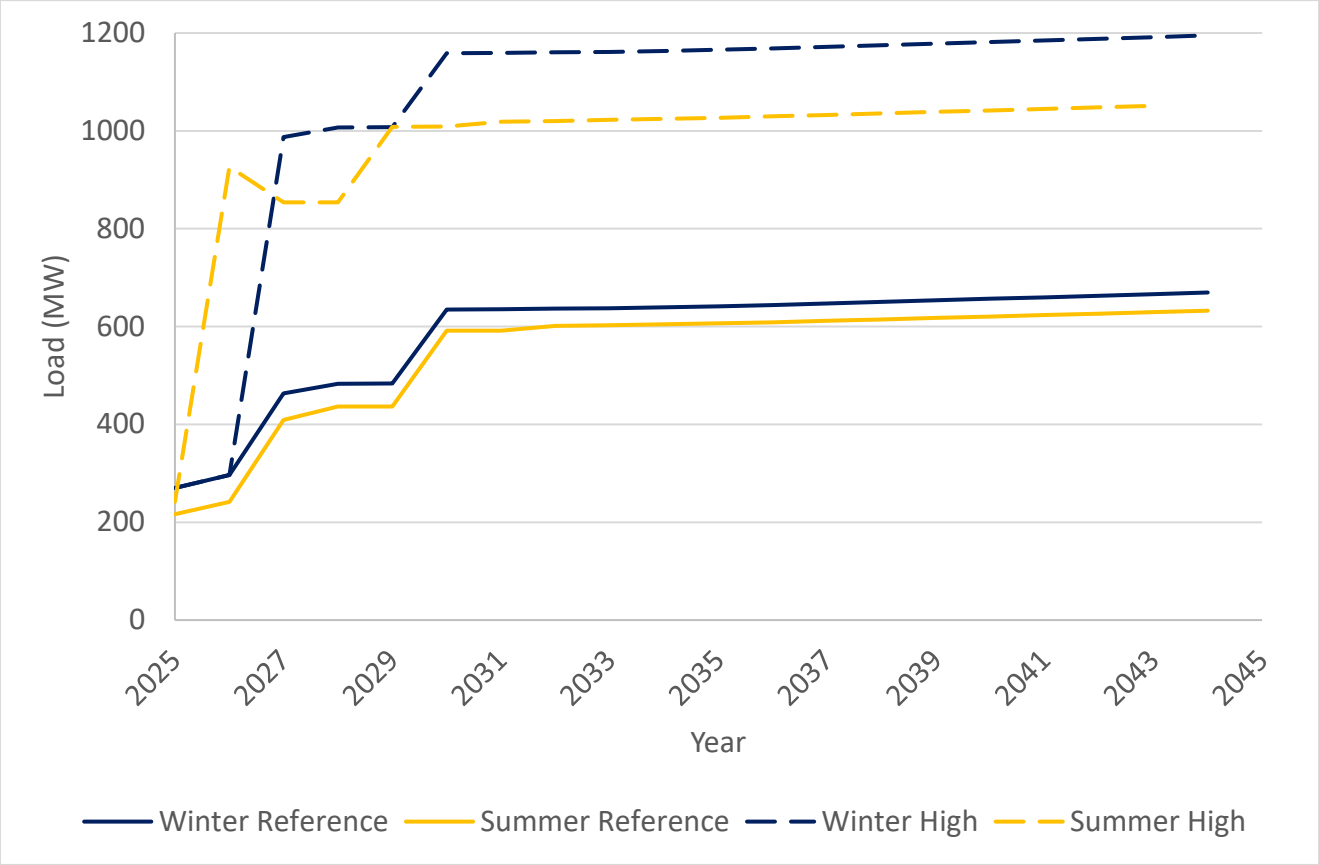


5.6 Planning Demand Forecast

After compiling the gross median forecasts from the LDCs and applying the weather correction factor and contributions of eDSM and DG, the net extreme forecast is achieved. Typically, the weather correction factor is first applied to the LDC forecast to obtain the gross extreme forecast. Then, the impact of eDSM and DG is deducted from the forecast to produce the net extreme forecast. The resulting net extreme weather demand forecast is then used to identify electricity system needs in the region and to inform the technical studies to develop options and recommendations.

The net extreme weather demand forecast for the ELS region is shown in Figure 10. This forecast includes the reference and high scenarios for each season and combines the distribution-connected and transmission-connected components of the forecast. In the winter reference scenario, the electricity demand grows significantly by 114% from 2026–2030 and stabilizes by year 2030. Also, its average annual growth rate throughout the planning period is approximately 5%. Similarly, in the winter high scenario, the same trend is observed. However, in the winter high scenario, demand could grow by 290% from 2026-2030, where the scenario encompasses potential customer connections in minerals processing, data centres, and construction. Its average annual growth rate throughout the planning period is also observed to be approximately 8%.

Figure 10 | Final ELS Net Extreme Weather Forecast



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles were also developed to support the evaluation of NWAs to address regional needs. These profiles were created for all 8,760 hours of the year over the 20-year forecast horizon for various stations and groups of stations. They were used to quantify the magnitude, frequency, and duration of needs. This supports the analysis of potential NWAs. The profiles are based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. They are then scaled to match the IRRP peak planning forecast for each year. Additional details on the hourly forecasting methodology are further provided in Appendix B.6

Note that these profiles are not intended to deterministically define hourly energy needs for NWAs. Instead, they provide a reasonable approximation of energy requirements for planning purposes, including estimating operating costs and selecting appropriate technologies. As consumer behaviour evolves, new businesses emerge, and electrification trends accelerate, demand patterns may shift significantly. The TWG will continue to monitor these developments as part of the ongoing planning process.

6. Electricity System Needs

This section summarizes the electricity system needs identified through the IRRP process for the ELS region. The assessment considers projected demand growth, electrification, and decarbonization trends, which are expected to increase pressure on the electricity system over the planning horizon, particularly during winter peak periods. The needs assessment methodology and the resulting electricity needs are described in the sections below.

6.1 Needs Assessment Methodology

Electricity needs were identified by the TWG based on an integrated assessment of planning demand forecasts, existing and forecasted system capability, the transmitter's identified asset replacement plans, and the application of established power system reliability standards and criteria, including ORTAC, NERC standards, and NPCC criteria.

Technical studies were conducted using industry-standard power system simulation tools to assess system performance under forecasted peak demand conditions and applicable contingency events. Based on this analysis, electricity needs were identified in the near-, medium-, and long-term timeframes and are categorized as follows.

Station Capacity Needs

Station capacity needs describe the electricity system's inability to deliver power to the local distribution network through regional step-down transformer stations during periods of peak demand. The capacity rating of a transformer station represents the maximum demand that can be reliably supplied and is constrained by station equipment.

Station capacity is typically determined based on the 10-day Limited Time Rating (LTR) of the station's smallest transformer, under the assumption that the largest transformer is out of service. In some cases, station capability may also be limited by the thermal or voltage constraints of upstream or downstream equipment, such as breakers, disconnect switches, low- or medium-voltage buses, or high-voltage circuits. Voltage drop limitations may further restrict station capacity independently of thermal ratings.

Supply Capacity Needs

Supply capacity needs describe the electricity system's inability to provide continuous electricity supply to a local area during peak demand conditions. These needs are defined by the LMC of the transmission system supplying the area.

LMC is determined by evaluating the maximum demand that can be served after accounting for the limitations of transmission elements—such as transmission lines, groups of lines, or autotransformers—when subjected to contingencies and criteria prescribed by ORTAC, NERC TPL-001-5.1, and NPCC Directory #1. LMC assessments are conducted using power system simulation analyses and may consider normal or extreme weather demand conditions, as applicable.

Asset Replacement Needs

Asset replacement needs are identified by the transmitter based on asset condition assessments and long-term asset management planning. These assessments consider a range of factors, including equipment deterioration due to age, weathering, or thermal stress; technical obsolescence associated with outdated designs; limited availability of spare parts or manufacturer support; and potential health and safety risks.

Asset replacement needs identified in the near- and early medium-term timeframes typically reflect condition-based information, while medium- and long-term replacement needs are often informed by the expected service life of equipment. As asset condition information is routinely updated, the timing of medium- and long-term replacement needs may change, and recommended need dates should be considered indicative.

Load Security and Load Restoration Needs

Load security and load restoration needs describe the electricity system's ability to minimize the impact of major transmission outages on customers. These needs are typically associated with severe but credible events, such as the loss of both circuits on a double circuit transmission line.

Load security refers to the total amount of customer demand that would be interrupted following a major transmission outage, while load restoration describes the system's ability to restore service to affected customers within reasonable timeframes. The specific load security and restoration requirements applied in this assessment are prescribed by ORTAC.

Based on the application of the needs assessment methodology described above, four electricity system needs were identified within the ELS study area. All identified needs are expected to emerge in the near-term, generally within the next five years, and therefore require timely action. The identified needs are limited to two categories: station capacity needs and supply capacity needs. With the inclusion of the Northeast Bulk Reinforcement, no new or distinct medium- or long-term electricity needs were identified over the planning horizon. Accordingly, the focus of this report is on addressing near-term system limitations, which are discussed in detail in the sections that follow.

6.2 Station Capacity Needs

Station capacity needs are determined by comparing forecast peak demand at step-down transformer stations with the available station capacity. For stations with multiple transformers, available capacity is typically defined using the 10-day LTR of the smallest transformer, assuming the largest transformer is out of service, in accordance with ORTAC. For single-transformer stations, available capacity is based on the transformer's continuous rating.

The asset owner is responsible for establishing transformer ratings. In most cases, the nameplate rating is used; however, in certain instances, a revised continuous rating may be calculated and applied.

Where feasible, load transfers between nearby stations are incorporated into the station-level demand forecast. These assumptions are based on information provided by local distribution company members of the TWG regarding transfer capabilities and normal operating practices.

Station capacity assessments consider both summer and winter peak demand conditions. While transformer thermal ratings are often lower in summer, increasing electrification and electric heating load can result in winter peak demand being more restrictive. As a result, both seasonal conditions are evaluated to identify the most constraining scenario.

Based on this assessment, no station capacity needs are identified in the ELS region under the Reference Scenario, as described below.

6.2.1 Chapleau DS Station Capacity Need

Based on the updated demand forecast and revised station capacity assessment methodology, Chapleau DS does not exhibit an existing or near-term station capacity need. Under the Reference Scenario, forecast station loading remains within available capacity for both summer and winter peak conditions throughout the study period. Under the High Growth Scenario, load increases more rapidly, with a station capacity need emerging in the late-2030s, driven primarily by summer peak demand.

Earlier assessments identified a potential station capacity limitation at Chapleau DS based on preliminary assumptions related to power factor, treatment of local cogeneration output, and the use of nameplate continuous transformer ratings to define available capacity. These assumptions have since been refined, and the station capacity assessment has been updated to reflect revised demand forecasting inputs and current Hydro One Distribution planning criteria.

Specifically, updated power factor values provided by Hydro One Distribution were incorporated into the station-level demand forecast. In addition, the treatment of the local biomass cogeneration facility was revised such that only generation coincident with system peak demand is credited, rather than the facility's allocated capacity. The forecast was also adjusted to a new baseline by subtracting the difference between the previous and updated starting points, ensuring alignment with observed station loading conditions. Collectively, these refinements result in a more accurate representation of net peak demand at Chapleau DS.

Chapleau DS is supplied by a single step-down transformer (T2) with nameplate ratings of 7.5 MVA under natural cooling (Oil Natural Air Natural, ONAN) and 11 MVA under fan-assisted cooling (Oil Natural Air Forced, ONAF). As fan monitoring is installed at the station, the 11 MVA ONAF rating is considered available under normal operating conditions. Unlike earlier assessments, which implicitly relied on the transformer's nameplate continuous rating, the current assessment applies Hydro One Distribution's Planned Loading Limit (PLL) methodology, which permits defined levels of continuous transformer loading above the nameplate rating.

Consistent with Hydro One Distribution planning standards, the applicable PLL factors are 125% of the ONAF rating under summer peak conditions and 155–160% under winter peak conditions, resulting in available station capacities of approximately 13.75 MVA in summer and 17 MVA in winter. When assessed against these PLL-based ratings, forecast summer and winter peak demand remains within available station capacity throughout the study period under the Reference Scenario.

As a single-transformer supplied station, Chapleau DS does not meet firm N-1 capability under transformer outage conditions. In the event of a transformer outage, continued supply would rely on the deployment of a Mobile Substation Unit (MSU). The maximum available MSU size for the

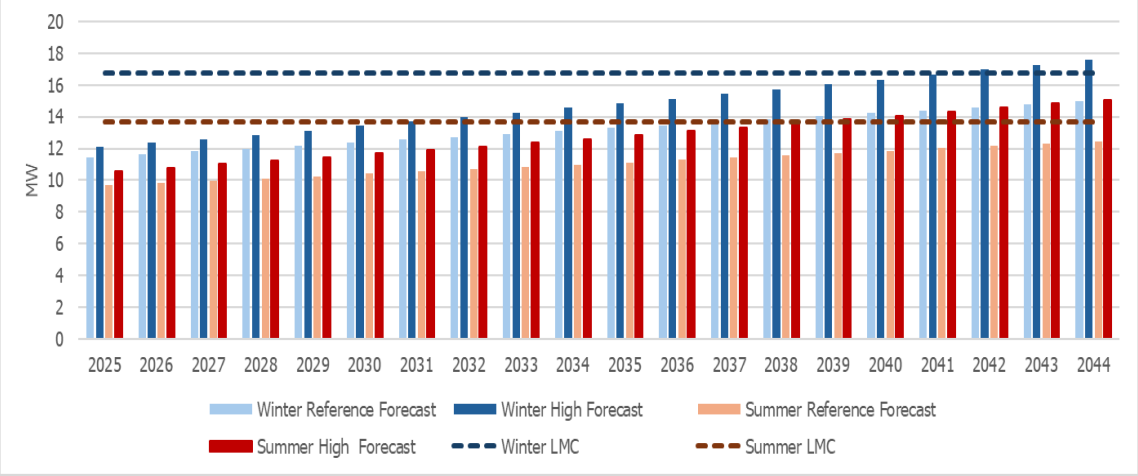
Chapleau area is 15 MVA, which effectively defines the station's supply capability under contingency conditions. While reliance on a MSU reduces operating margins during peak periods, particularly in winter; this represents a contingency-driven limitation, rather than a firm station capacity deficiency under normal operating conditions.

Overall, with the incorporation of updated power factor assumptions, revised treatment of cogeneration output at system peak, baseline-aligned demand forecasting, and the application of Hydro One Distribution's PLL methodology, Chapleau DS does not exhibit an existing or near-term station capacity need under the Reference Scenario. Forecast summer and winter peak demand remain within available station capacity throughout the study period. While a station capacity need is indicated under the High Growth Scenario in the late-2030s, this sensitivity is used to test robustness and timing rather than to establish need. Accordingly, Chapleau DS does not have an identified station capacity need in this IRRP; however, higher-growth sensitivities suggest when a capacity need could emerge should demand materially exceed the reference forecast.

Table 4 | Summary of Station Capacity Assessment – Chapleau DS

Scenario	Limiting Season	Result
Reference	Winter	No station capacity need
Reference	Summer	No station capacity need
High	Winter	Capacity need in late-2030s
High	Summer	Capacity need in late-2030s

Figure 11 | Chapleau DS Demand vs. LMC



6.3 Supply Capacity Needs

Supply capacity needs in the ELS region are associated with limitations in the ability of the transmission system to reliably supply forecast demand under applicable contingency conditions. These needs are defined by the LMC of the transmission system supplying the area and are assessed in accordance with ORTAC, NERC TPL-001-5.1, and NPCC Directory #1 criteria.

LMC assessments were conducted using industry-standard power system simulation analyses to evaluate the maximum demand that can be reliably served while maintaining compliance with applicable contingency requirements. Where system reliability depends on local generation, sensitivity analyses were performed to assess the impact of generation outages, consistent with ORTAC requirements.

Based on this assessment, three supply capacity needs were identified in the ELS region. Each is linked to a distinct transmission supply interface or corridor, as described in the sections below.

6.3.1 Chapleau Area Supply Capacity Need (W2C Supply Path)

A supply capacity need is expected to emerge in the Chapleau area, affecting both Chapleau DS and Chapleau DS2, which are supplied via the 115 kV W2C transmission path. While the transmission facilities are capable of thermally supplying forecast load, the ability of the system to reliably serve peak demand is constrained by voltage limitations at the Chapleau end of the transmission line.

This supply capacity need is distinct from station capacity considerations identified in the previous section, as it is driven by voltage performance on the W2C transmission path rather than transformer thermal capability at Chapleau DS.

As load increases, voltages in the Chapleau area are reduced and fall below the minimum voltage levels specified in planning criteria. This limits the load meeting capability of the W2C supply path and results in a supply capacity shortfall.

The voltage-limited supply capacity need is driven by forecast demand growth in the Chapleau area and potential increased reliance on the transmission system in the event that approximately 5 MW of local biomass cogeneration does not continue beyond the current contract term. While the future status of this facility is uncertain and no confirmed retirement has been communicated, the assessment conservatively considers a reduction in local generation to test system capability and inform planning.

The Chapleau area supply capacity need is expected to emerge in the near-term planning horizon and increases over time as demand continues to grow.

Figure 12 | Chapleau Area Demand vs. LMC

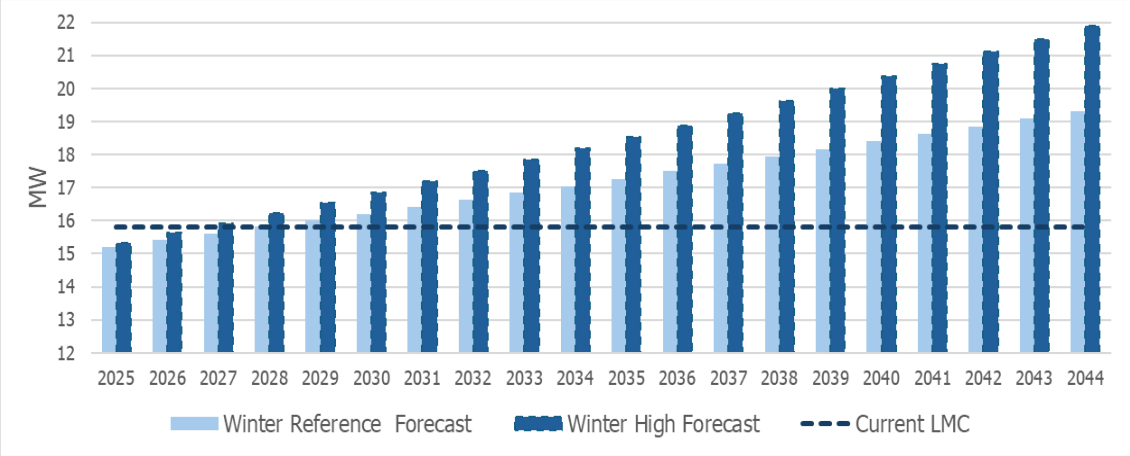
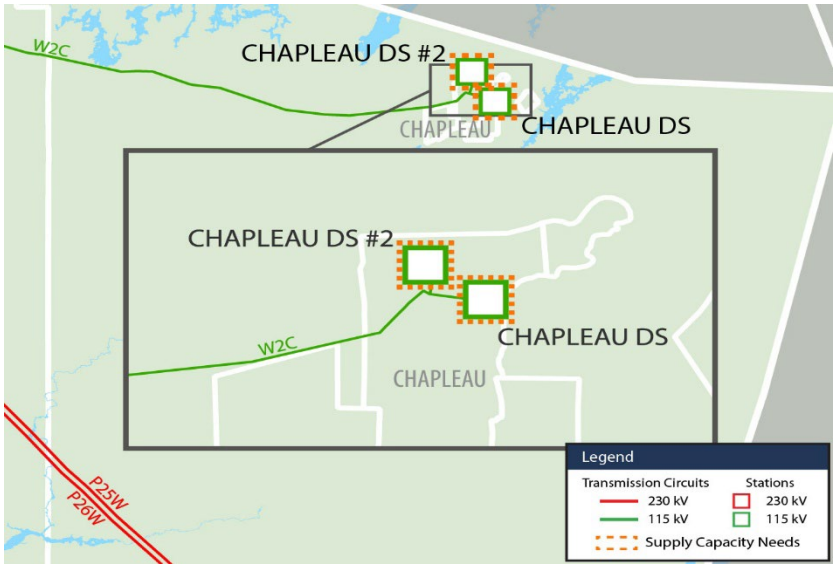


Figure 13 | Chapleau Area Need Map



6.3.2 Algoma 115 kV Interface Supply Capacity Need

A supply capacity need was identified at the Algoma 115 kV interface, which supplies load at Patrick Street, Flakeboard, and Wallace Terrace through three 115 kV transmission circuits (Algoma 1, Algoma 2, and Algoma 3). The interface also includes Clergue Generating Station, a local hydroelectric facility that provides dependable capacity to support load within the area.

The Algoma 115 kV interface reflects an existing transmission limitation rather than a need driven by forecast growth. No transmission reinforcements, generation additions, or material load growth are forecast within the study horizon. Despite the stable demand outlook, the interface is unable to meet applicable planning criteria under certain contingency conditions due to limitations in transmission transfer capability.

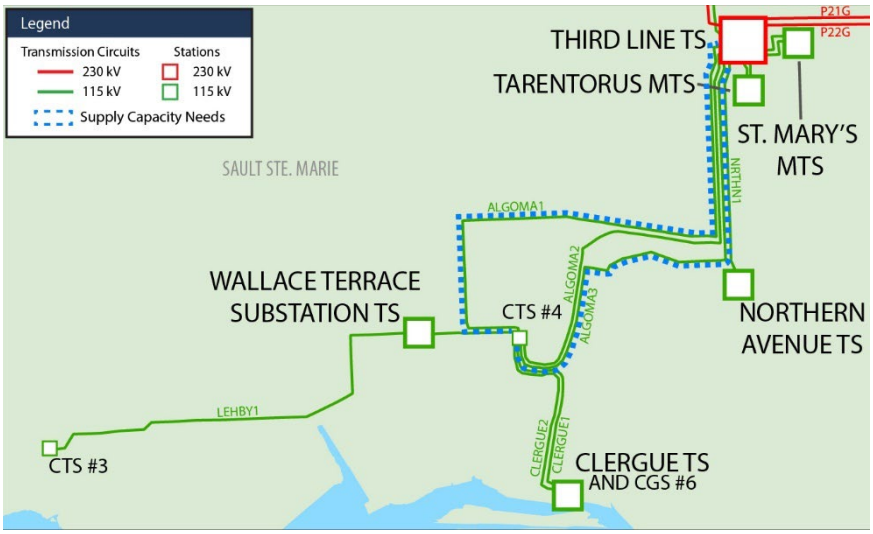
The identified supply capacity limitation is driven by the thermal performance of the Algoma 115 kV transmission lines under credible breaker failure and multiple-element outage contingencies.

Specifically, the loss of two Algoma circuits results in the remaining circuit, Algoma 1, which has the lowest thermal rating, being required to supply the full area load. Under these conditions, post-contingency loading exceeds applicable emergency thermal ratings, limiting the ability of the transmission system to reliably supply load in compliance with planning criteria.

To manage this condition, a RAS is currently in place that trips load within the Algoma interface under specific contingency scenarios. However, operation of the RAS can result in the interruption of more than 150 MW of customer load, exceeding the maximum allowable load rejection specified in ORTAC. Accordingly, the Algoma 115 kV interface does not satisfy planning criteria under these contingencies, even though forecast demand does not exceed the calculated load-meeting capability when non-compliant load rejection is assumed.

The impact of this limitation is mitigated in the near-term by local generation support from Lake Superior Power (LSP), which supplies load within the broader Sault Ste. Marie 115 kV System interface. This support reduces net loading on the Algoma facilities under contingency conditions, lowering the likelihood of thermal overloads following multiple element outages. However, for the purpose of need determination in this IRRP, planning criteria are applied without reliance on contracted generation such as LSP as firm supply. As a result, while LSP improves actual operating conditions, it is not assumed to be available in the planning assessment due to the treatment of contracted generation in the supply outlook. On this basis, the Algoma 115 kV interface continues to exhibit a supply capacity need under applicable planning criteria and must be identified in this IRRP.

Figure 14 | Algoma 115kV Need Map



6.3.3 Sault Ste. Marie Interface Supply Capacity Need

A supply capacity need has been identified for the Sault Ste. Marie 115 kV system interface, which supplies the majority of load within the Sault Ste. Marie area. The interface is anchored by Third Line TS, where power is transformed from the 230 kV system to the 115 kV system. For the purposes of this assessment, the interface includes the two 230/115 kV autotransformers at Third Line TS along

with the 115 kV transmission circuit from Mackay TS to Batchawana TS (K3G) [5] and associated downstream facilities.

Under normal operating conditions and single-contingency events, the Sault Ste. Marie 115 kV system is able to reliably serve forecast load and remains compliant with applicable planning criteria. However, a supply capacity limitation arises under a two-element contingency involving the loss of both autotransformers at Third Line TS.

Following the loss of both autotransformers, the 115 kV system must supply the full area load without support from the 230 kV system. Under these conditions, the remaining 115 kV network, including the K3G transmission line, is not sufficient to support the forecast demand. Voltage instability and thermal overloads limit the transfer capability of the interface, and as a result, the available supply is not sufficient to reliably serve load in accordance with planning criteria.

Figure 15 | Sault Ste. Marie Demand vs. LMC

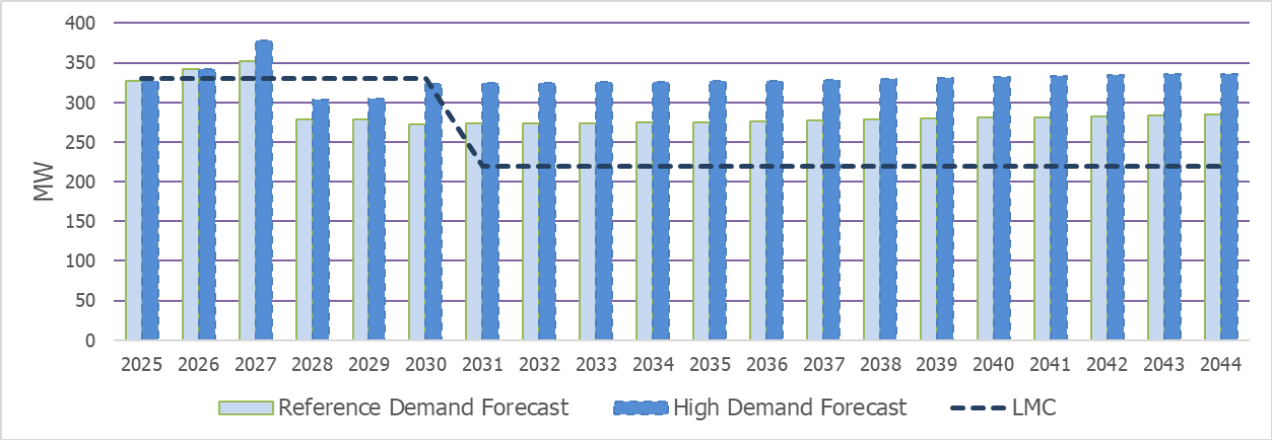
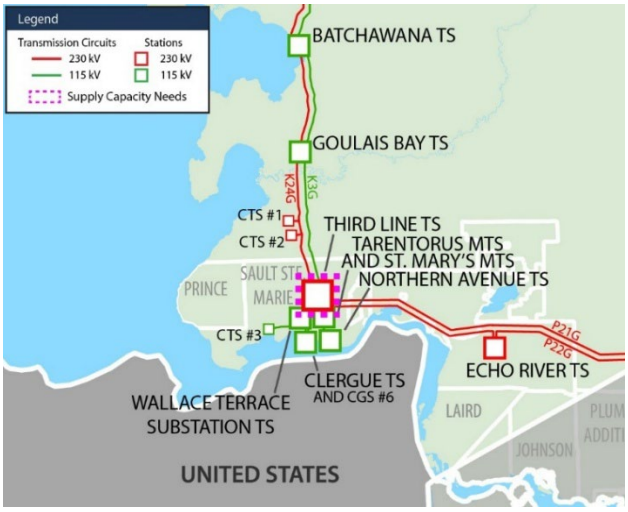


Figure 16 | Sault Ste. Marie Need Map



[5] For clarity, the 115 kV transmission circuit historically referred to as "Sault No. 3" has been re-designated as K3G following system updates.

6.4 Summary of Identified Needs

The identified needs were evaluated considering their timing, likelihood, and underlying drivers. The solution assessment therefore emphasizes proportional, flexible approaches that maintain compliance with reliability criteria while avoiding premature infrastructure investment.

Table 5 below provides an overview of all the Planning needs identified in this IRRP.

Table 5 | Summary of Planning Needs in ELS Region

Need	Need Date	2044 Need (MW)
Chapleau DS station capacity	None	n/a
Chapleau Area Supply Capacity Need (W2C Supply Path)	2028	5
Algoma 115 kV interface Supply Capacity Need	N/A	0[6]
Sault Ste. Marie Interface Supply Capacity Need	2030	95

[6] The Algoma 115 kV interface can accommodate the demand forecast under planning criteria, which permit the use of RAS schemes to trip up to 150 MW of load. However, the existing RAS is not sufficiently selective and can result in load rejection exceeding 150 MW, requiring updates to achieve compliance.

7. Plan Options and Recommendations

This section describes the solutions identified to address the electricity system needs outlined in Section 6 and presents the recommended actions for the ELS region.

A range of potential solutions were evaluated, including transmission, generation, demand-side, and operational alternatives. Options were assessed based on their ability to address the identified needs within the required timeframe, improve system reliability, accommodate future uncertainty, and be cost-effective to implement.

The recommended approaches reflect the most effective and practical means of addressing the underlying system limitations while maintaining compliance with applicable planning criteria.

As all identified needs are expected to emerge in the near-term, this section focuses on solutions that can be implemented within the required timeframe while preserving flexibility to respond to future changes in system conditions.

7.1 Solution Assessment Framework

Potential solutions were developed by the TWG and assessed to address the electricity system needs identified in Section 6. The assessment considered a range of solution types, including:

- transmission reinforcements or reconfigurations;
- station-level capacity additions or upgrades;
- local generation resources; and
- operational and NWAs, where feasible.

Each solution was assessed against key considerations including:

- effectiveness in addressing the identified need and maintaining compliance with ORTAC, NERC, and NPCC criteria;
- timing and deliverability;
- flexibility and scalability, particularly where needs increase in magnitude over time;
- cost-effectiveness, including capital and lifecycle considerations;
- consistency with broader system plans, including provincial planning outlooks and planned reinforcements such as the Northeast Bulk Reinforcement Plan.

The assessment framework recognizes that different solution types may be more appropriate for different needs. As a result, solutions were evaluated and compared separately for station capacity needs and supply capacity needs, as described in the sections below.

7.2 Plan Options and Recommendations for Station Capacity Needs

This section describes the approach used to assess and address station capacity needs in the ELS region and presents the options considered for identified and potential needs.

Station capacity needs arise when forecast demand exceeds the capability of transformer stations to supply load. These needs are typically addressed through two types of solutions. Wires solutions increase station capacity through transmission and distribution system investments, such as replacing or adding transformers, expanding existing stations, or developing new station infrastructure where required. NWAs reduce net peak demand to remain within existing station capacity. These may include demand-side measures, DG, or other local supply resources. However, NWAs are not suitable for all station capacity needs and are generally more dependent on the magnitude, timing, and duration of the constraint.

As a result, NWAs are first screened to determine whether they are technically feasible and appropriate for a given need. This screening considers the characteristics of demand growth, the nature of the underlying limitation, and the ability of NWAs to reliably address the constraint.

7.2.1 Plan Options and Recommendations for Chapleau DS Station Capacity Need

As described in Section 6.2, no station capacity need has been identified at Chapleau DS under the Reference Scenario within the planning horizon.

Consistent with the regional planning approach, implementation of station capacity solutions is typically advanced when forecast demand indicates a need within the required project lead time. Where potential needs are identified in the longer term or under sensitivity scenarios, options are reviewed at a high level and monitored through future planning cycles rather than advanced immediately. Under the High Growth Scenario, a potential station capacity need may emerge in the late-2030s, driven primarily by increased peak demand. This scenario has been assessed to provide insight into how the system may evolve under higher growth conditions and to support longer-term planning considerations. To inform this assessment, a range of potential options was reviewed at a high level, including both network-based solutions and NWAs.

A wires-based option involving Chapleau DS2 (Chapleau Municipal Station) was reviewed at a high level. This option would involve converting the existing 115 kV/4 kV Chapleau DS2 station to operate at a 25 kV secondary voltage, consistent with Chapleau DS, and transferring customers to the 25 kV system. This conversion would require replacement of existing transformers and associated modifications to feeders, protection, and control systems.

However, this work is not considered a capacity expansion option. Chapleau DS2 is an aging station with obsolete voltage configuration and is expected to require refurbishment or replacement in the near future. The proposed conversion would allow for the retirement of the aging Chapleau DS2 assets and enable all customers in the area to be served at a standardized 25 kV voltage level in alignment with Hydro One Distribution practices.

While the conversion does not materially increase system capacity, it would provide operational and reliability benefits by standardizing voltage levels across the Chapleau area. This would improve system flexibility, including enhanced ability to back feed circuits and respond to contingencies.

As such, this initiative is best characterized as an asset renewal and system modernization activity rather than a capacity solution. It is noted here for context but is not considered a plan option to address station capacity needs.

NWAs were also considered at a high level. While certain options may be technically feasible, their applicability is generally limited by the scale, timing, and location of the potential need, as well as available connection capacity within the existing distribution system. As such, NWAs were not identified as primary solutions for this need but may be reconsidered in future planning cycles.

Given the absence of a station capacity need under the Reference Scenario, no actions are required at this time. Load growth and system conditions will be reviewed through ongoing TWG activities, and station capacity solutions will be advanced when forecast demand indicates a need within project lead time.

7.3 Solutions to Address Supply Capacity Needs

This section describes the approach used to assess and address supply capacity needs in the ELS region and presents the options considered for identified needs.

Supply capacity needs arise when there are limitations in the ability of the transmission system to deliver sufficient power to a defined area under normal or contingency conditions. These needs are typically associated with transmission supply interfaces, where the amount of load that can be served is determined by the transfer capability of the interface and the availability of supply resources within the area.

To address supply capacity needs, a range of solutions is considered. These may include transmission reinforcements to increase transfer capability, such as new lines or autotransformers, or the addition of voltage support equipment to improve system performance. In many cases, local supply resources and NWAs can also play a role, particularly where they can be effectively located and operated to support the affected area.

The preferred approach in each case reflects the solution, or combination of solutions, that most effectively addresses the underlying limitation while maintaining compliance with planning criteria and remaining practical to implement. Given that supply capacity needs often affect a broader area and multiple stations, solutions are assessed with consideration of their ability to provide reliable and flexible support under a range of operating conditions.

The supply capacity needs assessed in this section include:

- The Chapleau area supply capacity need associated with voltage limitations on the W2C supply path.
- The Algoma 115 kV interface supply capacity need, driven by thermal limitations and non-compliant load rejection.
- The Sault Ste. Marie 115 kV System interface supply capacity need, driven by voltage instability under certain planning conditions.

Solutions were assessed based on their ability to improve load meeting capability, address voltage or thermal limitations, reduce reliance on non-compliant remedial actions, and maintain system reliability under applicable contingency conditions.

7.3.1 Plan Options and Recommendations for Chapleau Area Supply Capacity Need

As described in Section 6.3.1, a supply capacity need has been identified in the Chapleau area, driven by post-contingency voltage limitations on the W2C supply path. This near-term need requires a solution to address the underlying voltage limitation and maintain system reliability.

A range of potential options was considered, including transmission-based solutions, local supply resources, and NWAs. The preferred approach is the implementation of localized static reactive power support in the Chapleau area. Providing localized reactive support would improve voltage stability, increase load meeting capability, and restore voltage support previously provided by local generation. This approach directly addresses the underlying voltage limitation and provides a durable solution under contingency conditions.

The use of static reactive support represents a cost-effective and appropriate solution for the identified need. The specific sizing, siting, and configuration of the required equipment will be determined through the RIP, based on detailed technical and economic assessment.

Other options were also assessed to support the evaluation. NWAs, including combinations of wind generation, battery energy storage, and demand-side measures, may provide partial and short-term mitigation, particularly during the initial years following need onset. However, their applicability is constrained by technical limits on the system, including limited connection capacity at the distribution and transmission level, as well as voltage performance constraints on the W2C supply path. These constraints restrict the amount of additional generation or demand reduction that can be effectively integrated without further upstream reinforcement. As a result, NWAs could only be deployed in sufficient quantity to manage the need in the early-2030s and are not capable of providing a durable, long-term solution.

Local gas-fired generation was also found to be technically feasible, as it could provide firm supply and reactive capability. However, it represents a higher cost and less direct approach to addressing a voltage-driven need and was not advanced as the preferred solution.

Demand-side measures, including additional eDSM, may provide modest near-term load relief but are similarly insufficient to resolve the underlying constraint or provide sustained mitigation as demand increases.

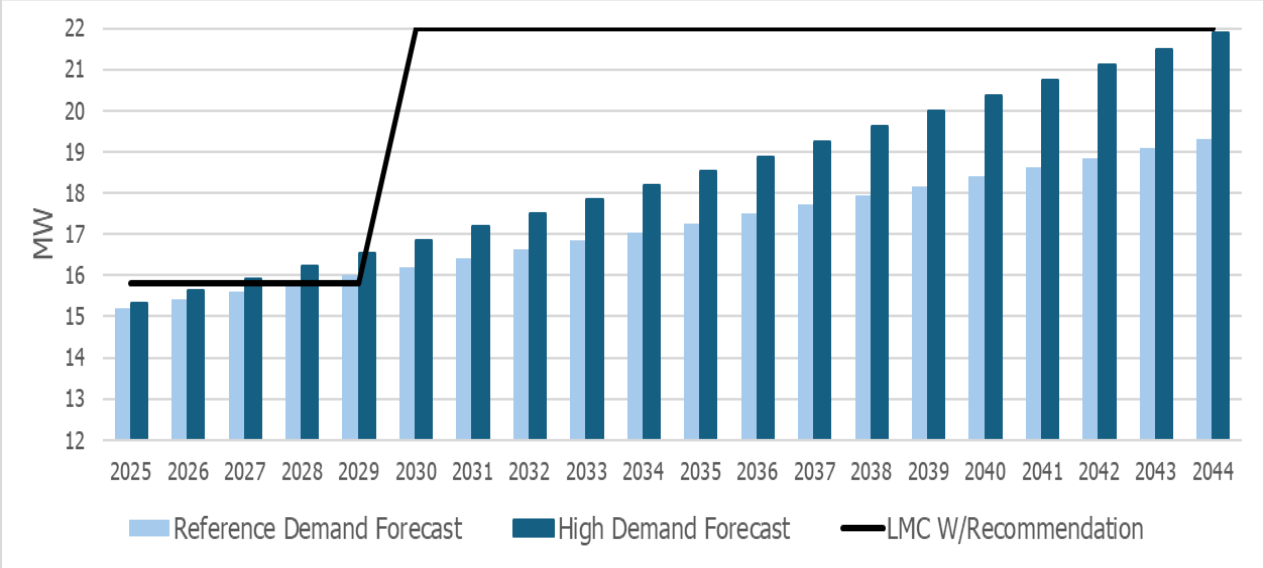
Accordingly, the recommended approach is to implement localized static reactive power support in the Chapleau area. Supplementary measures may be considered to support system needs during initial implementation; however, a permanent voltage support solution is required to address the identified supply capacity limitation. The detailed design, sizing, siting, and implementation timing of this solution will be confirmed through a RIP led by Hydro One.

During the preparation of this IRRP, Hydro One Distribution identified a potential project involving the addition of a new transformer at Chapleau DS. This project is currently in the early scoping phase and remains subject to further assessment and confirmation.

As this information became available late in the study process, its potential impact on system capacity and voltage performance in the Chapleau area has not been assessed. This potential development is separate from the 4 kV to 25 kV conversion initiative in the Chapleau area. While it may influence future system needs, it does not change the recommended approach at this time.

The TWG will continue to monitor this development and assess its implications as part of the RIP phase or future regional planning cycles.

Figure 17 | Chapleau Area Need with Recommendation



7.3.2 Plan Options and Recommendation for Algoma Area Supply Capacity Need

As described in Section 6.3.2, the Algoma 115 kV interface supply capacity limitation is driven by thermal constraints on the transmission system under contingency conditions. Under these conditions, post-contingency loading on the remaining transmission circuits can exceed applicable emergency thermal ratings, requiring corrective action to maintain system reliability.

This condition is currently managed through a RAS, which mitigates overloads by shedding load within the Algoma area following specific contingency events. Under planning criteria, the use of RAS is acceptable provided that the magnitude of load rejection remains within allowable limits. However, the existing scheme may result in load rejection in excess of the thresholds specified under ORTAC, resulting in non-compliance with planning criteria.

The preferred approach is to enhance the existing RAS to improve its selectivity and operational performance. Enhancements would focus on enabling more granular load shedding, allowing the system to reject only the minimum amount of load required to mitigate post-contingency thermal violations. This directly addresses the source of non-compliance by reducing the magnitude of load interruption while maintaining the effectiveness of the protection scheme.

This approach is appropriate given that the underlying limitation is driven by thermal performance under specific contingency conditions rather than sustained peak demand. By improving the performance of an existing system protection mechanism, it provides a targeted and efficient solution and avoids the need for more capital-intensive transmission reinforcements. It also maintains system operability under contingency conditions while aligning with applicable planning criteria.

Due to the lead time required to design, implement, and commission RAS enhancements, including engineering design, protection system upgrades, testing, and co-ordination with system operations, an interim measure is required to ensure continued reliable operation of the system. In the near term, the TWG will work with impacted customers to establish a load rejection exemption framework. Under this approach, customers would acknowledge and accept load interruption levels exceeding standard planning criteria under defined contingency conditions, providing a temporary and transparent mechanism to manage system risk while longer-term improvements are implemented.

Transmission reinforcement options were also assessed, including uprating the Algoma transmission circuits to increase transfer capability into the area. To meet reliability requirements under both single- and double-contingency conditions, co-ordinated uprating of Algoma No.1 and Algoma No.3 would be required. While technically feasible, this approach would significantly increase project scope, cost, and constructability risk, while providing a less targeted solution to a contingency-driven limitation.

As demand in the Algoma area evolves beyond the conditions assessed in this IRRP, transmission reinforcement options may be revisited in future planning cycles or TWG reviews to confirm whether additional infrastructure is warranted.

Accordingly, the recommended approach is a staged solution consisting of an interim load rejection arrangement followed by targeted enhancements to the existing RAS to restore compliance with planning criteria.

7.3.3 Plan Options and Recommendations for Sault Ste. Marie Supply Capacity Need

As described in Section 6.3.3, the Sault Ste. Marie 115 kV system interface supply capacity need is driven by voltage instability following the sequential loss of both autotransformers at Third Line TS. Under this condition, the remaining 115 kV network is unable to maintain acceptable voltage levels and reliably serve load, and thermal overloads are also observed on the K3G transmission section. This need is expected to emerge in the near term and requires a solution to maintain system reliability.

A range of potential options was considered, including transmission reinforcements, local supply resources, and NWAs. The recommended action is to pursue a cost-effective supply solution with performance characteristics aligned with the identified reliability risk. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed after a contingency, and capable of sustained operation for the duration of the contingency condition. This performance-based framing preserves flexibility with respect to the specific technology or acquisition approach, supports transparency with communities, and allows the need to be addressed, subject to demonstrated deliverability and applicable municipal and provincial siting requirements.

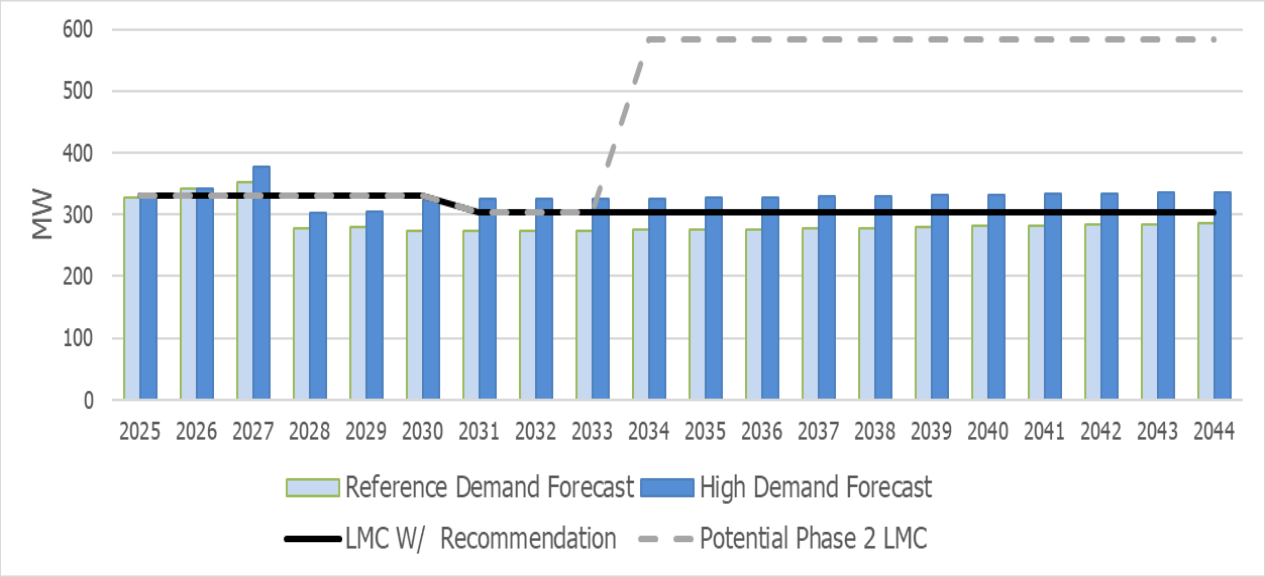
The ability to implement new supply resources in the Sault Ste. Marie area is currently constrained by system conditions, including limits on connection capacity and restrictions on the integration of certain resource types. These constraints limit the amount and type of resources that can be connected and reliably contribute to system needs and will need to be considered in the design and implementation of any solution.

Other NWAs were also assessed. Resource combinations such as wind generation, battery energy storage, and demand-side measures were found to be technically constrained in the area and are not capable of providing the firm, dispatchable, and sustained performance required to address the identified reliability need. Demand-side measures alone are similarly insufficient, as they do not provide the level of firm capacity or reactive support required under contingency conditions. Load transfer options were also assessed and found to be infeasible due to network limitations and the absence of sufficient alternate supply paths.

A transmission-based solution involving the addition of a third autotransformer at Third Line TS was also assessed as a longer-term option. This approach would increase system redundancy, improve voltage performance, and fully eliminate the identified limitation; however, it involves higher cost and longer lead times. In contrast, a supply resource with the required performance characteristics provides ongoing system value by contributing energy and capacity to the system, while also addressing the local transmission reliability risk under contingency conditions. As a result, a performance-based supply solution represents a more cost-effective and flexible approach in the near term. The addition of a third autotransformer at Third Line TS is therefore considered a potential future consideration (Phase 2) reinforcement, the timing of which is not predetermined and would depend on future demand growth and system conditions. As demand and system conditions evolve, transmission reinforcement options may be revisited through future planning cycles and TWG reviews to confirm whether a wires-based solution is required. Supply constraints and congestion in the region currently limit inverter-based generation integration. These constraints limit the ability of certain resource types to address system needs, even when they may be otherwise cost effective. During outage conditions, congestion also results in curtailment of low-cost generation options, which add increased costs to the market. A review of demand and supply conditions in the 2028 to 2029 timeframe is recommended to confirm timing and identify the appropriate long-term approach.

Accordingly, the recommended approach is to pursue a cost-effective supply solution that meets the defined dispatchability, duration, and voltage support requirements to address the identified supply capacity need in the near term.

Figure 18 | Sault Ste. Marie Need with Recommendation



For illustrative purposes, the potential Phase 2 reinforcement (addition of a third autotransformer at Third Line TS) is reflected in the LMC projection in the mid-2030s to demonstrate its impact on system capability; however, the timing of this reinforcement is not predetermined and will depend on future system conditions and demand growth.

7.4 Summary of Recommended Actions and Next Steps

The TWG recommends the actions summarized in Table 6 below to meet needs identified in the ELS region IRRP.

Table 6 | Summary of Recommendations for ELS Region

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service	High Level Planning Cost Estimate ($)
ELS region monitoring	Planning/ monitoring	Preserves long-term flexibility and informs future infrastructure-based solutions	ELS TWG	Ongoing	-
Chapleau reactive power support	Transmission-side static reactive power support, with demand side measures serving as	Address voltage-limited supply capacity constraints in the Chapleau Area	Hydro One (reactive support); IESO (eDSM)	Near-Term	~ 8M

Action	Reinforcement Type	Needs Addressed	Implementation	Expected In-Service	High Level Planning Cost Estimate ($)
	short-term supplement				
Address Algoma 115 kV interface supply capacity need	Enhance existing RAS to support more flexible control actions; load rejection exemption framework	Mitigates contingency-driven thermal limitation at the Algoma 115 kV interface	Hydro One	Near-Term (interim); TBD (RAS)	~5M
Address Sault Ste. Marie 115 kV interface supply capacity need	Performance based supply solution with demand side measures	Address voltage instability limitations in the Sault Ste. Marie 115 kV area	IESO (lead); TWG support	TBD	-[7]
Address Sault Ste. Marie 115 kV interface supply capacity need - Long-Term	Ongoing planning assessment through TWG and planning cycles	Ensure long-term supply adequacy and determine need for wires solution (i.e. new autotransformer) at Third Line TS	ELS TWG	Ongoing/ Trigger-based	-

[7] Costs for a supply resource in the region would be offset by system benefits that would be realized by any resource

8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the ELS IRRP.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework and is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose to foster trust and build understanding.

Figure 19 | The IESO's Engagement Principles



8.2 Engagement Tactics

To ensure that the IRRP reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement tactics involved:

- Leveraging the ELS engagement webpage to share information including engagement opportunities, meeting materials, input received and the IESO's response to feedback;

- Leading targeted discussions with key Indigenous communities and municipal staff to help inform the engagement approach for this planning cycle;
- Hosting public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and;
- Providing written updates through email and IESO's weekly Bulletin updates to all subscribers.

8.3 Engagement Approach

Four public engagement webinars were held at major stages during the Scoping Assessment and IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan.

Public engagement webinars were attended by municipal staff, community representatives, businesses, Indigenous communities, and other interested parties and written feedback was collected following a comment period after each webinar. The four stages of engagement at which input was invited were:

1. The draft scoping outcome assessment report to share the planning approach before delving into the full IRRP study;
2. The draft engagement plan and electricity demand forecast to set the foundation of this planning work;
3. The electricity needs for the region and an overview of wired solutions and NWAs that could meet the needs; and
4. The detailed analysis of all feasible wired solutions and NWAs and draft IRRP recommendations.

Comments received during the development of the IRRP primarily focused on:

- Accounting for growth and economic development projects across the region;
- Ensuring climate impacts are accounted for throughout the development of the IRRP, and;
- Exploring alternative solutions, such as NWAs, to meeting the area's electricity needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations, and are outlined in the stages below.

Scoping Assessment

The ELS region was anticipated to experience significant electricity demand growth given earlier regional and bulk plans in this area. Additional local needs were identified in the Needs Assessment and shared during this milestone, confirming the approach to proceed with an IRRP. Email communications were sent to all subscribers of the ELS region, including municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and encourage participation on the ELS Scoping Assessment

report finalization. A public webinar was held in December 2024 to provide an overview of the regional electricity planning process, the draft report and proposed approach.

Feedback received during this milestone encouraged the IESO to consider co-ordination between the electric and gas sectors to help optimize the energy systems in ELS and to consider expanding participation in the TWG. The IESO welcomed any additional information and meetings to help inform the study as it progresses. The final Scoping Assessment report was posted in January 2025, identifying the need for a co-ordinated regional planning approach for the ELS region.

Demand Forecast

Following finalizing the Scoping Assessment, the TWG began the development of region's electricity demand forecast. IRRP recommendations are typically driven by the Reference Demand Forecast, which includes firm loads (current and planned), organic growth, residential, electrification and energy plans, and industrial growth. A High Growth Scenario was also developed to capture growth and trends that are less certain such as large-scale customer connections.

To achieve this, the IESO engaged with all municipalities to understand any key loads to engage, as well as with transmission-connected loads, to understand their growth plans and ensure it was captured in the draft forecasts. The draft forecasts were shared through the launch of a broader public engagement initiative. Communications to IESO subscribers of the ELS region ensured all interested parties were made aware of the opportunity for input.

During this milestone, key information shared was that the electricity demand is growing significantly with demand estimated to grow by 112%. The primary drivers of growth are electrification initiatives, including Algoma Steel's EAF transformation project. The reference forecast was ultimately used to drive recommended solutions, however the TWG will identify options for long-term electricity needs and high-growth scenarios, refining these options in future planning cycles and activating them as growth occurs.

Based on the feedback through this engagement initiative, a key priority was to ensure the IRRP considered climate impacts into the demand forecast and incorporated resiliency into recommended actions. The TWG ensures the forecast reflects extreme weather conditions in various scenarios, which includes the system's ability to respond to disturbances, and committed to ongoing discussions about resiliency throughout plan development. Additionally, feedback was centred around ensuring strong justification for new or upgraded infrastructure developments are provided. The TWG committed to evaluating wired solutions and NWAs and sharing the analysis as planning work advances.

Electricity Needs and Options Identification

During this milestone, the TWG initially identified a station capacity need and three supply capacity needs, each with unique system challenges. During targeted municipal discussions and the public engagement webinar, the TWG shared the types of options that are considered as part of the regional planning process to meet needs. The examples illustrated the range of options typically considered, with further analysis underway to determine which solutions would be most appropriate based on system needs and constraints.

Feedback at this stage of the engagement sought to further clarify the options analysis stage of the IRRP, particularly if NWAs would be considered and if options would be advanced on high demand projections. The TWG committed to sharing a detailed options analysis in the upcoming milestone. Additionally, feedback received urged to consider forward-looking climate projections. The TWG acknowledged the importance of accounting for temperature trends in the forecasting development and shared information about how extreme weather is included in this process.

Options Analysis and Draft Recommendations

During this milestone, the TWG shared the options analysis for all feasible wired solutions and NWAs and the draft recommendations through targeted municipal discussions and a public engagement webinar. Since the last webinar, the previously identified station capacity need at Chapleau DS was resolved based on updated information showing sufficient station capacity, leaving three supply capacity needs remaining. To meet the needs, the Technical Working Group drafted the following recommendations:

- Install a reactive device (capacitor) to improve supply capacity and voltage performance for the Chapleau area, supported by electricity demand-side management as an interim measure.
- Pursue generation options at the Sault Ste. Marie 115kV interface and monitor the load growth in the area to determine whether an additional autotransformer is required in the future.
- Obtain an operational measure exemption at the Algoma 115kV interface as enhancements to the existing RAS is implemented.
- Monitor load growth and system performance to identify timing on advancing additional system improvements if needed to maintain compliance with reliability criteria.

Feedback at this stage of the engagement sought to further clarify if deliverability constraints will impact the generation recommendation and linkages to other ongoing work in the region.

8.4 Involving Municipalities in the Plan

Throughout the IRRP engagement, valuable feedback was received from municipalities and incorporated into the final IRRP including:

- Enhancing webinar materials to share technical updates in a transparent and digestible manner;
- Including the latest energy plans on electrification, HVAC systems and electric vehicles, and transmission-connected customers in and around the Sault Ste. Marie area; and
- Providing details on linkages with ongoing and previous regional and bulk plans, including the 2022 Northeast Bulk Plan recommendations and ongoing Sudbury/Algoma regional plan.

8.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with Indigenous communities to help shape long-term planning across Ontario. This engagement was part of a broader commitment to fostering respectful relationships, ensuring transparency, and supporting informed participation in

integrated regional electricity system planning. Throughout the development of this plan, the IESO's engagement with Indigenous communities included inviting Indigenous communities to participate in online information sessions held on December 4, 2024, July 9, 2025, December 11, 2025 and June 4, 2026, as well as Indigenous-focused meetings that were held those same days, in order to provide additional opportunities to ask questions and provide input.

To share information about the planning activities and invite participation in the engagement process, outreach was made to the following Indigenous communities:

- Batchewana First Nation
- Brunswick House First Nation
- Chapleau Cree First Nation
- Chapleau Ojibwe First Nation
- Garden River First Nation
- Michipicoten First Nation
- Missanabie Cree First Nation
- Mississauga First Nation
- Serpent River First Nation
- Thessalon First Nation
- Métis Nation of Ontario
- Bar River Métis
- Red Sky Métis Independent Nation

Detailed non-confidential feedback submitted to the IESO and the IESO's responses can be viewed on the East Lake Superior Planning Engagement webpage. At a high level, the IESO received the following feedback:

- M'Chigeeng First Nation requested more detailed data from the IESO on Algoma Steel Foundry electrification to better understand regional impacts and reduce uncertainty. They emphasized prioritizing Distributed Energy Resources (DERs)—including wind, solar, hydro, and battery storage—as the primary solution to address regional supply needs. They expressed concern that demand-side management (eDSM) may not effectively reduce consumption given anticipated rapid load growth. The Nation also suggested the IESO explore a new transmission line from the Sudbury/Algoma region, supported by DERs along the north shore, to enable future distribution-level load transfers—similar to proposed lines in the Northeast (Hanmer TS → Mississagi TS → Third Line TS).
- Batchewana First Nation did not raise concerns but requested to remain engaged and informed, highlighting the importance of any infrastructure development within their traditional territory.

9. Conclusion and Next Steps

This IRRP outlines a needs-based, staged approach to meeting electricity system needs and maintaining a reliable and cost-effective electricity system in the ELS region over the planning horizon. The plan was developed through collaboration among the IESO, the ELS TWG, and regional partners, informed by detailed technical analysis and engagement with communities and stakeholders.

The needs assessment identified a limited number of near-term electricity system needs, primarily related to supply capacity limitations driven by voltage and thermal performance under applicable contingency conditions. These needs are largely attributable to existing system configuration, operational constraints, and planning criteria requirements rather than widespread forecast demand growth. With the inclusion of the Northeast Bulk Reinforcement, no new or distinct medium- or long-term regional electricity needs were identified over the planning horizon.

A broad range of potential solutions was considered to address the identified needs, including transmission and distribution reinforcements, local generation, demand-side resources, operational measures, and NWAs. Preferred approaches were selected based on their ability to address the underlying drivers of each need, their technical feasibility and deliverability within the required timeframe, and their relative cost, risk and alignment with system needs.

For the Chapleau area, the preferred approach is the implementation of localized transmission-side reactive power support to address voltage-limited supply capacity on the W2C supply path. This solution directly addresses the root cause of the constraint and provides effective and durable voltage support. Demand-side resources and DERs, including eDSM, were identified as having the potential to provide modest, short-term relief but only as a supplementary measure and not as a standalone solution.

For the Algoma 115 kV interface, the preferred approach is a staged solution consisting of interim customer arrangements for controlled load interruption, followed by enhancements to the existing RAS. This reflects the industrial nature of the load served and the low-frequency, contingency-driven characteristics of the limitation. This approach provides a proportionate and practical means of maintaining compliance with planning criteria while avoiding significant infrastructure investment under stable demand conditions.

For the Sault Ste. Marie 115 kV system interface, the preferred approach is to pursue a cost-effective supply solution with performance characteristics aligned with the identified reliability risk. The capability of the resource must match the characteristics of the need, requiring a resource that is dispatchable when needed after a contingency and capable of sustained operation for the duration of the contingency condition. This performance-based framing preserves flexibility with respect to the specific technology or acquisition approach and allows the need to be addressed in a targeted and cost-effective manner, while delivering broader system value through energy and capacity contributions under normal operating conditions.

Future infrastructure-based options, including the addition of a third autotransformer at Third Line, have been identified to preserve optionality and may be reconsidered in subsequent planning cycles should there be an increase in load, changes in system conditions, or evolving reliability expectations that warrant a permanent reinforcement.

Engagement undertaken throughout the development of this IRRP supported transparency and provided valuable input to inform planning assumptions and option screening. Engagement will continue beyond the publication of this plan as recommended actions progress and as future regional planning activities are undertaken.

9.1 Path Forward and Ongoing Monitoring

Consistent with the approach taken in previous ELS IRRPs, this plan establishes a clear path forward while maintaining flexibility to respond to evolving system conditions.

In the near-term, next steps include:

- Advancing the preferred solutions identified in this IRRP through appropriate implementation mechanisms, including RIPs and contractual arrangements, as applicable;
- Continued co-ordination among the IESO, transmitters, and LDCs to support timely implementation; and
- Ongoing monitoring of system performance, load levels, and operating conditions through the TWG activities to validate planning assumptions and confirm implementation timing.

Over the longer-term, the IESO and regional planning partners will continue to monitor:

- Changes in load levels, electrification trends, and local development activity;
- The performance and effectiveness of implemented solutions; and
- Emerging risks or constraints that may give rise to new or evolving electricity system needs.

Should system conditions materially change, the TWG will review to confirm timing and identify appropriate actions to maintain system reliability.

Overall, this IRRP provides a clear, proportionate, and flexible plan to address the identified electricity system needs of the ELS region, balancing near-term reliability requirements with longer-term adaptability and prudent investment.

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Connecting Today.
Powering Tomorrow.

23 September 2026

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Via email

Dear,

Subject: Regional Planning Status letter

This letter is in response to your request for a Planning Status letter. For the purposes of regional planning the province has been divided into 21 regions. A map showing details with respect to the 21 regions[1] and the list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. is the lead transmitter in 20 regions and Hydro One Distributions' service area belongs to the Burlington to Nanticoke, Chatham-Lambton-Sarnia, GTA East, GTA North, GTA West, Greater Bruce/Huron, Greater Ottawa, Kitchener-Waterloo-Cambridge-Guelph (KWCG), London, Niagara, North/East of Sudbury, Northwest Ontario, Peterborough to Kingston, Renfrew, South Georgian Bay (SGB) / Muskoka, St. Lawrence, Sudbury / Algoma, Toronto, East Lake Superior and Windsor-Essex regions.

Hydro One Distribution is connected to the following transformer and transmission connected distribution stations:

Burlington to Nanticoke: Brant TS, Caledonia TS, Dundas TS, Dundas TS #2 Jarvis TS, Lake TS, Nebo TS, Norfolk TS and Bloomsburg DS.

Chatham-Lambton-Sarnia: Duart TS, Kent TS, Lambton TS, Wallaceburg TS, Wanstead TS and Forest Jura DS.

East Lake Superior: Chapleau DS and Chapleau DS#2

GTA East: Cherrywood TS, Enfield TS, Thornton TS, Whitby TS, and Wilson TS.

GTA North: Armitage TS, Brown Hill TS, Holland TS, Kleinburg TS, and Woodbridge TS.

GTA West: Bramalea TS, Halton TS, Palermo TS, Pleasant TS, Oakville #2 TS and Trafalgar TS.

Greater Bruce/Huron: Centralia TS, Douglas Point TS, Goderich TS, Hanover TS, Owen Sound TS, Palmerston TS, Seaforth TS, St. Marys TS, Stratford TS, Wingham TS, Grand Bend East DS and Constance DS.

Greater Ottawa: Almonte TS, Arnprior TS, Bilberry Creek TS, Hawthorne TS, Longueuil TS,

[1] Hydro One Regional Planning

Orleans TS, South March TS, St. Isidore TS, Stewartville TS, Wilhaven DS, Wendover DS, South Gloucester DS, Russell DS, Rockland East DS, Rockland DS, Navan DS, Marionville DS, Manotick DS, Greely DS, Cumberland DS, and Clarence DS.

Kitchener Waterloo Cambridge Guelph (KWCG): Elmira TS, Fergus TS, Wolverton DS and Puslinch DS.

London: Aylmer TS, Buchanan TS, Clarke TS, Commerce Way TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Strathroy TS, Tillsonburg TS, Wonderland TS, and Woodstock TS.

Niagara: Allanburg TS, Beamsville TS, Crowland TS, Dunnville TS, Murray TS, Port Colborne TS, Thorold TS, and Vineland DS.

North/East of Sudbury: Crystal Falls TS, Dymond TS, Hearst TS, Kapuskasing TS, Kirkland Lake TS, North Bay TS, Ramore TS, Timmins TS, Trout Lake TS, Calstock DS, Cochran West DS, Fauquier DS, Herridge Lake DS, Hoyle DS, Iroquois Falls DS, Laforest Road DS, Mattawa DS, Monteith DS, Moosonee DS, Shiningtree DS, Smooth Rock Falls DS, Temagami DS 2, Verner DS, Warren DS.

Northwest Ontario: Barwick TS, Port Arthur TS, Dryden TS, Manitouwadge TS, Longlac TS#2, Red Lake TS, Auguasabon DS, White River DS, White Dog DS, Vermilion Bay DS, Valora DS, Slate Falls DS, Sioux Narrows DS, Shabaqua DS, Schreiber Winnipeg DS, Sapawe DS, Sam Lake DS, Red Rock DS, Pic DS, Perrault Falls DS, Nipigon DS, Nestor Falls DS, Murillo DS, Minaki DS, Margach DS, Marathon DS, Manitouwadge DS #1, Kenora DS, Keewatin DS, Jellicoe DS #3, Eton DS, Ear Falls DS, Crow River DS, Crilly DS, Clearwater Bay DS, Burleigh DS, Beardmore DS #2, and Agimak DS.

Peterborough to Kingston: Belleville TS, Dobbin TS, Frontenac TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS, Port Hope TS, Sidney TS, Sharbot DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Dobbin DS, Battersea DS, and Ardoch DS.

Renfrew: Cobden TS, Pembroke TS, Petawawa DS, Mountain Chute DS, Mazinaw DS, Forest Lea DS, Des Joachims DS, Deep River DS, Craig DS, and Cobden DS.

SGB/Muskoka: Alliston TS, Barrie TS, Beaverton TS, Bracebridge TS, Everett TS, Lindsay TS, Meaford TS, Midhurst TS, Minden TS, Muskoka TS, Orangeville TS, Orillia TS, Parry Sound TS, Stayner TS, Wallace TS, and Waubaushene TS.

St. Lawrence: Brockville TS, Chesterville TS, Crosby TS, Morrisburg TS, Smiths Falls TS, St. Lawrence TS, and Newington DS.

Sudbury/Algoma: Clarabelle TS, Elliot Lake TS, Espanola TS, Larchwood TS, Manitoulin TS, Martindale TS, Massey DS, North Shore DS, Sowerby DS, Spanish DS, Striker DS, Verner DS, Warren DS, Wharncliffe DS, and Whitefish DS.

Toronto: Agincourt TS, Fairchild TS, Finch TS, Leslie TS, Malvern TS, Richview TS, and Sheppard TS.

Windsor-Essex: Belle River TS, Keith TS, Kingsville TS, Lauzon TS, Leamington TS, Malden TS, South Middle Road TS, Tilbury West DS.

This letter confirms that the second cycle of the Regional Planning (RP) process for all the above regions was completed in 2023. The third planning cycle is currently underway, with Needs Assessments (NA) completed for 18 regions except N/E of Sudbury and Chatham/Lambton/Sarnia region (currently underway). The NA for all the regions, except Greater Bruce Huron region have confirmed that further regional coordination is/was required for the regions and advanced to the subsequent planning phases. The Integrated Regional Resource Plan (IRRP) is completed for 7 regions, Burlington to Nanticoke, Toronto, Windsor Essex, GTA North, Greater Ottawa, KWCG and East Lake Superior regions as part of the third cycle, ensuring coordinated long-term planning for these regions. Burlington to Nanticoke, Toronto, Greater Bruce/Huron, GTA North, and Windsor-Essex, have completed the final phase of the process, the Regional Infrastructure Plan (RIP), with their third-cycle RIP reports published in 2025-2026.

All the Regional Planning reports are available on Hydro One Regional Planning website.

A summary of the regional planning status, including needs and plans currently identified in each region that affects Hydro One Distributions' service area is provided below.

Table 1 - Regional Planning Status Summary

Region	Sub-region	2nd Cycle (2017-2023)				3rd Cycle (2022→)			
		NA (1)	**SA** (1)	**IRRP** (1)	**RIP** (1)	**NA** (1)(3)	**SA** (1)(3)	**IRRP** (1)(3)	**RIP** (1)(3)
Burlington to Nanticoke	Greater Hamilton	May. 2017	Aug. 2017	Feb. 2019	Oct. 2019	Sep. 2022	Dec. 2022	TBD	TBD
	Brant							Nov. 2024	Jun. 2025
	Bronte								
	Caledonia-Norfolk								
Greater Ottawa	Ottawa	Jun. 2018	Sep. 2018	Mar. 2020	Dec. 2020	Dec. 2022	Mar. 2023	Jul. 2025	Feb. 2026
	Outer Ottawa		*Not Required*	*Not Required*			*Not Required*	*Not Required*	
GTA East		Aug. 2019	*Not Required*	*Not Required*	Feb. 2020	Dec. 2024	Apr. 2025	Oct. 2026	TBD
GTA North		Mar. 2018	Aug. 2018	Feb. 2020	Oct. 2020	Jul. 2023	Oct. 2023	Oct. 2025	May. 2026
GTA West		May. 2019	Aug. 2019	Jul. 2021	Feb. 2022	Aug. 2024	Nov. 2024	Nov. 2026	TBD
Kitchener-Waterloo-Cambridge-Guelph		Dec. 2018	May. 2019	May. 2021	Dec. 2021	Apr. 2024	Jul. 2024	Jul. 2026	Feb. 2027

Region	Sub-region	2nd Cycle (2017-2023)				3rd Cycle (2022→)			
		NA (1)	SA (1)	IRRP (1)	RIP (1)	NA (1)(3)	SA (1)(3)	IRRP (1)(3)	RIP (1)(3)
Toronto		Oct. 2017	Feb. 2018	Aug. 2019	Mar. 2020	Dec. 2022	Mar. 2023	Oct. 2025	May-26
Northwest Ontario		Jul. 2020	Jan. 2021	Jan. 2023	Aug. 2023	Sep. 2025	Sep. 2025	Mar. 2027	TBD
Windsor-Essex		Oct. 2017	Mar. 2018	Sep. 2019	Mar. 2020	Feb. 2023	May. 2023	Apr. 2025	Oct. 2025
London Area		May. 2020	*Not Required*	*Not Required*	Aug. 2022	Nov. 2024	Apr. 2025	Oct. 2026	TBD
Peterborough to Kingston		Feb. 2020	May. 2020	Nov. 2021	May. 2022	Dec. 2024	Apr. 2025	Oct. 2026	TBD
South Georgian Bay/Muskoka	Barrie/Innisfil	Apr. 2020	Nov. 2020	May. 2022	Dec. 2022	Aug. 2025	Nov. 2025	May. 2027	TBD
	Parry Sound/ Muskoka			May. 2022					
Sudbury/Algoma		Jun. 2020	*Not Required*	*Not Required*	Dec. 2020	Oct. 2025	Jan. 2026	Jul. 2027	TBD
Chatham/Lambton/Sarnia		Sep. 2021	Dec. 2021	*Not Required*	Aug. 2022	Nov. 2026	TBD	TBD	TBD
Greater Bruce/Huron		May. 2019	Sep. 2019	Sep. 2021	Apr. 2022	Sep. 2024	*Not Required*	*Not Required*	Apr. 2025
Niagara		May. 2021	Aug. 2021	Dec. 2022	Jul. 2023	Jul. 2026	Oct. 2026	TBD	TBD
North/East of Sudbury(4)		May. 2021	Aug. 2021	Apr. 2023	Nov. 2023	Nov. 2026	TBD	TBD	TBD
Renfrew		May. 2021	Aug. 2021	Dec. 2022	Jul. 2023	Jul. 2026	TBD	TBD	TBD
St. Lawrence (2)		Sep. 2021	*Not Required*	*Not Required*	Mar. 2022	Mar. 2026	Apr. 2026	Oct. 2027	TBD
East Lake Superior		Jun. 2019	Oct. 2019	Apr. 2021	Oct. 2021	Oct. 2024	Jan. 2025	Jul. 2026	Feb. 2027

Notes: (1): NA: Needs Assessment; SA: Scoping Assessment; IRRP: Integrated Regional Resource Plan; RIP: Regional Infrastructure Plan
(2): Note that St. Lawrence 2nd cycle NA was initiated two (2) months over the five (5) year period because of an error in oversight.
(3): All future completion dates are tentative based on Regional Planning Process timeline requirements.
(4):The IESO's recommended delaying the needs assessment for North/East of Sudbury until after the conclusion of the bulk plan. OEB agreed and granted extension to start NA in September 2026.

Burlington to Nanticoke:

- Brant TS: There is a need for additional area supply to be addressed through 230kV new stations near the existing Brant TS. This work is be planned for completion in 2032.
- Caledonia TS: Transformer T2 230/27.6 kV, 83 MVA is planned for replacement with a like-for-like unit in 2032.
- Dundas TS: There is a need for additional transformation capacity to be addressed either through building new DESN or upgrading the existing DESN to 230kV with larger transformers. This work is planned for completion in 2032.
- Jarvis TS: Transformers T3/T4 230/27.6 kV, 83 MVA is planned for replacement with like-for-like units in 2035.

- Lake TS: Transformers T3/T4 230/13.8 kV, 75 MVA and switchgear are planned for replacement with upgraded 100 MVA units in 2028.
- Norfolk Area Supply capacity: The total supply capacity of this area is limited due to the 115kV C9 and C12 circuits. It is recommended to continue with the load transfers out of the Norfolk area and provide additional new reactive support at Norfolk TS and open the LV bus-tie breakers at Norfolk TS and Bloomsburg DS as required and plan a BESS near Norfolk TS.
- The IESO will issue an IRRP addendum for the Hamilton sub-region and the Bronte TS supply area which may introduce new or modify current plans.

Chatham-Lambton-Sarnia:

- Kent TS: Transformer T2 230/27.6 kV, 75/100/125 MVA, along with switchyard and associated equipment are planned for replacement. T2 will be replaced with a like-for-like unit, with a planned in-service date by 2032.
- Forest Jura HVDS Capacity: It was recommended in 2nd cycle RIP to continue monitoring load growth and determine a plan to meet the capacity demand if required.

GTA East:

- Cherrywood TS: 230 kV breaker replacements, currently underway with planned in-service dates of 2033 and 2037.
- Thornton TS: Station capacity at Thornton TS T3/T4 (44 kV) is expected to be exceeded in the medium term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Whitby TS: Station capacity at Whitby TS T1/T2 (44 kV) is expected to be exceeded in the medium term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Wilson TS: Transformers T3/T4 230/44 kV, 75/100/125 MVA are planned for like-for-like replacement by 2031. Station capacity at Wilson TS T3/T4 & T7/T8 is expected to be exceeded in the medium term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- T23C/T29C corridor exceeds the load security limit of 600 MW in 2032. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.

GTA North:

- Kleinberg TS: 44 kV Loads in the Northern area served by Kleinberg TS will be transferred to Northern York TS to manage loading. The planned in-service date is in 2031.
- Woodbridge TS: Transformer T5 230/44-27.6 kV, 75/125 MVA is planned for replacement with a like-for-like unit in 2032.
- Kleinburg TS Station Capacity: Adding 230/44kV DESN Kleinburg TS (T3/T4). The current planned in-service date is 2028.
- Northern York supply capacity: Building three new 230/44kV DESN - Northern York TS #1 with a planned in-service date is 2031, Northern York TS #2 with planned in service date in 2034 and Northern York TS #3 with planned in service date in 2035.
- Buttonville TS supply capacity: Adding 230/27.6kV DESN Buttonville TS #2. The current planned in-service date is 2030.

- P45/P46 line capacity: Upgrade the line between Parkway TS to Markham MTS, Markham MTS#4 to Buttonville TS and extend and build new 7km line from Buttonville TS to future DESN. Planned ISD is between 2031-2034.
- Kleinburg TS Supply reliability: Build Kleinburg to Kirby Transmission link with planned in service date between 2031-2032. Development of Kleinburg TS as a 500/230 transformer station by building 500kV and 230kV switchyards and installing three 500/230kV autotransformers, with provision for a fourth to accommodate longer-term demand. The planned in-service date is 2031-2032
- V71P/V75P: Install in-line breakers to resolve load security issue. The planned in-service date is 2030.

GTA West:

- Bramalea TS T1/T2: Transformers T1/T2 are expected to exceed capacity in the medium term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Bramalea TS T3/T4: Transformers T3/T4 230/44 kV, 83 MVA to be upgraded with 125 MVA units in the medium term. Balance T3/T4 load with Bramalea T5/T6 as interim solution to address station capacity need for T3/T4 DESN expected in 2035.
- Halton TS: Transformers T3/T4 230/27.6 kV, 75/125 MVA are planned for replacement in the near term. Station capacity at Halton TS is also expected to be exceeded in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Pleasant TS T1/T2: The capacity of Pleasant TS T1/T2 DESN is expected to be exceeded in the near term. These transformers also require replacement and are planned for replacement with new standard transformers which have higher ratings to address the forecasted load growth.
- Pleasant TS T5/T6: Transformers T5/T6 230/27.6 kV, 75/125 MVA are planned for replacement in 2035. The T5/T6 DESN is also expected to have station capacity exceeded in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Palermo TS T3/T4: Transformers T3/T4 230/27.6 kV, 50/67/83 MVA are planned for replacement in 2027 with larger capacity units.
- Load security scenarios of T38B/T39B corridor which will exceed load security limit of 600MW in 2029. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.

Greater Bruce/Huron:

- Seaforth TS: Transformers T1/T2 & T5/T6 110-28 kV, 25/33.3/41.7 MVA are planned for like-for-like replacement. The current planned in-service date is 2026.
- Bruce A TS – 500 kV ABCB circuit breakers will be replaced with new SF6 tank circuit breakers. The current planned in-service date is 2027.
- Owen Sound TS – T5 autotransformers (150/250 MVA) will be replaced with like-for-like unit. The current planned in-service date is 2032.
- Douglas Point TS – T3/T4 transformers (50/83 MVA) will be replaced with like-for-like units. The current planned in-service date is 2037.
- Stratford TS – T2 transformer (50/83 MVA) will be replaced with like-for-like unit. The current planned in-service date is 2038.

Greater Ottawa:

- South March TS: Transformers T1/T2 230/44 kV, 50/83 MVA are planned for replacement with upgraded 125 MVA units based on asset conditions and capacity needs. This work is planned for completion in 2029.
- Marionville DS Station capacity: Install a second Transformer to increase station rating. The planned in-service date is in 2029.
- Greely DS Station capacity: Install SCADA fan monitoring to increase T1 and T2 transformer rating. The planned in-service date is 2026.
- Rockland DS Station Capacity: Install SCADA fan monitoring to increase transformer rating. The planned in-service date is 2026.
- Rockland East DS Station capacity: Install SCADA fan monitoring to increase transformer rating. The planned in-service date is 2027.
- Kanata area transmission reinforcement. Planned in service date is in 2033.
- East Ottawa area: retiring Bilberry Creek TS, upgrading Orleans TS, and completing the associated 230 kV circuit and station connections to address the long-term needs in East Ottawa. The planned in-service date is 2029-2030.
- L2M line build – Projected to reach capacity in 2034. To be reviewed in next RP cycle.

KWCG:

- Puslinch DS: To address the station capacity need, it is recommended to implement distribution connected resources between 2030 and 2042. If load trends beyond the high forecast scenario, the integrated non-wires recommendation will be re-evaluated, and a new station may be required or may be more cost-effective.
- Wolverton DS: To address the station capacity need, Hydro One Distribution to continue with fan monitor upgrade to increase the station LTR by early 2027.

London:

- Aylmer TS: Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Buchanan TS: Autotransformers T2/T3 230/115 kV, are planned for replacement in 2033.
- Clarke TS: Transformers T3/T4 230/27.6 kV, 50/83 MVA are planned for replacement in 2034. Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Commerce Way TS: Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Edgeware TS: Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Strathroy TS: Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Tillsonburg TS: Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Wonderland TS: Station forecast is expected to exceed capacity in the near term. This need

and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.

- Woodstock TS: Station forecast is expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- W44LC/W45LS Thermal Limits: For the loss of one of the W44LC or W45LS, the loading on the (Buchanan JCT x Edgeware JCT) section exceeds its post-contingency rating in the medium-Term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- WT1T/W14 Thermal Limits: The loading on the (Cranberry JCT x ESWF JCT) and the (ESWF JCT x Tillsonburg JCT) exceeds its pre-contingency rating in the Near-Term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.

Niagara:

- Allanburg TS: Transformers T7/T8 115/27.6kV, 50/83MVA are expected to exceed capacity in the near term. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Crowland TS: Transformers T5/T6 115/27.6 kV, 50/83 MVA are planned for replacement with upgraded 230/27.6 kV 170 MVA units in 2031.
- Murray TS Transformer replacement and supply capacity: Existing 45/60/75 MVA T11/T12 transformers will be replaced with new 60/80/100 MVA units, and 45/75 MVA T13/T14 are planned for like for like replacement in 2032. At this time, the transformer replacement project and forecast will be both monitored and adjusted to ensure the station capacity meets the future load requirement.
- Connect new DESN near Beamsville TS – The current planned in-service date for this new DESN is 2027.

North/East of Sudbury:

- Kirkland Lake TS – Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers. The current planned in-service date is 2027.
- Hearst TS – Replacement of low voltage circuit breakers, switches, P&C Equipment. The current planned in-service date is 2030.
- Timmins TS – T2 transformer (50/83 MVA) will be replaced with standard like-for-like units. The current planned in-service date is 2035.
- Kapuskasing TS – Replacement of low voltage circuit breakers, switches, station service equipment and protections. The current planned in-service date is 2032.
- Dymond TS – Replacement of low voltage breakers, and associated P&C equipment. The current planned in-service date is 2034.
- Crystal Falls TS – T5/T6 transformer (42 MVA) will be replaced with like-for-like units. The current planned in-service date is 2034.
- Trout Lake TS – T3/T4 transformers (75/125 MVA) will be replaced with like-for-like units. The current planned in-service date is 2034.
- K1/K2 - Overhead Conductor replacement and circuit refurbishment between Kirkland Lake TS x American Barrick Jct. The current planned in-service date is 2026.
- A4H/A5H – Overhead Conductor replacement and circuit refurbishment between Tunis Jct. x Fournier Jct. The current planned in-service date is 2032.

Northwest Ontario:

- Pic Jct. x Manitouwadge Jct. 115 kV M2W Line capacity need. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.
- Margach DS, White Dog DS and White River DS station capacity need. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.

Peterborough to Kingston:

- Dobbin TS: Transformers T1/T2 are planned for replacement with upgraded 150/250 MVA units and decommissioning existing T5 units in 2028. T3/T4 are expected to exceed capacity in 2032.
- Gardiner TS: Transformers T1/T2 230/44 kV 75/100/125 MVA are planned for replacement with upgraded units in 2027.
- Napanee TS: Transformers T1/T2 230/44 kV 83 MVA is expected to exceed its LTR in the near term and additional capacity will need to be reviewed in the next phase of the regional planning cycle.
- Picton TS: Transformers T1/T2 230/44 kV 83 MVA are expected to exceed its LTR and have been identified for replacement with similar size units in 2026. The replacement units will be of similar size but will have higher LTRs due to modern designs, which will be enough to supply the future loads.
- Peterborough to Quinte West P15C/Q6S - New 230kV double circuit line from Clarington TS to Dobbin TS. The current planned in-service date is 2029.
- Belleville TS New DESN #2 – The current planned in-service date for a new 75/125 MVA 230/44 kV DESN is 2026.
- Port Hope TS – T3 and T4 transformers (50/83 MVA) will be replaced with like-for-like units. The current planned in-service date is 2036.
- Cataraqui TS - T1 and T2 230/115kV Autotransformers to be replaced with 150/200/250 MVA units. The current planned in-service date is 2032.
- Frontenac TS: Plan a new 230/44kV station in the West Kingston area in the near term.
- Hinchinbrooke HVDS: Projected to reach capacity in 2028. Offloading options are being considered to address overloading in the near term.

Renfrew:

- Des Joachims TS x Petawawa/Craig DS 115 kV D6 Line refurbishment – The current planned in-service date is 2027.
- Cobden HVDS - Projected to reach capacity in 2029. Consideration of SCADA to increase transformer rating.
- Cobden TS - Projected to reach capacity in 2033. This need and alternatives will be reviewed in the IRRP and RIP phases of the current RP cycle.

SGB/Muskoka:

- Alliston TS: Transformers T3/T4 230/44 kV, 83 MVA are planned for replacement with new like-for-like units in 2040. However, a new capacity need has been identified and will be studied in the current RP cycle.
- Bracebridge TS: Transformer T1 230/44 kV 83 MVA is planned for replacement with a like-for-

like unit in 2026.

- Everett TS: Transformers T1/T2 230/44 kV 83 MVA is expected to exceed its normal supply capacity in the medium term. This need will be reviewed in the next phase of the regional planning process.
- Midhurst TS: Transformer T4 230/44 kV 125 MVA is planned for replacement with a new like-for-like unit in 2034.
- Orillia TS: Transformer T2 230/44 kV 125 MVA is planned for replacement with a like-for-like replacement in 2026.
- Wallace TS: Transformers T3/T4 230/44 kV 42 MVA are planned for replacement with a like-for-like unit in 2034.
- Waubaushene TS T5/T6: Replace 230/44kV, 83MVAtransformers T5/T6 with new 230/44kV 125MVA units in 2028.
- E8V/E9V – Essa TS x Orangeville TS line section will be upgraded. The current planned in-service date is 2031.

St. Lawrence:

- Brockville TS: Transformers T1/T2 230/44 kV 125 MVA are planned for replacement with like-for-like units in 2034.
- Brockville TS: Installation of new LV Capacitor bank to mitigate the voltage issues on 44kV bus. The planned in-service date is in 2029.
- St. Lawrence TS: Existing five (5) 115 kV oil filled breakers are planned for replacement with new SF6 circuit breakers along with associated P&C equipment. This work is planned for completion in 2034.**Sudbury/Algoma:**
- Martindale TS: Transformers T25/T26 230/44 kV 125 MVA are planned for replacement with like-for-like units in 2032.
- Elliot Lake TS – T1 transformer (25/42 MVA) will be replaced with like-for-like unit, and T2 transformer (19 MVA) will be removed from service. The current planned in-service date is 2027.
- Clarabelle TS – T1/T2 transformers (125 MVA) will be replaced with like-for-like units. The current planned in-service date is in 2035.

Toronto:

- Leslie TS: The T1 and T4 transformers will be replaced with standard 230-27.6 kV 75/125 MVA units to address asset renewal needs. The planned in-service date is 2032.
- Agincourt TS: The existing T5 and T6 transformers will be replaced with like-for-like units to address asset renewal needs. The planned in-service date is in 2033.
- Fairchild TS: The existing T3 and T4 transformers will be replaced with like-for-like units to address asset renewal needs. The planned in-service date is in 2034.

Windsor-Essex:

- Lauzon TS: Transformers T7/T8 50/83 MVA units with upgraded 75/125 MVA units in 2032. Lauzon TS: Transformer T5/T6 - The current planned in-service date for replacement of these transformers with upgraded units is 2026.
- Kingsville-Leamington sub system: Construction of new 34 km double-circuit 230 kV Lakeshore

TS x Lauzon TS line plus associated Lauzon 230 kV switching facility to support new development in this area. The current in-service date is 2032.

- West Essex and Windsor sub-system supply capacity: Construction of new 22 km double circuit 230 kV from Lakeshore TS to supply the new Leamington DESN 5 and 6. The current planned in -service date is 2029.
- Coatsworth Area supply capacity: Construction of new Chatham-by-Lakeshore 230 kV double-circuit transmission line. The current planned in -service date is 2029.
- Construction of Chatham SS x Lambton TS 2-cct 230 kV line. The current planned in -service date is 2028.
- Construction of Longwood TS x Lakeshore TS 1-cct 500 kV line. The current planned in service date is 2030.
- Kingsville – Leamington Greenhouse supply stations: Construction of two new 75/125 MVA 230/27.6 -27.6 kV DESN stations (Leamington DESN 5 and 6). The current planned in service date is 2027.
- Coatsworth Area Greenhouse Supply Station: Construction of new Coatsworth Area 75/125 MVA 230/27.6 -27.6 kV DESN1. The current planned in -service date is 2029.
- Keith TS – Phase angle regulator PSR5 installed in the J5D interconnection will be replaced. The current planned in-service date is 2028.
- Low voltage concern about loss of Lauzon TS HV capacitor bank with autotransformer: Development of an appropriate 230 kV switching at Lauzon TS will mitigate this concern. The current planned in-service date is 2032.

East Lake Superior:

- Chapleau Area supply capacity need (W2C): System's ability to serve peak load is limited by the voltage at the end of the transmission line. Localized static reactive power support is recommended as preferred solution.

Hydro One Networks Inc. (Transmission) would like to acknowledge and thank you for your work and effort in support of the Regional Planning process. We look forward to continuing to work with you in the future. If you have any further questions, please feel free to contact me.

Sincerely,



Ajay Garg,
Director - Long Term Strategic Transmission System Planning
Hydro One Networks Inc.
Tel: (647) 242-2105
ajay.garg@HydroOne.com

Appendix A: Map of Ontario's Planning Regions

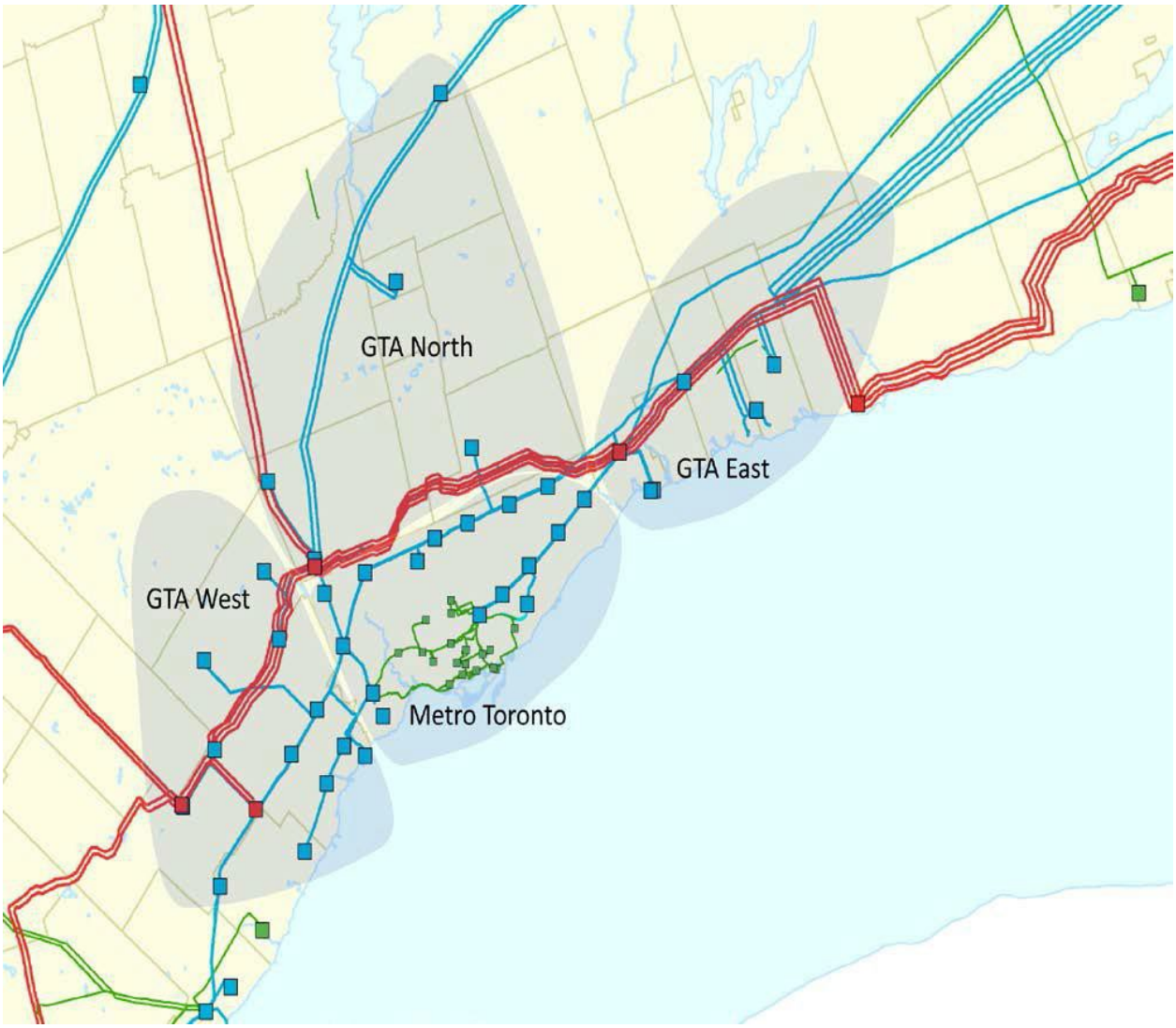
Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Burlington Hydro Inc. • GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power) • Alectra Utilities Corporation (Formerly Horizon Utilities Inc.) • Hydro One Networks Inc. (Distribution) • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Ottawa Limited • Hydro Hawkesbury Inc. • Ottawa River Power Corporation • Hydro One Networks Inc. (Distribution) • Renfrew Hydro Inc
3. GTA North	• Alectra Utilities Co. • Hydro One Networks Inc. (Distribution) • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited
4. GTA West	• Burlington Hydro Inc. • Hydro One Networks Inc. (Distribution) • Alectra Utilities Co. • Milton Hydro Distribution Inc. • Halton Hills Hydro Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Alectra Utilities Corporation. • Enova Power Corporation. • Grandbridge Energy Inc. • Centre Wellington Hydro Ltd. • Hydro One Networks Inc. (Distribution) • Halton Hills Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities • Elexicon Energy Inc. • Hydro One Networks Inc. (Distribution) • Toronto Hydro Electric System Limited
7. Northwest Ontario	• Atikokan Hydro Inc. • Fort Frances Power Corporation • Hydro One Networks Inc. (Distribution) • Synergy North • Sioux Lookout Hydro Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Powerlines Inc. (Chatham-Kent) • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc. (Distribution)
9. East Lake Superior [Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region]	• Algoma Power Inc. • Hydro One Networks Inc. (Distribution) • PUC Distribution
10. GTA East	• Elexicon Energy Inc. • Oshawa PUC Networks Inc. • Hydro One Networks Inc. (Distribution)
11. London Area	• Entegrus Powerlines Inc. • ERTH Power Inc. • Hydro One Networks Inc. (Distribution) • London Hydro Inc. • Tillsonburg Hydro Inc.

12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Elexicon Energy Inc. • Hydro One Networks Inc. (Distribution) • Kingston Hydro Corporation • Lakefront Utilities Inc.
13. South Georgian Bay/Muskoka	• Hydro One Networks Inc. (Distribution) • Alectra Utilities • InnPower • Orangeville Hydro • Elexicon Energy • Lakeland Power • EPCOR Electricity Dist. Ontario Inc. • Newmarket-Tay Power Distribution Ltd. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Greater Sudbury Hydro Inc. • North Bay Hydro • Hydro One Networks Inc. (Distribution)
15. Chatham-Kent/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. (Chatham-Kent) • Hydro One Networks Inc. (Distribution)
16. Greater Bruce/Huron	• Entegrus Powerlines Inc. • ERTH Power Corporation • Hydro One Networks Inc. (Distribution) • Festival Hydro Inc. • Wellington North Power Inc. • Westario Power Inc.

17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Hydro One Networks Inc. (Distribution) • Grimsby Power Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Alectra Utilities Co. • Welland Hydro-Electric System Corporation
18. North of Moosonee [Five Nations Energy Inc (FNEI) is the Lead Transmitter for the region]	• Distribution in this region is provided by FNEI
19. North/East of Sudbury	• Northern Ontario Wires Inc. • Hearst Power Distribution Company Limited • North Bay Hydro Distribution Ltd. • Hydro One Networks Inc. (Distribution) • Greater Sudbury Hydro Inc.
20. Renfrew	• Hydro One Networks Inc. (Distribution) • Ottawa River Power Corporation
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. (Distribution) • Rideau St. Lawrence Distribution Inc.

SECTION 1.3 – SPF – THIRD-PARTY REPORTS

1.3.1 INTRODUCTION

In support of the Application and, where applicable, to satisfy the terms of the OEB-approved Settlement Proposal from Hydro One's previous application (see Exhibit A-02-04), Hydro One engaged independent experts to undertake benchmarking studies, process reviews, asset condition analyses, and other reports. The reports included in the System Plans are provided in Table 1.

Table 1 - Reports included in the System Plans by Section

Section	Attachment	Report	Hydro One Sponsor
SPF Section 1.6	1	Customer Engagement Overview Report – Innovative Research Group (IRG)	Spencer Gill
TSP Section 2.3	1	Transmission Capital Project Execution Review (ESource)	Scott Vicary
	2	Transmission Wood Pole Benchmarking Study (Guidehouse and First Quartile)	Scott Vicary, Donna Jablonsky
DSP Section 3.3	1	2026 Hydro One Vegetation Management Study – CN Utility Consulting Inc (CNUC)	Paul Ankrett, Aimee Oabel
	2	Distribution Pole and Substation Transformer Benchmarking Study (Guidehouse and First Quartile)	Paul Ankrett, Peter Faltaous
	3	AMI 2.0 - Project Execution Process Review (ESource)	David Paish
	4	Practices of Distribution Loss Reduction Approaches in North America – Electric Power Research Institute (EPRI)	Peter Faltaous
	5	Vulnerability Assessment and System Hardening (VASH) Study (Guidehouse)	Spencer Gill
	6	Hydro One Networks Inc. Electrification Study 2030-2050 – Environmental Resource Management (ERM)	Peter Faltaous
GSP Section 4.3	1	2024 Fleet Operations Benchmarking Report (Utilimarc)	Chris Iveson
	2	Hydro One Fleet Lifecycle Study (Utilimarc)	Chris Iveson
	3	Helicopter Lifecycle Analysis Report (Utilimarc)	Chris Iveson
	4	Hydro One Fleet Investment Strategy Report – Analysis of Funding Outcomes (Utilimarc)	Chris Iveson
	5	Building Condition Assessment Review (JLL)	Julie Ricketts Daniel
	6	Enterprise IT Spending & Staffing Benchmark (Gartner)	Kevin Marcotte
	7	Enterprise IT Maturity Assessment (Gartner)	Kevin Marcotte

The reports included in Exhibits A, C, E and F of the Application are provided in Table 2.

Witness: Paul Ankrett, Kathleen Burke, Kevin Dickinson, Peter Faltaous, Lyndsay Fulton, Spencer Gill, Chris Iveson, Donna Jablonsky, Kevin Marcotte, Anthony Nava, Aimee Oabel, Ogbomah Osiemi, Julie Ricketts Daniel, Scott Vicary

Table 2 - Reports included in Exhibits A, C, E, and F

Exhibit	Attachment	Report	Hydro One Sponsor
A-04-01	1	Benchmarking, Productivity, and Incentive Regulation Parameter Study for Hydro One Networks' Joint Rate Application (Clearspring)	Kathleen Burke
A-06-01	1	US GAAP to IFRS Conversion Impact Review (PwC)	Ogbomah Osiemi
C-05-01	1	Working Capital Requirements of Hydro One Networks Inc.'s Transmission Business (Guidehouse)	Anthony Nava
C-05-01	2	Working Capital Requirements of Hydro One Networks Inc.'s Distribution Business (Guidehouse)	Anthony Nava
E-05-01	2	Supply Chain Practices Report (Wood Mackenzie)	Chris Iveson
E-04-02	1	Common Corporate Costs Benchmarking Study (ESource)	Anthony Nava
E-04-08	1	Report on Corporate Cost Allocation Review (Atrium)	Anthony Nava
E-06-01	2	Compensation Benchmarking Study (Mercer)	Lyndsay Fulton
E-06-01	3	Management and Non-Represented Role Benchmarking and Compensation Study (WTW)	Lyndsay Fulton
E-07-01	1	Hydro One Pension Plan – Actuarial Valuation as at December 31, 2024 (WTW)	Ogbomah Osiemi
E-07-01	2	Hydro One Inc. Projected 2026-2032 Benefit Cost Under FASB ASC 715-20-50 (WTW)	Ogbomah Osiemi
E-07-02	1	Hydro One Sault St. Marie Pension Plan – Actuarial Valuation as at December 31, 2025 (Mercer)	Ogbomah Osiemi
E-07-02	2	Projected 2026-2028 Pension Expense under US GAAP & IAS19 (Mercer)	Ogbomah Osiemi
E-08-01	1	Electric Utility Plant Depreciation Rate Study BU 210, 220, and 300 Transmission, Distribution and Common Business Units at December 31, 2024 (Alliance)	Anthony Nava
F-01-01	1	Hydro One Networks Inc. Cost of Capital Study (Concentric)	Kevin Dickinson
F-01-01	2	Credit-Focused Capital Markets Analysis (Utility Credit Consultancy LLC)	Kevin Dickinson

1.3.2 INFORMATION ABOUT THIRD-PARTY EXPERTS

Information about the third-party experts listed in Tables 1 and 2 is summarized below.

1.3.2.1 ALLIANCE CONSULTING GROUP (ALLIANCE)

Report: Electric Utility Plant Depreciation Rate Study BU 210, 220, and 300 Transmission, Distribution and Common Business Units at December 31, 2024

Witness: Paul Ankrett, Kathleen Burke, Kevin Dickinson, Peter Faltaous, Lyndsay Fulton, Spencer Gill, Chris Iveson, Donna Jablonsky, Kevin Marcotte, Anthony Nava, Aimee Oabel, Ogbomah Osiemi, Julie Ricketts Daniel, Scott Vicary

Alliance was engaged to provide a utility plant depreciation study. Alliance has experience completing a similar engagement in Hydro One's prior rate application.

Alliance is a U.S.-based firm that has conducted over 365 depreciation studies for regulated and non-regulated electric, gas, steam, water, wastewater, cable and communications utilities across the U.S. and Canada since 2004.

1.3.2.2 ATRIUM ECONOMICS

Report: Report on Corporate Cost Allocation Review

Atrium was engaged to provide an evaluation of Hydro One's affiliate cost allocation methods. Atrium's personnel have conducted affiliate cost allocation, overhead capitalization rate, and shared asset allocation reviews for utilities throughout North America. Atrium's primary consultant has experience completing similar engagements in Hydro One's last joint transmission and distribution rate application.

1.3.2.3 CLEARSPRING ENERGY ADVISORS (CLEARSPRING)

Report: Benchmarking, Productivity, and Incentive Regulation Parameter Study for Hydro One Networks' Joint Rate Application

Clearspring was engaged to conduct total cost benchmarking, industry productivity trend research, and analysis and recommendations in respect of certain revenue escalation parameters. Clearspring has extensive research experience in relation to Ontario's electricity sector and experience in completing similar engagements in Hydro One's prior rate applications.

Clearspring is an energy economics consulting firm with significant experience in the electric utility industry including performance-based ratemaking, econometric cost and reliability benchmarking, data analysis, long range load forecasting, and DSM analysis.

1.3.2.4 CONCENTRIC ENERGY ADVISORS (CONCENTRIC)

Report: Hydro One Networks Inc. Cost of Capital Study

Concentric Energy Advisors (Concentric) was engaged to perform a cost of capital study to assist Hydro One in assessing whether the current cost of capital remains appropriate for purposes of setting the capital structure in Hydro One's next rate application.

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, and with offices in Washington, D.C., and Calgary, Alberta, Concentric provides financial, economic, regulatory, and strategic advisory services to energy and utility clients across North America. Concentric has provided expert testimony on the cost of capital issues in more than 100 regulatory proceedings in Canada and the U.S. over the past five years.

1.3.2.5 CN UTILITY CONSULTING OF CANADA (CNUC)

Report: 2026 Hydro One Vegetation Management Study

Eocene's Canadian subsidiary, Wright Canada Holding, Inc. (operating as CN Utility Consulting of Canada (CNUC)) was engaged to complete a distribution vegetation management benchmarking study. CNUC has experience completing similar engagements in Hydro One's prior rate applications.

Founded in 1999, CNUC has spent the last two decades providing utility vegetation management consulting services and establishing themselves as industry experts on utility vegetation-related issues, practices, standards and requirements across North America.

1.3.2.6 ENVIRONMENTAL RESOURCES MANAGEMENT (ERM)

Report: Hydro One Networks Inc. Electrification Study 2030-2050

ERM was engaged to develop electrification scenarios for Hydro One's distribution system. ERM has supported distribution networks in Canada and internationally on assessing the impact of electrification on their networks.

ERM is a global sustainability consultancy with established expertise in long-term electricity system modelling, high-resolution load modelling, and future energy scenario development.

1.3.2.7 ELECTRIC POWER RESEARCH INSTITUTE (EPRI)

Report: Practices of Distribution Loss Reduction Approaches in North America

EPRI was engaged based on its experience supporting North American utilities across transmission and distribution, including asset performance, efficiency, and benchmarking initiatives.

EPRI is an independent, nonprofit organization that conducts research and development to address the technical, operational, and environmental challenges of the electric power industry. Founded to serve the public interest, EPRI brings together utilities, manufacturers, academia, and government partners to advance the generation, delivery, and use of electricity through objective, science-based research. As a nonprofit, it operates without commercial bias, emphasizing independence and rigor in its analysis while not advocating for any specific company or technology. Its mission is to help ensure that electric power is safe, reliable, affordable, and environmentally responsible, ultimately improving quality of life. Through collaborative programs, thought leadership, and technical expertise, EPRI plays a central role in guiding innovation, informing policy and planning, and supporting the industry's transition to a more resilient and sustainable energy future.

1.3.2.8 E SOURCE

Reports:

i. Transmission Capital Project Execution Review
ii. AMI 2.0 Project Execution Process Review
iii. Common Corporate Costs Benchmarking Study

E Source, formerly the UMS group, was engaged to provide three benchmarking reports. E Source has experience completing similar engagements in Hydro One's prior rate applications.

E Source (which acquired UMS Group in November 2023) is a leading provider of utility benchmarking services, with over 36 years of experience conducting comparative performance assessments for the global utilities industry. E Source has supported multiple assessments and global benchmarking programs on six continents, working with state and provincial utility commissions and more than 300 electric, gas, and water utilities. E Source leads Global Learning and Benchmarking consortia and maintains "real time" proprietary cost and operational performance data correlated to industry best practices, supported by analytical frameworks.

1.3.2.9 GARTNER

Reports:

i. Enterprise IT Spending & Staffing Benchmark
ii. Enterprise IT Maturity Assessment

Gartner was engaged to perform Enterprise IT benchmarking. Gartner has experience completing similar engagements in Hydro One's prior rate applications.

Gartner is a global research and advisory company, founded in 1979 with over 20,000 associates in 85 offices around the world serving over 13,000 client experiences in approximately 90 countries and territories. Gartner specializes in providing senior leaders with business insights, advice and tools they need to achieve their mission-critical priorities and build the organizations of tomorrow. Gartner's insights are developed through rigorous proprietary research methodologies to ensure insights are independent and objective.

1.3.2.10 GUIDEHOUSE CANADA LTD (GUIDEHOUSE) AND FIRST QUARTILE

Reports:

i. Transmission Wood Pole Benchmarking Study
ii. Distribution Pole and Substation Transformer Benchmarking Study
iii. Vulnerability Assessment and System Hardening (VASH) Study
iv. Working Capital Requirements of Hydro One Networks Inc.'s Transmission Business
v. Working Capital Requirements of Hydro One Networks Inc.'s Distribution Business

Guidehouse was engaged to complete several benchmarking and working capital studies because of their expertise in benchmarking, access to relevant data through First Quartile Consulting (First Quartile), and their experience completing similar engagements in Hydro One's prior rate applications.

Guidehouse is a consulting firm that provides advisory services, including work related to utility asset management and transmission and distribution (T&D) cost benchmarking.

1.3.2.11 INNOVATIVE RESEARCH GROUP (IRG)

Reports: Customer Engagement Overview Report, and the following appendices:

i. Phase I Low Volume Focus Group Report
ii. Phase I Large Business Customer In-Depth Interview Report
iii. Phase I Stakeholder In-Depth Interview Report
iv. Phase I First Nations Leadership In-Depth Interview Report
v. Phase I Métis Nation of Ontario Leadership In-Depth Interview Report
vi. Phase I Planning Placemat
vii. Phase I Survey Results Report
viii. Phase II Planning Placemat
ix. Phase II Survey Results Report

IRG was engaged to complete a two-phase customer engagement study. IRG is an expert in public opinion research and consultation and has experience completing similar engagements in Hydro One's prior rate applications.

IRG is a full-service market research firm founded in 1998 with expertise in stakeholder and public engagement, public affairs research, marketing and brand research, and corporate affairs and communications. Based in Vancouver and Toronto, IRG works closely and collaboratively with clients to create consultations that generate wide engagement and actionable results.

1.3.2.12 JONES LANG LASALLE AMERICAS, INC. (JLL)

Report: Building Condition Assessment Review

JLL was engaged to perform a building condition assessment review because of its extensive experience evaluating building condition assessments across diverse industries and asset types.

JLL is a global professional services firm specializing in real estate and investment management. Their Projects and Development services group provides expert technical due diligence, including the preparation and peer review of building condition assessments for institutional owners across North America. JLL's experience spans properties from small utility substations to multi-million-square-foot portfolio assessments for Fortune 500 companies, including institutional investors, pension funds, and government entities.

1.3.2.13 MERCER

Reports:

i. Compensation Benchmarking Study
ii. Hydro One Sault St. Marie Pension Plan – Actuarial Valuation as at December 31, 2025
iii. Projected 2026-2028 Pension Expense under US GAAP & IAS19

Mercer was engaged to conduct a compensation benchmarking study, consistent with prior applications, ensuring methodological continuity and comparability. Mercer was also engaged by Hydro One to conduct the pension valuation and projected pension expense forecast for Hydro One's Sault St. Marie business segment.

Witness: Paul Ankrett, Kathleen Burke, Kevin Dickinson, Peter Faltaous, Lyndsay Fulton, Spencer Gill, Chris Iveson, Donna Jablonsky, Kevin Marcotte, Anthony Nava, Aimee Oabel, Ogbomah Osiemi, Julie Ricketts Daniel, Scott Vicary

Mercer has extensive experience performing compensation benchmarking and market analyses for utilities operating within regulatory and rate-setting frameworks, leveraging deep industry expertise in utility sector compensation structures, market practices, and regulatory requirements. Mercer's experience with regulatory standards and requirements, combined with access to comprehensive utility industry compensation data, support the development of benchmarking analysis with the level of rigor and credibility for rate application purposes.

1.3.2.14 PRICEWATERHOUSECOOPERS LLP (PWC)

Report: US GAAP to IFRS Conversion Impact Review

PricewaterhouseCoopers LLP (PwC) was engaged to provide a revenue requirement impact and risk analysis with the transition from US GAAP to MIFRS. PwC has experience completing a similar engagement in Hydro One's prior rate application.

PwC is an Ontario limited liability partnership that provides professional services (such as advisory services) and is a member firm of PricewaterhouseCoopers International Limited, each member firm of which is a separate legal entity.

1.3.2.15 UTILIMARC

Reports:

i. 2024 Fleet Operations Benchmarking Report
ii. Hydro One Fleet Lifecycle Study
iii. Helicopter Lifecycle Analysis
iv. Hydro One Fleet Investment Strategy Report – Analysis of Funding Scenario Outcomes

Utilimarc was engaged to perform several benchmarking and lifecycle studies given its unique position to provide utility-specific fleet benchmarking and ready access to extensive data from many North American utilities to enable meaningful results. Utilimarc has experience completing similar engagements in Hydro One's prior rate applications.

Utilimarc provides an end-to-end business intelligence platform that delivers the insights needed to optimize fleet. Founded in 2001, Utilimarc began building products and services focused on benchmarking and optimizing the operational efficiency of utility fleets. Since then, it has developed a business intelligence platform that streamlines data management, and provides actionable insights and analyses. Utilimarc manages data and optimizes fleet for 85% of investor-owned utilities in North America and reports on over 300,000 fleet assets.

1.3.2.16 UTILITY CREDIT CONSULTANCY LLC

Report: Credit-Focused Capital Markets Analysis

Utility Credit Consultancy was engaged to provide an independent assessment of the capital markets context underlying Hydro One's proposed capital structure, with a particular focus on credit ratings and the perspective of investors.

Utility Credit Consultancy is a management consulting and economic advisory firm that focuses on the North American energy industry. Based in Orleans, Massachusetts, Utility Credit Consultancy provides financial and strategic advisory services related to credit analysis and credit ratings to utility and other clients across North America.

1.3.2.17 WILLIS TOWERS WATSON (WTW)

Reports:

i. Management and Non-Represented Role Benchmarking and Compensation Study
ii. Hydro One Inc. Projected 2026-2032 Benefit Cost Under FASB ASC 715-20-50

WTW was engaged to provide several compensation and benefit cost studies, consistent with prior applications, ensuring methodological continuity and comparability.

WTW brings extensive utility sector expertise, having supported over 100 utilities in the past year, and provides market intelligence on compensation competitiveness, emerging practices and program design.

1.3.2.18 WOOD MACKENZIE

Report: Supply Chain Practices Report

Wood Mackenzie Inc. (Wood Mackenzie) was engaged to conduct a review of Hydro One's supply chain strategies for mitigating inflationary pressures in relation to industry best practices.

Wood Mackenzie is a leading global research and consultancy firm with deep expertise in the energy and utilities sectors. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable its clients to leverage data analysis and assist them in navigating an ever-changing marketplace. SCC has dozens of concurrent North American utility clients for which it advises on operating model and leading-edge supply chain practices.

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SECTION 1.4 – SPF – PRODUCTIVITY FRAMEWORK

1.4.1 INTRODUCTION

Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the Company. Hydro One continues to execute its comprehensive and rigorous process for productivity, which develops, implements, monitors and measures productivity initiatives that reduce costs while maintaining or improving service quality and work outputs (the Productivity Framework). The Productivity Framework has resulted in significant cost savings and benefits to customers since its inception. From 2023-2025, Hydro One realized $517.7M in productivity savings across its Transmission and Distribution businesses and is planning to achieve an additional $586.0M of savings in 2026 and 2027 (see Section 1.4.3 below), with these efforts continuing throughout 2028-2032.

The Productivity Framework was previously reviewed as part of EB-2021-0110 by an external independent consultant, Concentric Energy Advisors (Concentric), who concluded that it is an effective program which stands out as a strong and robust program compared to that of utility peers. Hydro One continues to use the same Productivity Framework.

This exhibit is organized as follows:

- **Section 2** describes the Productivity Framework and prior validation of it, productivity governance, and the methodology and review process.
- **Section 3** describes Hydro One's productivity efforts and results in the current rate term.
- **Section 4** addresses productivity in the 2028-2032 rate term, including the re-setting of baselines and an overview of productivity savings for this period.

1.4.2 PRODUCTIVITY FRAMEWORK

Hydro One's Productivity Framework is a process, with internal governance, for:

i. identifying and developing productivity initiatives (which are internally approved as the initiatives qualify for the program);

ii. approving the initiative-level methodologies by which savings are to be measured;
iii. the ongoing tracking, reporting and auditing of performance; and
iv. integrating savings into the business plan.

The main goal of the Productivity Framework is to achieve and demonstrate continuous improvement in work execution and also to manage, and achieve, the proposed capital and OM&A productivity factors and supplemental stretch factor on capital for both the Transmission and Distribution businesses, as described in Exhibit A-04-01. All productivity factors are applied on a top-down, cumulative basis to the revenue requirement, reflecting the ongoing benefit to customers of Hydro One's productivity program.

Any incremental OM&A productivity achievements under the framework, beyond the productivity and supplemental stretch factors, will be tracked as part of the Earnings Sharing Mechanism (ESM) proposed in this Application, as further described in Exhibits A-04-01, G-01-01 and G-01-03. For capital, once the in-service additions and the rate base are approved as part of this Application, holding everything else constant, any incremental productivity can reduce in-service additions relative to OEB-approved levels forecasted. Customers could thus benefit in the long term via a planned rate base that would otherwise be higher. Customers are also receiving up front benefits in 2028 from previous rate period savings that are continuing.

1.4.2.1 VALIDATION OF PRODUCTIVITY FRAMEWORK

As noted above, Concentric previously reviewed the Productivity Framework and prepared a report entitled "Hydro One Productivity Framework Review" filed in EB-2021-0110, Exhibit B-01-01, Attachment 2**.**

Based on its review, Concentric concluded that the Productivity Framework is a robust, well defined, transparent, and effective productivity program at identifying and quantifying sustainable productivity improvements and driving benefits that can be considered true productivity gains. Concentric also noted that Hydro One may be more challenged to

continue to find new initiatives and cost savings going forward over the long term that meet the rigorous standards of the framework.[1]

The Productivity Framework, including its elements, operation and governance process, has remained consistent with the framework Concentric reviewed and validated, and will continue to be used going forward.

1.4.2.1.1 PRODUCTIVITY GOVERNANCE

The Productivity Framework is currently managed and maintained by the Enterprise Transformation Office (ETO), which oversees its implementation to ensure that productivity savings for all initiatives are appropriately and accurately approved, measured and reported. All productivity initiatives must be reviewed and approved by the ETO before any savings can be reported against the established targets. The ETO reviews all productivity initiatives to ensure they are consistently and appropriately documented, including detailed description/logic, identified systems/dependencies, clear calculation methodology/data sources, and review and approval by a VP or a delegate. This approval process ensures that each productivity initiative is carefully tracked using a detailed and robust calculation methodology to ensure savings are verifiable and auditable.

Each month, the executing Line of Business (LOB) reports productivity achievements in relation to plan commitments, and the ETO subsequently reports the results to senior executives.

1.4.2.1.2 METHODOLOGY AND REVIEW PROCESS

Hydro One evaluates expected productivity savings on an annual basis, in parallel with, and as an input into, its business planning process. Through the planning process, each of Hydro One's LOBs is asked to identify incremental productivity initiatives that can produce savings. In consultation with the ETO, the LOBs are required to demonstrate that each proposed initiative has an objective baseline as well as a defined and auditable measurement methodology.

[1] EB-2021-0110, Exhibit B-01-01, Section 1.4, Attachment 2, Hydro One Productivity Framework Review, June 23, 2021, p. 6 of 36

Once these points are demonstrated, the ETO works with initiative owners to validate specific planning assumptions to quantify demonstrable savings in the Company's annual business plan and the associated investments. The savings embedded in the plan result in actual reductions in the costs required to achieve desired outcomes, which would otherwise not have been attainable if the initiatives were not identified. Each LOB then plays an integral role in the implementation process to ensure execution of Hydro One's productivity initiatives. LOBs also report on productivity savings monthly, with the reported savings verified by the ETO using the approved baseline and calculation methodology. The program's results are also audited annually by Hydro One's external auditors.

1.4.3 PRODUCTIVITY EFFORTS AND RESULTS IN CURRENT RATE TERM

1.4.3.1 OVERVIEW

Since the inception of the program, Hydro One has used the Productivity Framework to achieve significant savings and provide benefits to customers, and it will continue to do so. Customers have received, and continue to receive, the benefit of sustained productivity improvements. OM&A-based productivity savings from previous initiatives have contributed to the sharing of earnings with customers through the ESM. Transmission and Distribution capital savings reflect the ability to efficiently replace or find alternate replacement opportunities for aging assets to serve customers while mitigating rate impacts. The ongoing savings from these initiatives are now considered part of regular business planning practices and have been incorporated into the OM&A and capital plans, as costs would have otherwise been higher in this Application.

The section below describes the savings achievements so far in the current 2023-2027 rate period, which includes 2023-2025 actuals and forecasts for 2026 and 2027. During this rate period, Hydro One has achieved significant productivity savings, including continuing to identify new savings initiatives that generate incremental year-over-year savings and provide value to customers and other stakeholders.

1.4.3.2 PRODUCTIVITY RESULTS IN CURRENT RATE TERM

Over the 2023 to 2027 rate term, Hydro One has achieved, and expects to further achieve, overall productivity savings under its Productivity Framework as shown in Table 1 below:

Table 1 - Breakdown of Productivity Savings by Line of Business ($M)[2]

Transmission Productivity	Actual	Actual	Actual	Plan	Plan
Line of Business	**2023**	**2024**	**2025**	**2026**	**2027**
Asset Management	7.7	2.6	1.8	1.0	0.0
Capital Portfolio Delivery	8.4	30.3	56.2	58.9	50.9
Customer Experience	0.0	0.0	0.0	0.0	0.0
Digital and Technology Solutions	0.2	0.2	1.3	2.4	3.0
Distribution Lines	0.0	0.0	0.0	0.0	0.0
Forestry Services	0.0	0.0	0.0	0.0	0.0
Facilities and Real Estate	19.3	14.5	25.0	18.7	24.6
Station Services	1.2	4.0	2.6	2.1	2.3
Supply Chain, incl. Fleet	7.6	10.8	15.4	9.9	12.0
Tx Macro OM&A	0.0	0.0	0.0	10.0	21.5
Total Defined	**44.3**	**62.4**	**102.4**	**103.0**	**114.3**
Distribution Productivity	**Actual**	**Actual**	**Actual**	**Plan**	**Plan**
Line of Business	**2023**	**2024**	**2025**	**2026**	**2027**
Asset Management	3.2	14.5	19.4	16.7	17.1
Capital Portfolio Delivery	0.0	0.0	0.0	0.0	0.0
Customer Experience	0.0	3.7	10.0	10.7	11.8
Digital and Technology Solutions	0.2	0.2	2.4	3.5	4.6
Distribution Lines	33.7	42.1	78.4	45.5	44.9
Forestry Services	16.2	8.1	7.6	7.5	7.7
Facilities and Real Estate	3.8	3.0	2.6	2.2	2.6
Station Services	0.0	0.0	0.0	0.0	0.0
Supply Chain, incl. Fleet	12.5	15.7	31.8	14.9	15.2
Total Defined	**69.6**	**87.1**	**152.0**	**101.2**	**103.8**
Total Stretch	0	0	0	56.1	107.6
Total Productivity	**113.9**	**149.5**	**254.3**	**260.3**	**325.7**

[2] Rounded figures within tables may not sum precisely due to rounding.

Attachment 1 to this exhibit lists each productivity initiative for the Transmission and Distribution businesses for 2023-2025 actuals, as well as plan for 2026 and 2027.

Hydro One Transmission

As shown above, Hydro One Transmission achieved productivity savings of $44.3M in 2023, $62.4M in 2024, and $102.4M in 2025, driven by initiatives across capital, OM&A and revenues.

Capital: Hydro One Transmission achieved capital savings of $23.0M in 2023, $42.5M in 2024, and $71.1M in 2025. These savings were primarily driven by labour efficiencies in the execution of end-of-life component replacement and refurbishment projects within Stations and Transmission Lines, lower project costs enabled by environmental assessment (EA) modernization, planning efficiencies for transformer replacements and right-sizing, and procurement savings. For example, the EA Modernization initiative reduced project costs by working with the Ministry of the Environment, Conservation and Parks (MECP) to amend the Class EA and align assessment thresholds with federal requirements. Similarly, the Transformer Right-Sizing initiative reduced costs through an equipment replacement strategy that incorporates design optimizations and more efficient configurations while maintaining equivalent service levels, generating savings compared to like-for-like replacements.

OM&A: OM&A initiatives generated savings of $5.8M in 2023, $8.4M in 2024 and $8.8M in 2025. The savings were driven by lease reductions, PCB bottom filled bushings initiatives, renegotiation of the CapGemini contract, and the use of x-ray breaker inspections.

Revenues: Incremental secondary land use revenues generated savings of $15.5M in 2023, $11.6M in 2024 and $22.4M in 2025.

Hydro One Distribution

Hydro One Distribution achieved productivity savings of $69.6M in 2023, $87.1M in 2024, and $152.0M in 2025, driven by initiatives across capital and OM&A.

Capital: Hydro One Distribution achieved capital savings of $28.4M in 2023, $40.7M in 2024 and $114.3M in 2025. These savings were driven by operational improvements supporting storm restoration resulting in faster restoration times and reduced outage durations; lower labour hours per unit in Field Business Centre and in trouble calls ultimately leading to faster response times and improved customer satisfaction; proactively refurbishing underground cables using a silicon fluid injection rather than replacing them to extend the useful life and reduce cable related outages; refurbishing poles rather than full replacements; and price efficiencies through contract management of procurement of services and materials.

OM&A: Hydro One Distribution achieved OM&A savings of $41.1M in 2023, $46.4M in 2024, and $37.7M in 2025. The savings were driven by utilization of contractors to perform PCB testing and inspections, reducing labour hours per km through more efficient defect vegetation clearing, increased eBilling enrolment, which allows customers to access their bills and information faster, lower labour hours per trouble call, and lease reduction.

As the above results demonstrate, Hydro One has achieved significant productivity savings relative to the updated initiative-level baselines since 2023. Customers have directly benefited from the incremental OM&A savings as the associated cost reductions have contributed to Hydro One's ESM, resulting in a refund to customers.

Hydro One remains committed to identifying new productivity initiatives for the benefit of customers and other stakeholders. This commitment is reflected in the unidentified stretch

targets in 2026 and 2027 (see Table 1 above), which are over and above defined initiative-level savings identified through the integrated business planning process.

However, as savings from existing initiatives become embedded in the business, identifying additional initiatives that meet the Productivity Framework's rigorous standards and eligibility criteria becomes increasingly challenging. In connection with identifying and achieving new productivity savings under the Productivity Framework, as well as other types of cost savings or efficiencies, Hydro One commenced an Enterprise Cost Optimization (ECO) program during the current rate term. This program has been a strategic, enterprise-wide initiative to identify, develop and implement cost control efforts while delivering safe, reliable and affordable service to customers. The program was established in response to inflationary pressures on labour, materials and contracted services, among other things. Since its inception, the program has delivered savings through a variety of initiatives, some of which qualify as productivity savings under the Productivity Framework, while others generate savings but do not satisfy the Framework's eligibility criteria.

Initiatives under the ECO program contributed approximately $37.2M to the total productivity savings of $254.3M achieved in 2025 as shown in Table 2. This contribution demonstrates the significant role the ECO program has played in supporting Hydro One's productivity and cost management objectives.

Table 2 - Breakdown of 2025 ECO Driven Savings embedded in Productivity ($M)

ECO driven savings embedded in Productivity	Total Productivity
2025A	**2025A**
37.2	254.3

In 2025, Hydro One achieved $123.6M in total savings through the ECO program and in 2026, Hydro One has planned $66.6M in additional savings. Table 3 below summarizes Hydro One's ECO initiatives by Transmission and Distribution. Savings opportunities for 2027 are being evaluated and developed, but have not yet been finalized.

Table 3 - Breakdown of ECO Savings by Line of Business ($M) [3]

	2025A	2026P
Transmission	**89.9**	**43.9**
Revenue	16.0	6.5
Capital	66.1	30.8
OM&A	7.9	6.6
Distribution	**33.7**	**22.6**
Capital	16.8	9.6
OM&A	17.0	13.1
Total ECO	**123.6**	**66.6**

1.4.4 PRODUCTIVITY IN THE 2028-2032 RATE TERM

Hydro One's Productivity Framework will continue to benefit customers through the current rate term and into the 2028-2032 rate period. Under the proposed Custom IR Framework for Transmission and Distribution (Exhibit A-04-01), productivity and supplemental stretch factors will provide direct and upfront reductions for customers and create meaningful incentives for Hydro One to identify and achieve incremental productivity improvements. Additionally, as the productivity factors and supplemental stretch factors on capital are proposed to be applied on a cumulative basis, productivity achievements will be embedded in the rate base. Productivity savings will be tracked and corroborated at the initiative-level using Hydro One's Productivity Framework. The maturity and established standards of that Framework are important considerations in assessing reasonable productivity expectations for the 2028-2032 rate term.

Hydro One has operated a rigorous Productivity Framework for many years. As discussed in Section 1.4.2, Concentric found that the Framework drives benefits that can be considered true productivity gains and is robust, well-defined and transparent relative to utility peers. In the earlier stages of a productivity program, readily identifiable opportunities can generally be captured more easily. Over successive rate periods, new initiatives are progressively more difficult to identify. Consistent with this principle,

[3] Rounded figures within tables may not sum precisely due to rounding.

Concentric recognized that, having already achieved significant savings, Hydro One may be more challenged over the long term to identify new initiatives and cost savings that meet the rigorous standards of the existing Framework.[4]

Those standards appropriately require demonstrable reductions in the cost of delivering the same or greater output. Accordingly, cost avoidance, work deferral and reduced output do not, on their own, qualify as true productivity under the Framework. If capital and OM&A productivity requirements materially exceed reasonably achievable opportunities, Hydro One may be required to defer or reduce work that supports safety, reliability, growth and customer benefits. Such work deferrals or reductions are undesirable since they may lead to challenges in improving reliability or accommodating customer growth and/or benefits. .

For these reasons, and as reflected in the proposed capital and OM&A productivity factors and supplemental stretch factors described in Exhibit A-04-01, Hydro One's objective is to provide customers with a level of productivity savings commensurate with the last rates proceeding and reasonably achievable through a mature, independently validated framework. The rate-setting framework should continue to incentivize achievable productivity without embedding assumptions at levels that would effectively require necessary work or system outputs to be reduced.

Hydro One will continue to pursue cost savings and operational improvements across the business. As demonstrated by ECO, initiatives that do not satisfy the Productivity Framework's criteria for true productivity can still generate meaningful customer value through cost containment, avoided costs and other efficiencies. Over time, experience with these initiatives may inform whether the criteria or scope of the Productivity Framework should be reassessed while preserving the rigor, transparency and customer benefits of the existing Framework.

[4] Ibid

1.4.4.1 UPDATING AND RESETTING BASELINES

Under the Productivity Framework, Hydro One will update and reset the baselines of its productivity initiatives to 2027 actuals for the 2028-2032 rate term.

This update and reset of baselines will achieve the following:

- demonstrate a clear link to continuous improvement during the 2028-2032 period relative to prior proceedings;
- assist in aligning the Productivity Framework and the Custom IR Framework to the OEB's incentive regulation framework;
- align with industry best practices;
- embed the historical achievements of existing initiatives in the new baseline, to measure and report only incremental savings over and above the prior and continuing savings from those initiatives. This will further challenge Hydro One to identify and deliver on new and incremental savings initiatives going forward in 2028, while prior initiatives will also continue to deliver savings that are embedded into the business plan; and
- simplify the governance and reporting process.

1.4.4.2 OVERVIEW OF PRODUCTIVITY SAVINGS FOR 2028-2032

Hydro One's current productivity plan is expected to achieve approximately $325.7M of savings in 2027 between Transmission and Distribution based on the current measurement approach under the Productivity Framework. This is the equivalent of reducing revenue requirement by approximately $56M and $58M in 2028, for Transmission and Distribution respectively. In other words, if Hydro One had not implemented these forecasted initiatives, while holding output constant, 2028 revenue requirement would be higher by these amounts. As these efficiencies have become embedded in normal business practices, customers will continue to benefit from them through lower rates both today and in future rebasing periods.

In addition, and incrementally, customers will receive the benefit of the value of the stretch factors and supplemental stretch on capital in revenue requirement, derived using the methodology detailed in Exhibit A-04-02 and Exhibit A-04-03. For Transmission and

Distribution respectively, this translates to a total of approximately $37M and $125M of revenue requirement reductions across 2029-2032. Hydro One will strive to achieve these savings through new initiatives and incremental improvements to existing initiatives relative to their updated 2027 baselines, recognizing that identifying additional productivity opportunities has become increasingly challenging. To the extent these savings are achieved, customers will benefit again through lower revenue requirements at rebasing in 2033.

In summary, the Productivity Framework provides customer benefits both today and in the future. Customers receive upfront revenue requirement reductions during the rate period, and any achieved productivity savings will be reflected in 2033. Any incremental OM&A and capital savings beyond those embedded in this Application will provide further customer value through a lower future revenue requirement, with incremental OM&A savings also shared with customers through the ESM during the rate term.

HYDRO ONE NETWORKS INC.
2023-2027 Transmission and Distribution Productivity Summary

		LOB	Initiative	Measurement and Expected Benefit	2023A	2024A	2025A	2026B	2027P
TRANSMISSION	Capital	Asset Management	Transformer Right Sizing	Lower costs from reduced equipment requirements at a Transformer Station. Cost savings while maintaining like-for-like service.	7.7	2.6	1.8	1.0	-
		Capital Portfolio Delivery	Continuous Improvement Model (CIM)	Lower labour hours per Unit. Lower costs per unit to construct and commission portfolio of Capital Portfolio Delivery projects at Transmission Stations. Lower labour hours per unit in Tx Lines Projects and Tx Lines Programs.	6.7	2.0	17.9	9.2	9.5
			Bell Standard Solution Concrete Testing Modernization Pre-built racks	(Historical Cost - New Cost) * # of Units. Cost reduction per bell fiber entrance installation, contest test and pre-built rack implementation.	-	0.6	0.8	1.1	1.1
			Telehandler Lifting Foundation Optimization Temporary Portable Access Roads Pre-cut Cable Trench Midsun Animal Abatement	(Historical Cost - New Cost) Cost savings from implementation of measures to generate efficiencies, including utilzation of telehandlers, foundation optimization, temporary access roads, pre-cur cable trench and updates to animal abatement equipment.	0.4	0.2	1.1	1.0	1.1
			CAPE ADI	Lower labour hours per Update. Reduced labour time required for updates to the CAPE database througfh automation.	-	-	0.4	0.2	0.2
			Crane vs Climb	(Crane daily cost * # days crane not used) + float moves/other misc costs saved Lower costs from reduced usage of cranes, by implementation of climb procedures.	-	-	0.4	-	-
			Environmental Assessment Modernization Initiative	Lower costs for environmental assessments resulting from Hydro One working with the Ministry of the Environment and Parks (MECP) to amend the Class EA to align EA thresholds with those of the federal government.	-	20.1	25.5	41.0	32.5
			Field Marked Print (FMP) Scanning Enhancement	(# documents directly uploaded) * cost per document scanned Reduction in external scanning costs by implementing new process and IT changes.	-	0.1	0.1	0.1	0.1
			Non-Productive Idling (NPI) Reduction	(baseline NPI ratio - current NPI ratio) * engine runtime * # vehicles * litres consumed per idle hour * average cost per litle of fuel. Reduced fuel consumption through reduction of non-productive idling (NPI).	-	0.1	0.0	0.1	0.1
			PML Meters Redundancy Savings	Savings per PML meter not used (material + labour) * # of units Reduced costs from removing redundant PM:L meters, which are replaced by protection relay programming capabilities to extract telemetry data from existing protection relays.	-	0.3	0.7	0.3	0.3
			Shieldwire Contracts	Lower Cost per Unit Savings in the Shieldwire capital replacement program as a result of outsourcing.	-	2.8	1.1	-	-
			Engineering OT Reductions	Lower % of overtime hours - Historical Baseline vs Actual. Lower costs from reduction in overtime.	1.0	0.5	1.4	1.0	1.0
			Reduce Perimeter Hydro Vac excavations	Hydro-Vac costs * reduced count of Hydro-Vac excavations. Reduced usage of Hydro-Vac equipment by having field staff trained on how to use available information, including station drawings and cable locates. This results in lower costs.	0.3	3.7	5.5	4.0	4.0
		Digital and Technology Services	Server Build Automation	Lower labour hours per server build. Savings through the usage of automation.	-	-	0.1	0.1	0.1
			SAP Functional Partnership Savings	Lower cost per Partnership Agreement Reduced SAP costs from bundling 10 partnership agreements together, instead of proceeding individually for each.	-	-	-	0.2	0.2
		Fleet	Electric Vehicles	Fuel Savings Lower operational costs from using electric vehicles instead of gas based vehicles.	0.0	0.0	0.1	0.1	0.1
			Ford Special Pricing	Rebate per Vehicle * # of vehicles. Reduced vehicle unit costs as a result of collaboration with vendor.	0.2	-	-	-	-
			Traction Parts Savings	Total vendor invoiced amount * % rebate Reduced heavy duty parts costs as a result of a rebate negotiated with vendor.	0.0	0.0	0.0	0.0	0.0
			Rental Savings	Historical Cost - New Cost Elimination of unneccessary rentals, which in turn drives reduction in rental costs.	-	-	0.2	0.9	0.9
		Supply Chain	Procurement	Lower Cost per Unit - Historical Baseline vs Actual Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions.	6.8	9.5	14.1	7.9	9.9

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2023-2027 Transmission and Distribution Productivity Summary

	LOB	Initiative	Measurement and Expected Benefit	2023A	2024A	2025A	2026B	2027P
OM&A	Capital Portfolio Delivery	Tx OM&A:HV UG Cable Locates and Prev MtceOH Asses	Lower labour hours per Unit. Reduction in labour hours per unit across major programs including Condition Assessment, Planned Corrective, Preventative Maintenance, HV UG Cable Locates and HV UG Cable Preventative Maintenance.	-	-	1.4	1.0	1.0
	Digital and Technology Services	CapGemini Contract Savings	Lower Cost per Contract. Lower costs from re-negotiated contract with vendor.	-	-	1.0	1.6	2.1
		Data Center Lease Savings	(Historical Cost - New Cost) Lease savings from property consolidation and elimination of the lease on Data Center East in Scarborough.	-	-	0.3	0.4	0.4
		Telecom services	Lower Cost per Contract. Reduced costs as a result of negotiated contract, while maintaining like-for-like service.	0.2	0.2	-	-	-
		SAP Functional Partnership Savings	Lower cost per Partnership Agreement Reduced SAP costs from bundling 10 partnership agreements together, instead of proceeding individually for each.	-	-	-	0.1	0.1
	Fleet	Electric Vehicles	Fuel Savings Lower operational costs from using electric vehicles instead of gas based vehicles.	0.0	0.0	0.0	0.0	0.0
		Traction Parts Savings	Total vendor invoiced amount * % rebate Reduced heavy duty parts costs as a result of a rebate negotiated with vendor.	0.0	0.0	0.0	0.0	0.0
		Rental Savings	Historical Cost - New Cost Elimination of unneccessary rentals, which in turn drives reduction in rental costs.	-	-	0.1	0.3	0.3
	Macro Defined OM&A	Tx OM&A Macro Defined	Tx OM&A OEB approved envelope - Actual Tx OM&A spend Quantified macro level savings by comparing OEB approved funding with actual Tx OM&A spend.	-	-	-	10.0	21.5
	Real Estate	Lease Reduction	Lower Contract Cost. Cost savings in relation to reduced lease costs as compared to historical baseline.	3.8	3.0	2.6	2.2	2.6
	Station Services	CIM 1.0 Stations Preventative Maintenance	Lower Cost per Unit - Historial Baseline vs Actual. Cost savings in the completion of preventative maintenance work.	-	-	-	1.0	1.3
		PCB - Tx Bottom Filled Bushings	Cost savings to the work program in relation to PCB testing.	-	3.5	1.6	-	-
		X-Ray Breaker Inspections	(Historical Cost - New Cost) * # of Units Cost savings from using x-ray technology in replacement of selective intrustion inspection.	1.2	0.5	1.0	1.1	1.1
	Supply Chain	Procurement	Lower Cost per Unit - Historical Baseline vs Actual Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions.	0.6	1.2	0.9	0.8	0.8
	Revenue	Real Estate	Secondary Land Use Revenue	Secondary Land Use Revenues - Historical Baseline. Incremental secondary land use revenues from licenses, easements, operational land sale agreements and licence renewal revenue.	15.5	11.6	22.4	16.5	22.0

HYDRO ONE NETWORKS INC.
2023-2027 Transmission and Distribution Productivity Summary

		LOB	Initiative	Measurement and Expected Benefit	2023A	2024A	2025A	2026B	2027P
DISTRIBUTION	Capital	Asset Management	Cable Injection	(Cost to replace cable - Cost to inject cable) x meters of cable injected Lower cost per meter of underground cable replacement. Use cable injection instead of cable replacement.	-	14.5	19.4	16.7	17.1
			Padmount Transformers	Lower Cost Infrastructure. Improved planning to enable deployment of lower cost infrastructure with like-for-like service.	3.2	-	-	-	-
		Digital and Technology Services	Server Build Automation	Lower labour hours per server build. Savings through the usage of automation.	-	-	0.2	0.2	0.2
			SAP Functional Partnership Savings	Lower cost per Partnership Agreement Reduced SAP costs from bundling 10 partnership agreements together, instead of proceeding individually for each.	-	-	-	-	-
		Distribution	Field Business Center (FBC) Productivity	Increased workload efficiency per staff member of the field business center, which in turn reduces upward pressure on headcount increases (thereby generating savings).	-	-	20.2	6.5	6.0
			Non-Productive Idling (NPI) Reduction	(baseline NPI ratio - current NPI ratio) * engine runtime * # vehicles * litres consumed per idle hour * average cost per litle of fuel. Reduced fuel consumption through reduction of non-productive idling (NPI).	-	0.1	0.0	0.0	0.0
			Planned OT Reduction	Lower % of overtime hours - Historical Baseline vs Actual. Lower costs from reduction in overtime.	-	-	4.2	3.2	2.5
			Standard Design Initiative	Reduced overall design costs from implementing standardized pole installation designs for low complexity end of life replacements.	-	0.7	0.0	-	-
			Storm Restoration Improvement	Lower cost per Customer Interruption Reduction in overall costs to restore a customer after storm interruption.	-	-	39.4	28.2	28.8
			Design Time Efficiency	Lower labour hours per Unit. Updates to the design and estimation tool, including automated calculations, standardized templates, simplified customer initiated redesign process, driving reduced labour hours to perform varied design tasks.	-	-	-	0.1	0.1
			Dx Lighthouse	Lower labour hours per Unit Savings across several Distribution programs.	-	-	-	0.4	0.4
			Pole Refurbishment	(Cost per pole replacement - Cost per pole refurbbishment normalized for lifespan) * # of Units Reduced costs from pole refurbishment instead of pole replacement.	14.1	10.7	-	-	-
		Fleet	Electric Vehicles	Fuel Savings Lower operational costs from using electric vehicles instead of gas based vehicles.	0.0	0.1	0.1	0.1	0.1
			Ford Special Pricing	Rebate per Vehicle * # of vehicles. Reduced vehicle unit costs as a result of collaboration with vendor.	0.2	-	-	-	-
			Traction Parts Savings	Total vendor invoiced amount * % rebate Reduced heavy duty parts costs as a result of a rebate negotiated with vendor.	0.0	0.0	0.0	0.0	0.0
			Rental Savings	Historical Cost - New Cost Elimination of unneccessary rentals, which in turn drives reduction in rental costs.	-	-	0.3	1.2	1.2
		Supply Chain	Procurement	Lower Cost per Unit - Historical Baseline vs Actual Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions.	11.0	14.7	30.5	12.0	12.1
		Customer Experience	Contact Centre Operational Efficiencies	Historical Cost - Current Cost Lower contact centre costs while improving customer experience.	-	1.7	2.9	3.0	3.7
			eBilling	Lower Cost per Customer Based on cost savings from eBilling as compared to traditional mail. Savings realized for customers enrolled to eBilling.	-	2.0	7.1	7.7	8.1
		Digital and Technology Services	CapGemini Contract Savings	Lower Cost per Contract. Lower costs from re-negotiated contract with vendor.	-	-	1.7	2.8	3.8
			Data Center Lease Savings	(Historical Cost - New Cost) Lease savings from property consolidation and elimination of the lease on Data Center East in Scarborough.	-	-	0.5	0.5	0.5
			Telecom services	Lower Cost per Contract. Reduced costs as a result of negotiated contract, while maintaining like-for-like service.	0.2	0.2	-	-	-
			SAP Functional Partnership Savings	Lower cost per Partnership Agreement Reduced SAP costs from bundling 10 partnership agreements together, instead of proceeding individually for each.	-	-	-	-	-
			Field Business Center (FBC) Productivity	Increased workload efficiency per staff member of the field business center, which in turn reduces upward pressure on headcount increases (thereby generating savings).	-	-	3.1	0.6	0.7

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2023-2027 Transmission and Distribution Productivity Summary

		LOB	Initiative	Measurement and Expected Benefit	2023A	2024A	2025A	2026B	2027P
	OM&A	Distribution	Non-Productive Idling (NPI) Reduction	(baseline NPI ratio - current NPI ratio) * engine runtime * # vehicles * litres consumed per idle hour * average cost per litle of fuel. Reduced fuel consumption through reduction of non-productive idling (NPI).	-	0.0	0.0	0.0	0.0
			Planned OT Reduction	Lower % of overtime hours - Historical Baseline vs Actual. Lower costs from reduction in overtime.	-	-	0.8	0.9	0.9
			Design Time Efficiency	Lower labour hours per Unit. Updates to the design and estimation tool, including automated calculations, standardized templates, simplified customer initiated redesign process, driving reduced labour hours to perform varied design tasks.	-	0.9	-	0.1	0.1
			Disconnect Reconnect Outsourcing	Cost savings from outsourcing disconnect reconnect work, and includes expedited customer service, reduction in OEB metric violations, less disruption to plannd work schedule, improved labour and equipment efficiency via fewer truck rolls.	-	0.0	-	-	-
			Dx Lighthouse	Lower labour hours per Unit Savings across several Distribution programs.	0.8	8.2	8.5	5.4	5.5
			PCB Outsourcing	(Internal Unit Cost - Outsourced Unit Cost) * # of Units Cost savings from outsourcing of work on PCB tests and inspects	18.8	21.4	2.1	-	-
		Fleet	Electric Vehicles	Fuel Savings Lower operational costs from using electric vehicles instead of gas based vehicles.	0.0	0.0	0.1	0.1	0.1
			Traction Parts Savings	Total vendor invoiced amount * % rebate Reduced heavy duty parts costs as a result of a rebate negotiated with vendor.	0.0	0.0	0.0	0.0	0.0
			Rental Savings	Historical Cost - New Cost Elimination of unneccessary rentals, which in turn drives reduction in rental costs.	-	-	0.2	0.9	0.9
		Forestry	Optimal Cycle Protocol (OCP) Inspection and Execution	Lower Cost per KM. Savings from more experienced staff and work on corridors that have been managed to Optimal Cycle Protocol (OCP)	14.1	8.1	4.5	4.7	4.8
			Forestry OT Reduction	Lower % of overtime hours - Historical Baseline vs Actual. Lower costs from reduction in overtime.	2.1	-	2.4	2.0	2.1
			Customer Request - Enhanced Screening	(% inquiries beyond scope * (labour + fleet rate) * average hours/ inspection trip Customer call screening to ensure only those within work parameters of technicians are scheduled, resulting in lower costs from reduced 'beyond scope' visits.	-	-	0.2	0.2	0.2
			FO FUR OT Reduction	Elimination of Forestry Urgent Requests (FO FURs) Overtime Savings from transitioning FO FURs to Customer Requests (CRs) handled during regular business hours. Cost savings from elimination of overtime.	-	-	0.5	0.6	0.6
		Real Estate	Lease Reduction	Lower Contract Cost. Cost savings in relation to reduced lease costs as compared to historical baseline.	3.8	3.0	2.6	2.2	2.6
		Supply Chain	Procurement	Lower Cost per Unit - Historical Baseline vs Actual Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions.	1.3	0.8	0.6	0.6	0.6
Undefined			Undefined	Undefined Productivity Savings				56.1	107.6
					113.9	**149.5**	**254.3**	**260.3**	**325.7**

HYDRO ONE NETWORKS INC.
2023-2027 Transmission and Distribution Productivity Summary

	LOB	Initiative	Measurement and Expected Benefit	2023A	2024A	2025A	2026B	2027P
Transmission	**Total Capital**			$ 23.0	$ 42.5	$ 71.1	$ 68.1	$ 61.1
	Total OM&A			$ 5.8	$ 8.4	$ 8.8	$ 18.4	$ 31.2
	Total External Revenue			$ 15.5	$ 11.6	$ 22.4	$ 16.5	$ 22.0
	Total Productivity			$ 44.3	$ 62.4	$ 102.4	$ 103.0	$ 114.3
				-	-	-	-	-
Distribution	**Total Capital**			$ 28.4	$ 40.7	$ 114.3	$ 68.7	$ 68.6
	Total OM&A			$ 41.1	$ 46.4	$ 37.7	$ 32.5	$ 35.2
	Total External Revenue			$ -	$ -	$ -	$ -	$ -
	Total Productivity			$ 69.6	$ 87.1	$ 152.0	$ 101.2	$ 103.8
				-	-	-	-	-
TOTAL	**Total Capital**			$ 51.5	$ 83.2	$ 185.4	$ 136.8	$ 129.7
	Total OM&A			$ 46.9	$ 54.8	$ 46.5	$ 50.9	$ 66.4
	Total External Revenue			$ 15.5	$ 11.6	$ 22.4	$ 16.5	$ 22.0
	Total Undefined			$ -	$ -	$ -	$ 56.1	$ 107.6
	Total Productivity			113.9	149.5	254.3	260.3	325.7

SECTION 1.5 – SPF – PERFORMANCE MEASUREMENT AND OUTCOMES

1.5.1 INTRODUCTION

Hydro One is committed to achieving the goals underpinning the TSP and DSP. To give effect to this commitment, Hydro One has aligned its planning, execution and reporting functions around performance outcomes that are consistent with the OEB's Renewed Regulatory Framework (RRF) outcomes. The RRF outcomes relate to Customer Focus, Operational Effectiveness, Policy Responsiveness and Financial Performance. Hydro One's overall performance against these targets is reported by means of regulatory scorecards for each of the transmission and distribution businesses, as well as through Hydro One's Team Scorecard and Operational Scorecard.

In the sections that follow, Hydro One describes its performance measurement process, including governance and methodologies used for each of the measures.

1.5.1.1 PERFORMANCE MEASUREMENT STRUCTURE, PROCESS, AND GOVERNANCE

Hydro One is focused on performance measurement and planning. Hydro One's budgeting and performance measurement processes ensure that cross-functional stakeholders, such as various lines of business, its Finance and Regulatory Affairs groups, the Executive Leadership Team (ELT) and Operations Managers, are equipped with up-to-date information to drive business decisions and achieve performance targets.

The Regulatory Scorecards found in TSP Section 2.5, TSP Section 2.10 Attachment 3, and DSP Section 3.5 detail Hydro One's and Hydro One Sault Ste. Marie's (HOSSM) historical performance in each area and establish performance outcomes that have been targeted over the 2028 to 2032 period. Hydro One is committed to achieving the performance outcomes for each measure. As noted in SPF Section 1.7, the investment plan will drive performance towards these outcomes, ensuring regulatory compliance, and balancing customers' needs and preferences, the asset and system needs, and rate impacts. The Regulatory Scorecards are made up of performance measures that enable

Hydro One to monitor, track and demonstrate performance relative to outcomes that are valued by its customers.

There are a number of internal stakeholders that are directly engaged in and have responsibility for overseeing or implementing Hydro One's performance measurement and monitoring process. Details of this process are set out in Hydro One's Performance Reporting Governance Framework, a copy of which is provided in Attachment 1.

1.5.2 TRANSMISSION AND DISTRIBUTION SCORECARDS OVERVIEW

Hydro One has four scorecards that it uses to assess its performance relative to the OEB's RRF outcomes. As discussed above these scorecards are used internally, as well as to communicate results and targets to the OEB.

For Transmission, Hydro One proposes to continue to file the Transmission OEB Scorecard approved in EB-2021-0110 (see TSP Section 2.5). In addition, HOSSM proposes to continue to file its scorecard approved in EB-2018-0218 (see TSP Section 2.10 Attachment 3). For Distribution, Hydro One will continue to file both the Electricity Distributor Scorecard that the OEB requires from all electricity distributors and the Distribution OEB Scorecard approved in EB-2021-0110 (see DSP Section 3.5), which provides measures offering additional granularity in the areas of Customer Satisfaction, Cost Control and System Reliability.

TSP Section 2.5 and TSP Section 2.10, Attachment 3 discuss each measure in Hydro One's and HOSSM's respective scorecards. The discussion provides the definition of the measures, historical performance over the current rate period and targets for the forthcoming rate period. These sections also address proposals to modify or eliminate certain measures.

DSP Section 3.5 discusses each measure in the Electricity Distributor Scorecard and the Distribution OEB Scorecard. The discussion provides the definition of the measures, historical performance over the current rate period and targets for the forthcoming rate period. This section also addresses proposals to modify or eliminate certain measures.

SECTION 1.5 – ATTACHMENT 1 – PERFORMANCE REPORTING GOVERNANCE FRAMEWORK

Performance Reporting Governance Framework

Distribution & Transmission

May 2026

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Hydro One Operational Scorecards – Example 13

PERFORMANCE MEASUREMENT GOVERNANCE

The Ontario Energy Board (OEB) assesses Hydro One's transmission and distribution rate applications using a performance- and outcomes-based approach, as established in the OEB's Renewed Regulatory Framework (RRF). The RRF outlines four performance outcomes (customer focus, operational effectiveness, public policy responsiveness, and financial performance), which articulate the OEB's goals of aligning the interests of customers and utilities. The outcomes are supported by key principles in the RRF, which include the expectation of continuous improvement, robust integrated planning and asset management that pace and prioritize investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

Performance scorecards are used to capture the four outcomes and the key principles of the RRF, assess alignment between a utility's rate application and the RRF, and assess the alignment of the utility's interests with those of its customers. This document describes how Hydro One tracks and reports performance outcomes on its scorecards in alignment with the OEB's performance- and outcomes-based approach.

PERFORMANCE PRINCIPLES & MEASURES

The OEB requires Hydro One to report on its performance using a variety of measures contained in scorecards that are either developed or required by the OEB. For distribution rate applications, Hydro One uses the following scorecards: (i) the *OEB Electricity Distributor Scorecard (A)*; and (ii) the *Hydro One Distribution Scorecard (B)*. The Electricity Distributor Scorecard is produced by the OEB using Hydro One Distribution's annual Reporting and Record-keeping Requirements (RRR) filings. The Distribution Scorecard provides measures in addition to those in the Electricity Distributor Scorecard.

For transmission revenue requirement applications, Hydro One uses the following scorecards: (i) the *Hydro One Transmission Scorecard (C)*; (ii) the *Hydro One Sault Ste. Marie Limited Partnership Scorecard (HOSSM)*; and (iii) Hydro One's *Limited Partnerships (LP) Scorecards*.

Together, these seven scorecards are referred to as the regulatory scorecards. At the overall corporate level, Hydro One uses the Team Scorecard and Operational Scorecards. The interactions between the various scorecards are shown below in Figure 1.

The regulatory scorecards are organized around the four RRF outcomes, and each outcome informs subsequent "performance categories," which are evaluated, for the most part, using quantitative measures that are tracked over time and compared with targets that are specific to either the industry, Hydro One, or both. The regulatory scorecards include the complete list of measures used to track and report performance improvements.

PLANNING FOR PERFORMANCE OUTCOMES

To meet the targets in the regulatory scorecards, Hydro One incorporates the RRF principles and associated measures into its planning, execution, and reporting functions. RRF principles are integrated into Hydro One's corporate objectives and business plan, and specific measures from each of the Distribution and Transmission regulatory scorecards are included in Hydro One's internal scorecards - the Team Scorecard and the Operational Scorecards.

Figure 1 below shows how the RRF principles are incorporated into the performance reporting process for the regulatory scorecards, Hydro One's Team Scorecard, and Operational Scorecards.

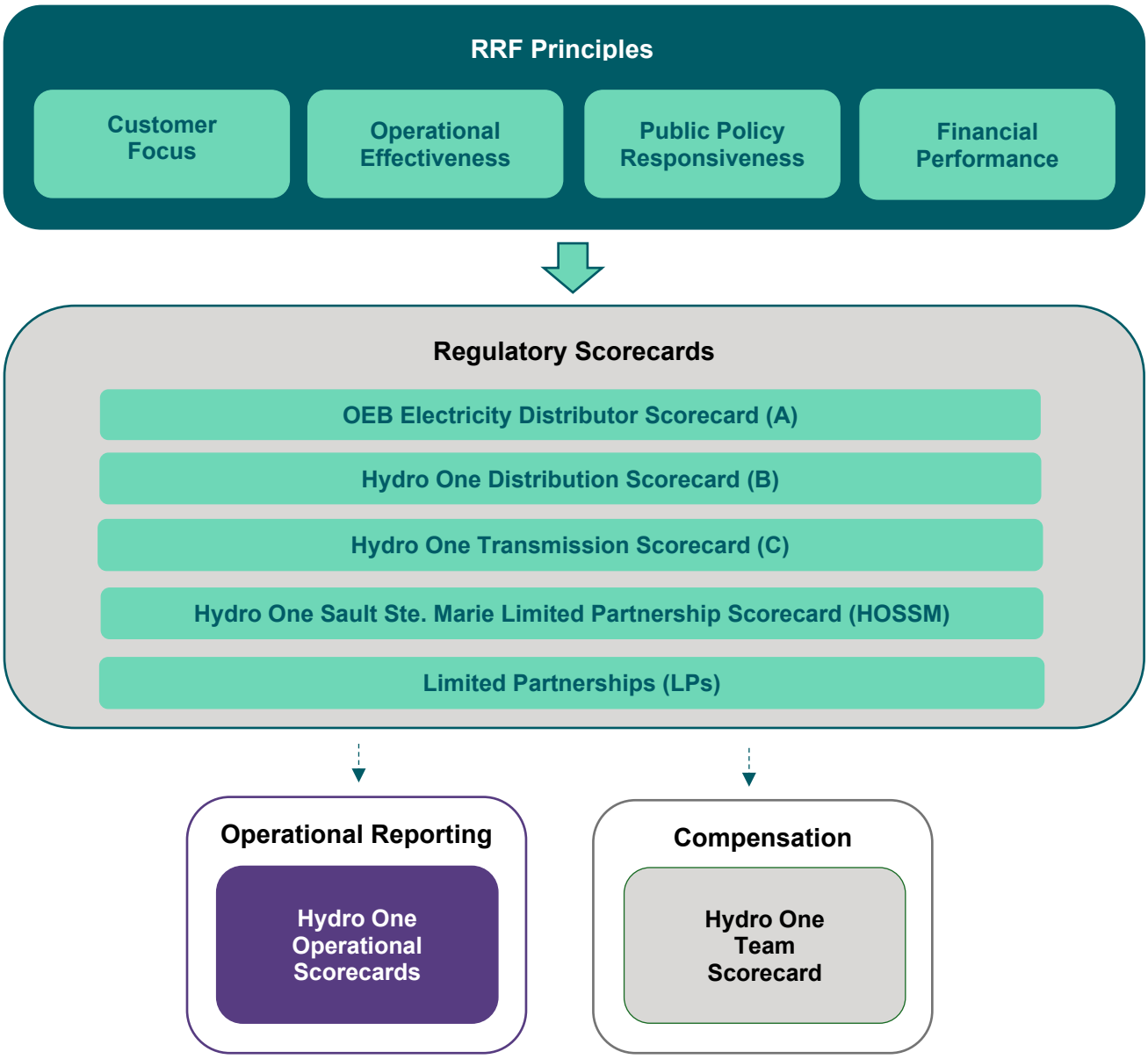


Figure 1: Performance Reporting Scorecards & Interactions

GOVERNANCE FOR REPORTING & DEVELOPMENT OF MEASURES AND TARGETS

Hydro One's governance framework is designed to support the key RRF principles of continuous improvement, robust integrated planning and asset management, strong incentives to enhance performance, ongoing monitoring of performance against targets, and customer engagement to inform rate applications. The framework focuses on two primary activities: (i) performance reporting; and (ii) measure and target development.

The primary stakeholders supporting the governance framework are listed in Table 1:

Table 1 - Stakeholder Accountabilities

Business area	Accountability
Operations	Historical performance
System Planning	Investment strategy and prioritization
Regulatory Affairs	OEB RRR process
Finance	Financial reporting

OEB ELECTRICITY DISTRIBUTOR SCORECARD (A) – EXAMPLE

Performance Outcomes	Performance Categories	Measure
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time
		Scheduled Appointments Met On Time
		Telephone Calls Answered On Time
	Customer Satisfaction	First Contact Resolution
		Billing Accuracy
		Customer Satisfaction Index
Operational Effectiveness	Safety	Level of Public Awareness (Public Awareness of Electrical Safety)
		Compliance with Ontario Regulation 22/04
		Serious Electric Incident Index - Number of General Public Incidents
		Serious Electric Incident Index - Rate per 10, 100, 1000km of line
	System Reliability	SAIDI - Average Number of Hours that Power to a Customer is Interrupted (SAIDI)
		SAIFI - Average Number of Times that Power to a Customer is Interrupted (SAIFI)
	Asset Management	Distribution System Plan Implementation Progress
	Cost Control	Efficiency Assessment
		Total Cost per Customer
		Total Cost per Kilometre of Line
Public Policy Responsiveness	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio
		Profitability: Regulatory Return on Equity – Deemed (included in rates)
		Profitability: Regulatory Return on Equity – Achieved

EXAMPLE

HYDRO ONE DISTRIBUTION SCORECARD (B) – EXAMPLE

Performance Outcomes	Performance Categories	Measures
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)
		Handling of Unplanned Outages Satisfaction (%)
		Call Centre Customer Satisfaction (%)
		My Account Customer Satisfaction (%)
[illegible] Effectiveness	Cost Control	Pole Replacement - Gross Cost per Urban ($)
		Vegetation Management - Gross [illegible] Correction [illegible] Cost per km ($)
		Station Refurbishment - Gross Cost Per MVA ($)
		OM&A dollars per customer ($)
		OM&A dollars per km of line ($)
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)
		SAIDI for Vegetation Caused Interruptions (hrs)
		SAIDI - Rural - duration (hrs)
		SAIFI - Rural - frequency of outages
		SAIDI - Urban - duration (hrs)
		SAIFI - Urban - frequency of outages
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA

EXAMPLE

HYDRO ONE TRANSMISSION SCORECARD (C) – EXAMPLE

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs (%)	
	Customer Satisfaction	Overall Customer Satisfaction (%)	
		Satisfaction with Outage Planning Procedures (%)	
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses pe[illegible]00 hours worked)	
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Poin[illegible]	
		T-SAIFI-M (Ave. # of Momentary interru[illegible]ns per Delivery Po[illegible]	
		T-SAIDI (Ave. minutes of i[illegible]ruptions pe[illegible]liver Po[illegible]t)	
		System Unavailabi[illegible]e)	
		Unsupplied energy ([illegible]	
	Asset & Project Management	Transi[illegible]n System P[illegible] Implementation Progress (%)	
		[illegible]oEx [illegible]f Budget (%)	
		[illegible] P[illegible]gra[illegible] Accomplishment (composite index)	
		T[illegible]smi[illegible]n Capital Accomplishment Index (%)	
	Cost Control	Tot[illegible] OM&A and Capital per Gross Fixed Asset Value (%)	
		OM&A per Gross Fixed Asset Value (%)	
		Line Clearing Cost per kilometer ($/km)	
		Brush Control Cost per Hectare ($/Ha)	
Public P[illegible]y Respo[illegible]veness	Connecti[illegible]ewable Generation	% on-time completion of renewables customer impact assessments (CIAs)	
	Regional In[illegible]structure Planning & Long-Term [illegible]ergy Plan Right-Sizing	Regional Infrastructure Planning progress - Deliverables met (%)	
		End-of-Life Right-Sizing Assessment Expectation	
Financia[illegible] Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	
		Profitability: Regulatory Return on Equity	Deemed
			Achieved RROE %

EXAMPLE

HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP SCORECARD (HOSSM) – EXAMPLE

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Service Quality	Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points	
	Customer Satisfaction	Overall Customer Satisfaction	
		Satisfaction with Outage Planning Procedures	
Operational Effectiveness	Safety	Recordable Injury # of recordable injuries/illnesses per 2 [illegible] hours worked	
	System Reliability	T-SAIFI-S (Average Number of Sustained Interruptions per [illegible] Point)	
		T-SAIFI-M (Average Number of Momentary Interruptions per Delivery Point)	
		T-SAIDI (Average Minutes [illegible] Interruptions per Delivery Point)	
		System Unavailability (%)	
		Unsupplied E[illegible]y (minutes	
	Asset and Project Management	In-Se[illegible] Ad[illegible]as % of OEB approved plan	
		CapEx [illegible]% [illegible]EB approved plan	
	Cost Control	Total OM[illegible]anc Capital per Gross Fixed Asset Value (%)	
		M&A per Gross Fixed Asset Value (%)	
		Sustainment Capital per Gross Fixed Asset Value (%)	
Public Policy Responsiveness	Connection of Renew[illegible]Generation	% On-time Completion of Renewables Connection Impact Assessments	
	Regional Infra[illegible]ucture Plan[illegible]g ([illegible]) & Long-Term [illegible]rgy Plan (LTEP) [illegible]ght-Sizing	Regional Infrastructure Planning progress - Deliverables Met (%)	
Financial Performance	[illegible]ancial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	
		Profitability: Regulatory Return on Equity	Deemed
			Achieved RROE %

EXAMPLE

HYDRO ONE'S LIMITED PARTNERSHIPS SCORECARD – EXAMPLE

RRF Outcome	Performance Measure
Operational Excellence	Average System Availability (%)
Operational Excellence	T-SAIDI B2M LP Contribution
Operational Excellence	T-SAIFI B2M LP Contribution
Public Policy Responsiveness	NERC Vegetation Compliance
Operational Excellence	Maintenance Cost ($K) per circuit kilometre
Financial Performance	Annual Achieved Return on Equity (ROE) (%)

EXAMPLE

HYDRO ONE TEAM SCORECARD – EXAMPLE

Corporate Goal	Component Weight	Definition	Measure
Health and Safety	20%	High Energy Serious Injury and Fatality Rate	Incidents per 200,000 hours
Sustainability	5%	Women Executives representation	% of women executives
		Convert our fleet of sedans and SUVs to EVs or hybrids	Converted % of fleet [illegible]s or hybrids
		Increase Indigenous procurement spend	Indigenous procurement sp[illegible] as [illegible] of purchased materia and services
Customer	25%	Overall Brand Impression	Overa[illegible]and [illegible]ression
		Overall Customer [illegible]atisfaction	Overall Customer Satisfaction
		Transm[illegible]tions ([illegible]ability - average length [illegible] [illegible]nne[illegible]n[illegible]uptions to multi-circuit sup[illegible]n[illegible]v[illegible] po[illegible]s (SAIDI)	Minutes per Delivery Point
		Di[illegible]hution (Dx) Reliab[illegible]- a[illegible]ge length of outages in hours that a custo[illegible]r experiences (SAIDI)	Hours per Customer
Financial	40%	Tra[illegible]ation Efficiency Savings (Inclusive of Productivity)	$M
		Net Income to Common Shareholders	$M
Work Program	10%	Tx In Service Additions	Variance (%) to approved budget
		Dx In Service Additions	Variance (%) to approved budget
		ATP & EDW In Service Additions	Variance (%) to approved budget

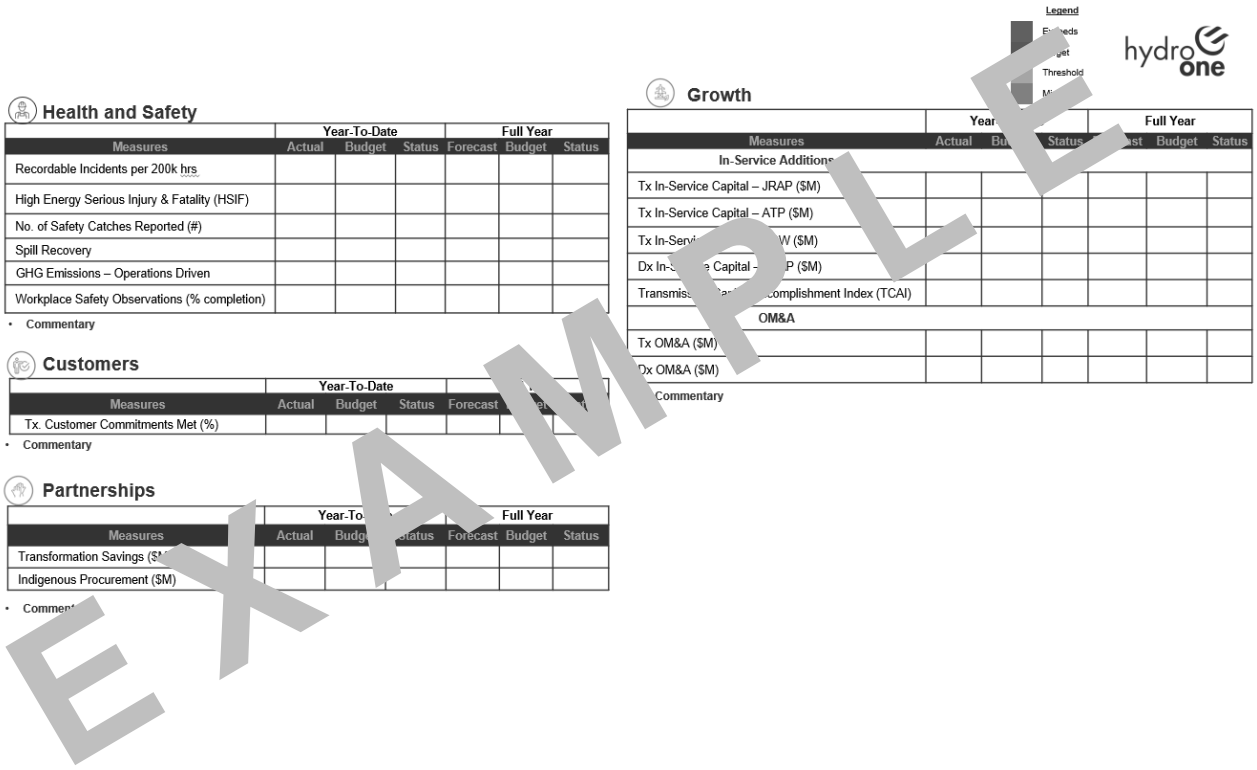
EX

HYDRO ONE OPERATIONAL SCORECARDS – EXAMPLE

Strategic Priorities	Measures
Health and Safety	*High Energy Serious Injury & Fatality Rate (Incidents per 200K hours)
Growth	*Transformation Savings – Tier 1 Dx, Forestry, & Stations ($M)
	*Total Operations & Customer Experience Work Program OM&A ($
	*In-Service Additions Index: Tx In Service Additions – Delivery Accura (Variance to approved budget, excluding EDW, Tx P nerships) ($M)
	*In-Service Additions Index: Dx In Service Additions – livery Accuracy (Variance to approved budget, exclu g Br dband, JU M) [1]
	Total Overdue Distribution Energy Re es ($M)
Customers	Tx Average length of unpl d interrup s to multi-circuit (mc) supplied delivery (S Minutes per Delivery Point)
	Dx Average length o ta in hours that a customer experiences (SAI ours per Cu mer)
	Over pression (%)
	Overa Customer Satisfaction for all segments (%)
	% of Accurate Bills as per OEB (%)
Partnerships	Community - Indigenous procurement spend as a % of purchased materials and services (%)
Solutions	Storm ETRs: ETR Accuracy (% of Total Issued)
	Business processes reviewed for effieciency (number)

EXAMPLE

1



Legend
Exceeds
Target
Threshold
Miss

hydro one

Health and Safety

Measures	Year-To-Date			Full Year		
	Actual	Budget	Status	Forecast	Budget	Status
Recordable Incidents per 200k hrs						
High Energy Serious Injury & Fatality (HSIF)						
No. of Safety Catches Reported (#)						
Spill Recovery						
GHG Emissions – Operations Driven						
Workplace Safety Observations (% completion)						

- Commentary

Customers

Measures	Year-To-Date			Forecast		
	Actual	Budget	Status			
Tx. Customer Commitments Met (%)						

- Commentary

Partnerships

Measures	Year-To-Date			Full Year		
	Actual	Budget	Status	Forecast	Budget	Status
Transformation Savings ($M)						
Indigenous Procurement ($M)						

- Comment

Growth

Measures	Year			Full Year		
	Actual	Bu	Status	ast	Budget	Status
In-Service Additions						
Tx In-Service Capital – JRAP ($M)						
Tx In-Service Capital – ATP ($M)						
Tx In-Serv W ($M)						
Dx In- e Capital - P ($M)						
Transmis ear omplishment Index (TCAI)						
OM&A						
Tx OM&A ($M)						
Dx OM&A ($M)						

Commentary

EXAMPLE

2

SECTION 1.6 – SPF – CUSTOMER, STAKEHOLDER AND INDIGENOUS COMMUNITIES ENGAGEMENT

1.6.1 INTRODUCTION

Hydro One serves 1.5 million predominantly rural residential, seasonal and small business customers (including customers in Indigenous communities), and over 8,000 large business customers, including commercial and industrial customers, local distribution companies, and transmission-connected end-users and generators. Through its distribution network, Hydro One serves approximately 26% of the total number of electricity customers in Ontario. Hydro One's transmission system delivers electricity to 98% of customers in the province. Both systems cover vast geographical areas and serve a diverse customer base throughout the province.

This Exhibit describes Hydro One's strategy and approach to customer engagement that places customers and their needs at the core of investment and operational decisions. The following sections describe:

- the multi-phase application-specific customer engagement study conducted by Innovative Research Group (IRG) and the results of it; and
- the various other forms of ongoing customer engagement carried out by Hydro One, including through: the Customer Contact Centre; large customer account management and oversight committees; customer satisfaction research; Indigenous engagement, including engagement with First Nations communities and Métis organizations; external relations; and the Office of the Hydro One Ombudsman.

1.6.2 CUSTOMER ENGAGEMENT OVERVIEW

Hydro One's approach to customer engagement comprises two primary streams: a multi-phased study conducted by independent expert consultant IRG for this Application, and ongoing engagement activities that continually inform planning and operations across the organization.

To identify customer needs and preferences in preparation for its 2028 – 2032 investment planning process and this Application, Hydro One engaged IRG to develop and conduct a customer engagement study (IRG Study). IRG employed a two-phased approach, engaging customers in advance of the investment planning process, in mid-to-late 2024, and again after draft investment plans were prepared, in late 2025. This allowed Hydro One to develop and finalize investment plans that are informed by customer input and have been refined based on specific investment trade-offs to achieve outcomes valued by customers.

Hydro One understands that the IRG Study is the largest customer engagement documented at the OEB to date.[1] In total, over 100,000 customers participated in the IRG Study through various types of activities, including focus groups, in-depth interviews, telephone surveys, and online surveys. The activities also included conversations with First Nations Chiefs or their representatives, Métis Nation of Ontario regional representatives, stakeholders and municipalities.

The Transmission System Plan, Distribution System Plan and General Plant System Plan (TSP, DSP, GSP and collectively the System Plans) are closely aligned with customer needs and preferences. The IRG Study results indicate strong support for Hydro One's proposed investment plans. As stated in the IRG Overview Report: "Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans."[2] Depending on customer type, 68% to 88% of customers support spending at or above the level of investment included in the plans.[3] Similar levels of support were observed for categories of investments in the transmission and distribution systems, as well as shared services.[4]

[1] SPF Section 1.6 Attachment 1, IRG Overview Report p. 20
[2] SPF Section 1.6 Attachment 1, IRG Overview Report p. 3
[3] SPF Section 1.6 Attachment 1, IRG Overview Report p. 3 and p.14
[4] SPF Section 1.6 Attachment 1, IRG Overview Report p. 14-18

Customers consistently supported Hydro One investing at the level of the draft plan (or higher) to ensure a reliable, resilient and future-ready system at a reasonable rate.[5] Customers are in favour of replacing poor condition distribution and transmission assets to improve reliability or reduce risk of outages related to severe weather.[6] Customers also see value in investing in reducing risk of critical facility asset failure to enable field operation and in modernizing technology capabilities to enhance services and improve efficiency.[7]

Customer feedback from both phases of the IRG Study was integrated directly into, and informed, the preparation and finalization of the investment plans as described in Section 1.6.3 below.

The IRG Study is further described below, and IRG's reports detailing the study are included as Attachment 1, with the IRG Overview Report providing an overview of the study and its results.

In addition to the results of the above application-specific IRG Study, Hydro One's investment plans are also informed by customer feedback from other forms of ongoing engagement. These other forms of engagement include conversations with residential and small business customers through the Customer Contact Centre, in-depth conversations with large customers through the Account Executives, ongoing customer satisfaction research, and regular dialogue with industry stakeholders and consumer groups. These ongoing customer engagement activities are further described in Section 1.6.4 below.

1.6.3 THE IRG STUDY

1.6.3.1 TIMING AND PROCESS

As detailed in the IRG Overview Report, the IRG Study was a two-phased process that gave all customers the opportunity to participate in Hydro One's investment planning process. Figure 1 below depicts the integrated customer engagement and investment

[5] SPF Section 1.6 Attachment 1, IRG Overview Report p. 20
[6] SPF Section 1.6 Attachment 1, IRG Overview Report p. 15-17
[7] SPF Section 1.6 Attachment 1, IRG Overview Report p. 17-18

planning process and timing. This integration and the impacts of the customer engagement process on investment planning are further discussed in the System Plans Framework (SPF) section 1.7, TSP section 2.7, DSP section 3.7 and GSP section 4.7.

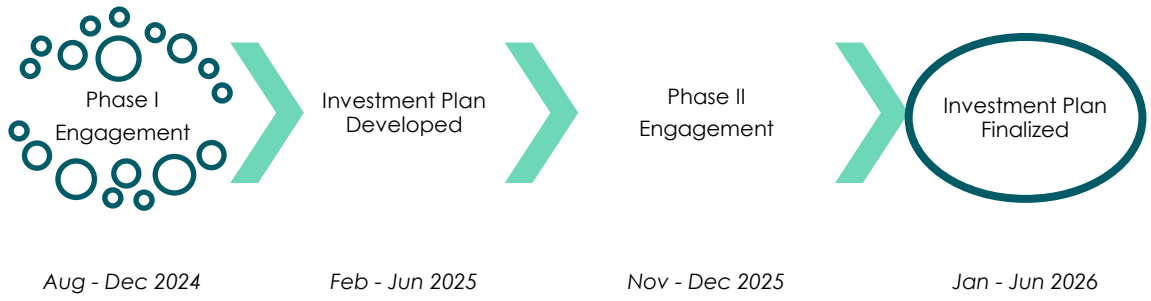


Figure 1: Integrated Customer Engagement and Investment Planning Process

Phase I took place in mid-to-late 2024, prior to the beginning of the investment planning process for the years 2028-2032, and focused on identifying customer needs and preferences to inform the initial stages of investment planning. Phase II was carried out in late fall 2025 and provided customers with an opportunity to provide specific feedback on Hydro One's draft investment plans, including on significant investment trade-offs in the plans. The Phase II results informed and were incorporated into the final investment plans submitted in this Application.

1.6.3.2 BROAD PARTICIPATION

Given the variety and number of Hydro One's customers, as noted further above, the IRG Study needed to obtain feedback from a broad range of customers.

Hydro One's distribution customers fall into three categories: (i) Residential and Small Business (GS<50kW) customers; (ii) Commercial and Industrial (C&I) customers (<2MW); and (iii) Large Distribution Accounts (LDA), or Key Accounts (>2MW). Customers directly connected to the transmission system are made up of: (i) Electricity Generators who deliver power to the transmission system; (ii) Distributors who deliver power to direct customers; and (iii) End-users such as mining and industrial enterprises that use the

power themselves at transmission level voltage. In addition, both systems serve First Nations and Métis customers in different areas of the province.

The IRG Study included a range of outreach methods tailored to the different customer segments above. Hydro One's distribution customers – both residential and non-residential – were invited to participate in the IRG Study and thus have input into the distribution and transmission system planning process and resulting investment plans. They include:

- (Primary and seasonal) residential customers
- First Nations and Métis customers
- Small business customers (GS<50kW)
- C&I Customers (50kW – 2MW)
- LDA (>2MW)

The following customers who are directly connected to Hydro One's transmission system (including Hydro One Sault Ste. Marie's system), as well as customers that are served by other Ontario Local Distribution Companies (LDCs), also had the opportunity to participate in the IRG Study and thus have input into the transmission system planning process and resulting investment plan:

- Transmission-connected end-users
- Transmission-connected generators
- Transmission-connected LDCs
- Residential customers outside of Hydro One's distribution territory
- Small Business customers outside of Hydro One's distribution territory

As further detailed in the IRG Report, and shown in Figure 2 below, over 100,000 customers from all segments participated in a variety of engagement activities throughout both phases of the IRG Study.

Customer/Stakeholder Group		Phase I			Phase II	Total
		Focus Group	In-depth Interview	Online Survey	Online Survey	
		Aug 2024	Aug - Oct 2024	Nov - Dec 2024	Nov - Dec 2025	
Hydro One Distribution & Transmission Customers	Residential (including Seasonal)	59	-	6,053	94,611	**100,723**
	First Nations On-Reserve Residential	-	-	426	793	**1,219**
	Small Business	27	-	477	2,791	**3,295**
	Commercial & Industrial	-	9	311	368	**688**
	Large Distribution Accounts	-	11	61	53	**125**
Hydro One Transmission-Only Customers	Other LDC Residential	-	-	1,019	2,071	**3,090**
	Other LDC Small Businesses	-	-	-	305	**305**
	Large Transmission Accounts	-	17	72	73	**162**
Indigenous Leadership	First Nations Leadership	-	18	-	-	**18**
	Métis Nation of Ontario Leadership	-	8	-	-	**8**
Stakeholders	Association Stakeholders	-	9	-	-	**9**
	Municipality Stakeholders	-	9	-	-	**9**

Figure 2: Overview of IRG Study Customer Engagement Activities[8]

In respect of customers of other LDCs, they were given the opportunity to directly participate in the IRG Study during both phases of the customer engagement. These customers were able to identify their needs and outcome priorities and to comment on investments in Hydro One's draft Transmission System Plan and General Plant System Plan, including proposed price increases. This was accomplished through representative surveys of electricity customers in Ontario that are outside of Hydro One's distribution territory via online research panels. Phase I included a representative online survey. Phase II included both a representative online survey and an open call to participate via an open-access link on Hydro One's website.[9]

Hydro One also obtained and incorporated meaningful input from First Nations representatives. All First Nations customers were invited to complete an online survey in Phases I and II of the IRG Study. On-reserve First Nations residential customers received a separate workbook in both phases to reflect the First Nations Delivery Credit. In addition, First Nations Chiefs or delegates had the opportunity to provide input into the investment

[8] SPF Section 1.6 Attachment 1, IRG Overview Report p. 6 – 7 and p. 14
[9] SPF Section 1.6 Attachment 1, IRG Overview Report p. 7 and p.13

planning process and share their communities' specific needs and preferences during Phase I. Hydro One further reached out to the Métis Nation of Ontario (MNO), whose views were considered throughout the engagement. MNO representatives were invited to discuss the needs and outcome preferences. Likewise, stakeholders and municipalities across Ontario had opportunities to provide their input into Hydro One's investment planning process.

Through the broad range of customer engagement activities in the IRG Study, Hydro One developed a strong understanding of the specific outcomes that its distribution and transmission customers value and care most about, as well as the level of spending and mix of investments that customers would most like to see included in Hydro One's investment plans. This customer feedback was an important and direct input into Hydro One's investment planning process. Consequently, Hydro One's planned transmission, distribution, and general plant capital investments are aligned with and responsive to the needs and preferences of its customers.

1.6.3.3 PHASE I: CUSTOMER NEEDS AND PREFERENCES

Phase I of the IRG Study focused on customers' general needs and outcome preferences for the electricity system. Customers expressed high levels of satisfaction with the electricity service they receive and identified reasonable rates and reliable electricity as the top priorities across all customer segments.[10] C&I, LDA, and other LDC Residential customers also indicated meeting growing electricity demand as a top priority.[11]

After obtaining customer input on general needs and outcome priorities, customers were invited to provide feedback on high-level investment trade-offs in Phase I. Hydro One's planners identified a range of illustrative investment categories that have historically comprised a material portion of controllable investment in prior plans. The intent of this part of the engagement was to provide early insight into the types of investments that customers value most and their general willingness to pay, in advance of the investment planning process.

[10] SPF Section 1.6 Attachment 1, IRG Overview Report p. 8
[11] SPF Section 1.6 Attachment 1, IRG Overview Report p. 9

While reasonable rates are of importance to customers, they also indicated that they value and are willing to pay for investments that maintain or improve performance on reliability, resiliency, enabling economic growth and system visibility where costs for these benefits are within the directional bill impacts provided.[12] A majority or near majority of customers across all customer types supported investments to achieve various outcome objectives. There was variation amongst the customer types in terms of level of support for proactive investments, with stronger support being demonstrated by residential customers and LDA customers, for example.

The needs and outcome preferences of on-reserve First Nations residential customers, and their feedback on high-level investment trade-offs, largely aligned with the results from other customer segments. Affordability and reliability were identified as top priorities. First Nations customers are generally willing to pay more to invest in maintaining or improving reliability.[13] While First Nations customers are slightly less willing to pay more to make these investments than residential customers, they still support investments in the electricity system and are willing to accept potential bill impacts.[14]

Customer feedback and key findings from Phase I were provided to Hydro One's planners for their consideration in developing the draft investment plans for the distribution, transmission, and general plant systems. Throughout the spring and summer of 2025, planners reviewed this customer feedback and incorporated it into the development of the draft investment plans as described in SPF section 1.7, TSP section 2.7, DSP section 3.7 and GSP section 4.7.

The sections immediately below provide further details regarding the Phase I customer feedback, including preferences for specific investments in respect of the distribution and transmission systems.

[12] SPF Section 1.6 Attachment 1, IRG Overview Report p. 10 – 12
[13] SPF Section 1.6 Attachment 1, IRG Overview Report p. 10
[14] SPF Section 1.6 Attachment 1 Appendix 6, Hydro One Phase I Planning Placemat, p. 155-157

1.6.3.3.1 Distribution system

As described in the IRG Overview Report, key customer feedback in respect of distribution included the following:

- A majority of customers support Hydro One making necessary investments in the distribution system to improve or maintain current levels of reliability related to the distribution grid.[15]
- A majority of customers want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.[16]
- A majority of customers want Hydro One to make investments to make the system more resilient to severe weather events as part of the ongoing replacement of old or failing equipment. A plurality of customers support Hydro One in making proactive investments to make the system more resilient to severe weather events.[17]
- A plurality of customers support Hydro One making proactive investments to enable anticipated growth and accommodate new connections and service upgrades in a timely manner.[18]
- A majority of customers want Hydro One to make proactive investments in technology to accommodate customer requests and improve system visibility.[19]

1.6.3.3.2 Transmission system

As described in the IRG Overview Report, key customer feedback in respect of transmission included the following:

- A majority of customers want Hydro One to make investments to either maintain or increase current levels of reliability related to the transmission grid.[20]

1.6.3.4 PHASE II: FEEDBACK ON THE DRAFT INVESTMENT PLANS

After Hydro One had developed its draft 2028-2032 investment plans, Phase II of the IRG Study, over the late fall of 2025, gave customers an opportunity through an online survey

[15] SPF Section 1.6 Attachment 1, IRG Overview Report p. 10
[16] SPF Section 1.6 Attachment 1, IRG Overview Report p. 10
[17] SPF Section 1.6 Attachment 1, IRG Overview Report p. 11
[18] SPF Section 1.6 Attachment 1, IRG Overview Report p. 11
[19] SPF Section 1.6 Attachment 1, IRG Overview Report p. 12
[20] SPF Section 1.6 Attachment 1, IRG Overview Report p. 12

to provide feedback on the draft plans, including specific investment trade-offs included in the plans. Distribution customers were asked to provide their feedback on the distribution, transmission and shared services investment trade-offs. Transmission customers and other LDC customers were asked to provide their feedback on the transmission and shared services investment trade-offs. As part of Phase II, IRG engaged with over 100,000 customers.

In respect of Distribution, Transmission and Shared Services, customers were presented with investment trade-offs relating to the following areas and objectives:

- Distribution: (i) overall system reliability; (ii) managing the impacts of severe weather; and (iii) targeted reliability;
- Transmission: (i) keeping pace with transmission renewal; and (ii) stewardship of transmission system; and
- Shared Services: (i) maintaining buildings and facilities; and (ii) information technology.

In respect of the above areas, customers were generally given options to choose between spending at the level of the draft plan, higher than the plan, or lower than the plan, with associated impacts on outcomes. The specific investment trade-off questions and options presented are described in the IRG Overview Report and further detailed in their Phase II results report.

As noted in the IRG Overview Report, the Phase II results indicated that customers value the proposed investments in the electricity system and are supportive of Hydro One's draft investment plans. Across all customer types, most customers support Hydro One spending at or above the level of investment included in the draft plans.[21] They are willing to accept bill increases in exchange for prudent investments in the distribution and transmission systems.

[21] SPF Section 1.6 Attachment 1, IRG Overview Report p. 14

Some differences exist between customer segments regarding the specific level of investment, and corresponding bill impact, they prefer. The results included that most on-reserve First Nations residential customers support the proposed investments in the electricity system and support Hydro One spending at or above the level of investment included in the draft plans.[22] This includes support for the proposed investments in overall distribution system reliability, managing severe weather, targeted reliability improvements, keeping pace with transmission renewal and system stewardship, as well as maintaining buildings and facilities and making technology investments.[23]

The sections immediately below provide further details regarding the Phase II customer feedback, including their preferences for specific investments in the distribution and transmission systems.

1.6.3.4.1 Distribution system

As described in the IRG Overview Report, key customer feedback in respect of distribution included the following:

- Across all customer types, most customers support Hydro One spending at or above the level of investment in the draft plan as it relates to distribution investments in overall system reliability, managing severe weather, and targeted reliability improvements.[24]
- Customers support the investments included in the draft plan regarding the replacement of distribution assets in poor condition, such as overhead lines, transformer stations and underground cables to improve day-to-day reliability. A plurality of customers supports a level of spending more than the draft plan to further reduce the risk of outages.[25]
- Regarding investments to manage the impacts of severe weather on the distribution system, customers support the level of investments in the draft plan with respect to relocating or reinforcing vulnerable power lines with more resilient

[22] SPF Section 1.6 Attachment 1, IRG Overview Report, p. 14
[23] SPF Section 1.6 Attachment 1, IRG Overview Report, p. 15 - 18
[24] SPF Section 1.6 Attachment 1, IRG Overview Report p. 15
[25] SPF Section 1.6 Attachment 1, IRG Overview Report p. 15

equipment, clearing more overgrown trees and brush than historically, and more installation of automated “intelligent switches”. A plurality of customers would like to see an increased level of investment beyond the level in the draft plan.[26]

- For investments to achieve targeted reliability, customers support the level of investment in the draft plan, including in respect of investing in community-scale and individual customer batteries to target reliability improvements for individual customers and communities that experience the poorest reliability. [27]

1.6.3.4.2 Transmission system

As described in the IRG Overview Report, key customer feedback in respect of transmission included the following:

- Across all customer types, most customers support spending at or above the level of investment in the draft plan as it relates to keeping pace with transmission renewal, and stewardship of the transmission system. [28]
- Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to manage the risk of equipment failure and support growth across the province. These include the replacement of transmission station transformers and breakers, and high-impact underground transmission cables.[29]
- Customers also expressed strong support for investments to enhance Hydro One’s stewardship of the transmission system. A majority of customers support the draft plan, including replacing at-risk transmission lines, reinforcing wood poles and extending the life of steel towers and accelerating the clearing of overgrown trees.[30]

1.6.3.4.3 Shared Services

As described in the IRG Overview Report, key customer feedback in respect of Shared Services (general plant) included the following:

[26] SPF Section 1.6 Attachment 1, IRG Overview Report p. 15
[27] SPF Section 1.6 Attachment 1, IRG Overview Report p. 16
[28] SPF Section 1.6 Attachment 1, IRG Overview Report p. 16
[29] SPF Section 1.6 Attachment 1, IRG Overview Report p. 16
[30] SPF Section 1.6 Attachment 1, IRG Overview Report p. 17

- Across all customer types, most customers support Hydro One spending at or above the level of investment in the draft plan as it relates to shared investments in maintaining buildings and facilities, and information technology.[31]
- A majority of customers support the draft plan level of spending to address at-risk building components, making at-risk sites more resilient to severe weather, and repair and retrofit field offices to meet modern and accessibility standards. [32]
- A majority of customers support the draft plan level of information technology spending, to maintain the current state of technology systems, enhance customer service, improve operational efficiency, and protect the grid from physical and cyber attacks. [33]

The Phase II results were presented to Hydro One's planners. The planners then used this customer feedback to help inform the finalization of the proposed investment plans. This allowed Hydro One to ensure the final plans for 2028-2032 take into account, and are responsive to, customer needs and preferences, including customer feedback on specific investment trade-offs.

Overall, as described above, the Phase II customer feedback confirmed strong customer support for Hydro One's draft investment plans across its various customer types, resulting in a decision to generally maintain the draft plan spending levels, with minor adjustments in selected investment areas.

SPF Section 1.7.4.5.2 further describes the integrated nature of the customer engagement process and the investment planning process. TSP Section 2.7.4.4.2, DSP Section 3.7.5 and GSP Section 4.7.2.1 further describe how the final proposed capital expenditure plans reflect the customer feedback and will achieve the outcomes valued by customers.

Following customer engagement and further investment plan review, Hydro One further refined and repaced certain investments to balance customer priorities, system needs,

[31] SPF Section 1.6 Attachment 1, IRG Overview Report p. 17
[32] SPF Section 1.6 Attachment 1, IRG Overview Report p. 17
[33] SPF Section 1.6 Attachment 1, IRG Overview Report p. 18

execution considerations, and affordability. This adjustment is further described in DSP Section 3.1.1.

1.6.4 ONGOING CUSTOMER, INDIGENOUS COMMUNITIES AND STAKEHOLDER ENGAGEMENT ACTIVITIES

In addition to the IRG Study, Hydro One regularly engages with and obtains feedback from its customers through a variety of other channels and methods. This allows Hydro One to gain a solid understanding of what different customer segments expect from their electricity provider and where the company can make improvements to its services for customers. As applicable, feedback from other forms of customer engagement (besides the results of the IRG Study) was also taken into account during, and helped inform, the investment planning process.

To ensure Hydro One maintains a regular view of its customers' needs and preferences, Hydro One engages with customers via the following avenues on an ongoing basis to monitor customer expectations and evolving service trends:

- Customer Contact Centre (Section 1.6.4.1 below);
- Large Customer Account Management and Oversight Committees (Section 1.6.4.2 & 1.6.4.3 below);
- Customer Satisfaction Research (Section 1.6.4.4 below);
- Indigenous (First Nations and Métis) Engagement (Section 1.6.4.5 below);
- External Relations (MPPs, Agencies, and Municipalities) (Section 1.6.4.6 below); and
- Office of the Hydro One Ombudsman (Section 1.6.4.7 below).

1.6.4.1 CUSTOMER CONTACT CENTRE

Residential and small business customers work with the Customer Contact Centre (CCC) when they have a question about their service or bill. Whether the customer contacts Hydro One by phone, e-mail, chat, or mail, these interactions are monitored closely, and any concerning trends are escalated and analyzed to ensure Hydro One's performance is continuously improving, and distribution system outcomes are aligned with customer needs and preferences.

Customer interactions are actively monitored for quality control purposes to ensure Hydro One customers receive quality service and the timely and accurate information they need. Feedback is also received through the Customer Relations Centre, which addresses escalated calls that require more detailed investigation and resolution.

DSP Section 3.5.2.1 shows the historical performance of the service quality and customer satisfaction. These are important metrics on Hydro One's performance scorecard which inform operational decisions. Details on investments in respect of Customer Contact Centre can be found in Exhibit E-03-04, Distribution Customer Care OM&A.

1.6.4.2 LARGE CUSTOMER ACCOUNT MANAGEMENT

1.6.4.2.1 Distribution

Hydro One provides large distribution-connected customers (including C&I and LDA customers) with a comprehensive and structured support framework. This includes access to expert analysts and, in many cases, a dedicated single point of contact. The team assists customers with a wide range of matters, including new connection requests, power quality and reliability, energy billing and cost of power, and participation in industry programs.

This proactive and relationship-focused approach enables a strategic understanding of customer needs and preferences, which in turn informs Hydro One's distribution planning and investment decisions. By maintaining strong partnerships with customers, it ensures that the voice of the customer is reflected in system planning priorities and operational enhancements.

Over time, the Key Account Management model has evolved to offer more personalized and responsive service. The shift toward increased single-point-of-contact support reflects both the growing complexity of the electricity sector and the expanding expectations of large customers. This model strengthens strategic alignment between Hydro One's customer service, operational teams, and system planning functions.

Witness: Spencer Gill; Matthew Jackson

Hydro One's Key Account Management representatives engage regularly with customers to review operational experiences, identify emerging needs, and develop targeted action plans. Where these plans lead to new or modified connection facilities or infrastructure investments, the assigned representative works directly with the customer to ensure a shared understanding of the process, including connection timelines, cost estimates, and capital cost recovery agreements.

In addition, Hydro One actively monitors and analyzes customer inquiries and case management activities. This data-driven approach supports continuous improvement and ensures that Hydro One remains responsive to the evolving needs of its large distribution customers.

Overall feedback from ongoing engagement with large distribution customers remains consistent with the results of the IRG Study. Reliability and power quality continue to be identified as top priorities. Many large distribution customers expect substantial growth in electricity demand and are looking to Hydro One to facilitate the necessary capacity increases and streamline the connection process.

This feedback is provided to the Planning team to inform investment decisions. Given that affordability is a key priority, Hydro One's Key Account Management representatives actively provide guidance on available cost mitigation strategies to help customers manage potential impacts where possible. Hydro One is also proposing investments in technology to support large distribution customers by providing enhanced data and insights to help them make informed and cost-effective decisions. Please see GSP Section 4.11 G-GP-07 for the investment details on the customer operations enablement tool.

1.6.4.2.2 Transmission

Hydro One Account Executives provide large transmission-connected customers with a single point of contact at Hydro One for all types of interactions, including matters related to customer connection requests, sustainment and system development plans and

projects, and concerns regarding service levels or power reliability and quality and advocate for them across the organization. This approach facilitates a consistent and more comprehensive reporting of customer needs and preferences for use by planners, operators, and customer service teams – feedback that is considered when making transmission planning and investment decisions.

Account Executives meet with their customers on a regular basis to ensure that the needs and preferences of customers are identified and discussed, and action plans are developed to address them. If an action plan results in new or modified connection facilities and/or asset needs, the Account Executive will directly communicate with the affected customer(s) to ensure a common understanding of the related connection process and contractual requirements, such as connection cost estimates and capital cost recovery agreements.

Hydro One's Account Executives and Customer Operating Support team proactively engage with transmission customers to review and support planned outage activities to minimize impacts on customers and to optimize opportunities for both Hydro One and customers to plan and execute work on their respective facilities. The outcomes of these discussions are used as inputs to the Integrated System Operations Center (ISOC) Transmission System Outage (TSO) process to coordinate multiple work activities on the same equipment during a single outage, as discussed further below. Account Executives also participate in the ISOC's meetings with transmission customers to discuss planned outages and work as part of the regional planning process. The ISOC's Outage Planning Group works directly with transmission customers to efficiently plan real-time outage operations, coordinate planned outages so Hydro One or the customer can complete required work, to respond quickly to unexpected outages, and to coordinate switching activities.

Account Executives organize bi-annual customer meetings throughout the province to coordinate outage planning activities. These meetings are a key activity in Hydro One's TSO process. The ISOC sends reports, customized for individual customers that provide a rolling, one-year window of the planned outages that will affect the customer's delivery

point. These reports contain information on outage start and end dates, the equipment involved, purpose, recall time and schedule profile. The reports provide an opportunity for customers to provide feedback. The Outage Planning Group also provides information on Hydro One's plans, particularly with respect to outages, for the balance of the year and/or the next scheduling year. During these meetings, transmission customers may bring forward their own maintenance plans for their facilities, with a view to scheduling or bundling outages in a manner that minimizes the frequency and duration of outages for both the utility and the customer.

1.6.4.3 OVERSIGHT COMMITTEES

Hydro One has established several oversight committees to ensure that the ongoing operational needs and preferences of these transmission customer groups are accounted for in a timely fashion. Coordination with other entities is especially important for effective and aligned health and safety oversight. While the specific purpose of these oversight committee meetings is not to direct investment plans, these oversight committees provide an early insight as to future investment needs more generally, and this can be useful information for investment planning purposes. Hydro One has established and maintains a number of oversight committees as follows.

1.6.4.3.1 SARNIA AREA RELIABILITY OVERSIGHT COMMITTEE

The Sarnia Area Reliability Oversight Committee consists of Hydro One staff and industrial and generation-connected customers and LDCs in the Sarnia Chemical Valley area. Chemical Valley customers include a large number of facilities and refineries with very sensitive manufacturing processes. The industry in the Sarnia area is particularly concerned with reliability and power quality such as loss of supply, loss of redundancy, and voltage fluctuations that can result in possible widespread health and safety issues such as gas flares and can cause very costly damage to customer manufacturing equipment and halt their processes. This committee meets twice a year to identify issues regarding reliability in the Sarnia Area and to review proposed annual work plans to ensure that issues will be addressed appropriately, having regard for the environmental and safety concerns of these customers.

1.6.4.3.2 TORONTO HYDRO OVERSIGHT COMMITTEE

Hydro One holds quarterly Oversight Committee meetings with Toronto Hydro-Electric System Limited to identify and resolve issues and to coordinate efforts on capital projects and other matters. This forum allows the two utilities to coordinate their operations in a safe and efficient manner.

1.6.4.3.3 BRUCE POWER OVERSIGHT COMMITTEE

Hydro One facilitates and participates in a switchyard oversight committee with Bruce Power. This committee assists the parties in overseeing and coordinating matters of mutual interest, such as interface equipment, procedures and policies that pertain to Hydro One equipment at Bruce Power's nuclear generation facilities. This committee ensures the safe and efficient operation of switchyards at Bruce Power's site in Bruce County, which supplies approximately 30% of Ontario's electricity. The collaboration helps maintain compliance with legal requirements and allows for the efficient coordination of capital projects and other matters. This committee meets approximately three times each year.

1.6.4.3.4 METROLINX OVERSIGHT COMMITTEE

Hydro One's Metrolinx Working Group provides a forum to review issues arising during the large-scale transportation infrastructure work that Metrolinx is undertaking in Ontario. The working group reviews and addresses customer escalations arising from the Metrolinx work program and ensures that issues are addressed in a timely manner.

1.6.4.3.5 HYDRO OTTAWA OVERSIGHT COMMITTEE

The Hydro Ottawa Oversight Committee provides a forum for Hydro Ottawa and Hydro One to meet as needed to identify and resolve any issues, and to ensure safe and efficient operations between Hydro One and Hydro Ottawa. Meetings also allow the parties to coordinate efforts relating to capital projects and other matters.

1.6.4.3.6 ALECTRA OVERSIGHT COMMITTEE

The Alectra Oversight Committee provides a forum for Alectra and Hydro One to meet twice a year to identify and resolve any issues, and to ensure safe and efficient operations

between Hydro One and Alectra. Meetings also allow the parties to coordinate efforts relating to capital projects and other matters.

1.6.4.3.7 OPG OVERSIGHT COMMITTEE

Hydro One facilitates and participates in switchyard oversight committees and plant group meetings with Ontario Power Generation (OPG). These committees assist the parties in overseeing and coordinating matters of mutual interest, such as interface equipment, procedures and policies that pertain to Hydro One equipment at OPG's sites across the province. There are five active committees: Nuclear Switchyard Oversight Committee, Northeastern Plant Group meeting, Northwestern Plant Group meeting, South Central Plant Group meeting, and South Eastern Plant Group meeting. The purpose is to ensure the safe and efficient operation of switchyards at OPG's hydroelectric and nuclear generation facilities, help maintain compliance with legal requirements, and allow for the efficient coordination of capital projects and other matters. These committees each meet three times per year.

1.6.4.4 CUSTOMER SATISFACTION RESEARCH

Hydro One collects feedback from customers through a comprehensive customer satisfaction research program. This research includes both transactional satisfaction and perception studies, with the majority conducted by independent, expert customer research firms. Some surveys and "voice of the customer" analysis are conducted in-house as part of ongoing efforts to capture real-time customer insights in a cost-effective manner. The customer satisfaction research program is informed by industry best practices.

Hydro One conducts transactional surveys on an ongoing basis to measure customer satisfaction after a specific experience or touchpoint. These surveys contact a subset of Hydro One customers after they have had an interaction with the company to determine how well its customer service met their expectations. Transactional surveys monitor customer needs and preferences, monitor trends, help address transactional concerns in a timely fashion, and inform process improvements. These surveys measure operational effectiveness for the contact centre, the myAccount customer online portal, website experience, service upgrades, new connections, outage management, and forestry work.

Hydro One also conducts perception surveys on a regular basis to measure customers' perceptions of the company as a whole. These surveys are an opportunity for customers to communicate what matters to them, voice their concerns, and express their expectations for future service. They monitor how well the company meets customers' expectations and how well the company delivers on critical success factors. These perception surveys are conducted monthly for residential and small business customers and annually for Commercial and Industrial, Large Distribution and Large Transmission customers.

The trending of results from both transactional and perception research over time assists Hydro One in driving deeper customer understanding, enhancing customer centricity, and identifying areas to improve customer satisfaction.

In addition to the surveys commissioned by Hydro One, Hydro One subscribes to secondary research studies and partners with leading research firms to identify best practices and gain segmentation insights that help us enhance customer experience.

Survey results, customer feedback and research studies are shared with the relevant lines of business through multiple channels. Hydro One uses these findings to continuously improve business practices and stay informed about the trends that matter most to its distribution and transmission customers. The Customer Satisfaction scores serve as important performance measures and are included in various scorecards (as described in TSP Section 2.5.3.2 and DSP Section 3.5.2.3).

1.6.4.5 INDIGENOUS COMMUNITIES ENGAGEMENT

For several decades Hydro One has built partnerships with First Nations communities and Métis organizations through ongoing engagement, collaboration and partnership initiatives across its operations, maintenance activities and customer service. Hydro One regularly seeks input from First Nations and Métis groups to understand their specific customer needs and preferences with respect to its distribution and transmission systems.

1.6.4.5.1 INDIGENOUS CUSTOMERS

Hydro One serves Indigenous communities across Ontario through its Distribution and Transmission businesses. The distribution network provides electricity to 89 First Nations communities, including 23,000 First Nations residential customers living on reserve, and serves many Métis customers across the province while engaging with the Métis Nation of Ontario (MNO) and its 31 Métis Chartered Community Councils. Hydro One serves the First Nations communities through 104 distribution feeders and 84 distribution stations, which are supplied through 73 transmission delivery points, including 50 transmission lines and six direct connections to high-voltage stations. Hydro One's transmission assets are located on the reserve lands of 24 First Nations communities and within the traditional territories of Indigenous communities across Ontario.

As Indigenous communities continue to invest and expand in housing, community facilities, economic development and critical infrastructure, reliable electricity service plays an increasingly important role in supporting long-term growth and prosperity. Hydro One is committed to working in partnership with Indigenous communities to understand their unique needs, priorities and evolving energy requirements.

Through ongoing and meaningful engagement, Hydro One maintains partnerships with Indigenous communities across the province. The company remains focused on being a trusted partner by supporting community objectives, enabling infrastructure development, and helping ensure the electricity system can meet growing demand.

Through these efforts, Hydro One continues to strengthen partnerships with Indigenous communities while supporting their aspirations for sustainable growth and economic opportunity.

1.6.4.5.2 ONGOING ENGAGEMENT

Hydro One is committed to building long-term, transparent and respectful partnerships with Indigenous communities across its service territory. Through ongoing engagement that extends beyond individual projects, the company works collaboratively with communities to understand local priorities, address concerns, and support economic and community development goals.

Regular dialogue helps ensure Hydro One's system investments, planning activities and service delivery continue to meet the evolving energy needs of Indigenous communities while providing safe, reliable electricity that supports community growth.

In addition to formal engagement activities, Hydro One maintains a continuous presence in communities through participating in community-led events, gatherings and forums to deepen partnerships, gather feedback on emerging priorities, and support informed decision-making that reflects community needs. This ongoing collaboration helps Hydro One to respond to local priorities, enhance the customer experience, and remain a trusted partner of choice for Indigenous communities.

Hydro One also partners with Indigenous organizations, including the Gord Downie & Chanie Wenjack Fund and Four Seasons of Reconciliation, to provide cultural awareness and learning opportunities for employees, supporting respectful and effective engagement across all aspects of the business.

SPF Section 1.6 Attachment 2 addresses Hydro One's Indigenous Relations Policy and steps taken by Hydro One to address the needs and preferences of Indigenous communities.

1.6.4.6 EXTERNAL RELATIONS

Hydro One's Government and Stakeholder Relations group supports the Company's engagement with governments, municipalities, industry associations, and other external stakeholders to build and maintain constructive relationships and informed dialogue on matters affecting customers and communities. Through ongoing engagement, Hydro One

gains insight into stakeholder priorities and perspectives, communicates upcoming and in-flight plans and initiatives, and seeks opportunities to address concerns and advance shared objectives.

The group engages with stakeholders in a manner that is inclusive, transparent and respectful of stakeholder perspectives on matters of mutual concern. Engagement is undertaken through the following areas:

- **Government Relations and Partnerships** engages with the Ontario and federal governments, elected officials, government staff, industry associations and key external stakeholder groups that represent sectoral thought leadership and large customer segments. Engagement also occurs through Hydro One's industry association memberships and participation in key industry events.
- **Community & Municipal Relations** engages with local communities and municipal leaders. The Community Relations team leads engagement, consultation, and communications in support of major capital projects, ensuring that local stakeholders are informed and engaged throughout the project lifecycle. Municipal Relations oversees Hydro One's ongoing relationships with municipalities, acting as the point of contact for elected officials and municipal staff, maintaining regular dialogue to understand and support local priorities.
- **Energy Policy** is responsible for developing Hydro One's position on proposed legislative and regulatory changes. Energy Policy supports the Company's advocacy efforts by managing relationships with industry associations, leading responses to public consultations, and conducting research on market developments across North America.

Through these engagement activities, Hydro One stays informed of issues the key stakeholders and their constituents or members may have, and coordinates assistance on behalf of the Company. These engagement activities also help inform decision-making, identify and respond to emerging issues, and support the effective planning and delivery of programs and investments across the province.

1.6.4.7 OFFICE OF THE HYDRO ONE OMBUDSMAN

When customers do not feel that a response or decision made by Hydro One was appropriate or fair, they can reach out to the Office of the Hydro One Ombudsman (the Office). The Office addresses these specific customer issues, and also performs systemic investigations. These investigations can highlight where changes are needed to better meet customers' needs and preferences. The customer service teams work with the Office on a regular basis to understand any underlying trends of concern which may have arisen, which can then assist the customer service teams to better align how it works with its residential and commercial customers.

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Hydro One's Joint Rate Application Customer Engagement

Overview Report

Prepared for:

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This Report and all the information and data contained within it may not be used for any purpose other than the upcoming Hydro One rate application, without the prior, written consent of Hydro One.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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1. Introduction & Overview of Findings

Innovative Research Group Inc. (INNOVATIVE) was engaged to help design, execute, and document the results of Hydro One's customer engagement as part of its Joint Rate Application (JRAP) to the Ontario Energy Board (OEB) for the years 2028 to 2032.

This customer engagement sought to build off the learnings from Hydro One's previous engagement efforts, with an emphasis on increasing customer participation and offering ample opportunities for feedback to be collected. Between August 2024 and December 2025, over 100,000 customers participated in this engagement – surpassing any previous customer engagement efforts documented at the OEB.

Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans.

In fact, depending on customer type, between 68% and 88% of customers support spending at or above the level of investment included in the 2028-2032 draft plans.

Overall support for the draft plans (Draft plan + Spend more)

Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
75%	77%	70%	68%	70%	82%	80%	88%

Similar levels of support are also observed for categories of investments in the transmission and distribution systems, as well as shared services.

Distribution Investment Trade-Offs
Across all customer types, a majority selected a level of investment at or above Hydro One's draft investment plan as it relates to distribution investments in overall system reliability, managing severe weather, and targeted reliability improvements.

Transmission Investment Trade-Offs
Across all customer types, a majority selected a level of investment at or above Hydro One's draft investment plan as it relates to transmission investments in keeping pace with transmission renewal, and stewardship of the transmission system.

Shared Investment Trade-Offs
Across all customer types, a majority selected a level of investment at or above Hydro One's draft investment plan as it relates to shared investments in maintaining buildings and facilities, and information technology.

Approach to Meaningful Customer Engagement

This customer engagement was designed to be responsive to both the best practices in customer engagement and, importantly, the OEB's guidelines for a "consumer-centric" approach to rate applications, as laid out in the

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Renewed Regulatory Framework for Electricity (RRF)[1] and the *Handbook for Utility Rate Applications (Handbook)*[2]. A key excerpt from the Chapter 2 Filing Requirements for Electrical Distribution Rate Applications formed the foundation for much of the focus of this customer engagement:

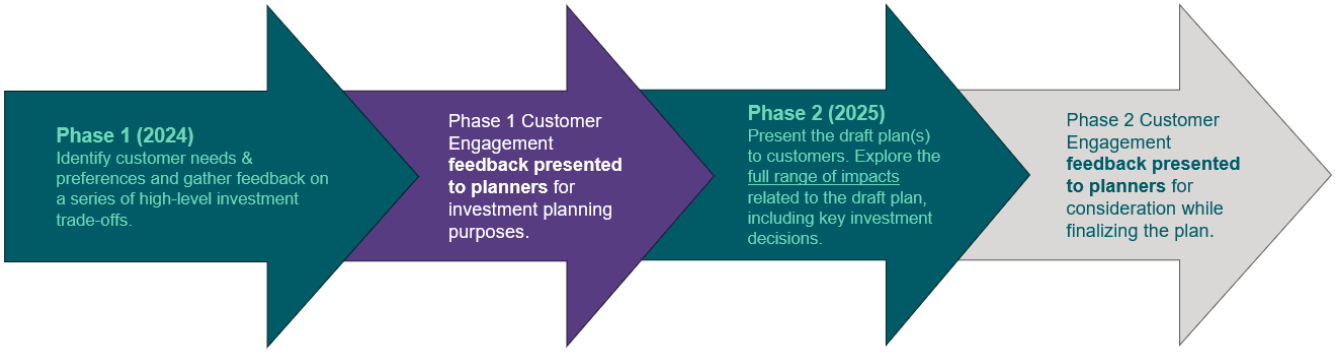
> *"Distributors must be able to demonstrate how customer needs and priorities were factored into the utility's decision-making process, particularly for aspects such as prioritizing capital investments, or weighing the tradeoffs between costs/bill impacts and reliability or other services."*
> *Chapter 2, Filing Requirements for Electricity Distribution Rate Applications, Page 11*

Customer Engagement Principles

INNOVATIVE developed a process built on five key principles:

1. Create open, voluntary processes that allow all customers an opportunity to participate
2. Leverage research techniques that ensure a representative sample of customers are engaged, ensuring the generalizability of the findings
3. Provide customers with the context necessary to provide informed feedback
4. Do not expect customers to be electricity experts – focus on outcomes rather than technical questions
5. Allow customers the opportunity to provide open-ended feedback

To achieve these principles, Hydro One's 2028-2032 customer engagement was conducted in two phases with clear and documented opportunities to incorporate customer feedback into the investment planning process.



Phase 1 took place between August and December 2024. In this phase, INNOVATIVE engaged with customers, community leaders, and stakeholder groups to identify customer needs and preferences, and to gather feedback on a series of high-level investment trade-offs covering both the distribution and transmission systems. Phase 1 included a series of focus groups and interviews to understand customer needs and preferences and then a series of surveys to quantify customer needs, preferences, and high-level investment trade-offs.

In February 2025, both qualitative and quantitative feedback received from customers in phase 1 was presented to Hydro One planners to provide initial customer input into the development of draft investment plans for the

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.
[2] Handbook for Utility Rate Applications (October 13, 2016)

distribution and transmission systems. This quantitative survey feedback was summarized in a “planning placemat” that was shared with all planners.

Based on the insights gained in phase 1, INNOVATIVE then developed the phase 2 online survey that centered around key investment decisions, as well as providing the necessary background to capture informed customer feedback. The online survey was customized for different customer types and rate classes with estimated bill impacts provided.

The **phase 2** survey was conducted in November and December 2025. In this phase, INNOVATIVE engaged with over 100,000 customers to gather feedback on Hydro One’s draft 2028-2032 investment plans, including key investment decisions. These investment choices covered both the distribution and transmission systems, as well as shared services.

In January 2026, quantitative feedback received from customers in phase 2 was presented to Hydro One planners for consideration while finalizing the draft investment plans. Like in phase 1, this feedback was summarized in a “planning placemat” that was shared with all planners.

Summarized below are the results of both phases of customer engagement, with a focus on quantitative, generalizable results. Detailed results can be found in the attached appendices.

2. Phase 1: Focus on Needs and Preferences

In phase 1, Hydro One and INNOVATIVE set out to develop an understanding of **customer needs** and **preferences**, as well as gain preliminary insights on more specific investment areas that could be further explored in phase 2. High-level investment trade-off questions were asked relating to both the distribution and transmission systems.

2.1. Methodology Overview

Phase 1 was divided into two sub-phases – one qualitative (phase 1a) and one quantitative (phase 1b).

Phase 1a (Qualitative)

Low-Volume Focus Groups

Phase 1a began with INNOVATIVE conducting a series of virtual focus group sessions to explore residential, seasonal, and small business customer priorities and preferences when it comes to the electricity service that they receive from Hydro One.

Twelve focus groups with a random selection of residential, seasonal, and small business customers from across Hydro One's service territory took place over a three-week period in **August 2024**. In total, 86 customers participated in these focus group sessions.

Large Business One-on-One Interviews

Between **August and September 2024**, INNOVATIVE conducted a series of 37 one-on-one interviews with a random selection of commercial & industrial (C&I), large distribution (LDA), and large transmission (LTX) customers. The purpose of these interviews was to allow large business customers an opportunity to share their needs, preferences, and priorities as it relates to the service they receive from Hydro One.

Industry Association and Municipality One-on-One Interviews

In **October 2024**, INNOVATIVE conducted a series of one-in-one interviews with 9 industry associations and 9 municipalities who either directly or indirectly serve Hydro One transmission or distribution customers. The purpose of these interviews was to allow industry associations and municipalities an opportunity to share the needs and preferences of their organization or members as they relate to Hydro One's Joint Rate Application covering the years 2028 to 2032.

First Nations Leadership One-on-One Interviews

Between **August and October 2024**, INNOVATIVE invited leaders from all 89 of the First Nations served by Hydro One to participate in an interview. From this, INNOVATIVE conducted a series of 18 one-on-one interviews with First Nations leadership. The purpose of these interviews was to allow First Nations leaders to share their understanding of their communities' needs, preferences, and priorities as it relates to the electricity service they receive from Hydro One.

Métis Nation of Ontario (MNO) Leadership One-on-One Interviews

Between **September and October 2024**, INNOVATIVE invited leaders from all 9 Regional Councils as well as 30 local Community Councils to participate in an interview. From this, INNOVATIVE conducted a series of 8 one-on-

one interviews with MNO leadership. The purpose of these interviews was to allow MNO leaders to share their understanding of their citizens' needs, preferences, and priorities as it relates to the electricity service they receive from Hydro One, either directly or indirectly.

Phase 1b (Quantitative)

Telephone Reference Surveys

As part of a rigorous "sample validation" process to understand whether and where differences exist between customers who have provided their email to Hydro One and the full population of customers, telephone reference surveys were conducted for all low-volume customer types. This included residential (both primary and seasonal), First Nations On-Reserve residential, and small business.

The telephone reference surveys allow us to compare responses on core demographics, firmographics, and environmental controls that may impact outcomes. This exercise allows us to identify any sample differences that may be corrected for with weighting, focusing on differences that meaningfully impact the overall results of the online surveys. No further weighting adjustments were made to the online surveys based on demographics, firmographics, or environmental controls measured in the telephone reference surveys.

Online Surveys

A random selection of low-volume customers (residential including seasonal, First Nations On-Reserve residential, and small business) and all large business customers (commercial & industrial, large distribution accounts, and large transmission accounts) with an available email were invited to participate in an online survey to further understand customer needs and preferences and gather feedback from customers on a series of high-level investment trade-off questions.

Responses from other LDC residential customers were collected through an online research panel.

In total, over 8,000 customers completed the phase 1b online survey. Below is a summary of participation by customer type:

Customer Type		Online Survey
Hydro One Distribution & Transmission Customers	**Residential (including Seasonal)**	6,053
	First Nations On-Reserve Residential	426
	Small Business	477
	Commercial & Industrial	311
	Large Distribution Accounts	61
Hydro One Transmission-Only Customers	**Other LDC Residential**	1,019
	Large Transmission Accounts	72

2.2. Customer Needs and Preferences

The phase 1 results indicate that customers tend to be satisfied with the services they receive from Hydro One with a majority of customers across all customer types saying they are either very or somewhat satisfied.

Satisfaction with Hydro One	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Satisfied	85%	89%	79%	82%	89%		85%
Neither	9%	8%	13%	8%	7%		8%
Dissatisfied	6%	3%	8%	9%	5%		6%
Don't know	<1%	1%	1%	1%	--		1%

When asked if there is anything Hydro One could do to improve its services, most customers do not identify any specific needs. Among those who do, the top responses include decreased outages, lower rates, address/proactive tree trimming, communications during outages, and improving customer service.

% Mentioned		1st most common response	2nd most common response	3rd most common response
Hydro One Distribution & Transmission Customers	**Residential**	Decrease outages (9%)	Lower rates (9%)	Address/proactive tree trimming (7%)
	First Nations On-Reserve Residential	Lower rates (7%)	Decrease outages (6%)	Improve outages response times (3%)
	Small Business	Lower rates (10%)	Decrease outages (5%)	Address/proactive tree trimming (4%)
	Commercial & Industrial	Decrease outages (9%)	Improve customer service (4%)	Upgrade/better maintain infrastructure (3%)
	Large Dx Accounts	Decrease outages (15%)	Communication during outages (10%)	Building capacity/ addressing growth (7%)
Hydro One Transmission-Only Customers	**Other LDC Residential**			
	Large Tx Accounts	Improve customer service (19%)	Decrease outages (13%)	Improve information sharing (7%)

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2.3. Outcome Priorities

As part of phase 1, customers were presented with a list of potential investment priorities that Hydro One could focus on and were asked to select up to three of the most important priorities.

Reasonable rates and reliable electricity are top priorities for all customer types. Meeting growing demand for electricity is a top priority for Commercial & Industrial, Large Distribution, and other LDC Residential customers.

% selected in top-3 priorities		1st most frequently selected priority	2nd most frequently selected priority	3rd most frequently selected priority
Hydro One Distribution & Transmission Customers	**Residential**	Reasonable rates (80%)	Reliable electricity (69%)	Ensuring safety (40%)
	First Nations On-Reserve Residential	Reasonable rates (76%)	Reliable electricity (49%)	Ensuring safety (38%)
	Small Business	Reasonable rates (82%)	Reliable electricity (52%)	Enhancing the grid for new technology (37%)
	Commercial & Industrial	Reasonable rates (83%)	Reliable electricity (67%)	Meeting growing demand (39%)
	Large Dx Accounts	Reasonable rates (75%)	Reliable electricity (69%)	Meeting growing demand (43%)
Hydro One Transmission-Only Customers	**Other LDC Residential**	Reasonable rates (76%)	Meeting growing demand (59%)	Reliable electricity (57%)
	Large Tx Accounts	Reliable electricity (81%)	Reasonable rates (61%)	Ensuring safety (53%)

2.4. High-Level Investment Trade-Offs

After collecting customer input on general needs and outcome priorities, the phase 1 survey presented a series of high-level investment trade-offs. Hydro One distribution customers – those who receive distribution services from Hydro One – had the opportunity to comment on both distribution and transmission related questions. Hydro One transmission-only customers – those who do not receive distribution services from Hydro One – were only presented with transmission-related questions.

Distribution System Trade-Offs

High-Level Reliability

The phase 1 results indicate that a majority of customers want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid. Across all customer types, a plurality of customers want Hydro One to make investments to improve reliability rather than just maintain reliability.

High-Level Reliability	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Improve reliability	68%	48%	58%	55%	75%		
Maintain reliability	19%	28%	21%	27%	16%		
Defer investments	7%	11%	11%	9%	3%		
Don't know	6%	14%	10%	9%	5%		

Targeted Reliability Improvements

A majority of customers want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.

Targeted Reliability Improvements	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Make targeted investments	78%	66%	73%	70%	87%		
Minimize investments	12%	19%	16%	15%	10%		
Don't know	10%	15%	11%	15%	3%		

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Responding to Severe Weather

A majority of customers want Hydro One to make investments to make the system more resilient to severe weather. Across all customer types, a plurality want Hydro One to proactively invest rather than make the investments as part of ongoing replacement.

Responding to Severe Weather	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Proactively invest	64%	45%	62%	51%	67%		
As part of ongoing replacement	23%	28%	23%	32%	23%		
Minimize investments	7%	17%	8%	8%	5%		
Don't know	5%	10%	6%	8%	5%		

Enabling Economic Growth

A plurality of customers in all customer types want Hydro One to make proactive investments to enable anticipated growth and accommodate new connections and service upgrades in a timely manner.

Enabling Economic Growth	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Proactively invest	52%	50%	48%	44%	62%		
Only as growth materializes	34%	29%	35%	34%	31%		
Don't know	14%	20%	16%	22%	7%		

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Evolving Customer Requests & System Visibility

A majority of customers want Hydro One to make proactive investments in technology to accommodate customer requests and improve system visibility.

Evolving Customer Requests & System Visibility	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Proactively invest	69%	57%	63%	61%	77%		
Limit/delay investments	20%	28%	25%	22%	16%		
Don't know	11%	15%	13%	17%	7%		

Transmission System Trade-Off

Transmission Renewal

The phase 1 results indicate that a majority of customers want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

Transmission Renewal	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve Residential n=426 (400)	Small business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Increase reliability	48%	37%	43%	30%	41%	37%	56%
Maintain reliability	34%	38%	36%	45%	46%	35%	36%
Accept more risk	10%	12%	11%	12%	8%	20%	3%
Don't know	7%	13%	9%	13%	5%	8%	6%

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3. Phase 2: Feedback on Hydro One's Draft Investment Plans

In phase 2, after Hydro One had developed its draft 2028-2032 investment plans, INNOVATIVE gathered feedback on the draft plans, including key investment decisions. These investment choices covered both the distribution and transmission systems, as well as shared services. All feedback was collected through an online survey customized for different customer types and rate classes, with estimated bill impacts provided.

After providing background information and introducing customers to the draft plans, they were asked about their preferences regarding key investment decisions. They were also asked for their preferences on the overall plans, and before doing so they had the opportunity to review the cumulative impact of their earlier choices on key investment decisions and make any adjustments.

3.1. Methodology Overview

Online Survey

In phase 2, all Hydro One distribution customers and large transmission customers with an available email address on file were invited to participate in the phase 2 online survey via direct email outreach. For those without an email address on file, an open-access survey link was made available. Customers who accessed the survey through the open link could verify themselves and were routed into the "representative" stream, where their account information was appended to their survey results for segmentation and weighting purposes.

Customers who chose not to verify their account information or were unable to do so could still participate by self-selecting the appropriate survey version (residential including seasonal, First Nations On-Reserve residential, or small business) and were included in the "voluntary", unverified stream. Results from the feedback collected through the voluntary stream are detailed in **Appendix 9**.

Transmission-Only customer results for other LDC residential and other LDC small business customers were collected through online research panels.

Other LDC customers could also participate through the open-access survey link. Those entering through this route self-selected the residential or small business survey version and were included in the voluntary stream rather than the representative sample. Results from the feedback collected through the voluntary stream are detailed in **Appendix 9**.

Phase 2 Participation

As part of phase 2, INNOVATIVE engaged with over 100,000 customers. Below is a summary of participation by customer type:

Customer Type		Online Survey
Hydro One Distribution & Transmission Customers	Residential (including Seasonal)	94,611
	First Nations On-Reserve Residential	793
	Small Business	2,791
	Commercial & Industrial	368
	Large Distribution Accounts	53
Hydro One Transmission-Only Customers	Other LDC Residential	2,071
	Other LDC Small Business	305
	Large Transmission Accounts	73

3.2. Overall Support for Hydro One's Draft Plans

The phase 2 results indicate that, across all customer types, most customers support Hydro One spending at or above the level of investment included in the 2028-2032 draft plan(s).

Overall support for the draft plans	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	25%	28%	21%	16%	23%	37%	35%	33%
Draft plan	50%	49%	49%	52%	47%	45%	44%	55%
Spend less	16%	11%	21%	22%	26%	12%	15%	8%
Other	3%	2%	4%	5%	2%	1%	1%	3%
Don't know	6%	9%	5%	5%	2%	6%	4%	1%
Draft plan + Spend more	**75%**	**77%**	**70%**	**68%**	**70%**	**82%**	**80%**	**88%**

3.3. Investment Trade-Offs

Customers were invited to provide feedback on a series of key investment decisions. Hydro One distribution customers – those who receive distribution services from Hydro One – had the opportunity to comment on both

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distribution and transmission related questions. Hydro One transmission-only customers – those who do not receive distribution services from Hydro One – were only presented with transmission-related questions.

Distribution System Trade-Offs

The phase 2 results indicate that, across all customer types, most customers support Hydro One spending at or above the level of investment included in the 2028-2032 draft distribution investment plan as it relates to overall system reliability, managing severe weather, and targeted reliability improvements.

Below is a summary of the three distribution investment trade-offs, including a description of the types of investments included.

Overall System Reliability

Investments in overall system reliability included repairing or replacing overhead line defects, maintaining, repairing, or replacing major stations' equipment, and replacing or repairing underground cables.

Overall system reliability	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	28%	27%	23%	16%	23%			
Draft plan	49%	47%	49%	59%	58%			
Spend less	23%	26%	28%	25%	19%			
Draft plan + Spend more	**77%**	**74%**	**72%**	**75%**	**81%**			

Managing the Impacts of Severe Weather

Investments in managing the impacts of severe weather included relocating or reinforcing vulnerable power lines, clearing of overhead trees and brush, and installing automated "intelligent" switches.

Managing impacts of severe weather	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	28%	27%	23%	19%	21%			
Draft plan	50%	50%	49%	52%	60%			
Spend less	22%	23%	28%	29%	19%			
Draft plan + Spend more	**78%**	**77%**	**72%**	**71%**	**81%**			

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Targeted Reliability Improvements

Investments in targeted reliability improvements included community-scale batteries and smaller individual customer batteries.

Targeted reliability improve-ments	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	23%	25%	18%	16%	13%			
Draft plan	50%	51%	48%	50%	51%			
Spend less	27%	23%	34%	33%	36%			
Draft plan + Spend more	**73%**	**77%**	**66%**	**67%**	**64%**			

Transmission System Trade-Offs

The phase 2 results indicate that, across all customer types, most customers support Hydro One spending at or above the level of investment included in the 2028-2032 draft transmission investment plan as it relates to keeping pace with transmission renewal and stewardship of the transmission system.

Below is a summary of the two transmission investment trade-offs, including a description of the types of investments included.

Keeping Pace with Transmission Renewal

Investments in keeping pace with transmission renewal included replacing major transmission station equipment and replacing high-impact underground transmission cables.

Keeping pace with renewal	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	32%	32%	27%	24%	25%	33%	29%	36%
Draft plan	50%	50%	50%	54%	60%	50%	53%	58%
Spend less	18%	18%	23%	22%	15%	17%	18%	7%
Draft plan + Spend more	**82%**	**82%**	**77%**	**78%**	**85%**	**83%**	**82%**	**93%**

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Stewardship of the Transmission System

Investments in stewardship of the transmission system included replacing at-risk transmission lines, reinforcing wood poles and extending the life of steel towers, and clearing overgrowth trees and brush.

Steward-ship of the system	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	30%	28%	25%	20%	21%	33%	33%	37%
Draft plan	51%	52%	51%	54%	66%	48%	47%	58%
Spend less	19%	20%	24%	25%	13%	19%	20%	5%
Draft plan + Spend more	**81%**	**80%**	**76%**	**75%**	**87%**	**81%**	**80%**	**95%**

Shared Service Trade-Offs

The phase 2 results indicate that, across all customer types, most customers support Hydro One spending at or above the levels of investment included in the 2028-2032 draft distribution and transmission investment plans as it relates to shared investments in maintaining buildings and facilities, and information technology.

Below is a summary of the two shared service investment trade-offs, including a description of the types of investments included.

Maintaining Buildings and Facilities

Investments in maintaining buildings and facilities included addressing at-risk building components, making at-risk sites more resilient to severe weather, and repairing or retrofitting field offices.

Maintain-ing Buildings and Facilities	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Spend more	25%	24%	21%	16%	19%	34%	32%	29%
Draft plan	51%	55%	50%	55%	60%	46%	45%	48%
Spend less	24%	21%	29%	29%	21%	20%	23%	23%
Draft plan + Spend more	**76%**	**79%**	**71%**	**71%**	**79%**	**80%**	**77%**	**77%**

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Information Technology

Investments in information technology included maintaining the current state of technology systems, enhancing customer service, improving operational efficiency, and protecting the grid from both cyber and physical security threats.

Informa-tion Technology	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Draft plan	73%	72%	67%	68%	68%	70%	69%	77%
Spend less	27%	28%	33%	32%	32%	30%	31%	23%

Note: There was no 'Spend more' option provided in this investment trade-off.

3.4. Diagnostic Measures

After providing their feedback on Hydro One's draft investment plans, respondents had the opportunity to provide feedback on the survey itself, both in terms of their overall favourability towards the customer engagement and the amount of information it provided.

Across all customer types, a majority of customers said they have either a very or somewhat favourable impression of the customer engagement they completed.

Impression of engage-ment	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Favourable	79%	76%	79%	78%	89%	89%	84%	90%
Unfavourable	12%	11%	13%	14%	9%	7%	11%	7%
Don't know	8%	13%	8%	8%	2%	4%	4%	3%

Across all customer types, a majority of customers said that they feel Hydro One provided just the right amount of information in the customer engagement.

Amount of Information	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Too little	7%	8%	7%	8%	4%	6%	7%	11%
Just the right amount	78%	80%	80%	85%	91%	84%	82%	85%
Too much	15%	12%	13%	8%	6%	10%	10%	4%

*Local Distribution Company

4. Summary

Hydro One's 2028 to 2032 customer engagement collected feedback from more than 100,000 customers, Indigenous leaders, municipalities and industry associations, becoming the single largest customer engagement documented at the OEB to date.

This customer engagement built off Hydro One's previous engagement efforts, while seeking to engage more customers in the process.

Overall, this engagement saw customer participation increase by more than double Hydro One's 2023 to 2027 customer engagement, growing from approximately 48,000 in Hydro One's 2023 to 2027 customer engagement to more than 100,000 now.

This increase in engagement included significantly increased First Nations participation. In the phase 2 surveys, participation among First Nations on-reserve residential customers increased more than threefold relative to the 2023 to 2027 engagement – from 261 customers to 793 customers.

Additionally, all 89 of the First Nations served by Hydro One were invited to participate in a one-on-one interview to provide their feedback prior to the development of Hydro One's draft investment plans. Likewise, leaders from all 9 Metis Nations of Ontario Regional Councils, as well as 30 local Community Councils were invited to provide feedback in the same manner. This approach ensured that feedback could be incorporated early into Hydro One's planning process, prior to the development of the draft plans.

This customer engagement also included significantly increased participation among large businesses, including commercial and industrial customers and large distribution accounts, signaling a high degree of interest in the application among large businesses.

In addition to significantly boosting customer participation, this engagement also expanded the scope of investment trade-offs presented to customers. This expanded scope included, for the first time, investment trade-offs in shared services, including information technology and facilities, as well as operational spending, including vegetation management. This expanded scope allowed customers to provide feedback on a wider range of investment decisions that Hydro One was considering compared to previous customer engagements.

Overall, phase 1 of this customer engagement demonstrated that most customers tend to be satisfied with the services they receive from Hydro One and do not identify any specific needs, but that reasonable rates and reliable electricity are among the top priorities for all customer types.

Overall, phase 2 demonstrated that Hydro One's draft distribution and transmission investment plans contain the right balance of investment and rate impacts. That is, feedback collected from customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's draft plans.

Appendix 1

Hydro One Customer Engagement Low-Volume Focus Groups

Phase I Report

2028-2032 Joint Rate Application

Prepared for:

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Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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2. Introduction

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Inc. (Hydro One), to gain a deeper understanding of the needs and preferences of customers, specifically as it relates to Hydro One's Joint Rate Application to the Ontario Energy Board (OEB) covering the years 2028 to 2032.

As part of this engagement, INNOVATIVE conducted a series of focus group sessions to explore residential, seasonal, and small business customer priorities and preferences when it comes to the electricity service that they receive from Hydro One.

These focus groups were conducted over a three-week period in August 2024. INNOVATIVE engaged with residential, small business, and seasonal customers of Hydro One in separate groups via the Teams video-conference platform.

The focus groups were led by a trained moderator who followed a structured discussion guide and presented short stimuli to facilitate conversation.

This report summarizes the key findings based on these discussions. In general, our approach is to report representative verbatim comments and offer interpretation and/or commentary where necessary. Verbatim responses are shown in blue italics.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used directionally. In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view.

Focus Group Customer Recruitment Process

Residential, small business (GS<50) and seasonal customers were recruited over email using a customer list provided by Hydro One. A random selection of participants was invited to complete a screening survey. Qualified participants were selected to ensure that customers from a range of demographic or firmographic groups participated.

Residential and seasonal customers who participated in the focus groups received a $100 cash incentive as compensation for their time. Small business customers who participated in the groups received a $120 cash incentive.

3. Methodology

Twelve focus groups with residential, small business (GS<50) and seasonal customers from across Hydro One's service territory took place between August 13th and August 28th, 2024. Where possible, INNOVATIVE segmented these participants into service area groups to ensure the discussion remained relevant to their communities. The details of each of these groups can be found in the table below.

Date	Focus Group Times	Number of Participants	Customer Type	Service Area
August 13th, 2024	5:30 pm – 7:30 pm	7 participants	Residential	West
	7:30 pm – 9:30 pm	7 participants	Residential	West Central
August 14th, 2024	5:30 pm – 7:30 pm	6 participants	Residential	Central
	7:30 pm – 9:30 pm	8 participants	Residential	East Central
August 15th, 2024	5:30 pm – 7:30 pm	7 participants	Residential	East
	7:30 pm – 9:30 pm	8 participants	Residential	North
August 20th, 2024	5:30 pm – 7:30 pm	9 participants	Seasonal	All regions
	7:30 pm – 9:30 pm	7 participants	Seasonal	All regions
August 22nd, 2024	5:30 pm – 7:30 pm	9 participants	Small Business	East, Central, and East Central
	7:30 pm – 9:30 pm	5 participants	Small Business	West
August 28th, 2024	5:30 pm – 7:30 pm	6 participants	Small Business	West Central
	7:30 pm – 9:30 pm	7 participants	Small Business	North

4. Key Findings

Residential Customers

Participants were generally familiar with Hydro One.

Most participants recognized Hydro one's role as their electricity provider and generally understood their role in the distribution system. However, many participants expressed surprise when they learned about the breakdown of their electricity bill, particularly the portion allocated to Hydro One.

Most expressed satisfaction with the level of service.

Overall, most customers expressed satisfaction with Hydro One and could not immediately identify any gaps in the service. In terms of reliability, most participants were generally satisfied, with a few who encountered frequent outages expressing a strong desire for improvement. Many participants attributed their satisfaction to Hydro One's customer service and efforts to restore power when outages do occur.

Despite strong satisfaction, many participants felt that electricity prices remain high.

Many rural customers acknowledged that their remote locations contributed to higher costs due to the complexities of servicing these areas. However, they also felt that increased rates in comparison to other utilities should be accompanied by improved reliability.

Reliability was a core measure of Hydro One's performance.

Most customers viewed reliability as the most important indicator of Hydro One's performance, with strong emphasis on its impact on community safety, and access to essential services. While occasional outages, especially in rural areas, were generally accepted, frequent or poorly timed unplanned outages drew frustration.

Generally, customers were split on whether they would be willing to pay more for enhanced reliability.

Some participants were not willing to pay more for increased reliability as they expected reliability to be a standard feature of their service. Others felt that reliability was critical that they would be open to paying more for meaningful improvements.

Many customers highlighted the need to upgrade Hydro One's infrastructure and modernize the grid.

Participants emphasized the need to upgrade Hydro One's infrastructure to prepare for the growing demand from electric vehicles and emerging technologies, as well as to better withstand extreme weather events. While some acknowledged that storm-related outages may be unavoidable and praised Hydro One's response times, they expressed a preference for prioritizing long-term investments in grid modernization.

Residential customers were split on whether they anticipate their electricity usage to change.

Participants had mixed views on electric vehicles (EVs), with some open to purchasing them and others skeptical about their reliability in rural areas due to inadequate infrastructure. While some showed interest in solar panels and battery storage, many hesitated because of uncertainty about the technology and felt Hydro One should provide more education on these options.

Seasonal Customers

Most were familiar with Hydro One.

Most participants were aware that Hydro One is their local electricity provider and responsible for restoring power during outages. However, familiarity with Hydro One's role in the broader electricity system was not immediately known by most.

Most seasonal participants were satisfied with the service they receive from Hydro One.

Generally, most participants were satisfied, and beyond reliability, could not point to many specific areas for improvement.

Most participants were heavily focused on reliability, especially when it comes to more prolonged outages.

Participants were generally satisfied with the reliability they experience, however, point to more prolonged outages as an area of concern, especially in the face of more frequent severe weather.

Because of the importance of reliability, some were willing to pay more for improvements, but the associated costs should be controlled and prudent.

Some participants supported modest rate increases if they lead to improvements in reliability and are accompanied by clear communication about progress and spending. Others, however, questioned why improved reliability isn't already guaranteed given the costs they currently pay.

In the absence of seasonal rates, many participants were focused on the cost of their electricity bills.

Among some customers, there was a degree of frustration with electricity costs. Some felt that their electricity bills have been rising and the quality of service has not been keeping up with increased costs.

Many participants said they would like to see Hydro One provide additional guidance and advice on reducing their bills.

Most welcomed the idea of Hydro One providing enhanced advisory services, especially focused on ways to reduce electricity bills.

Small Business Customers

Most were generally familiar with Hydro One's responsibilities and satisfied with the services they receive.

Most participants knew that Hydro One is their local electricity provider and were satisfied with their overall experience with the utility.

While most were satisfied with reliability, some were concerned about frequent and extended outages in recent years due to extreme weather.

Most participants were generally satisfied with the reliability of service they receive. Many small businesses emphasized the critical importance of reliability for their operations. Customers mentioned that inaccurate outage time estimates make planning difficult and costly.

Some small business customers seek more support from Hydro One to reduce energy consumption.

Some small business customers seek more support from Hydro One to manage electricity costs, suggesting subsidies or incentive programs to reduce energy consumption and improve affordability. Additionally, they noted that off-peak rates often don't align with their operational needs and seek targeted programs to help reduce peak usage costs.

Participants had mixed opinions about whether the rates were reasonable.

Opinions on whether current rates were reasonable were mixed, with some finding them high relative to other expenses. Small businesses expressed a need for reduced rate programs due to operational constraints during off-peak hours. Concerns were also raised about Hydro One's spending on employee benefits.

Many felt that Hydro One needs to invest more to plan for severe weather conditions.

Many agreed that Hydro One needs to invest in more resilient equipment and plan for severe weather conditions. Participants stressed the importance of improved equipment maintenance, more proactive preventative measures and addressing the economic and health impacts of outages during extreme weather.

Expectations of future consumption were mixed with a call for Hydro One's assistance to help customers invest in technologies.

Opinions were mixed regarding future consumption, with some expecting increases due to business expansion and others anticipating decreases due to investments in energy-efficient technologies like heat pumps. Recommendations for Hydro One included supporting investments in energy-efficient technologies by working with the government to provide incentives, educational programs, and assistance with upgrades.

5. Residential Customers

5.1 Familiarity with Hydro One

The focus group discussion began by assessing participants' understanding of Hydro One's role within the electricity system. This was followed by the moderator's explanation of Hydro One's responsibilities, including its role in transmission and distribution, and participants' reactions to this information.

A majority of participants, without prompting, recognized Hydro One as the utility in charge of electricity transmission, distribution, infrastructure, and maintenance. However, some have a more limited understanding, believing Hydro One's responsibilities were confined to regional distribution.

> *"Hydro One does transmission all across the province. Hydro One doesn't do any generation. Transmission is the biggest part of the business, and it is also a local distribution company for all of our communities, and it is only some of the bigger communities that have their own distribution system."*
>
> *"They are supposed to supply the infrastructure, and the power to get the electricity to our sites."*
>
> *"They are responsible for keeping the [electricity] lines off the roads."*
>
> *"I think they're one of the they're the main distributor of hydro across the province."*

5.2 General Satisfactions and Needs

Following the opening discussion, participants were asked to reflect on their overall satisfaction with Hydro One's services and highlight areas where they felt improvements could be made.

Overall satisfaction with Hydro One

A majority of the participants expressed satisfaction with Hydro One and could not immediately identify gaps in service.

> *"I'm with Hydro One from 2021 and I don't remember a day when the power went, and I really have to think of what I'm going to do now. So yeah, they're doing pretty good."*
>
> *"I'm pretty happy with the way that they get our service back up and running, and keep us informed… So, I think it's pretty good."*
>
> *[When asked if there's any way Hydro One could serve them better] "I think they're doing the best that they can. There's not much you can say."*
>
> *[When asked if there's any way Hydro One could serve them better] "No, not really. I mean, maybe provide education on how to use electricity more efficiently… but other than that I can't really think of anything."*

Meanwhile, some other participants, though satisfied, felt like improvements could be made.

> *"I think satisfied is a very, like, middle ground. I also do think that there's room for improvement among things that they do. So, I'm not saying, 'It's wonderful, it's great,' but I'm satisfied if that makes sense."*

"Satisfied is kind of bare minimum. If the power's on, I'm happy. If it's not on, I'm not happy. Is it too expensive? Of course it is, but other than that, I would say I'm satisfied."

Reliability

Most participants acknowledged the occasional outage but remain generally satisfied with the overall reliability of the service they receive.

"I appreciate that knowing that the Hydro backups there and knowing that that 90% of the time it's very reliable and it runs everything."

"I'm very happy… We have very, very little power outages here considering we are rural and a lot of old lines."

"In general, I'd say that I'm fairly happy, but since we moved from Hamilton ON and I can definitely recall that we would have less disruptions in Hamilton area than we would here."

However, some participants who encounter frequent outages expressed a strong desire for improvement.

"At least once a week, the hydro goes off for a few seconds. Everything shuts down, and then it all starts up again. I think [Hydro] is expensive for us and I don't understand why."

"Now that I'm a Hydro One customer, we were always having power outages [almost all the time] and Hydro One is the only one that we've always had a power outage with. It's probably more windy or whatever"

Aging Infrastructure

Some participants noted that poles and other equipment installed by Hydro One are visibly aging and show concern about the potential implications.

"We have a lot of wind around here and when it's really windy, [the electricity] constantly flips. So yeah, I think if they could uh get rid of some of this old infrastructure they have and, you know, put some new stuff in, it might help."

"The poles and the equipment here are older than I am. They were put in in the 30s, 40s and 50s and they're becoming beyond unattainable and without maintenance, that reliability is definitely going to disappear."

"They are doing a good job working in the storms and getting the power back on, but there is that infrastructure that really needs to be looked at a lot more."

Communication

Most participants expressed general satisfaction with Hydro One's communications but noted that their accuracy of estimated time of restoration can be unreliable. Some residential customers reported experiencing outages on unexpected days instead of the planned times, which leaves them unprepared or causes inconvenience.

"I like about Hydro One is they are very good at communicating. They follow up and check, which I do really appreciate that from them as well as their communication."

"I've had really good experiences with Hydro One… The communication is always very good. It's very prompt. I get notifications by text as well as by email…. They check in, they make sure we're okay. They're very quick to respond."

"For the most part, I do receive reliable, stable electricity now. When you have a storm… it still goes to maybe a little brownout for a moment or something flickers. But if we do lose the electricity, Hydro One is pretty good… they communicate about working on it or when they expect to be able to have some Hydro service back to your community."

"There's the other issue where when Hydro One will send us a letter saying they're putting the Hydro off for a certain amount of time, but then they don't, they pick a different day, and they don't tell us… So, it's off for three or four hours and we had no idea [so] could not plan for that... We have a sub pump and if the Hydro's off for too long, we can float our basement. So, it's nice to know about these ahead of time."

Billing Structure

Some participants expressed a need for a more transparent billing structure that clearly reflects the impact of their consumption on their bill, with some indicating that despite adopting careful consumption practices, they have not observed significant changes in their bills.

"I don't really think it's reasonable and I just find that I can't. This year, my cooling systems been down, so I've been around 80C at all summer and I'm using less electricity, but my bills are essentially the same every month as they were last summer."

"I know [my bill] is going to go up in my dollar value even though my usage goes down."

Customer Service

Most participants attributed their satisfaction with Hydro One primarily to the company's strong customer service and the efforts of its crews to restore power when outages do occur.

"We have outages a couple times a year, and the guys get out there and hustle to get the electricity back up, they do a good job. They're probably in the worst weather when these things happen. I'm pretty happy with the way that they get our service back up and running and keep us informed."

"I am satisfied with their service. They do a good job especially since they tried during the pandemic and their bills are descriptive."

"We are always having power outages. I think they do an OK job because they do try to restore the power as fast as they can."

"They've been very fast at fixing things. There was an accident the other day and somebody hit a hydro pole, and it was back in no time."

5.3 Rates

During the discussion about satisfaction with Hydo One, the moderator provided a breakdown of a typical residential customer's bill and outlined the percentage that goes to Hydro One. Participants

shared their views on these rates, discussing whether Hydro One's share of the price they pay was reasonable or unreasonable.

Some participants found it surprising that only a small share of their electricity bill goes to Hydro One. Conversely, a minority of participants were aware of this breakdown and recognized that it is outlined on their bills.

> *"I mean, I've only paid 2 bills so far and I was quite surprised at the broken down costs and how high they were. And now to find out that only 34% is actually going to my hydro bill, I'm pretty disappointed. That's not acceptable… I definitely think it could be less."*

Many participants acknowledged the inherent value of electricity, and the difficulties associated with serving rural areas.

> *"I think it is [value for money] considering that I am more rural, I do think that considering all of the elements that go into what they do, I think that $56 a month for my household and my family is a is probably a fair average."*

> *"I'm at the end of a line and that's running everything in my house. So yes, I think I get value for money, and I mean there aren't a lot of other options here."*

In considering value, some customers assessed cost-effectiveness by comparing prices from other provinces and countries.

> *"Yes, I think I get value for money. There are a lot of provinces that don't have time of use. I try to use off peak as much as possible."*

A few participants who consider the price unreasonable felt it is unfair that different parts of the province pay different amounts for electricity.

> *"I kind of live by the premise that if a gallon of gas is a dollar in Cornwall, it should be a dollar in Kenora. Everything is already set up [and the] distribution lines are already there. So why should I pay more than someone [else] that's closer to where they're where they're picking it up from? I don't understand."*

> *"I think that across this province they should be getting the same kind of services and reliability that they get Southern Ontario, if we were paying the same price. Others should be getting that same sense of security that we have here."*

Among residential customers, perceptions of the fairness of electricity rates were varied. There does appear to be variance in perceptions depending on region. In this case, customers in the Northeast Zone were generally less satisfied with the rates they pay for electricity.

> *"I don't really think it's reasonable and I just find that I can't. My cooling system has been down…and I'm using less electricity, but my bills are essentially the same every month as they were last summer."*

> *"I know whether we're here or not and everything is shut down, I'm still paying that that fee, that same price every month."*

> *"The bill itself is colorful, and it's got a ton of data on it, but I wonder if it's truly customer friendly. I can break it down and press on the colors. But I don't know that the average [customer] really understands the bill. And so, I think I'm paying too much."*

A few participants who have adopted newer technologies, such as heat pumps, noted the impact these have on their electricity rates.

> *"We got a heat pump, and I have to say, I've been very happy since then and I would say I get good value because it dropped my bill probably by 35-40%."*

5.4 Reliability

The next part of the discussion started by evaluating the significance of reliability and explored what it means to customers. For many customers, reliability is the primary factor they use to evaluate how well Hydro One is doing. Participants emphasized the importance of reliability, particularly in terms of community well-being. On a personal level, good reliability is seen as a convenience, but on a broader scale, it is essential for safety and ensuring access to electricity for critical needs in the communities served by Hydro One.

> *"I would say good reliability is expected, and without it, I don't think Hydro One would be successful as a company."*

> *"For me, the number one thing is reliability. Without reliability, there's no business. We're not making money. I would even be willing to pay more to ensure [there are] more redundancies and things like that."*

> *"For me personally, reliability is about convenience. But when I think about the community at large, its critical people need to feel safe, and they need to be able to access the electricity for a variety of reasons."*

When discussing reliability, many participants expressed satisfaction despite experiencing occasional outages. Many recognized that some outages will be unpreventable, especially in more rural and remote areas.

> *"I definitely think that for me personally, it doesn't bother me a ton when we have shorter outages. There is I guess a little bit of nostalgia. Thinking back to being a child and having a power outage, it's this big thing and everyone engages together during those types of experiences."*

> *"I think the number of outages, and I'm thinking back over the past few years… We haven't had many unscheduled outages."*

However, some voiced frustration regarding unplanned outages, particularly those that are frequent or occur during severe weather conditions.

> *"We have outages in the middle of February for six hours when you are out in the country, water can freeze and all of these other realities of country living. So, we do not appreciate that."*

> *"In the summer months, if the power were to go out and I was worried about stuff in the fridge. But in the winter, if I'm snowed in, which is typically when the power goes down, then I need to have some kind of backup thing, which I really don't want."*

> *"Thinking about reliability, I think the number of outages and I'm thinking back over the past few years, we have many unscheduled outages throughout the year."*

Most participants noted that the duration of outages significantly impacts their experience with unreliable service and shaped their perception of its unpleasantness.

> *"When they do schedule power outages, they always do them like for four to six hours at a time on a time when it's your weekend like so I don't understand why they can't do it during the regular working week when these people are working except they bring in all these people to work on a Sunday for four to six hours."*

> *"When the power cuts out and my battery backups have run out, I lose access to my services. So, if I am unable to fulfill the agreements within the contract, then there's penalties that will be applied for the missed service, that is that has occurred."*

Some participants identified inadequate reliability as a direct consequence of perceptions around aging and poorly maintained infrastructure. However, they also acknowledged that replacing older infrastructure would likely be costly, with the financial burden eventually passed on to customers.

> *"if [outages] are recurring outside of Mother Nature because the grid is failing it's got nothing to do with bad weather. Now I've got a concern because it's more infrastructure related as opposed to uncontrolled by a Thunder shower or a storm that is causing the power outage.]*

> *"I think if they could get rid of some of this old infrastructure they have and put some new stuff in, it might help [reduce outages]."*

> *"It would be maybe nicer to see some updated infrastructure, but I imagine that the cost to do that would be very high and there would be no way to avoid having that trickle down to us."*

> *"The outages are because of the wind and that sort of thing you know"*

5.5 Hydro One Priorities

Following the discussion about reliability, the discussion shifted towards Hydro One's priorities.

The moderator shared how Hydro One was entirely funded by the rates paid by its customers and that it was required to file a rate application with the Ontario Energy Board. Participants were then asked what they thought should be Hydro One's priorities in the next 5 to 10 years.

In this portion of the conversation, many similar themes emerged from the initial section on satisfaction with Hydro One's service and where improvements could be made.

Communication

While many participants acknowledged Hydro One's efforts in customer communication through text alerts and outage maps, some suggested these tools could be better utilized. They also called for more accurate estimates for power restoration times and more precise notifications about outage locations.

> *"Communication with customers, which I think they're trying and they're they have, you know, their texting and their outage maps and whatever, but maybe that could be utilized better also?"*

> *"I think they should be more accurate with their estimated time of fixing the prodigy, and they also need to be more accurate in their notifications of where their power is out."*

Focus on Reliability

While many customers identified reliability as a top focus, they are split on whether they would be willing to pay more for improvements.

> *"The thing about reliability, I think it's top priority… We're in the 21st century. You should not have to pay extra for it… Reliability is a kind of quality, and I get annoyed when I'm told 'Well, we can give you better quality if you pay more for it.' No, that should be part of your product, everything should be high quality."*

> *"I want to maintain the level that I've had with them, and I don't want to see rising cost for it."*

> *"The funding to Hydro One has to change, it can't just come from us."*

When it comes to reliability, some customers said they want assurance that Hydro One has a plan in place to handle growth while also maintaining existing levels of reliability.

> *"I think they should supply the power reliably and also plan ahead for growth in the neighborhood."*

> *"They definitely need to be looking at how they're going to maintain [reliability] as well, like to keep the levels that we expect… as well as being able to grow into the areas as we're expanding in… need to have plans that are achievable and that are not going to raise our rates astronomically… last thing you want is one more bill going up."*

When asked directly, many participants expressed that Hydro One should invest in bringing reliability up to the Ontario average. Some said that Hydro One should strive to exceed the average.

> *"People aren't going to be able to continue on without air conditioning because our bodies can't regulate the heat… So, do we need to just bite the bullet now for our future generations and get ourselves to a par with the rest… and get us more consistent across the board? I say, yeah, it's an investment for a future."*

> *"And I would personally want to pay a little bit extra to know that other people wouldn't be in in very dangerous situations."*

> *"Bringing yourself to average should just be a basic thing. It shouldn't be, 'try to exceed everybody else.'"*

> *"We're part of Ontario as well. We should be reaping the same benefits as anybody else and any other part of Ontario."*

Some also emphasized the need for cautious spending, as any investment would impact the rates customers pay. A few were concerned about how much it would cost to bring reliability in line with the Ontario average. For these customers, price increases can only be justified if there are subsequent increases in service quality.

> *"So, any anything they do in in that aspect, ultimately it will, it will come down to like, you know, delivery, bills and everyone has to share it. So, in that perspective, they have to be really careful when they're spending on such a thing."*

> *"But on this conversation, and I agree with [participant], right, that being fair and equitable, however, do I, I and I live rural kind of, you know, do I want to pay for someone who to have*

equitable service, who has decided to live way out in Timbuktu, and that's going to significantly increase my bill?"

"'Oh, you scored well on all these metrics, so therefore you get to raise your prices.'
It should be more like you are responsible to service people at a certain level and your family to do so, and if you can make a good business case that you need to raise prices in order to get that service level up, that makes more sense to me."

However, for some participants that had stable electricity, they didn't perceive bringing reliability up to the Ontario average as a significant priority.

"We don't really have any complaints, so I don't know if striving to close a gap that I don't really notice is important."

Addressing Growth

Many participants expressed concerns that Hydro One's current infrastructure would not be able to handle future demand for electricity, particularly with the rise of electric vehicles (EVs). They emphasizes the need for significant investments in upgrading infrastructure to ensure reliability, especially as capacity constraints increase with increased EV adoption. However, there was a concern regarding higher rates to build additional infrastructure to address increased demand.

"They're current infrastructure because I again, I don't believe it would sustain EVs either."

"Now I'm in agreement there, but you know, we have to make investments, not have an outdated system."

"So there's gonna have to be a monumental investment in a upgrading the infrastructure."

"However, there was a concern regarding increasing rates due to the increasing demand for EVs."

Some participants expressed a need to improve the grid for the future, particularly with the rise of EVs and emerging technologies. They emphasized that infrastructure is not adequately prepared for these changes and highlighted the importance of making improvements for future generations.

"I think we need to leave it in a better situation because of the future of the EV and like was already mentioned, I'm the world is changing, and I don't think our grid is ready for it.
So I think it does need to be improved for the future generations."

"Well, you know, I'm in my opinion it's only gonna get worse in terms of because the, the, the generation that's coming up, they're all technology based. And I'm still about the investing if they have to invest in upgrade the grid so that it can manage the load because it's not gonna get any better this generation that's coming up."

Managing Electricity Prices

A few customers said that Hydro One should try to find a way to deliver electricity in a more efficient manner to manage the costs. These customers suggested that Hydro One should prioritize investments that make a tangible difference for consumers.

"Adopt various ways and to deliver electricity to end users. Maybe in a in a cheaper way."

"So, my focus is or would be just on spend money that makes a difference to us as customers and not difference to things that people are doing that are nice."

Some customers expressed their desire for Hydro One to keep rates affordable by controlling their executive salaries and voiced their needs for transparency. For them, rate increases should be predictable and gradual.

"And else has said like no significant increases in cost to the Customer, especially kind of seeing like executive salaries being reported."

"So, I would want to see transparency on those numbers that the executives are making and reasoning behind it."

"If they're going to consider upping costs, that's going to have a huge impact on everyone… more so on those that don't have bigger incomes. And when these hear that the executives at Hydro One are making $1.5 million a year, how can they possibly think that they should increase cost to us? Our regular Joes, don't have that kind of money."

"But, but that's the kind of thing I would want is a predictability and stability, that kind of stuff."

Extreme Weather

Many echoed concerns about the changing climate and more intense storms, emphasizing the need for Hydro One to prepare for these shifts.

"I would echo kind of the thoughts that have come up so far.
Just thinking about the changing climate, the more stressed storms that we're having, umm, the increase that we're going to see with more electric vehicles, all of those things came to mind right away. And I definitely think that, yeah, just being prepared for those shifts that have already started would be a good use of money."

"I've always assumed since I moved here in in experienced more outages that I'm considered rural because before I never if we did have it, it was a blip in a city. Some of them are storm related. You can get it, but maybe we need to do something about the infrastructure so that it can withstand better or utilize resources better for putting power."

Some participants suggested that Hydro One should invest in strengthening infrastructure to better withstand increasingly severe weather. This improvement would also involve clearing trees away from power lines and ensuring availability of staff to resolve power outages.

"So in in looking at that, sure, I think Hydro should be hardening the lines or hardening the system because we're only at dissipating worse weather coming. Part of that is strengthening some of the transmission and transmission towers and distribution towers, but also part of that is the forestry aspect and clearing trees away from the lines."

"But if they invest in something that's more sustainable, then of course it will lessen the power outages so that that so that we're not getting 12 power outages, maybe we'll get three."

"Well, I do want to reiterate the equipment is incredibly important I think across this province, everybody should have their equipment updated. We have more and more weather bombs

happening all the time. I think they have to be sure that their staffing is in place so that their clients are not without power for too long."

However, some said that power outages that happen during storms are beyond Hydro One's control, especially since these storms don't happen regularly. They appreciated that Hydro One restores power within a reasonable time. However, their concern is not about handling those occasional outages but rather prioritizing the allocation of resources. They prefer that those limited funds be directed towards expanding and upgrading the grid for future needs

"Where I mean, to [participant]'s point, when the power goes out on our house, all it's driven by a bad storm. And if they happen two or three times a year, that's not something that Hydro can control and they get the power up within a reasonable [time] and published or communicated amount of time."

"That isn't a concern of mine. It's more that we put that money because it's not an unlimited resource. It's, you know, there's limits and I'd rather it be used to expand the grid for future needs."

While preemptively replacing outdated infrastructure might incur upfront costs, some suggested that investing in more resilient technology could ultimately lead to long-term savings.

"Yes, it would be a good big cost up front to go through and replace everything preemptively. But if the technology and the capacity to withstand storms and everything else is that much better, maybe in the long run, that's actually a cost savings rather than just doing a section here and a section there."

They emphasize the need for thorough studies to determine where enhancements would have the most impact, suggesting that areas with less storm impact and quicker restoration could potentially be prioritized lower for upgrades.

"How much we have to do is what should be thoroughly studied. Everything right, you have to look at how much the major impact, where it is more focused on and let's say there are areas where the storms impact is like, you know, not too much, but like Hydro One can restore the services quickly even today then maybe those areas they can leave."

5.6 Future Expectations and Plans

The moderator asked participants about future changes in their own electricity usage. Regarding electric vehicles (EVs), opinions were mixed. While some participants indicated they might consider purchasing electric vehicles in the near future, many others expressed skepticism regarding their reliability in rural areas, particularly in the absence of adequate infrastructure.

"So that would be that you know, a change that may happen if you know the system is able to support it. But the way things are now, I just don't see how that's going to happen, unfortunately."

"We just don't have the infrastructure in place yet for that."

"I'm not sold on electric vehicles yet. I drive to Ottawa three days a week and electric vehicle today in bad weather probably isn't getting me home if I can't charge it in Ottawa, most parking lots can't support it."

Participants noted that energy consumption can vary based on personal life changes, such as retirement, moving, or downsizing home. Those changes might lower their usage.

> *"If I downsize and leave our home that that will change my consumption because I'll move to you know, a smaller living space versus you know, a home that has myself, my wife, two dogs and three sons."*

> *"But probably in another 10 to 12 years, I'm hoping to be able to retire. We may find a smaller house, at which point my usage will go down. Will we find a newer house? Most likely more energy efficient."*

Some participants indicated that they would aim to be more energy efficient if given the opportunity.

> *"I don't go to extremes, but if I have to buy a new appliance, I always look at the energy rating and I'm always trying to find something that's going to use less energy."*

> *"If I find out about better ways of doing things, I would certainly be open to that."*

A few participants mentioned that the costs are too high and suggested that incentives should be offered.

> *"If there was enough rebate available for it, possibly because I'm the sole income owner in the home recently, my past my husband passed away. So, it makes things difficult to be able to do so many upgrades without that extra income."*

> *"We have looked into alternative, umm ways to produce hydro too like solar, but it's so expensive to put in and maintain that we've just stayed without, yeah."*

Some participants showed interest in installing solar panels or battery storage. However, many hesitated, particularly with battery storage, due to uncertainty about the technology's current state or lack of knowledge. While people are more familiar with solar panels, they felt Hydro One should take a more proactive role in educating the public about these technologies. Participants expressed a desire for more information, noting the difficulty in finding reliable sources despite actively searching.

> *"I'd be open to different options if they were to send me some information on things that would be more cost efficient."*

> *"To generate some power, I'd be open to all of those things if somebody wanted to educate me on it and show me how I could either be saving money or making money on, I'm open to those things for sure."*

> *Because yeah, I didn't know that about the batteries and it's an interesting concept.*

> *"The battery technology is not there at this point. Solar is the cheapest way to charge batteries because it they charge like 14 hours a day, not 100%, but they charge all the time."*

> *"Here are the batteries, but you got to figure out how to do this yourself... I want somebody who can come out who can actually assess what's happening in my house and give me some good professional advice."*

> *"I would like information from whoever's going to give me information at this point, because it's been very difficult to gather information and I've been actively looking for information and I found somebody now who's going to hopefully come and give me some good advice around this."*

For some participants, word of mouth was crucial in determining the success of the technology. They said that knowing a neighbor has adopted a technology would increase the likelihood of trying it themselves as this demonstrated a proven record.

> *"I like being able to have a group of people who could talk about what they do and what's successful. And I think that's important. And I think if you know that your neighbor is doing it like you said, then you're more likely to try it yourself."*

The moderator shifted the discussion to the importance of Hydro One investing in efforts to reduce carbon footprints.

A few participants emphasized the need for Hydro One to invest wisely and demonstrate the benefits of their spending.

> *"They need to prove that they're worth the money they're spending on them.*
>
> *"The other thing is if they do invest in new technologies that will prove them and also kind of be an example for homeowners to follow suit, especially if they have proved the technologies and kind of honed to them and optimized them."*

Meanwhile, some participants noted that the energy industry has historically contributed to the climate crisis and should play a role in addressing it. They emphasized that both industries and households need to work towards reducing their carbon footprints.

> *"Some would say in the past this industry, umm, the energy industry has contributed to, you know, the climate crisis. So they should help solve it."*
>
> *"Every industry and every household as well should be trying to reduce the carbon footprint."*

For few individuals, reducing carbon footprints did not rank as a priority.

> *"So, I just maybe it would be over time if I knew a little bit more, but at this point I've never thought about it. It's just not on my radar as important."*

6. Seasonal Customers

6.1 Familiarity with Hydro One

Most participants stated that Hydro One's primary responsibility is to ensure reliable and affordable electricity, maintain equipment, and restore power following outages.

> *"They are responsible for providing electricity at a rate that householders and cottage owners can afford it."*

> *"Think their role has been to try to deliver reliable electricity to rural residents and to some communities throughout the province, from generators like OPG and others."*

6.2 General Satisfaction and Needs

Following the introductory discussion, participants were asked to comment on their level of satisfaction with the service they receive from Hydro One, as well as the areas of services that Hydro One could do better.

Reliability

Reliability is one of the main factors that customers use to determine their overall satisfaction. Most said that they are quite satisfied, experiencing an appropriate number of outages and noting that Hydro One has historically reacted quickly when issues occurred.

> *"I can't even tell you the last time we lost power. Very reliable."*

> *"[Power restoration] almost instantaneously this summer it has been much better."*

> *"I'm pretty satisfied. I do like the text messages to know that power has been out in the area."*

> *"Quite satisfied. I don't remember the last time there was an outage… Overall, no major issues that stand out in my mind."*

> *"We're quite happy… We've had them come in, take down trees. We lose power at least 4 or 5 times a year, and they react quite quickly. I think they do a great job."*

However, some said that they are dissatisfied with reliability, noting that outages have become longer in duration. These longer duration outages are seen as more of a concern than brief interruptions that are quickly resolved.

> *"It's getting worse from the standpoint that the outages are longer, a little blip is no big deal."*

> *"Alright, very dissatisfied. This year's probably been our best year. We've had four or five outages of at least 12 hours previous years, been much more serious outages, probably because many of the distribution lines and long-haul lines go cruel cross countries."*

Cost/Billing

Some participants commented on what they perceive to be high delivery charges. Some felt that the services they receive are not adequate for the price they pay. Many expressed their desire to have

seasonal rates back as they find it harder to accept lower-quality power supply after the elimination of the seasonal rate, especially when compared to more urban service levels.

> *"And with the elimination of the seasonal rate, it's a little harder to swallow a lower quality power supply then one would get in the city."*

> *"I wasn't there when they did have the seasonal rates, but I have heard about it and I do think that that is something that would be very important to bring that back for people that, yeah, just it's very costly and then for me to start thinking about these alternative ways to keep things running."*

> *"Little delivery charges are exorbitant, and they're not commensurate with the delivery of the service, you know."*

Participants also expressed their surprise to learn that they would still have to pay for delivery charges even when they were not using their properties.

> *"First of all, I will say I thought we'd save a whole bunch of money by not having the cottage open when it wasn't. We weren't using it, but it turns out you get Hydro bills anyways, even though you're not using any."*

> *"Uh, I've noticed that the cost is quite high, and I was really tracking, you know, compared to home where my monthly hydro bill is about $100. Uh, you know, for a seasonal property with not a lot of power usage, we don't have big appliances or a large cottage."*

Although acknowledging the necessity of having electricity and accepting the associated costs, some commented that they have been seeing an increase in their bills.

> *"We have to have it, and it costs what it costs, so I don't really quibble about it, but I have had a sense that those costs have crept up quite a bit."*

Outage Communication

While most participants said they find the current outage notification system to be helpful, others expressed frustration with what they perceive to be incorrect time estimates for power restoration. They said that they prefer Hydro One to be honest about the time estimates rather than overpromising.

> *"I do like the text messages to know you know that power has been out in the area."*

> *"Oh yeah, you know, to [participant]'s point, power's going to be back on in four hours and then four hours later, I get another text that it's going to be another 7 hours."*

> *"I would rather them just be real with me and say, you know, it's going to take us six hours to figure out what's wrong…If you're up there in the winter, you you're making decisions on whether you need to drain your plumbing. You know, there are major economic impacts to losing the heat."*

Many participants said they appreciate the mobile app that allows them to report outages and get updates on maintenance and emergency response.

> *"One of the features that we really appreciate is the storm warning storm tracking, being able to report storms through the app, you know, and outages and to get text alerts for those outages."*

Maintenance

Many said they are satisfied with how Hydro One performs its preventative maintenance. Some noted Hydro One's preventative efforts, such as cutting down trees and clearing brush along the roads during the summer to avoid future problems. While most said they do not interact with Hydro One frequently, they appreciate the annual tree inspections and proactive action on large, older trees on their property.

> *"You know, there's also the preventative, we see them cutting down trees in advance, you know, a future problem that are to come on the side of the road clearing bushes and trees, you know, throughout the summer."*

> *'That's the, you know, I don't have a lot of interaction with them, but they do come every annually and do a tree inspection."*

> *"Uh, we have some old large old trees on the main lot, which they're proactive at investigating and taking action where required."*

6.3 Rates

Following the discussion about customer needs, the discussion shifted towards Hydro One's rates.

To begin with, the moderator asked how much of their monthly bill customers believe went to Hydro One. The moderator then shared a short description of Hydro One's portion of the electricity bill. Participants were then asked if they thought the price they paid for electricity was reasonable or unreasonable. They were then asked if they thought they received good value for the price they paid for electricity.

Some participants expressed their frustration at having seasonal rates eliminated.

> *"With the elimination of the seasonal rate, it's a little harder to swallow a lower quality power supply than one would get in the city."*

> *"I do think that this [seasonal rates] is something that would be very important to bring that back… It's very costly and then for me to start thinking about these alternatives ways to keep things running, I don't have the money."*

Some mentioned that they did not like having to pay even if they did not use electricity.

> *"I just think about it from time to time when I see that I'm at the cottage for two days in the month and then my Hydro, there is more expensive than my home where I'm home every day doing all kinds of things."*

> *"I've noticed that the cost is quite high - and I was really tracking compared to my home where my monthly hydro bill is about $100 - for a seasonal property with not a lot of power usage. We don't have big appliances or a large cottage… The cost does sting a bit."*

In terms of value for money, a few believed that they are getting value for what they pay to Hydro One.

> *"I would say probably yes. Given the outages we get, we're paying pretty low prices in Ontario."*

However, others said they were paying for high delivery costs without an improvement in services.

> *"I don't have anything to compare it to, like I know all that I'm paying at a hell of a lot more for power now than I did just handful of years ago, and nothing's changed on my end."*

"Most of my neighbors have generators, so they're used to the power going out very frequently and for long days in the wintertime. And so that's a huge frustration for me, especially when I look at the delivery charge on my bill and I'm thinking, what am I actually paying that for if that's supposed to be going into building and maintaining the infrastructure? They're not doing a great job at that, so a lot of frustration there."

"Delivery charges are exorbitant, and they're not commensurate with the delivery of the service."

A few mentioned that there were no comparable options as they had to stay with Hydro One.

"There's no competition or anything like that, so I'm stuck paying this bill on that."

"We don't have other options, not all of us can go fully solar or install winter vine or any of these alternatives. We're rural consumers. We're pretty much locked into Hydro One."

Some participants mentioned that, despite more frequent outages in rural areas, energy prices in Ontario are relatively low. However, they suggested that the Ontario Energy Board and Hydro One should explore alternative pricing models other than time-of-use pricing.

"No dispute that they should be there, but how we should pay them the entire energy Board and Hydro One and move to time of use and time of day type billing. I think we should need more creative models that have been tried in other jurisdictions to account for these delivery charges."

Some participants expressed a desire for more proactive engagement with Hydro One. They mentioned that they would appreciate Hydro One approaching them with a range of options and solutions, acknowledging their challenges and offering ways to help offset costs.

"So, to answer your question first, yeah, I like I would love them to be more proactive with options and come to me and say here, you know, we know you've got these challenges, but we've got this whole litany of things that we can help you with to offset your cost things."

6.4 Hydro One Priorities

Following the discussion about reliability, the discussion shifted towards Hydro One's priorities.

The moderator shared how Hydro One was entirely funded by the rates paid by its customers and that it had to file a rate application with the Ontario Energy Board. Participants were then asked what they thought should be Hydro One's priorities in the next 5 to 10 years.

Maintaining or Improving Reliability

For most seasonal participants in the focus groups, reliability is the single most important area of focus.

Seasonal participants were most concerned about the length of outages, but they also emphasized the importance of being informed about the cause of the outage.

"Yeah, it's the length of the outage is key."

"Also useful to know on the Hydro One outage map, what was the cause of the outage"

"Yeah, it's definitely there's a lot more activity on our island Facebook when an outage is ongoing and the umm, there's restoration keeps moving out, but we don't feel like that's poor delivery of service."

Some agreed that Hydro One should invest to improve reliability. However, these customers want to see a clear improvement and only modest price increases. Some also expressed a desire for Hydro One to communicate where they were against their current expectations and how they would be using customers' money.

> *"If there was a visible increase in reliability, I don't think I'd have a problem with that. I again, I would think it would have to be a modest increase, but you know then then you get into the issue of what's modest."*

> *"I'd be willing to give the money if they document how they actually use it."*

> *"And before Hydro One was to increase the rate to increase reliability, I would like to know where are they against their current expectations? Have they allowed the system to become less resilient over time and is that's now a cost to just bring it back up to where it was supposed to be?"*

6.5 Future Expectations and Plans

Future Consumption

Many participants said that they are already finding ways to reduce their energy consumption. They also noted that they are now more cautious and considerate about their electricity usage.

> *"I think we're more cautious about like maybe cautious is the right word, certainly more considerate about how we use power."*

> *"So right now the only way that it makes sense to start introducing something like solar or small wind or anything like that, frankly, is to cut the cord completely and just say, OK, fine, I'm not going to be dealing with hydro at all anymore."*

Advisory Services

Some participants expressed a preference for Hydro One to take a more proactive approach to connecting them options to address their future energy needs. However, they cautioned against charging extra just to provide tips and advice and emphasized that Hydro One needed to clearly demonstrate the benefits of any actions, whether cost or managing their electricity usage.

> *"I'd love to see them be proactive and come with ideas."*

> *"I think, yeah, I think they do play a primary role, but it has to be self-funding and showing some net benefit or it's worthless."*

New Technologies and Innovation

Few participants said they are actively considering adopting new technologies, like heat pumps and solar panels. Some participants acknowledged that while they feel these technologies are important, they might not personally be the "target audience" for them.

> *"So, I think there's room for that innovation. I don't think we're really the target market and as far as you know, Tesla batteries and things like that."*

Some participants suggested that funding innovation and new technologies should not be passed down to customers unless there is clear and demonstratable customer value.

> *"But we don't want that to come back to our level that we need to fund that. I think that sort of needs to be hived off by Hydro One to where we're investing in innovation."*

> *"Needs to be Innovative, needs to invest in innovation, but they need to kind of prove the case before they can download those costs to us."*

Most participants preferred that Hydro One follow established practices rather than trying to "reinvent the wheel".

> *"Hydro One has not been known for it doesn't have a mandate to date for innovation. It would be nice to see the regulator, the OEB or the province, though, invest separately in small companies, say like Bullfrog power and other companies to do these Innovative things like micro grids, vehicle to grids and so forth."*

7. Small Business Customers

7.1 Familiarity with Hydro One

Each focus group discussion started by gauging participants' awareness of Hydro One's role in the electricity system. It was then followed by the moderator explaining Hydro One's role in the system and seeking participants' reactions to it.

Most participants recognized that Hydro One handles the transmission and distribution of electricity, with many stressing the importance of reliability in its services.

> *"But certainly, it should be a source of electricity to provide fair, reliable and equitable service to all communities within the province of Ontario."*

> *"Uh, yeah, I would say just a reliable and safe transmission of electricity for the province."*

Besides delivering electricity, Hydro One is seen to be responsible for maintaining the distribution system.

> *"I think Hydro One is responsible for electricity transmission and distribution, and they're also responsible to make sure you know if there's any alright trees or any branches kind of in the way of the lines to make sure that it's cleared and take care of it."*

Additionally, some noted that Hydro One's role is to ensure that electricity remains affordable and support the development of new renewable energy programs.

> *"Yeah, I would, I would say providing electricity, infrastructure for electricity and maybe putting electricity back into the grid going the opposite way from solar and renewable energy and developing maybe renewable energy programs and, yeah, innovating for electricity hydro delivery."*

> *"What everyone has said, but I also think part of the role should be to make it affordable."*

A few participants mentioned that outage communications including estimates for power restoration are part of Hydro One's responsibilities. They also said they value the guidance provided to businesses on how to handle outages.

> *"I find helpful that Hydro One is the way they manage the network or the system, particularly in times of outage the way they communicate power outages and estimates for time right you know estimates of time for recovery, uh so you know managing the network but also helping people understand how to how to you know stay in business or manage outages so."*

7.2 General Satisfaction and Needs

Following the introductory discussion, participants were asked to comment on their level of satisfaction with the service they receive from Hydro One, as well as the areas of services that Hydro One could do better.

Reliability

Opinions on whether Hydro One is doing a good or bad job primarily depended on the reliability of their service. Most participants said they are satisfied with the reliability of service that they currently experience.

> *"I just wanted to say that the way that we know that Hydro One is doing a good or a bad job depends on the service or reliability."*
>
> *"I think you could judge it by, I mean the service we're receiving and if it's everybody has Hydro and then that would go with the outages and also the services that they provide."*
>
> *"Well, just to come back on how do I know they're doing a good job? It's a question of reliability. Yeah, I'd say 90%."*
>
> *"I think you know, compared to many other places internationally, even they're just in North America, like we're really fortunate to have a pretty secure and reliable system that we do."*

However, some felt that reliability can be problematic during severe weather events. Some participants reported experiencing frequent and extended outages in recent years, and despite recent improvements in reliability, there is concern about whether it will be sustained.

> *"Every time that the thunder cracks, the Hydro's gone. So that's my not satisfied, which is true of the summer often and through the winter a fair amount every time we get a storm, we have no hydro and in the spring the Ottawa River here floods and then we again have no Hydro."*
>
> *"Climate change is certainly something that we can argue about the effects… It seems to be in the last few years, storms have been more severe."*

Electricity Costs and Billing

For many participants, the cost of their electricity bill is among their top concerns. Some participants voiced dissatisfaction, saying that Hydro One's delivery costs were higher than the costs of some other utilities or regions.

> *"But you know the cost of Hydro is really expensive and for businesses like it's definitely a takes a big bite out of our you know our profits and our operational costs for sure."*
>
> *"It's like the as compared to other states like our price is still very much higher than normal other places."*

However, some said they could not really assess whether Hydro One was doing a good job or a bad job because there are no direct comparables. These customers highlighted the monopoly of having Hydro One as the sole electricity provider and expressed a desire for more options to compare services.

> *"And secondly, is there like a no comparison like there's Hydro One and Hydro 1. So if we have like a good doing, good job versus not doing good job, how we had to compare that like you can't compare with the Hydro One with Hydro One."*
>
> *"It's a monopoly. We don't have a choice if we if we want the lights on, this is who we gotta go to."*

Interactions with Hydro One

Most customers reported having minimal interactions with Hydro One. In most cases, the only interactions they may have involve paying their bills.

> *"My bill is automatic payment from my account, finished and never call them. No issues, only I've called them when there's no power."*

> *"Thankfully we haven't had any issues with Hydro, so it's been very minimal at this point and I do use the online platform quite a bit."*

Some small business customers said they are looking for more support in managing electricity costs, expressing interest in subsidies, incentives, or programs that can help offset costs and make service more affordable.

> *"If there were programs where there's either subsidies or cost-effective ways of servicing a premise that would be interesting."*

> *"So, I'm gonna say that would be great if they were more reasonable or reduced or offset somehow or there would be more opportunities to offset costs, whether it be incentive programs, something other."*

Some participants mentioned that the current pricing structure, including time-of-use pricing, does not align well with their current business operation hours. They felt that Hydro One could do more to help them navigate these challenges, including managing their peaks.

> *"You know the time the high peaks and the low peaks or whatever is not always beneficial to us, that's for sure just and by nature of sort of how our business operates."*

> *"It's quite expensive at the peak period, you know on a percentage basis, it'd be great if they had programs that they could share and maybe subsidies to help you offload your peak."*

Communications

When discussing communications with Hydro One, many participants acknowledged the importance of proactive communications during outages.

> *"Things have been improved dramatically, so for us it's more the steady supply, the predictability. It's knowing when there will be disruptions."*

> *"The communication that comes to you when there is an outage and the expected recovery time frame makes a big difference... in being able to communicate back to our customers or tenants."*

Many stated that they are very satisfied with Hydro One's communication efforts, especially during outages. Participants were generally pleased with Hydro One's quick response to power outages and appreciate receiving timely notifications via email and text.

> *"Things that we get like emails and stuff, tell us that power is off like that comes right on my phone. So, we need to know that immediately, yeah."*

> *"They're out here pretty quick and we get notifications through emails, and it works great that way. So, we're really happy with the with the response with if there's any power outages, I get that on my phone immediately."*

"If there's a storm in, in Ontario, I don't know about it. But so, I got text messages that I think quite responsive saying there's a storm coming or we're planning a plan service outage. So, I feel that as a remote customer that I'm informed about things."

Some participants stressed the importance of accurate restoration times and note how inaccurate estimates can negatively impact their operations.

"I think last year about five or six times and all of those six days I lost my business because of that. I lost lots of sales, plus I had to pay my employees all the wages because I don't know because they don't give you particular time when the power doesn't come back."

With regards to general communications, some participants expressed positivity with Hydro One's website and educational resources. They mentioned that the website is both clear and easy to navigate.

"I think more just from like a technology point of view like the website has gone better, email communications, things like that."

"And with bills that there is a lot of extra information like how to save money or other, and strategies to improve your insulation or different, just different really, it's mostly money saving, but just really practical tips that I find are helpful."

Customer Service

Beyond the reliability they experience, many participants evaluate Hydro One through the lens of customer service. Specially, some evaluate Hydro One based on the time it takes to receive a response from customer service when they have an issue or concern.

"I would say the most important thing for me, having many Hydro One accounts is customer service. So, wait times on the phone. Maybe the hours that they're open and you know if they're friendly - customer service."

"Yeah, I think it's normal or nice but depends on time - customer service - whether you're picking the call or not and how quickly you are picking the call depends on that also."

Among those who have interacted with Hydro One's customer service team, most find the service to be friendly and helpful.

"Anytime I've spoken to them on the phone like service, why is they've been wonderful."

"I've taken on the role of commercial property owner fairly recently… I've had to deal with them and there were some issues at the beginning, and they were so supportive and really helpful. So, it's been a good relationship."

"Anytime we've contacted Hydro One, they're right on top of it."

When asked specifically what Hydro One could better serve them, some participants said Hydro One should take on a more proactive advisory roles to help small businesses be more energy efficient, educate them about energy conservation programs and provide subsidies to enroll in those programs.

"Something that Hydro One could do is like educational programs like provide educational resources about energy conservation and efficient use."

"I do think there is an accountability on organizations like Hydro One to actively work with people and organizations to be as efficient as they can be."

"Education about the options that are available to us – I think that's the main thing… On website maybe, or even grants, or just educate the customer about some of the systems that are available."

"I think it would be really nice to have a human being come to the premise and suggest ways to reduce hydro usage."

System Maintenance

Many participants also emphasized the importance of continued need for more preventative maintenance since some areas experienced frequent outages during storms due to older hydro lines and surrounding trees. They recommended that Hydro One continue maintaining the systems.

"Also, we live in a rural community… so there is a significant number of trees and stuff that are all around Hydro lines are older and we do get a lot of outages during storms and stuff because trees will fall and because of where we're located, they're not in a hurry to come and fix them."

"I do agree with like the cutting down of the trees like the preventative maintenance as opposed to the responding."

7.3 Rates

Following the discussion about customer needs, the discussion shifted towards Hydro One's affordability.

To begin with, the moderator asked how much of customer's monthly electricity bill went to Hydro One. A short description of Hydro One's portion of the electricity bill was then shared. Participants were then asked if they thought the price they paid for electricity was reasonable or unreasonable and whether they felt that they received good value for the price they pay for electricity.

Most customers were not aware of how much of their monthly electricity bill goes to Hydro One. There were mixed views about whether what they are paying is reasonable or not.

Many customers tied value to reliability. Those that experience good reliability were more likely to say that they receive good value for the price they pay.

"I would say reasonable just because we like the reliability of the service. Like, we barely get any outages and stuff, and since it is a necessity, that's like a really like, great value for us in the sense that we don't have outages, and we can continue to operate."

"If you need it and it helps you function in your daily life, then it's providing the service."

Additionally, some viewed value-for-money through the lens of how quickly Hydro One crews can respond when there is an outage.

"Delivery and the accessibility to have somebody assist when they're sending issues."

"So, I think yes in that, any time we've ever had outages here, they have been responded to very quickly that maybe it's just our proximity to Hamilton. There's lots of crews around as opposed to a very rural area, but our point of view, it's good value."

Some participants felt that the price they pay for electricity is reasonable when compared to other services and utilities like water.

> *"And when I look at our Hydro costs, look at our water cost, look at our property taxes, it is in line, it looks like relative to other expenses we have that it's reasonable."*

However, some felt that the rates they currently pay are higher than other jurisdictions or for other utilities that are seen to be similar.

> *"I'm paying a lot less within the city than I am for my rural property, so for me, no, I'm not getting a good value."*

> *"I don't feel like outages are corrected as quickly as I would like them to be and I mean I understand that we are kind of outside of town limits, but if I can get the same product from Enbridge for a cheaper cost and they don't engage with me just like I'm not engaging with Hydro One, then why would I not pick that option?"*

One participant noted that they are concerned with Hydro One employee salaries. They expressed a desire for Hydro One to make cost-saving adjustments like those faced by other sectors and businesses.

> *"But for sure, like Hydro One, employees have like some very, very, very good perks that probably are like more than necessary... I think people would like to see that Hydro One is sort of you know having to tighten their belts just like everybody else on certain things and that their employees would understand that as well."*

7.4 Reliability

Most participants expressed that the reliability they experience is acceptable, often describing it as dependable, and meeting their expectations.

> *"[Reliability] It's always there. It's very seldom it's out… Hydro is always there was us really."*

> *"Why we feel it's acceptable?... Because they have been reliable in the past. Because you can depend on them, you assume that's a level of acceptability."*

> *"I've had no real issues with the reliability, especially on the three-phase."*

For many, power outages can have serious consequences for their business. Participants described the challenges of managing staff during power outages, noting that staff remain on site with limited tasks to perform without power. They highlighted the lack of backup generators as a significant issue, leading to potential losses of products and spoilage due to outages. They mentioned that inaccurate power restoration estimates make planning difficult and costly.

> *"My staff still stays because you're waiting on it [power] to come back. So, you are paying staff to basically sit around and you can find some jobs for them to do, but there's only so much that can be done without power, especially in our industry."*

> *"So basically, we cannot do anything because we don't have any backup generator or anything."*

> *"So, I'm the impact would be like potentially the loss of livestock. As I said, the loss of our product and stock."*

"Reliability is a big thing, especially for us. Like if you don't have power, we're pretty much pooched to work with hand tools."

7.5 Hydro One Priorities

Following the discussion about reliability, the discussion shifted towards Hydro One's priorities.

The moderator shared how Hydro One was entirely funded by the rates paid by its customers and that it had to file a rate application with the Ontario Energy Board. Participants were then asked what they thought should be Hydro One's priorities in the next 5 to 10 years.

Reliability

For most, reliability remains one of their top priorities. Some participants suggested that Hydro One's primary focus should be on reducing the number of outages, especially more prolonged instances.

"I would say is to keep the capacity to where, like and [participant]'s case, eliminate those brownouts."

"I think the priority should be the fixing the blackouts and the brown outs on the current customers."

"Priority should be on making sure that our existing services are more reliable and dependable."

When asked whether they would be willing to pay more to improve reliability, many customers were torn. Some felt that reliability is so critical that they would be willing to pay more, within reason.

"I would say at the end of the day, it's got it be reliability and the unfortunate part is it comes with a cost."

"It's also a safety issue…People under health situations and stuff like that, I don't see that you can take that risk even if it's going to cost you more."

While others felt that everything should be viewed through the lens of affordability.

"I don't get why it's an either-or question though. Well, I mean, well, you constrain for more reliability and at the same time look for less expensive ways of you achieving them."

Many customers felt that Hydro One's reliability should be more on par with the Ontario average. Some customers felt that rural areas receive services that are inferior to those in major metropolitan areas, despite contributing the same taxes and electricity rates. They suggested that rural services should either match or exceed those provided in urban areas.

"So, if we are with for Hydro One, we are paying more than the smaller power companies and reliability should be at least on par."

"You know, I think that more rural areas often feel like our services don't match those of the major metro areas, and yet we still have our regular taxes and all kinds of other things that we have to contribute to. So, we should absolutely try and match it or be better than it."

Some participants felt that Hydro One should prioritize reducing the length of outages, rather than the number. For these customers, they see longer outages as having a more significant impact on their business operations.

"I'd say of those that you mentioned, I would say that duration of outages would be you know anything that's gonna be safety impact safety or you know damage people's goods."

While some felt that the focus should be on the length of outages, customers would like to see Hydro One focus on all aspects of reliability, including length, frequency and communications. Some noted that proactive replacement and maintenance of equipment are crucial.

"Yeah, I also think like all the above that you mentioned reduced outages, reduced duration of outages, increased communication, all that should be a priority."

"Umm, uh, I don't think there's any business owner who just waits until everything breaks before you replace it…. And you also need sufficient personnel to maintain that a lot of the times, getting back up after a storm is entirely reliant on how many crews are available."

Maintaining and Upgrading Infrastructure

Some participants suggested improving and maintaining equipment to prevent major issues (e.g., burying wires, replacing old components), especially during extreme weather events. Some felt that increased maintenance could further reduce the overhead costs and allow Hydro One to invest more in improving reliability.

"Just because you know, whenever there are weather events, that's when I notice we get the most outages and things like that."

"So, I feel that Hydro One needs to look at their own infrastructure at where they can save money so that they have more money to put into improving hydro poles, improving brownouts, having more manpower to deal with power outages or preventative cutting of trees."

Some participants were concerned that Hydro One will not be able to keep up with the growing demand. Some said that they would like to see Hydro One work with the provincial government to address the growth in demand.

"I cannot see how the lines that they have in this area are going to be able to support all of the green technology electric vehicles without breaking down because they can hardly support the power that needs to be distributed now."

"They need to say, you know, maybe sit down with government and or and tell the people that, yeah, we have to have all this power for what we need to generate for the for the coming future."

Extreme Weather Preparation

While customers generally understood that severe weather-related outages are often beyond Hydro One's control, many still wanted to see the company invest in areas it does have influence over.

"Except for reliability, I don't have any problems. I mean, they can't predict the weather."

"I mean, like if I if we have a huge windstorm and a whole bunch of trees come down, I don't consider Hydro ones responsible for that."

"I think extreme weather is something that's not going to be decreasing, and so it's just prudent to look to what the future will hold and invest more money expecting more of it."

"I think as climate changes, and the weather becomes more extreme. People are going to start getting injured or killed and they'll need to have reliable power sources to help prevent that from happening."

Many agreed that Hydro One should invest in more resilient equipment and plan for extreme weather conditions, even if it involves higher costs.

"I would think it would be beneficial to invest in sturdier equipment to help prevent the issues."

"And so, it's just, it's just prudent to look to what the future will hold and invest more money expecting more of it."

"Hydro is not just a privilege it you know it's a human right. And so, when it comes right down to the to that, I think that looking at the general health and safety of the public, it should be #1 in terms of how any kind of changes are implemented in the system."

To prepare for more frequent severe weather, some customers also felt that Hydro One should undertake more preventative maintenance, such as trimming trees and the use of resilient equipment.

"I feel like it's important, but you can do a lot and spend a lot of money to prevent things, but if you don't do other things that go with it, like trimming the trees and other things, it's not gonna make it flawless."

Costs

Many suggested Hydro One keep the costs affordable and look for other ways to reduce costs. They recommended exploring cost efficiencies.

"And just making sure it's more accessible to all incomes."

"So, looking at ways to reduce that cost efficiencies, what's what are other competitors doing that they're not doing?"

"If there are opportunities to kind of make sure that our consumption can go down or we can save by the idea that I guess was passed on earlier about maybe storing electricity when it is cheaper and then using it at a higher peak time."

7.6 Future Expectations and Plans

Customer views of the future are mixed. Some anticipated increased electricity usage as their business operations evolve, while others expect a decrease due to investments in heat pumps and other energy-saving technologies.

"I would say that our electricity use would decrease because we're investing in efficient means of say heating or using electricity, but at the same time you know business is expanding and we're purchasing more property. So I would say it's going both ways."

"We're also doing like planning on doing expansions with our grain dryer set up, which takes a ton of electricity."

"So by retrofitting a newer windows, adding exterior insulation, adding mini splits, I've already done energy modeling. I can slash the energy consumption by about 70 to even 80%."

In terms of investing in new technologies, cost remains the primary barrier for many small business customers. Some felt that Hydro One could play an increased role in helping customers navigate newer technologies like heat pumps and solar panels, including government incentives and equipment leasing opportunities.

> *"If there was more of an availability of grants, and somehow even loans."*
>
> *"Probably more of government to be able to supply, you know grants and that type of thing that would probably promote more things like that."*
>
> *"Yeah, work with the government to give small businesses incentives to make changes to reduce."*

Additionally, some felt that Hydro One could provide education on energy-efficient technologies and assist with upgrades and investments in those technologies. Initiatives can include offering a generator rental program, connect customers with electricians, facilitate rental or purchase costs, and offer a payment plan to support with installation.

> *"Education about the options that are available to us."*
>
> *"I suggested earlier, but if they would come with a program where I could, I could rent a standby generator, for instance, from the on the monthly basis"*

Some customers also noted that they would like Hydro One to provide more information on their electricity usage and tailor tips on how to save on their bills.

> *"I do think that they can work with individual customers and small businesses to highlight based on usage and what they know about our organizations already highlight ways in which we can reduce our costs and use it."*
>
> *"And as far as I'm just thinking like about tips and things on ways to make money, they do have that on the website, like just different articles how to save money in different ways."*

Some customers felt that it is important for Hydro One to reduce their own carbon footprint, however, they weren't sure how much that would cost or how it would be achieved. Other customers were more focused on cost and improving reliability and felt that any focus on reducing Hydro One's carbon footprint would take away from those priorities.

> *"Is very important because if, like federal government spending so much money on that and other companies had to play their part in that too."*
>
> *"So, we have to rely that whatever they do, their engineers that they have in place, that they're gonna that that's their responsibility. Not for me to tell them what to do."*
>
> "*In my opinion, it doesn't affect the overall experience of Hydro, so if they put money into that, they're taking away from actually like the reliability, everything like that for something I'm not seeing value."*

Appendix 2

Hydro One Large Business Customer In-Depth Interviews

Phase I Report

2028-2032 Joint Rate Application

Prepared for:

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Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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2. Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Inc. (Hydro One), to gain a deeper understanding of the needs and preferences of customers, specifically as it relates to Hydro One's Joint Rate Application to the Ontario Energy Board (OEB) covering the years 2028 to 2032.

As part of this engagement, INNOVATIVE conducted qualitative research to uncover specific electricity needs, outcomes and priorities from Hydro One large business customers in order to inform planners for the 2023 – 2027 draft investment planning process.

This report summarizes the results of a series of in-depth interviews with large business customers, including commercial & industrial (C&I), large distribution (LDA), and large transmission (LTX) customers.

Approach to Large Business Customer Engagement

Hydro One provided INNOVATIVE with account details and contact information of Hydro One's C&I, LDA, and LTX customers. INNOVATIVE invited a random selection of customers within each customer group to schedule a meeting with INNOVATIVE to share their business' needs and preferences as they relate to Hydro One's Joint Rate Application covering the years 2028 to 2032.

INNOVATIVE began sending initial invitations to customers to participate in an interview on August 12th, 2024. Customers who had not yet signed up to participate in an interview received up to two subsequent reminder emails from INNOVATIVE between August 21st, 2024 and September 25th, 2024. Customers who had not signed up were also contacted directly by their Hydro One account representative or another staff member to encourage participation. This outreach led to 37 interviews being completed via videoconference or telephone.

Customer Group	Completed Interviews
C&I Customers	**9** customers
LDA Customers	**11** customers
LTX Customers	**7** *end-users* **5** *generators* **5** *local distribution companies (LDCs)*

Interviews were approximately 45 minutes in length and were conducted by a trained moderator following a discussion guide. In appreciation of the time provided by participants, INNOVATIVE provided a $150 cheque for each participating business.

About this Report

This report summarizes the key findings based on these interviews. In general, our approach is to report representative verbatim comments and offer interpretation and/or commentary where necessary. Verbatim responses are shown in blue italics.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for directionally. In interview-based research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view.

3. Key Findings

Commercial & Industrial Customers

Most are satisfied or neutral towards the overall service that they receive from Hydro One.

Overall, most customers do not identify any significant issues with the services that they receive. When asked about their overall satisfaction with Hydro One, many emphasize the importance of consistent, reliable service.

Many identify improvements to communication as an area they would like Hydro One to focus.

Some customers say that they would like a dedicated point of contact to streamline interactions as they note challenges in their communications with Hydro One.

Most are satisfied with current levels of reliability and efforts made by Hydro One to restore power quickly.

Reliability is consistently seen as critical for commercial & industrial customers, with significant consequences of poor reliability. While some report more frequent outages, many of these customers have backup power systems in place to reduce disruptions from outages if they do happen.

Customers are largely willing to pay more for Hydro One to make investments to maintain or improve reliability and build resiliency to severe events.

Most customers say they are willing to pay more to maintain or improve current levels of reliability and many support Hydro One making investments in greater resiliency to severe events.

Many customers anticipate an increase in electricity demand over the next five to ten years and support Hydro One making investments to meet growing demand.

For some, they expect their demand to increase *significantly*. Several customers emphasize the importance of Hydro One making investments to accommodate increasing demand while maintaining current levels of reliability.

Large Distribution Customers

Most express satisfaction towards the overall service they receive from Hydro One.

When asked about their overall satisfaction with Hydro One, many customers focus on strong reliability, communication, and appreciation for their dedicated point of contact at Hydro One.

Some customers desire stronger communication with Hydro One, especially around response times.

Some report slow or infrequent communications with the utility, expressing a desire for clearer, more consistent, or more timely communications.

Many are satisfied with current levels of reliability, with some noting significant improvements over the last several years.

Nearly all customers describe the consequences of poor reliability as severe and having significant financial and operational consequences. However, current reliability is generally described as strong, with very few noting frequent unplanned outages.

Power quality is of significant importance to some Large Distribution customers.

Some customers identify significant problems with voltage fluctuations, which in some cases lead to equipment damage or disruptions to operations.

Customers are generally prepared to pay more to ensure that current levels of reliability are improved or maintained.

While a few customers emphasize the importance of cost competitiveness, most customers say they will pay more to ensure reliability, recognizing its importance to their operations. Many express concerns about the increasing frequency of severe weather, and several agree that Hydro One should make investments in greater resiliency.

Many recognize the need for Hydro One to make investments to proactively address growth.

Most customers anticipate an increases in their own electricity use over the next five to ten years, with many emphasizing the importance of preparing the grid for growth across the province.

Large Transmission Customers

Nearly all customers are satisfied with the services they receive from Hydro One.

Many describe their relationship with Hydro One as positive, open, and collaborative. Still, some would like Hydro One to make further efforts to have regular and personal interactions with their company.

Customers would like to see Hydro One focus on improving communications.

When it comes to improving communications, there is a particular focus on outage planning, project timelines, and coordination with Hydro One's operations. Some customers mention a desire for further automation or modernization of communications, especially around the status of service interruptions.

Most customers are satisfied with current levels of reliability, with some recognizing Hydro One's ongoing efforts to make improvements.

Across all types of LTX customers (Generators, End-Users, and LDCs), customers emphasize the severe operational or financial consequences of poor reliability. Overall, reliability is seen as acceptable and consistent.

Customers are consistently willing to pay more to maintain or improve current levels of reliability.

Citing the significant costs associated with poor reliability on their operations, customers are willing to pay more to ensure service remains at current levels or improves.

Customers want Hydro One to proactively address growing demand in the next five to ten years.

Many customers emphasize the importance of Hydro One making investments to support increasing demand without compromising reliability and expect their own demand to grow over the next five to ten years.

4. Commercial & Industrial Customers

4.1. Respondent Profile

The organizations that participated in the discussion span various industries, including manufacturing, transportation, education, and agricultural operations. Responsibilities of participants include managing, tracking, and optimizing energy usage, as well as billing. Additionally, there were some participants from energy and facilities management teams overseeing utility consumption for Ontario municipalities. Most participants note that their energy demand remains relatively consistent throughout the year, with some fluctuations during the winter or summer months.

> *"We're manufacturing – we're a company that extrudes [REDACTED]… So, we're high energy user. Most of our energy is used to drive a few very large horsepower motors in our plant, and we use typically about 850-kilowatts an hour when our plant's running at in a stable mode."*
>
> *"It's a family farm operation that's been in the family for close to 150 years… I do most of the accounting and bookkeeping for the farm"*
>
> *"I basically oversee the contracts, and the facility guys are the hands-on and deal with most of the contractors and everything. I oversee it and pay bills."*
>
> *"I'm the project lead for energy and facilities for [REDACTED]. I take care of all of our utility billing, energy management side of it. I don't pay the bills, our accounting department does, but I do set up any new accounts. I also work with our retailer who's the wholesaler for our utilities through Hydro One."*
>
> *"It fluctuates a little bit [demand], because in the wintertime it's darker and if we have growing lights, there is more power required. But in general, it's pretty much the same all year long."*
>
> *"The peak demand in the winter for heating is less than the peak demand in the summer for air conditioning."*
>
> *"Harvest time, it'll be a lot more used, so we have a high peak through probably October, November, December, and then it kind of levels off."*

4.2. Satisfaction with Hydro One

Overall satisfaction with Hydro One

Most customers express satisfaction with Hydro One, mentioning no significant issues and meeting expectations when it comes to providing electricity.

> *"I'd rate them fairly high."*
>
> *"No complaints here. Yeah, we're satisfied… On a scale of 1 to 10, probably at 7 or so."*
>
> *"They do a good job, all in all. Really, the litmus test is that when people turn on something that uses electricity and it works. They've met the bar."*

Some customers express indifference, stating that they know anything different, and mention some areas for improvement.

"I guess we don't know anything different, so I guess neither satisfied or unsatisfied. I guess that we're kind of used to it."

"I would give it a 3 [out of five], but my only reason why I don't 5… is there's still some tweaks that are needed. Out of all of our accounts, not all of them have been set up with smart meters yet. The online platform does not work very often."

Overall, very few customers expressed dissatisfaction with the service they receive, reporting problems with communication between the business and utility.

"We had a lot of issues with Hydro One trying to connect the building and getting service… There is no other place I can go… I'm stuck with them… The service I get from Hydro One is terrible."

How Hydro One can better serve organizations and their energy needs

Several customers suggest improving communication by providing a dedicated point of contact to streamline interactions, as they note challenges in contacting Hydro One and experiencing slow response times.

"Communication can be a little tough. It would be nice to have sort of a better regional point of contact rather than having to go though sort of the business customer centre every time, which can take several days to hear back from."

"We don't have regular communications with them, so I wouldn't say we have much of a relationship."

"I tried calling them and couldn't really get through their phone system. So now, I just email. I don't think they're very easy to get a hold of, to be honest…communication and administration can be tightened up a whole lot."

"Just like having a solid key contact for the organization…just someone that can direct you to the proper channels to go through."

Other customers feel that Hydro One could improve their cost-effectiveness to minimize rate increases and remain competitive globally.

"I guess get more cost effective. Get quicker at giving us upgrades."

"Just be efficient so we have efficient because we gotta compete in the global market. And if our costs are higher than the United State or Brazil or China or whatever, we can't compete."

"We're pushing so many businesses out of Ontario because of high fees like they're doing right now… people can't afford these fees… I think if you charge what is right, you'll have continued customers.'"

4.3. Rates

Where electricity fits within monthly expenses

For many commercial & industrial customers, electricity bills represent a significant portion of monthly expenses.

"It's a fairly big impact… It's like $20,000 or $30,000 a month, I think."

"Our biggest facilities sort of consumers are rinks and arenas, and 3 out of 5 are Hydro One, so that would be making up significant portion of our monthly utility budget… It's the highest."

"It's always the most by a lot… $325,000 to $350,000 a year, so I don't know where that puts in the scale of businesses. But when I look at that, I don't have a water bill for $350,000 or a gas bill for that matter."

Value for price

Most customers feel that the price they pay for electricity is reasonable given the importance of electricity or for the amount of energy they use.

"For the power that I'm using, I think it's relatively good."

"It's comparable to what we're getting with Utilities Kingston as far as sort of commodity cost goes."

"I'm not unhappy with pricing… If you look at energy costs, it's still pretty reasonable in terms of what you can achieve with that power once you put it to work through a piece of equipment."

"It's a function we need. We need electricity to run our [equipment]… to run the compressors, to make [REDACTED]… to run the pumps, to pump the water… keep the lights on in the buildings."

However, some customers express concerns about the price that they pay for electricity.

"I don't think it should be as exorbitant as it is… We switched all [bulbs] to LED, which did make a 30% savings and it's [price] still 2 ½ times for the heating. So, I think it's excessive."

"Affordability is huge… If you look at our hydro bills, it's really not affordable."

"Pricing of hydro right now is at a record high, and we have no service and no reliability."

Billing

Some customers express frustration with specific billing issues related to billing cycles, consolidating multiple bills, and net metering.

"Going through the summary billing, I'm downloading close to 300 PDFs a month… If there was an option to just download like Enbridge where you can just download your monthly bills and it comes out in a spreadsheet, that would be fantastic."

"Just the net metering billing. The way it's set up is we can never actually get our bills to zero with net metering even if we are over producing... Utilities Kingston, for example, if you generate $1,500, say of electricity in a billing period, and your bill is $1,400, then you completely nullified your bill, and you've got $100 credit for next month. Whereas, with Hydro One, only certain portions of the bills are eligible for credits… So, Utilities Kingston is much more preferable in that regard."

"I get four different bills. So, it would be much better if they were itemized on one bill, which I have talked to them about. They're like, well, you need to do this and put this in the subject line and send this out, and it took me several emails just to try and get them all dated the same time. I'm like, I don't have time to go online constantly checking for a hydro bill for four different locations here."

"When we tried to change our billing day to be in line with our demand schedule… there was no action and response saying, 'it is what it is.' And the reason that they gave me was, it was something along the lines of that for Hydro One to manage their billing, they had to have so many people on each day of the month, so that they had consistent cash flow or whatever they were looking at. But in them saying that straight up, and not making any bones about it, an absolute disregard for any of the consumers of the

product. It had everything to do with their banking and it was all about them. There was no we. There was no us there."

4.4. Reliability

Importance of good reliability

Reliability is seen as critical for customers, as power outages directly impact their ability to operate. The consequences of poor reliability are significant, with some customers facing operational shutdowns, disruptions to municipal services, or even the loss of livestock or crops.

"Each time I lose power, I can't operate anything in my building."

"For our hundred-day season (winter), it's paramount...If we do not have electricity, we can't turn the [REDACTED]… We have a night operation, so we can't turn the lights on at night."

"We can't function without electricity… Without power, we don't have wi-fi and we've had days where we've had a day of no wi-fi… If there's no hydro, we're kind of screwed all across the board."

"It would mean the majority of the municipal workforce going home for the day if we're experiencing power outages. It would mean disruptions to traffic, big municipal disruptions."

"We'd have dead animals [without power]. So, we have standby generators at most of our locations because if the power goes out, and we don't have standby power, we have dead livestock pretty quickly."

Current levels of reliability

Customers are generally satisfied with the current levels of reliability, with many mentioning that they rarely experience outages. They also emphasize that Hydro One works quickly to restore power during outages.

"It's reliable 90%... There is always power, like we have two sources of backup."

"I've always been impressed with their service when there is an outage… They've all been pretty reliable and certainly work with you to try to get you back online as soon as possible."

"The brownouts from 5 to 10 years ago don't seem to be happening as frequently."

"I feel like reliability wise, we don't really have many power outages, which we're thankful for."

"Sometimes you do have an emergency, but we have our own backup power system, so we're never without power for any length of time."

Some customers note more frequent outages, with some locations experiencing outages two to three times a month. Others mention issues with outdated grid infrastructure causing power fluctuations. However, many participants note that they have backup power systems in place to ensure continuity during outages.

"Depends on the location. There are some locations that hardly ever go out of power off the grid, and then there's other locations, probably two or three times a month. Mostly outages for 20 minutes to an hour… But then the generator just works."

"Actually, we do lose power semi regularly… I have two generators on site which do kick in occasionally… Short little blips, like an hour, half an hour, 20 minutes, 10 minutes, whatever."

"The grid where I'm on presently… dates back to 1967 and has barely been updated. It could be a sunny day here and my whole building will drop to one phase… It burns all the lights, it's hard on the HVAC system, it's hard on my compressors… This will happen once a month."

For a number of customers, maintaining consistent voltage levels is important, especially when running sensitive electronic equipment. While some customers explicitly mention issues with power quality, for most, it is not a top-of-mind issue.

"It's important if we're running equipment on the system… The bigger concern is the consistency of the voltage levels on the lines because it can do damage to some of the electronic equipment… Any of that fluctuation, if it's delicate equipment, it can be affected."

"The fluctuations where it's a quick fluctuation or blip that goes through, and it's a little but more than what can be absorbed, then all the computers go off. All of the point of sale goes down."

"We do experience some of that, but honestly, I would probably say like 20% of the time it's really not a huge issue."

4.5. Hydro One Priorities

Areas Hydro One should focus in the next five to ten years

When asked what Hydro One should focus on in the next five to ten years, the main areas that customers mention include providing reliable power and the need for increased capacity.

"I would certainly be prioritizing stability of the network… We just need more robust systems, and we have a quickly aging infrastructure."

"Probably increasing local capacity for solar installation. We're really looking at doing some big projects… and we're not always getting the approval for capacity at the local distribution."

"Please give us more power. That would be the biggest thing… We are producing more than 50% our own power not because we want to, but because there's no power."

"Length of the outages is key because that's when it becomes disruptive. Everybody can live with 1 minutes to 5 minutes, nobody can live with an hour or more."

Maintaining or improving reliability

Most customers want Hydro One to make investments to maintain or improve reliability, even if it means higher costs.

"I think the reliability is reasonable now… Stay reliable, or at least the same reliability."

"I would say that investing in maintaining the right reliability since we have quite good reliability now …it wouldn't be worth it to pay less and it impact the reliability."

"For us in the business…reliability much more than price."

"[When asked about the trade-off between reliability and affordability] Reliability, yes."

Closing the gap with the Ontario average

Some customers express a desire for Hydro One to make investments that would close the gap on reliability performance between Hydro One and the average Ontario local distribution company, emphasizing the importance of reliable electricity for their business.

> *"[When asked whether Hydro One should make investments to get closer to the Ontario average] Very important."*
>
> *"I think that would be very important goal to have. I mean, as I said for us in the business reliability, much more than price."*
>
> *"Yes. [They should make investments in] outages and capacity… increasing the infrastructure so that we can reliably continue to run our buildings effectively."*

Addressing growth

Several customers highlight the importance of Hydro One making investments that enable both the maintenance of current reliability and the accommodation of increasing demand for electricity.

> *"We have plans for future growth on our property and obviously we'll need hydro at them. Keep in mind the way it looks right now is that hydro needs can't be met, and they're not that reliable. So, it's a tall order for you guys to be able to say, 'We need to ramp up by 25% in Ontario in the next 5 years.'"*
>
> *"[When balancing growth and reliability] I think the reliability is going to be more important. It's great if we can install more heat pumps at more buildings, but it doesn't help if they're constantly blacking out."*
>
> *"Very important… I don't think that it would be worth to pay less for prices and it impact the reliability only because we have so many public use facilities. If the reliability wasn't as up to par or as good as it is today, we'd probably be experiencing a lot of service disruptions and service issues."*

Many customers report increasing capacity and infrastructure as a key area they want Hydro One to focus on to meet future energy needs.

> *"We switch more and more to electric heat. Our demand is just wild and we're really wanting to get off the natural gas and it's not always an option at this point [due to grid limitations]."*
>
> *"We definitely need more capacity on the grid… We are missing out continually on grant programs because we're unable to install renewable energy systems because there's just no capacity on the grid."*
>
> *"You're gonna have to get a lot more grid or more services within the grid. If everybody's gonna want all this hydro out there… I think they're just gonna need a lot more infrastructure in their grid."*

Resiliency to severe events

For some customers, severe weather events have little to no impact on them.

> *"In terms of extremes, we haven't been affected yet."*
>
> *"80% of it [reliability issues] is old equipment and 20% is related to weather."*

While for others, events such as increased rainfall, storms, and flooding have started to have a greater impact on reliability. There is growing concern that these severe weather events are becoming more common, leading to more disruptions in some areas.

> *"It's kind of the same. Maybe in the last one year period, there have been more severe rain… Rain and winds definitely impact things here with hydro and even wi-fi."*
>
> *"In our area, and I think in most areas, there's still a lot of dead trees along the road that come down and take it through ice storms and wind storms, and that kind of stuff."*
>
> *"We've been having increasing flooding and…well…increased precipitation which is increasing flooding in our low-lying areas. Also, just more frequent and intense storms which has increased the number of power outages we're seeing in our area."*
>
> *"We have a lot of trees, so that leads to actually it's not the storms itself, it's the trees falling over during the storms that are impacting the infrastructure."*
>
> *"That's about as important as the reliability piece. If we've got three-day long blackouts, as a result of a storm, we're seeing some problems."*
>
> *"Every building has got a genset system because you can't count on it [Hydro One] … We live in Canada. We've got weather patterns and so on and so forth. I find it rough that everybody's gonna invest $100,000 into backup systems because [Hydro One] can't supply."*

Many customers suggest that Hydro One should increase investment in more resilient equipment or facilities to better withstand severe weather. Suggestions include burying lines and more proactive tree trimming to help further mitigate weather-related disruptions.

> *"Absolutely. I think future proofing everything as much as possible and anytime anything's up for renewal or new construction is considered."*
>
> *"I think it should be strategically. They should look at the location and look at the vulnerabilities."*
>
> *"I have often wondered if you could put all the lines underground, it would get rid of a lot of ice and snow issues."*
>
> *"I really do believe that a whole bunch of our power should be underground in Canada."*
>
> *"Yeah, I would guess so. They used to do a lot more tree trimming than they used to, and most of the weather-related stuff is trees coming down… They used to be a lot more active on that."*

4.6. Future Expectations and Plans

Anticipated changes in electricity usage

Some customers expect their electricity usage to remain relatively steady, with no significant increases anticipated in the next five to ten years. For some, their focus is on improving efficiencies within their current operations rather than growth.

> *"I personally never had a desire to just keep growing and growing. I think it's more important to do what you're doing and do it well and try to gain efficiencies within what you're already managing."*

"No, we don't expect it to change much more apart from just continuing on our net zero transition plan and continuing to electrify more heating systems."

"Smaller electricity demands, and that's based on the technologies that we're using… Things like that increase the efficiency so that we end up making more [REDACTED] with the same amount of electricity."

On the other hand, many customers anticipate an increase in electricity demand, with some anticipating a near doubling of their demand in the next five to ten years due to projected growth in their business operations.

"It'll [demand] increase at least 20%, maybe to 30%."

"Probably will use more because we're going to expand."

"There's some huge expansions coming up in the next five years here, where we will need the power."

"Probably will increase… But if we could somehow make it work to generate some of our own power, we would if it was feasible."

"I would say almost double to be quite honest… Only because of our growth projection… We're going to see a lot more development going through within the next 5 to 10 years in all of our surrounding towns."

Organization's investments to transition from fossil fuels to electricity

Some customers either already do not use a lot of fossil fuels or are actively transitioning away from fossil fuels by adopting things like electric heating systems, LED light retrofits, heat pumps, or electrified equipment. Some have set net-zero carbon footprint goals.

"We don't use a lot of fossil fuels."

"With [REDACTED] target of net 0 by 2040, we are switching over more and more to electric heating, and so we are seeing those electrical consumption increases as well."

"We're definitely looking to go towards more electrification here…We've done all the LED retrofits in all of our facilities already."

"It's a pretty comprehensive program… Anytime any fossil fuel fired heating equipment is up for replacement, we're looking at switching that to heat pumps."

"Our goal going in every year is not to turn on the diesel compressors because it costs so much money… We would like to use the electric generators. We are continuing down the road of reducing consumptions."

Others may have explored electrification options but have found them to be cost-prohibitive given their specific circumstances. These customers express interest in transitioning away from fossil fuels if it was more cost effective for them to do so.

"We did that by putting in LED lighting. We have looked into geothermal heating. We've looking a lot and had different companies coming in, and we actually aren't able to do it based on the specs and bridge and all the stuff. I've got all the costs on it. We've tried."

"Haven't given much thought to that because I guess initially you would say, 'Well that'd be crazy,' cause it probably wouldn't be cost effective… We are kind of motivated by making money... But if a better way of electricity comes in that's more economical to use than gas, then we would switch to electricity."

Organization's investments in new technology

Some customers have already invested in renewable energy solutions or prepared their facilities for technology like solar panels and energy-efficient equipment.

> *"We do have a net metering contract for some solar panels … Energy efficient appliances, it's just standard now… as soon as there's something more efficient, you switch those out. So, we try to keep up with the technology if we know there's going to be a saving."*
>
> *"We're electrifying our fleet. We just finished… really big solar feasibility study on 25 different sites and we're hoping to explore the possibility of virtual net metering."*
>
> *"We've invested well enough that we've invested the last three barns that we built. We've designed and engineered the trusses to take solar if we decide to do that."*

Others have plans to invest in renewable energy sources or new technologies like solar panels, windmills, or battery storage systems.

> *"What one of our big goals is environment, or environmentally friendly sources of hydro…windmills or solar panels. Some way of connecting those into the grid and being able to utilize them efficiently."*
>
> *"The battery storage and the Cogen facilities. Those would be things that we would look at… where we have battery storage and then we put it back into the grid when the grid needs it."*
>
> *"We would love to have the option of virtual net metering. Right now, we can only use electricity that is generated on site for that site…we've got a lot of unused area, we've got a lot of big open roofs with building that has a fairly low demand. So, if we're able to produce offsite and sort of have municipal wide account pool for that net metering, that would be amazing."*
>
> *"Thought, but we haven't started. We haven't looked into it yet... We haven't talked about solar but we have been exploring."*

Importance of Hydro One reducing their own carbon footprint

Several customers believe it's important for Hydro One to take steps to reduce their own carbon footprint.

> *"I think that it sends a good signal to their customers… If we all do a little bit, it does add up… I think technologies that would fit, I'd be receptive and encouraging for them to look into things like that."*
>
> *"If our electric provider is not net zero, then we aren't really either. So that is very important."*
>
> *"I think if we can't do something about climate change, and I do believe it's changing… But anything we can do to compensate for that or reverse it, I think we have to be trying to do."*
>
> *"I think it's very important, because our emissions are basically reflected on the cleanliness of the grid…It would be interesting to see them invest a little bit more in efficiency program for commercial customers, because if we're conserving energy and consuming less, there's more room on the grid."*
>
> *"If it makes hydro more affordable, then it's worthwhile… I'm all for it, and I've even done eco-footprint tests and everything else. But at the end of the day, what they do, only people see how it affects the bottom line."*

At the same time, some customers are not concerned about Hydro One reducing their carbon footprint or feel that it is only relevant if it makes economic sense to do so.

> *"That doesn't really play a role. I mean, is it need to do or is it just a feel-good thing?"*

> *"Unless it makes economic sense, 0 interest in doing that… I don't think you have to do the politically right thing and move to something just to say you're green."*

5. Large Distribution Customers

5.1. Respondent Profile

The participants represent organizations from a variety of sectors, including manufacturing, agriculture, automotive, and more. Participants represent a range of roles and responsibilities in their business, including energy management, billing, sustainability, and operations. For most large distribution customers, electricity usage tends to be relatively consistent, with variations driven by specific operational needs and working hours.

> *"We run a fairly complex operation of [REDACTED] production. It's a fairly complex process and it is very sensitive to any interruptions."*
>
> *"We're a tier one [REDACTED] supplier…we're a manufacturer…we're a 24 hour shift operation with working on weekends…my title is engineering division senior manager. I am Hydro One's primary contact. I look after utilities, maintenance, more maintenance, purchasing materials…I'm also in charge of our greenhouse gas reductions and environmental aspects."*
>
> *"We're a greenhouse company. We start young plants for our greenhouse grower customers. So we're an important part of the food chain in Ontario."*
>
> *"We're a [REDACTED] manufacturing plant. So we have also a warehouse on sit and we have a store on site."*
>
> *"We are a greenhouse company…we do that and we have our own marketing company as well in sales. With the help of Hydro One, we're able to grow year round 365 days a year with the lights we have purchased."*
>
> *"So I deal with all the electrical distribution for the plant and if there's any major electrical changes inside the plant I'm privy to that. If there's new business coming in, I deal with that…we'll run typically size days a week, 24 hours."*
>
> *"Ramps up from September through till June with weekend work… Maybe the odd weekend that we're running a few things, but basically, we're pretty stable."*
>
> *"52 weeks of the year, it doesn't change."*

5.2. Satisfaction with Hydro One

Overall satisfaction with Hydro One

Most customers express satisfaction with Hydro One, citing reliable service and strong communication. Customers identify appreciation having a dedicated contact or account manager who is responsive, particularly in times of outage or maintenance.

> *"They do a good job of delivering the hydro I need when I need it… They're fairly attentive… I've got a contact with Hydro One… I can contact if I have issues…I get pretty good service from Hydro One."*
>
> *"Our large account rep is really good… Communication on outages or planned work has gotten better."*

"I know our account manager really well. So, if the power flickers or goes off, I can just drop him a text, and I hear back in 30 seconds… If they're doing maintenance work, they're really good too."

"It looks like 11 out of 10… The guy I deal with, he's fantastic… I have legitimately 0 complaints. They fulfill what we need 99.9% of the time. He's prompt with responding."

"Generally, they are reacting quite good… It's much more reliable... I can't complain about the service."

Some customers indicate that they feel neutral towards Hydro One. While they recognize efforts to improve, they still experience frustration with reaching the right contacts within the organization.

"They treat us more as a customer than before that you had no choice but to deal with them… Is it still perfect? No, but at least there's a communication line open."

"The people are good, but it's frustrating. It's the same as any large corporation, we feel like we get bounced around… We keep getting pushed through without knowing the right person to talk to… I would probably end up in the middle as a kind of not satisfied."

One customer expresses dissatisfaction due to slow responses and issues with system reliability, particularly regarding infrastructure changes.

"Our experience with dealing with Hydro One for infrastructure changes has been poor… Slow response is a problem… We do struggle with the reliability of the system."

How Hydro One can better serve organizations and their energy needs

Some customers suggest improving communication, as they report slow, infrequent, or unhelpful interactions, expressing a desire for clearer and more consistent communication.

"We really don't engage a whole lot back and forth… We do have our representative, that our electrician and I reach out to once in a while... I can't tell you her name right now. That's how infrequent we talk."

"They weren't super responsive… I wasn't always getting the answers that I wanted right away."

"Maintain the open conversation… that's the important thing… Both need to gain from that synergy."

"Not the easiest communication possible. You cannot get confirmation of when things will happen… then you hear 'Ohh by the way, you didn't fill out this form.'… And we don't know all the requirements they have… Every time there was a reason it took much longer than we anticipated to get the connection."

Some customers also raise concerns about capacity, expressing worry about the system's ability to meet future energy needs. While some customers mention increasing capacity, others mention finding ways to store extra power to be utilized at times of peak demand.

"Have more capacity… What we hear from Quebec… they're saying in 2035, there's going to be not enough power with all the electric car coming in and the new plants making batteries. The concern is everywhere. Is it possible in Ontario? We're going to be in the same boat."

"Concern from my point of view is the growth in the future. Are we going to have enough capacity to grow in the future?"

"They need to improve the transmission province wide though to allow for anyone to generate power and distribute it… We'd also like to produce power, and that's not an option just because of the capacity on the system."

"Can we have an energy system where we bank that energy that we are not using?... If we're consuming 1500 in peaks, while we're using only 1000 or 700 at night, if there's a system that we can bank that energy and use during the day."

5.3. Rates

Where electricity fits within monthly expenses

While some customers acknowledge the cost is higher than they'd prefer, they view it as a necessary expense, especially when compared to fluctuating gas prices.

"Is the bill higher than I'd like it? Sure. But even if it was lower, it would probably still be a little higher than I like it. So, it is what it is."

"Electricity as far as utilities goes would be second to gas but is still a significant expenditure."

"It's quite big compared to our natural gas and it's quite a bit more stable… Gas prices in the last year have gone up substantially compared to our hydro."

Value for price

Most customers generally view the value of electricity from Hydro One as fair, with the price being considered reasonable for the service provided.

"I would have to say the value is ok. I wouldn't say it's fantastic."

"Well, there's only really 2 options, option 1) you can get hydro from Hydro One, and option 2) would be your own generation… We've tried it and it just doesn't compare. So, options 1 is always the play for us."

"Overall, I think we get good value… For us to be competitive globally, our utilities need to be competitive. So, for them to benchmark globally would be important because that's who their supplying power to in the industrial sector."

"Everybody wants to try to save money, but I would say overall, it's a fair price."

"I've no complaints when at the end of the year, I take the amount of power I used and divide it by what it cost."

5.4. Reliability

Importance of good reliability

Nearly all large distribution customers interviewed describe the consequences of poor reliability as severe. Power outages can lead to substantial financial losses, damage to equipment, or operational downtime.

"They're [outages] pretty severe… If we have an outage, we have 200 people and not making parts… We've had equipment break… We actually broke a tie bar in an injection machine last year because the hydro had flickered off and, on a few times… So that was a $10,000 hit."

"Unscheduled outages for us are measured in hundreds of thousands to millions of dollars. So, they're materially impactful to our yearly performance."

"If our system shut off in the middle of winter and we didn't have our generators then and the boilers didn't work, and we couldn't heat our facility, then we'd be in trouble. The whole place would freeze."

"Reliability is key… We have backup generators and emergency plans in place for our water system. The challenge when we lose is that we have large pumps and large equipment running and that is hard stop in a pressurized system."

Current levels of reliability

Many customers report positive experiences with the levels of reliability they experience, with some noting significant improvements in reliability with outages becoming rare and overall service stabilizing.

"I have seen a big change in reliability with Hydro One over the years. It's fantastic… Overall, I'm happy."

"Before we built the new line, it was nightmare for brownouts and power outages, and just dirty power in general. Since we built the new line, it's been excellent… Now we have reliable clean power."

"We really haven't had outages… It's been pretty stable versus what we had been experiencing prior."

"I would say that the reliability has been acceptable. Our staff aren't walking around commenting 'Oh, here we go again with another outage'."

"I can honestly say I don't have as many issues with spikes or brownouts or stuff like that with Hydro, then I do from other distributors… I have complete backup… diesel generators that can run my facility for two days."

Power Quality

When it comes to power quality, some customers report no significant issues. Some mention using uninterruptible power supplies (UPS) to regulate power and avoid any disruptions.

"I have no complaints… We have UPS that regulate power function… I get alarms when we get that kind of thing, and I have very little problems with power fluctuation."

"I don't think we've been subject to a lot of fluctuations or things that are causing any issues in our equipment on site."

On the other hand, some customers identify significant problems with what they describe as voltage fluctuations or "dirty power." For some, power quality issues have led to equipment damage.

"We have a lot of power fluctuation, so have the engineer that challenged Hydro stating that it's unbelievable that we blew a lot of drives and things like that in the plant because it was too much power fluctuation."

"If the grid isn't stable, I've seen so many motherboards fry because of unstable and dirty power… I will say we're generally set up pretty good. We do have towers in our system, so we can be down for a period of time and still comfortably provide reliable water on the ways."

"Our variable frequency drives that we have on some of our pumps, they do not like dirty power. I've blown a couple of them over my career from dirty power, and they're expensive and usually significant operational impacts… It's pretty high impact for us."

5.5. Hydro One Priorities

Areas Hydro One should focus in the next five to ten years

When asked about the areas that Hydro One should focus on in the next five to ten years, large distribution customers largely focus on addressing infrastructure, expanding the system to enable growth, and safeguarding reliability.

"I think new technologies probably where they need to focus… Probably upgrading some of the older systems would be first thing that comes to my mind. Some of the older major lines."

"You know we want to make sure that our power supply to our site is reliable and that starts with our power feeds… We would want to make sure that that transformer station is healthy."

"I probably put distribution and increasing the ability to transmit power across the province as number one. And number two, I'd say reliability."

"Investments in reliability are important… We hear from Hydro and others that the grid will be taxed as electrification happens. We would not want that to result in a decay in reliability for the site."

Maintaining or improving reliability

Many customers are willing to pay more to ensure reliability is maintained or improved, recognizing its importance to their operations.

"I'm willing to pay a bit more to have the reliability…as long as I have the reliability, I don't mind paying the extra."

"I would [pay more] since our reliability is not where we would like it to be, I would say it's likely very important that there be investments there."

"I would go with option 2 to increase reliability for our industry."

"That's 100% if they maintain [reliability], I'd be happy."

A few customers emphasize the importance of keeping rates down to remain competitive relative to other jurisdictions. They generally feel that the current reliability level is adequate and would not support additional investments that would increase costs.

"I can't say that I would value reliability over cost competitiveness because that's you can lose both ways unfortunately in business."

"Don't think we should spend a whole bunch more money to make it better… I wouldn't want rates to have to go up… I wouldn't go and spend a whole bunch more cause it's pretty reliable now."

When it comes to aspects of reliability that customers believe Hydro One should focus on, some customers focus on outage communication and reducing the duration of outages. Clearer communication about outages, such as notifications, is identified by some customers as an area for improvement.

"Their workforce… every time something is a major outage, they do have issues with getting the right people in the right places."

"Well, communication on what actually happens for the outages… it would be nice if there was some sort of system out there that would say, 'Power flicker at 11:54'… I mean just send out an email."

"Limiting the lengths of outages… It's never been bad but if it ever becomes bad, it could be a catastrophe for this area."

Closing the gap with the Ontario average

Customers are largely ambivalent when it comes to whether Hydro One should invest in closing the gap with the average local distribution company (LDC) and recognize the contribution of the rural and remote nature of Hydro One's service territory to reliability outcomes.

"I think it would be a lot of money and maybe a waste of investment to try and catch up to other companies that have a smaller area to look after… I don't think that's a good investment at all."

"For me, I don't see that gap… I don't have any concerns."

"I pay more for Hydro One than I do for one in Brampton… I don't have issues in Brampton either, but yet I pay less… If there was Brampton Power here, I'd switch probably just for savings."

Addressing growth

Many customers recognize the need for Hydro One to proactively address growth while also maintaining current reliability.

"Very important, unfortunately. The government and society have put our hydro and our hydro suppliers in a rough spot with EV, with all the EV technology and forcing it on people. They want me to put easy chargers and just that alone, the extra amount of power is gonna be a lot."

"I trust that they're looking at this, and I trust that they're making the correct moves to continue with providing the same service that they are."

"So our concern is really that hydro's going to be able to supply us with the power, the right power for the future growth…there's no more promises [from Hydro One] on power availability…it's creating more concern than before."

"They have to do some sort of planning out for sure…we want investors to want to be able to come here and think that, 'yeah, I'm gonna have access to power'. It shouldn't have to wait ten years, and who's going to invest if they have to wait ten years to get enough power?"

"I would say they definitely should plan for [growth] now. And if you can plan, they're probably going to be cheaper than if you get thrown in where you have to do something overnight. That's when you really have to pay more. So I think if they plan it now and build it into their future budgets, it would probably be more of a gradual increase in rates."

Resiliency to severe events

Most customers report that while they occasionally experience power outages due to severe weather events, the outages are generally short in duration with power tending to be restored quickly.

> *"Other than lightning storms, major thunderstorms, I've never had any major outages... We had one major thunderstorm that knocked power out. Power was only out for 20 minutes."*

> *"Once in a while with the big winds, with big storm, we have power failure, but what can you do?... It's not major… They restore us really fast."*

> *"There might have been a couple storms, but our lines are above the residential. So even sometimes the residences will be out, but we'll still be on."*

> *"There was a bad winter storm, about two years ago. Hydro was out everywhere for probably that was the longest I've experienced it, probably 15 hours… I don't think anybody got affected by it severely… Had enough generation to last 15 hours."*

Many express concerns about the increasing frequency and severity of storms, such as stronger wind, rain, and snow.

> *"The storms are getting terrible. Everything just seems to be getting worse and worse, like the wind storms are worse, the rain storms are worse. It hasn't really affected the hydro to this point, but I can see it happening."*

> *"The weather's changing every day. It's getting worse. We don't get as much snow, but when we do, it's worse… When we get a thunderstorm, we get a flood."*

> *"Right now, they're doing an awesome job, but we need to also be realistic with all the weather changing like it is right now, maybe it's going to be more and more problematic in certain region… There's cost too, because every time there is big damage, it's not free."*

> *"The weather one is probably the most important because it's inevitable and because you don't know how long or severe it can be… The ones that last the longest usually cause the most issues… 2 very severe versus 7 small ones, I would the 7 small ones."*

A number of customers agree that Hydro One should increase investments in equipment and infrastructure that can better withstand severe weather events.

> *"If they're going to spend money, that's where I would go."*

> *"Definitely… There may be 1 or 2 at most, maybe 3 [outages last year]… Potentially with whole global warming and how severe storms are getting, maybe that might go up."*

> *"Anything that is reasonable, I expect them to do for planning purposes for the storms or something like that."*

5.6. Future Expectations and Plans

Anticipated changes in electricity usage

Most customers anticipate increases in electricity usage, driven by expansions in their operations such as growing automation or facility sizes.

> *"We're gonna grow in the future. There's no choice…We need to survive and the only way to survive is to be bigger…That means we're gonna consume more electricity."*
>
> *"We're going to use more…All of our facilities are going to grow… Double or triple the size of our automation, which would mean a lot more hydro. Probably 2 or 3 times more."*
>
> *"I think it'll just keep increasing and increasing. I don't really have an answer on how much."*
>
> *"Right now, we're only using about 11 megawatts and this would be about another 3 megawatts that we'd be consuming."*

However, some customers anticipate no significant change in their electricity usage, noting that while their equipment might increase, they expect efficiency improvements, which could reduce overall consumption.

> *"I don't know if it will [increase] or not. We're looking at more [REDACTED] machines, however I've been replacing hydraulic machines with electric and there's a 60-65% decrease in usage when I do that… We'll probably see a status quo, even though our equipment is going to increase."*

Organization's investments to transition from fossil fuels to electricity

Several customers are taking various approaches to reduce their carbon footprint. Some have explicit carbon reduction targets, with efforts to minimize energy use and reduce emissions. Others are already using mostly renewable energy sources and engaging in energy-saving practices.

> *"We want to be carbon zero by 2028… We don't have a large carbon footprint as it is, but we want to be carbon 0 because we don't manufacture anything… It's a little easier to have a 0 carbon footprint in a distribution center."*
>
> *"I would say we do a pretty good job at that. We don't really use that much gas in to begin with. We use mostly hydro when it comes to everything."*
>
> *"We're doing a bunch of different things - we have these light abatement currents, energy abatement currents, everything to try to keep in the heat to use as least amount of gas as possible… I can't day we do zero because that's impossible, but we're working on it."*
>
> *"We're working on plans to 2050 to try to be as clean as we can."*

Some customers are considering or actively transitioning away from fossil fuels and towards renewable energy sources.

> *"We're decarbonizing our fleet. As we're decarbonizing, we're looking to put in EV charging stations… The next step would be to look at our grid setup so that we can put charging stations fairly robustly throughout the city to be able to move towards the greener fleet kind of thing."*

"We produce natural gas because we have anaerobic digestion here on site so we're looking at potential cogeneration impacts…There was a lot of discussion about moving the natural gas heating supply over to the electrical grid."

Some other customers do not have plans to transition from fossil fuels to electricity, citing concerns about the ability of the grid to handle the increased demand and the high costs of switching.

"I don't have any plan here to do that. I just don't see the system being able to handle it or grid. I have 60 rooftop units that run on natural gas right now. If I were to switch those all over now, it would basically triple our hydro bill."

"I've investigated heat pumps to replace natural gas, and the cost factor is just astronomical. Like right now, it's not feasible for us to do that."

Organization's investments in new technology

Several customers are considering or have already made significant investments in new technologies to improve energy efficiency or generate their own power, such as energy efficiency upgrades on equipment, solar power, or battery storage.

"We just did a LED project to save $14,000 a month on our hydro bill… That's a huge reduction in hydro bills. If we can find more things like that to do, that's what we'll do."

"We're always considering new investments, if they're profitable… We have peak saving at the site because that is a mechanism that is that is profitable for us. So, we participate in that and we participate in demand response programs."

"We've done a lot of energy efficiency upgrades, a lot of upgrades on a boiler - burner upgrades, our control upgrades on boilers that help save quite a bit as well. We've changed our heating system fully. We have a condenser on all our boilers."

"Things like solar walls where we put the power back to the grid… Looking at going from AC motors to DC motors to variable speed frequency drives… Anything we can do for energy efficiency to make ourselves more green, we will… We're an environmentally friendly company and saving money is big."

"I can't say that we have concrete plans right now to invest in, for example, solar or batteries, but we absolutely have been looking at those things as possibilities."

"Our shareholders are also thinking about clear energy; they're looking at sustainable energy. We are looking at investing in quite a large solar generator on our greenhouse."

Importance of Hydro One reducing their own carbon footprint

Customers generally support Hydro One making investments that reduce their own carbon footprint.

"I'm going to say everybody to do their best to reduce their carbon footprint… I don't know their business inside out, but I would say it's just as important as anybody else."

"I wish I knew more about their initiatives for green energy… They're a big animal and I'd like to see that they're on the same track… Like are they electrifying their vehicles?...I would like to see them go green."

"There needs to be a shift in policy towards using renewable products for power generation, like with forest biomass being a renewable product."

"I think it's important…we're all going to have to do our part, so I think they should go down the same path as all of us…"

Some customers emphasize the importance of Hydro One ensuring that investments to reduce their own carbon footprint are carefully planned and come at a minimal cost to customers.

"I think it's important for the environment, but it's gotta be done properly…you have to have a plan on how you're gonna get there…It needs to be smart investment. It needs to be investment that the customer, the environment, and the company are all going to gain from."

"If they could clearly lay out the cost…here's how much we're going to save, you know? We probably would [support Hydro One to make investments to reduce their carbon footprint]…as long as it was reasonable…obviously if it was ridiculous, then it wouldn't be that attractive."

6. Large Transmission Customers

6.1. Respondent Profile

The large transmission customers interviews include those representing generators, end users, and local distribution companies (LDCs). End users largely represent sectors such as mining, chemical processing, and other large-scale industrial manufacturing. Most participants hold senior roles in their organization in operations or engineering. Energy usage patterns are unique across the organizations that participated, but can follow a seasonal pattern, with higher demand in summer and winter. Some customers, depending on their operations, report consistent and continuous energy use.

> *"If the demand is high enough and there isn't any [or sufficient] wind and solar, then our plant gets dispatched. We are probably running about 20% of the hours in the year." (Generator)*

> *"Maybe in the winter and shoulder seasons it's a little bit less only because we get more output from our generation. So, we use a little less from the grid. But other than that, we're flat line 24/365… It never shuts down." (End-User)*

> *"Our facilities are sometimes meant to run in the cold more so they can produce more in the in winter. That said, in the summer we use a lot of cooling water which would use a lot more electricity. But other than that, it's just meant to run 24/7." (End-User)*

> *"We service [REDACTED] customers and our service territory… [is] quite geographically diverse." (LDC)*

6.2. Satisfaction with Hydro One

Overall satisfaction with Hydro One

Nearly all large transmission customers interviewed are satisfied with Hydro One and describe their relationship as positive, open, and collaborative.

> *"Our relationship [with Hydro One] is quite good. It's open. They've made for the better based on input we provided, and I would think they'd say the same with us." (Generator)*

> *"In terms of customer service, I am happy with Hydro One." (End-User)*

> *"Hydro One's been a good partner with us to make us aware of whether or not the work that they're doing on transmission is going to affect our load. [Our contact is] very attentive to our inquiries in helping us understand what they need to do us and them listening to what we need as well. So, I think that's really positive." (LDC)*

> *"Our relationship with Hydro One is good. We're satisfied with the response that we get. There's always some room for improvement, but no significant concerns with their service to us." (LDC)*

Only one participant describes their overall relationship with Hydro One negatively due to perceived competitiveness from Hydro One along with other operational challenges.

> *"Great people work there. [But] they don't treat us like a customer. They treat us like a competitor." (LDC)*

How Hydro One can better serve organizations and their energy needs

Some customers identify areas for improvement to further strengthen their relationship with Hydro One, such as streamlining processes, communication, and long-term infrastructure planning and timelines.

> *"The largest challenge is timing with them. The two companies need to get better at aligning and streamlining these [application] processes so that we can move forward on both ends." (Generator)*

> *"There are some logistical concerns. The company does struggle with fluctuating timelines and communication." (End-User)*

> *"One concern I have is just their ability to meet timelines. [They are] tied in their own internal processes, and then you might end up [with] six months of delay that didn't have to happen because it sat on approval points of process." (LDC)*

> *"If they can share the future capital plans, information like what's [their] requirement gate is expecting on the northern part of Ontario… it's good to know." (End-User)*

Some customers suggest an improvement in efforts by Hydro One to have regular, and personal interactions with their company.

> *"There's a lot of one-way nonverbal communication nowadays, and a lot of it gets overlooked because It's just an e-mail… I don't think I got that, like a personal call." (End-User)*

> *"When I brought up [requests], I haven't heard feedback. It's falling through cracks. It either wasn't delivered or was [not] considered, but nobody got back to me." (End-User)*

> *"The planning sector sends me a spreadsheet of planned outages. The one part that's missing is I usually have to reply to that e-mail to say 'hey, does this affect our load?' Because of course they can redirect power and not affect our load. That's never clear." (LDC)*

Some specifically mention automation or improvement to interfaces that would enable real-time information sharing, especially in cases of service interruptions.

> *"Having an active software that can show me outages that are coming up, and I can plan for and have real time access to … I would say that's honestly the best." (End-User)*

> *"A lot of their [Hydro One's] processes are manual. Automation [could help] a lot of these things." (Generator)*

> *"But the communication interfaces sometimes just aren't as up to date as they should be… It should probably be a web page that you can actively check and get notifications if anything is changed. So I can hear instantly rather than wait for my automated email that comes every Friday." (End-User)*

6.3. Rates

Where electricity fits within monthly expenses

Most large transmission customers consider electricity costs as a manageable part of their monthly operations.

> *"Drop in the bucket…it doesn't move the meter, figuratively speaking." (Generator)*

"[The bill] is still going to be positive for the month because we did run for the first two weeks and then producing at a good amount, enough to pay the bills and stuff like that." (Generator)

"Right now, energy is 8% of our total operational costs, that includes gas. [If] I break it down, [it would] probably be half for electricity, half gas." (End-User)

"Ever since we changed over to a direct connect, that significantly changed our overall rate that we were paying… But we were now paying like a kind of a blended rate per kWh, that definitely positively impacted the financials of the company." (End-User)

Value for price

Most say that they get good value for the price that they pay for electricity.

"We have the lowest energy price in our group, and I think we have probably the lowest energy price anywhere in North America. So, we're pretty satisfied with what we're doing right now… Overall, we're very satisfied with the price we pay." (End-User)

"We generate our own power as well, so I can compare what it costs to generate as opposed to what it costs to purchase. We're a flat base load all year. But I can see what the difference in prices from Hydro One or the grid, from generation…we're not unhappy." (End-User)

"[The value] is not bad… Our overall blended rate is a lot less than what is on the residential side, simply because we take advantage of the global adjustment side, which reduce the overall rates." (End-User)

One participant feels that electricity prices are higher in Ontario relative to other jurisdictions, which they say may lead them to grow their operations elsewhere.

"[Looking at] the overall cost for electricity, [Ontario] is our most expensive region… We just grew and are scarred from that growth experience… The Ontario market might not be the market we grow again [in the] next 10 [years] for a number of reasons, one of them being the electricity costs." (End-User)

6.4. Reliability

Importance of good reliability

Across each type of LTX customer (generators, end-users, and LDCs), customers emphasize the severe operational or financial consequences of experiencing poor reliability.

For generators, most customers highlight the importance of reliable power in their ability to generate power and feed it back into the grid.

"Even though we generate [electricity], if their system isn't available, then we can't generate. The reliability of their transmission network is vital." (Generator)

"Reliability would be at the very top... In the generation world, [we measure by] EFOR – equivalent forced outage rate. It measures how bad we do things. The smaller the number of, the better we look." (Generator)

End-users commonly cite significant financial losses and sometimes safety issues when facing interruptions or power quality issues.

"[Interruption] causes our equipment to trip. It usually shuts down very hard… Our facilities are billion-dollar assets. It's a commoditized product and they're making in a very large amount of volume. [Also], there'll be a cleaning cycle… because you have to clean out the vessels and reactors and start again." (End-User)

"Lots of money goes out the window when that [outage] happens… It's a lot of money to get them back because you can't just dump them down the drain and start over. So yeah, it's very expensive." (End-User)

For LDC participants, reliability issues have a broad impact on their customer base and in some cases, their relationship with their own customers.

"It's a big deal to us because that's going to affect 1/3 to 1/2 of our customers and it's going to take us some time to bring all the customers back online. It's a pretty devastating loss to a good portion of the town." (LDC)

"The impact [of an outage] on us is tremendous… With one issue on the Hydro One transmission line, you could be easily affecting 40%, sometimes up to 50% of our customers… like tens of thousands [of customers]." (LDC)

"When there are outages… some of the grocery stores need to get mobile generation units or mobile refrigeration units, or it's spoilage. So even though it's uncontrollable by [our company], it will still [affect our] brand reputation negatively." (LDC)

Current levels of reliability

Most customers are satisfied with the current levels of reliability, commonly citing improvements over the years.

"Reliability has continued to improve over the years. If you look back about 10 years ago, it [outages] was very frequent." (Generator)

"They [Hydro One] do a great job… I would say their reliability's got to be on par with anyone in the world." (End-User)

"Reliability is better than what it used to be. [But] it still has room to grow." (LDC)

Some customers recognize Hydro One's continuous efforts to improve reliability.

"There was historically not as good reliability, because the [REDACTED] transmission connection was a singular connection and so whenever there was maintenance done on that Hydro One substation, they would have to take the town out for a full 8 hours. Hydro One installed the switch so that we could go to a different feeder. And so, we found that that has dramatically minimized the time that we've had again the entire city out, which is really produced a lot of positive feedback from our customers. Because, they're starting to see improvements being made." (LDC)

"In the last four or five years, we have only one or two [outages]. […] Other than that, I'm pretty happy and I like they are doing some projects to further reliability on the system." (End-User)

"Hydro One is doing pretty good right now [on reliability]. I've seen them doing some projects to improve the reliability." (End-User)

6.5. Hydro One Priorities

Areas Hydro One should focus in the next five to ten years

Many customers mention proactively addressing growing demand as a key area that Hydro One should focus on in the next five to ten years. Generators are especially likely to want Hydro One to focus on preparing for growth.

> *"Ultimately the biggest challenge for [Hydro One] is the grid, the grid is going to have to grow… Over the next five years, [we need to] start to plan out with them – where is the generation going to be? How will the grid have to change to support that?" (Generator)*

> *"Infrastructure. Obviously. A lot of the sites that we are looking to develop are remote. So obviously, we're going to need to have transmission installed to go to these sites. […] We need Hydro One to work together with the suppliers to make it happen." (Generator)*

> *"Transmission expansion. The IESO, Ministry of Energy [… announced] 'we're going to put in 5,000 megawatts by 2031 or 32. The existing transmission infrastructure can't support that. So all transmission has to grow." (Generator)*

> *"The electrification is coming there. We have to be ready for it. Everyone has to be ready for it." (End-User)*

Some customers mention investments in infrastructure renewal as a key area that Hydro One should focus on in the next five to ten years.

> *"The whole power grid in Ontario is made in the 80s… We're getting up to that point at which it's exceeding that threshold significantly. So that's something that they should probably look into investing into, upgrading their infrastructure so that it can be more reliable for the future." (End-User)*

> *"Some old transmission lines are still connected. Those could be a hazard. So, there is still a lot of infrastructure they need to improve." (End-User)*

> *"Hydro One in the past had a metric that said if so and so much load is connected to only a single transmission line, according to their metric, they needed to up size it to a double transmission line. Having that metric be low enough, addressing single transmission lines and single contingency failures is an area for improvement." (LDC)*

Maintaining or improving reliability

When discussing the trade-off between cost and reliability, LTX participants are overwhelmingly willing to pay more to maintain or improve reliability, citing the costs of poor reliability to their operations.

> *"The reliability is more important than a few cents on the bill. I can understand having my own house that I don't want the rates to go up and I'm OK with power outages every once in awhile, but not here. Different here." (End-User)*

> *"...categorically investments in improving their posture for resiliency. I probably tolerate a cost increase associated with that just because the cost associated with failure is much more significant." (LDC)*

"Hydro One's system is in good, favourable reliability… and there's not so much you can do [with] winds and hailstorms. So keeping it in good condition to sort of operate at the normal level, but then pre-investing where it makes sense." (LDC)

Addressing growth

LTX customers emphasize the importance of Hydro One making investments to support increasing energy demand without compromising reliability.

"[Hydro One] have a tremendous task ahead of them as the sector grows and demand increases in Ontario and similarly so do we. The model is forecasting that Ontario's demand is expected to double by 2050. So that their infrastructure and everything has to improve just as we have to find more generation." (Generator)

"I think that's extremely important." (End-User)

"Significant, [it] is very significantly important because if they don't start the investment today, they won't be able to meet the requirements for sure." (End-User)

"[In areas] where they're already investing in assets, [they can] pre-invest that extra to prepare for a potential future of higher needs from customers." (LDC)

Resiliency to severe events

Most generators are satisfied with reliability related to severe weather events, acknowledging Hydro One's timely response to outages caused by severe weather.

"It's about the same. Even I'd say it's even been down a bit from when I first started here from outages in the summer due to lightning. This year I think we had one for lightning. So that's very good." (Generator)

"We're not so concerned about Hydro One [regarding severe weather events]. It tends to come back up fairly fast. And they're pretty good at moving from maintenance mode to all hands on deck in a hurry." (Generator)

"You should keep up time there, but we're not really affected." (Generator)

Further investments in resiliency are seen as more important to some end users and LDCs due to the significant impact on reliability.

"Without electricity our plants don't work. Those are billion-dollar assets that would be just sitting. So yeah, if there are threats to power supply like severe weather, insulating their system would be key for us." (End-User)

"The whole industry is under that microscope right now of resiliency. To me, that's almost just standard operating procedure that we need to strengthen the backbone of our systems." (LDC)

6.6. Future Expectations and Plans

Anticipated changes in electricity usage

Anticipated changes in electricity use vary across the organizations interviewed. Some customers expect their usage to stay relatively stable over the next five to ten years.

> *"It'll be the same. It'll be flat, baseload all the time." (End-User)*

> *"We have 1% growth in both population and in new business. So not a lot [of growth]. Even none of our developers are electrifying the new subdivisions. They're still putting in natural gas. They're not putting in EV connections in these new homes… On the residential side, we're not seeing residential load switching." (LDC)*

While others anticipate growing demand over the next five to ten years.

> *"I can see [us] going to increase the load gradually, like 15% to 20% maximum in maybe 7-8 years." (End-User)*

> *"There might be a slight increase. We still have a bit of room in the contract. I don't see it substantially increasing." (End-User)*

> *"We've seen a lot of inquiries on the larger data center. We're talking about 30 to even 100 or even 200 MW. That's two or three transformer stations by itself. We foresee that electrification will drive the load for the whole service area. When we did the load forecast [and] identified [that] we need to, in the next 20 years, probably increase the existing transmission capacity by 50% to 60% to meet the need." (LDC)*

> *"We're in early planning for a potential addition of up to 4,800 megawatts on site. That's part of that powering growth of Ontario [that] the province has asked us to look at that." (Generator)*

> *"The only place I can see that being a problem is if we start cording things like data centers. I think EV charging will be some of that, but I think that's going to settle down." (LDC)*

Organization's investments to transition from fossil fuels to electricity

Many customers say they have taken steps to transition their facilities and operations from fossil fuels to renewable sources of energy. These investments are often driven by corporate electrification strategies and a perception of long-term return on investment.

> *"We are in discussions with solar farms [for] different ways of producing. We're mostly renewable energy, so no coal-fired the boilers, no gas boilers, no stuff like that." (Generator)*

> *"The owner [of our company] has said that 'carbon neutral is our license to operate.' So, all the expansion, all the new products and new plants that we're going to build are all dependent on us being carbon neutral. To decarbonize, we'll need a new transformer station... We'll have to bring in an electric boiler." (End-User)*

> *"We are having electrical boilers to [replace] the existing natural gas boilers. [These are in] their five-year planning. Some fundings are already in. Some of them are currently under design." (End-User)*

But, not all customers say that they have taken steps or have plans to transition away from fossil fuels in the next five to ten years, as other strategic priorities or financial considerations have taken precedence.

> *"Nothing significant, unfortunately. That's not really on the company priority list right now. The company is looking for a more accurate way of making [products], not really changing any of the electrical infrastructure to support a more efficient plant." (End-User)*

> *"It's driven by a business case… In the future, I wouldn't discount it [if] the price of solar keeps on getting less cost prohibitive." (End-User)*

Organization's investments in new technology

For those who plan to invest in new technology, battery and solar are mentioned as common considerations. Some customers say that these new technologies can provide opportunities to enhance flexibility around peak load and lower overall costs.

> *"The only thing we are thinking [about is] maybe the battery storage... But we haven't really built anything like that yet. The main driver on that is again for the curtailment." (End-User)*

> *"Battery seems to be the flavor of the day right now." (Generator)*

> *"There are currently plans to potentially have a solar area or a battery energy storage system in the future, but nothing concrete… The primary goal for the company is money… to charge up the batteries off peak hours, and then we could effectively lower the overall electricity rate that we're paying on average." (End-User)*

> *"I know we have had meetings for various solar projects and that would be to offset our peak electricity in the summer." (End-User)*

Importance of Hydro One reducing their own carbon footprint

Many customers believe it is important for Hydro One to make investments to reduce their own carbon footprint, but priority levels and reasons for support vary.

> *"[We are] a green, renewable energy company. That's the goal of everybody to be as green as you can." (Generator)*

> *"It is important because if somebody tell us the grid is not clean, now we have to invest something else to make it clean, because otherwise how do you meet the target?" (End-User)*

> *"It is in the strategic objectives of our board to reduce our carbon footprint [and] to promote and enable that to the greatest degree possible… Anything Hydro One could do would provide a better overall footprint. I know there'd be a cost premium for that, but we would support carbon footprint reduction initiatives." (LDC)*

Other customer say that they worry making investments into reducing Hydro One's carbon footprint could come at the expense of other priorities, such as reliability or cost.

> *"If you can do it and still maintain everything else, fine. [But] it may impact reliability because I'm not sure battery powered fleets work so well in Northern Ontario when it's -40." (Generator)*

"They want to be decarbonized, which means there's going to be a lot of large investments in nuclear and hydro, which is not a bad thing. But it makes [Hydro One] uncompetitive for energy intensive industry. If there are other jurisdictions with lower energy costs, it just inherently puts Ontario into a bad position." (End-User)

"A company like Hydro One, that is so integral to the success of every person in Ontario basically… It's very important for them to be reliable, regardless of [whether] they can have more energy efficient facilities, try and decarbonize their fleets, get hybrid vehicles for local areas, initiatives that help them overall. But nothing to ever restrict the reliability of a company." (End-User)

Appendix 3

Hydro One Stakeholder In-Depth Interviews

Phase I Report

2028-2032 Joint Rate Application

Prepared for:

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Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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2. Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Inc. (Hydro One), to gain a deeper understanding of the needs and preferences of customers, specifically as it relates to Hydro One's Joint Rate Application to the Ontario Energy Board (OEB) covering the years 2028 to 2032.

As part of this engagement, INNOVATIVE conducted qualitative research to uncover specific electricity needs, outcomes and priorities from municipalities and industry associations in order to inform planners for the 2028 – 2032 draft investment planning process. All industry associations and municipalities interviewed either directly or indirectly serve Hydro One transmission or distribution customers.

This report summarizes the results of a series of in-depth interviews with municipalities and industry associations.

Approach to Stakeholder Engagement

Hydro One provided INNOVATIVE with the contact information of selected industry associations and municipalities who either directly or indirectly serve Hydro One transmission or distribution customers. INNOVATIVE invited associations and municipalities to schedule a meeting with INNOVATIVE to share their needs and preferences as they related to Hydro One's Joint Rate Application covering the years 2028-2032.

Outreach efforts included Hydro One's community and municipal relations team and external relations team pre-socializing the interview opportunity, providing a brief summary of what to expect from the interview, and that INNOVATIVE would be reaching out to them in the coming weeks.

INNOVATIVE began sending initial invitations to associations and municipalities to participate in an interview on October 7th, 2024. Those who had not yet signed up to participate in an interview received a reminder email from INNOVATIVE between October 15th and October 17th, 2024. This outreach led to interviews being conducted with 9 industry associations and 9 municipalities via videoconference or telephone.

Audience	Participants
Industry Associations	Association of Power Producers of Ontario BOMA Ontario Ontario Chamber of Commerce Canadian Renewable Energy Association Ontario Federation of Agriculture Canadian Federal of Independent Businesses Ontario Greenhouse Vegetable Growers Automotive Parts Manufacturers Association Canadian Manufacturers and Exporters
Municipalities	Durham Region City of Sault Ste. Marie County of Essex Chatham-Kent

	City of Toronto City of Greater Sudbury City of Kingston Region of Niagara City of Peterborough

Interviews were approximately 45 minutes in length and were conducted by a trained moderator following a discussion guide. In appreciation of the time provided by participants, INNOVATIVE offered a $150 cheque in either the form of a cheque or a charitable donation for each participant.

About this Report

This report summarizes the key findings based on these interviews. In general, our approach is to report representative verbatim comments and offer interpretation and/or commentary where necessary. Verbatim responses are shown in blue italics.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for directionally. In interview-based research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view.

3. Key Findings

Industry Associations

Most associations report having a strong relationship with Hydro One.

For those who do, they cite positive communications and collaboration on major projects and planning.

Some associations report very limited contact with Hydro One and are unsure of who they would approach if they needed to engage with someone from the utility.

Some would like Hydro One to be more proactive in their communications and share more information with them or their members on things like energy saving opportunities, better understanding bills, and information about how the system works.

Associations largely report strong reliability on behalf of their members, with some concern in more rural and remote areas.

Good reliability is of significant importance for members of many associations. Overall, the current state of reliability is viewed positively; however, there are concerns about more significant impacts in rural and remote areas.

Many associations strongly emphasize the importance of Hydro One preparing for growing demand of electricity in the province.

Some associations express concerns about capacity constraints, especially as it relates to growing demand due to electrification and the changing ways their members are using electricity. Many believe that Hydro One should prioritize preparing for the energy transition in the next five to ten years.

Several associations want Hydro One to explore new technologies and approaches to help meet growing demand and build resiliency to severe weather.

Some associations specifically mention the exploration of non-wires alternatives and enabling more local, small-scale generation to meet these emerging challenges.

Municipalities

Municipalities' relationship with Hydro One vary, with some describing a strong, collaborative relationship and others reporting little to no engagement with the utility.

For some, this limited relationship is not identified as an issue, especially since they have a closer relationship with the LDC in their own municipality. Others desire more proactive engagement, specifically mentioning more frequent meetings or touch-points.

Many highlight affordability of electricity as an important priority.

This is especially in the context of the ability to attract businesses and growing industry to their community and for more vulnerable populations, such as seniors and those on fixed incomes.

Most municipalities are satisfied with the reliability they experience today.

Municipalities largely note that outages are rare and when they do occur, they are happy with Hydro One's response. Some call for Hydro One to make investments that improve the resiliency of the system in order to better withstand extreme weather.

Several municipalities anticipate their communities will experience growing electricity demand in the next five to ten years.

This is driven by a variety of factors such as residential growth, industrial growth, electric vehicle uptake, and electrification of transit or fleets.

Many express concern over the adequacy of capacity to meet future demands for electricity.

They emphasize the importance of Hydro One looking to the future and making the necessary investments to meet this growth. Some specifically call for improved communication and sharing of information between Hydro One, municipalities, and key planning entities like the IESO.

4. Industry Associations

4.1. Relationship with Hydro One

Current relationship with Hydro One

Most associations express a strong relationships with Hydro One, frequently engaging in discussions or collaborating on large projects.

> *"We engage with Hydro One on the need for more transmission build out in this province to enable more load, but also enable more generation on the system… I think we have a good working relationship with senior leaders at Hydro One in transmission and distribution"*

> *"I have a very extensive relationship with Hydro One… We have a member service rep that helps the local customers and our members. We participate in Hydro One town halls, and whenever they're doing large projects… We have dealt with Hydro One for years."*

> *"The relationship that we have with Hydro One is pretty good and they do proactively kind of reach out to our members."*

However, a few associations report limited or no contact, not knowing who to approach at Hydro One.

> *"No interaction in my current role… interactions are primarily with Toronto Hydro."*

> *"I wouldn't really know who to contact, like who's working within the building ecosystem in Toronto from Hydro One."*

Some want Hydro One to take more initiative in communications, with one suggesting that they should be more proactive in developing relationships with associations.

> *"I reached out to them… My advice would be for them to actually reach out to associations like ours… I think it's incumbent on them to reach out… and establishing that relationship."*

Overall satisfaction with Hydro One

Most associations express general satisfaction with Hydro One, mentioning their visibility in communities or leadership in the sector.

> *"Hydro One seems to be doing pretty well with being visible in communities. Being open to dialogue and feedback from people in communities… I think their commitment to the local footprint is impressive."*

> *"I see them as a leader… Look at the level of success we were able to achieve because we've had backing from a company like Hydro One, who's done a very good job of listening to the people."*

4.2. Current and Emerging Needs

Preparing for growing demand

Some customers express concerns about capacity constraints, particularly noting anticipated increases in demand due to electrification or the changing ways electricity is being used. They emphasize the need for Hydro One to proactively prepare for growing demand.

> *"Capacity issues are definitely something that's coming up... They want to start putting electric vehicle charging, electrifying their boilers, their water heaters… Is there capacity to do that? Toronto Hydro says yes, but a lot of media says no."*

> *"There's so much capacity constraint down here and a lot of demand for energy… There isn't a lot of capacity in these smaller distribution lines."*

> *"I think there was an incentive out a couple of years ago to have electric [redacted] machine… except I couldn't install that because there isn't the capacity in my distribution network for me to suddenly for three months of the year, have that much draw on the system."*

> *"There's a lot of concern about energy supply, given how many of these electric vehicles the Ontario government wants to put on the market… So, there is a concern about energy supply on the EV side, and energy charging."*

> *"I anticipate that there's going to be significant development in Ontario. Infrastructure development, electricity… They need to be ready… ready for the large amounts of development and everything that comes along with that… Build it out now. It's cheaper now to do it than later."*

Information sharing

Some associations say they would like Hydro One to share more information with them or their members on things like how to reduce rates through energy efficiency, explaining billing and costs, or information about the system.

> *"The biggest thing is for Hydro One to make known more through our association how they can help reduce rates through energy efficiency."*

> *"Our members would like to have more detailed, more streamlined, useful interactions with Hydro One when they're looking to connect hypothetical project or a potential project that would connect to Hydro One's transmission or distribution grid."*

> *"How careful and cautious they are with sharing their maps and their system, and their connection capacity limits on each of those lines and circuits on their map…We need this information to make good development decisions… Let's have an open access information, all these other jurisdictions provide it."*

> *"Hosting public sessions for information sharing just so that people can understand… the way the bills are set up, understanding why the costs are what they are."*

Affordability

Affordability is a significant concern for most associations, as electricity is identified as a significant cost for many association members.

> *"Cost of energy is probably the main issue I would say… They want to know that there's energy available for the long term at a reasonable price."*
>
> *"Cost of doing business is always right up there… a slice of that is electricity as a major cost that they [members] have to deal with… So, it comes up as a concern since the sustainability of their business relies on access to electricity."*
>
> *"I hear the general thing. Everyone says that it costs too much for electricity. And for my customers, they don't have a lot of options that you might have… They're also a business, so it's not like we can shift to off peak times… We can't participate in a lot of things that are designed for the general customers."*
>
> *"40% of our members say that electricity costs are a major cost constraint, so keeping costs low… A lot of small businesses have yet to pay off COVID debts. They cannot afford any cost increases at this time."*
>
> *"In an ideal world, we don't raise rates. We freeze them ideally and the energy supply be reliable… If you have to raise them at some point, reach out to businesses to see what they can afford."*

Reliability

Good reliability is critical for members of many associations, recognizing the importance of stable electricity supply.

> *"In the summer…the floods. That reminded people how important electricity is… But in terms of day-to-day reliability, there hasn't been any serious concerns."*
>
> *"Those connections need to be reliable… If there are situations that occur that are a problem, they need to be remedied relatively quickly."*

Overall, most report good reliability for their members with no significant concerns. However, some challenges exist in remote and rural areas, where power outages can have additional consequences.

> *"We're not having brownouts or reliability concerns… There's not concerns about the current system."*
>
> *"The reliability for the most part is quite good. I will say this - there are certain areas, more remote areas, ends of radial lines, that kind of thing where either a [REDACTED] customer maybe doesn't have the optionality associated with taking some of their feeders out of service and doing some work and still being able to do their job."*
>
> *"Power outages in the rural system are significant… If they have to do some upgrading… what they end up doing is going in there and replacing as much as they can… they'll replace stuff that doesn't even need to be replaced yet because they know they can't come back here next week or next month or even next year and replace things… So, it's an unfortunate kind of situation in one way it wastes money. In another way, they're aware that they have to have an uninterrupted service for their customers."*
>
> *"I personally think they do a pretty good job [communicating about outages]. I think it's more education for the general public to understand that there are these pieces of information available… I don't know how much more they can do to improve that communication."*

4.3. Hydro One's Priorities

Preparing for the energy transition

Many associations believe Hydro One should prioritize preparing for the energy transition in the next five to ten years.

> *"Energy transition… So, generation's part of it but transmission is part of it as well… Hydro One is the best advocate for transmission… They need to provide information to policymakers, to the IESO…this is not just a single-issue discussion… if they have a situation where they think they can propose something that is more reasonable in terms of costs and reliability, then by all means it is up to them to do so."*

> *"We're obviously aware of the energy transition that is taking place is going to be a fundamental change in the electricity sector. I think the IESO is suppose to be coming out with a new forecast… I'm expecting they're going to say we are further behind that we though we were in terms of both capacity and energy."*

> *"I see them as an enabler for sure, and in fact even catalyst to [energy transition]. The more positive news and strides that Hydro One makes… to me, that's a win. It's a social responsibility for large companies like this. I feel to do their part, I think it's a great thing."*

Exploring new technology and local generation

Several associations want Hydro One to explore new technologies and approaches like non wires alternatives and enable more local generation to help meet growing demand and build system resiliency.

> *"I don't remember a period of time where we had as daunting a task in front of us as we do today … So, from a transmission side, Hydro One hasn't done this kind of a build out either and they haven't worked in this way where they're looking at non wires alternatives as well as wires alternatives to generation sources and being reasonable in terms of this is what it could mean."*

> *"Building in redundancy. Building in microgrids that they can tap into so if there is large scale outage, we can still operate… Adding in new non-wires alternatives, or other infrastructure, smaller infrastructure they can tap into is increasing."*

> *"Enable more generation. We have to build out more transmission, but at a local level Hydro One should look to slightly soften its ultra conservative limits on its distribution system to enable more local generation to be connected… Open up their grid a little bit more."*

> *"I would say the first thing is that we have the capacity in place to expand and sustain our business. And in addition to that, we have to have a more resilient system. So, a little bit more redundancy in place so that when there are power interruptions, they're less frequent and shorter duration… I think the cost looks after itself as more renewable generation becomes less expensive and we're avoiding carbon charges."*

4.4. Future Expectations

Anticipated changes in electricity use

Most associations expect an increase in electricity use for their members, which they expect to be primarily driven by increased demand from electric vehicles and business expansion.

> *"Yes, energy as a whole for sure… Things like demands, from the electric vehicle side as well, increasing those within our building. Parking lots as well."*

> *"We're probably going to be putting a little bit more steel on the ground because we're going to need increased facilities, the facilities we have are fine, but they're not going to deal with the kind of load increases."*

> *"We very much want and need to be able to serve the interest of growing companies… In our last report, we had just over 50% of responding members in our survey said that they anticipate growing in 2024."*

Investments to transition from fossil fuels to electricity

A number of associations report a shift from natural gas to electricity as their members pursue decarbonization and electrification to support climate goals. One association emphasizes the importance of low-carbon electricity generation.

> *"Less natural gas, more electricity on site, certainly… I suspect that more companies will be looking at electrification, decarbonization, moving away from fossil fuels."*

> *"If we are pursuing decarbonization, which is the appropriate thing to do with respect to climate change, we will be doing so at least partly with an electrification agenda… We will be growing the load to replace things that weren't necessarily powered electrically before."*

> *"There's certainly a significant concern about the greening of the grid, the maintenance of the grid, the generation of clean energy in Ontario. Very strong support in our membership for nuclear as an energy source."*

However, some associations cite concerns around transitioning away from fossil fuels, including capacity constraints and reliability of renewables like wind and solar.

> *"We still need natural gas and propane… We're very aware that the public in Toronto says you guys should be using air heat exchangers… It's just unrealistic for us to do, there isn't the capacity for us to do that… I don't have the three phase power."*

> *"I think there's the concern more than anything is the uncertainty… Concerns raised about how the government policy of the green energy has first rights on the grid, and then we're selling it for almost nothing to places like Michigan and Quebec… The lack of reliable energy from windmills, the unpredictability of solar and wind power. So, there's a strong support from our members for traditional types of power like natural gas and also nuclear power."*

5. Municipalities

5.1. Relationship with Hydro One

Relationship with Hydro One

Some municipalities describe their relationship with Hydro One positively, pointing to strong collaboration and communication and describing regular and productive interactions on major projects.

> *"Pretty good… They're collaborative. Free speech on many topics, there's no reservations. There were no hidden agendas or anything like that. Everyone seemed to be working well together."*

> *"The engagement has to do with these projects where we need to build something bigger and we need to coordinate with Hydro One to move the poles, the transformers… Most common interaction is just that back and forth for relocating utilities... When we're working together, it's very good."*

> *"Over the past couple years, we certainly have developed a pretty good relationship… Constantly we are in communication like every week… continuous discussion… not like an appointment basis… It can directly come to me, and I can go to the different stakeholders for proper communication, decision making, everything."*

On the other hand, some municipalities report limited engagement with Hydro One, citing that interactions are infrequent.

> *"Very rarely. In my 15 or so years in the region, maybe once or twice… There's hasn't been a particular problem. For better or worse, it's working well."*

> *"I don't have too much of a direct relationship with Hydro One. Among the three local distribution companies, I'd say I've got sort of the least contact with Hydro One… partly because our other LDC's are more locally based or municipally owned, so there's more of a greater accountability."*

> *"I would say it's arm's length. We primarily deal with [LDC] and the IESO… [LDC], we work with them very closely because they are the local company."*

Some municipalities with little to no engagement with Hydro One desire more proactive engagement, particularly through regular meetings, such as quarterly check-ins.

> *"Quarterly meetings with local hydro people are probably a good idea… discuss things like upcoming subdivision developments or upcoming industrial development or things like that."*

> *"Take a bit more of a proactive approach to working with municipalities in partnership… Build relationships with local municipalities."*

Overall satisfaction with Hydro One

Some municipalities express satisfaction with Hydro One, mentioning responsiveness of staff.

> *"They're really good people and they respond, and they're very helpful… The complaints I hear more often are from the local distributors, not Hydro One."*

> *"Pretty good… We are able to reach out when we need to."*

Meanwhile, other municipalities highlight challenges in obtaining timely and consistent responses, with Hydro One being harder to contact compared to other local distributors.

> *"In terms of timely responses, I would say that they're definitely harder to get in contact with in a timely manner than our local provider."*

> *"I find it quite challenging to obtain clear information from Hydro One. So when we have initiatives, projects that come up… different hydro needs will get an answer in terms of capacity, and then we get a different answer 2 weeks later. So, it is unclear."*

5.2. Current and Emerging Needs

Preparing for growing demand

A few municipalities say Hydro One is already doing the right things to address their needs in response to the increasing demand for electricity.

> *"I think they've already heard the call for electricity, and they're already on it. So, from what I've seen anyway, they're focused on the right thing."*

> *[When asked if their community's electricity needs are being met] "Yes, at a high level, I would say so, with the additional comment that I think people are starting to wonder or looking perhaps for more certainly that will be the case in the longer term as more electrical vehicles hit the street."*

Many municipalities express concern about the adequacy of current energy capacity to meet future demands, especially regarding the adoption of electric vehicles.

> *"It's important we continue to plan forward… The idea for their electrification of everything in the EV space… It's going to eat up a lot of capacity and not have much left for any other sort of growth in the community… We need to start planning for that."*

> *"There's some parts of [REDACTED] region… there's not enough short circuit capacity for people to install level 2 solar chargers… And Hydro One's not planning to upgrade that anytime soon… To what extent can Hydro One as a transmission utility help to prioritize areas that are currently constraining adoption of the tech that we need."*

> *"I worry about Ontario's long-term plan because our two major nuclear plants are well past their expiration date and are being kept operational because of the absolute necessity. But I worry that if those have to go offline, what happens to our provincial grid?... I don't believe that has been considered enough for this huge potential growth that we are already showing, let alone will be coming."*

> *"We are on the verge of having exhausted the capacity based on what we understand… Current residents have power, but if I have someone coming in with a subdivision tomorrow or large businesses that are going to consume a lot of electricity in that area of the city, probably would have to be declines based on the fact that there is not sufficient electrical capacity."*

> *"Given the way things are going, the types of developments that we're seeing in the electric mobility space around EV. Those are all going to require significant capacity that I think normally we haven't seen in the past… There's definitely not enough available as it stands."*

Communication and information sharing

Some municipalities call for more effective communication and information sharing between Hydro One, municipalities, and other entities like the IESO.

> *"Within the IESO, there's like 20-year load forecast that gets updated every 5 years… Hydro One didn't reach out to us… There's still very much a lot of gaps in information between municipalities and the LDC to create a load forecast that's informed by and aligned with broader decarbonization agenda."*

> *"You got IESO driving their current regional plans and looking at forecasted needs, and then you get Hydro One kind of doing this exercise. Maybe there's an opportunity for collaborative discussion around that."*

> *"We are constantly trying to guess whether or not there is capacity in the system… The information sharing is not on our side… We need to be able to openly share information and have faith and trust in the information that we're receiving that it won't change literally weeks later."*

Affordability

For a minority of municipalities, the cost of electricity is not a significant issue and affordability of electricity isn't a pressing concern compared to other factors like grocery or gas prices.

> *"You can get complaints about a lot of things – grocery prices, gas prices, service delays, and things like that. I don't think I've ever heard anyone complain about hydro prices."*

However, several other municipalities highlight affordability of electricity as a concern, especially in the context of economic development and vulnerable populations, such as seniors and others on fixed incomes.

> *"It's a very significant concern. From an economic development side and new business is coming… Generally, companies have not landed in [REDACTED] because of price of electricity."*

> *"Like the whole affordability question, can we tailor incentives and programs for the lowest income, for seniors struggling with fixed incomes, and in particular the seniors that are most at risk during extreme heat events of dying… So how can we help people on the fixed income make these moves?"*

> *"Keep costs low but more targeted towards people who actually need it a little bit more."*

> *"We would be looking at how to balance affordability within the system… We still have to advocate for the residents in terms of impacts that are just environmental but also related to kind of overall cost."*

Importance of good reliability

Many municipalities emphasize the importance of reliable electricity, particularly in the context of changing weather as extreme events become more frequent.

> *"I worry more about resiliency when it comes to the future, from impacts of changing climate, whether that is significant rainstorms, whether that is prolonged heat events that stress the system."*

> *"My worry is that we are not going to prepare for the existing system, make the investments for the weather events that will lead to impacts on residents… people without cooling… not able to access elevators, etc.… These events will become more frequent and more extreme in terms of the levels based on our analysis and our projections."*

"If there is a storm that takes out a tower, then the whole region is kind of screwed… because they're being fed by one line."

Current levels of reliability

Most municipalities highlight positive reliability experiences, noting that outages are rare and when they do occur due, they are happy with Hydro One's response.

"We have a smart grid here… It stores power when it's not being utilized, but when it's required, it'll draw that power… So, we don't have a lot of power outage other than old trees falling on lines, or animals."

"When there's been big storm events and there's been disruptions, they've been dealt with relatively expediently, I would say."

"I believe in the [REDACTED] area, yeah, it's good."

"Quite good… I've not experienced any real outages with the exception of winter storms."

"My own impression is that it's good. When there have been storm related outages, I think Ontario Hydro does a very good job of keeping its website up to date. You can check and get updates in terms of when things are coming back online."

However, one municipality reported ongoing concerns with reliability, particularly in smaller or rural communities where frequent outages and power surges are common.

"I just got a note this morning from somebody in one of the smaller communities about still having concerns about their power supply in the community of [REDACTED]… They still get constant outages and a lot of power surges. So, I know there's some other rural areas where there's power outages longer than what you might experience in most of the urban centers."

5.3. Hydro One's Priorities

Preparing for the energy transition

Several municipalities emphasize the importance of preparing for the energy transition and supporting future growth. There is a strong desire for Hydro One to focus on understanding and preparing for the rising demand of electricity related to things like increased electric vehicle adoption and new residential developments.

"Focus on understanding where the growth is going to be and just making sure that they've got the right plans in place to be able to accommodate that growth as it happens."

"Better understand how Hydro One is potentially planning for the electrification of the grid… Some more insights into Hydro One's planning to know how to respond to businesses that are coming or how to respond to anticipated growth."

"Hydro One, along with all the other kind of main players in the electricity system, have a key role in terms of enabling electrification. And that's not just electrification for climate… but it is also for growth, that can be regular population growth or economic growth."

"Making sure that our grid is ready for the electrification of vehicles and the 3000 to 5000 new residential units that we anticipate coming online before 2030."

"We're all sort of collectively concerned… With increasing electrification and higher demand and how that will be."

"Need collectively to start to chart out the plan for the future, and not just at the really high level of demand and general supply. But start to talk about what are the infrastructure investments and when they need to happen over time. Start to pick a path… We're spending a lot of time talking about all the different paths as opposed to saying, here a path that looks like it's a good place to go."

"Enabling overall electrification… If I'm Hydro One… I see this huge opportunity around that energy transition away from natural gas… make money by building infrastructure, supply, electricity… Success for them would be seeing that opportunity and be looking how they can monetize that being part of a transition away from fossil fuels, because they're in the supply chain of electrons as opposed to the supply chain of fossil fuel molecules."

"An integrated approach to how energy is moved into the city… how the bulk system interacts with the local system. And how we find the right balance, right investment of activity that supports electrification, supports growth."

Building system resiliency

A few municipalities emphasize the need to invest in the resiliency of the existing system, not just growth for the future. Some are concerned about the grid's ability to withstand extreme weather events.

"My worry is that we are not going to prepare for the existing system - make the investments for the weather events that will lead to impacts on residents… I don't think we're necessarily investing in the resiliency of the system. We often focus on growing the system for the future as opposed to how do we ensure the existing system doesn't fall apart? And that's in every type of infrastructure we have."

"Will the grid be reliable in the context of extreme weather? That's what we're going to be dealing with, longer heat waves, more intense heat waves. They are going to drive up cool air conditioning demand... So, that's a concern."

5.4. Future Expectations

Anticipated changes in electricity use

Several municipalities anticipate an increase in electricity usage, driven by a variety of factors such as residential growth, industrial growth, electric vehicle uptake, and electrification of transit.

"We're projecting to grow continually over the next number of years, mainly from newcomers and expansion, more affordable housing… We're seeing growth comes from all over the world. We have a local immigration partnership here… So that's been very successful as well to drive people here."

"Significant residential and industrial growth as well… There is a significant more amount of electric cars on our street… Absolutely, it's going to be a significant larger draw on residential power."

"We do have recent growth projection show that in the next 20 to 25 years, the region could increase by almost 100,000 people."

"More of it going forward as we electrify our fleets. So power requirements are going to be substantial, especially with transit… We can order one charger and charge one bus right now, but we don't have the power to do multiple units right now. So, we're working a bit with our local utility provider."

We've been experiencing a population growth that has been much higher than anything we've seen in the past, at a rate of 7%. We expect this growth to continue… Demand is coming from additional housing development… I also want to stress our employment growth… far greater than anything we've seen… A lot of the EV sector businesses… they come in and have massive power requirements."

Hydro One's role in helping meet changing energy needs

When asked about Hydro One's role in helping them meet their changing energy needs, some municipalities highlight the importance of Hydro One making investments in infrastructure that will enable growing demand.

"They need to build the infrastructure, like in one example - for transit, to be able to supply our buses, they can't deliver, in the current fashion, to that site without doing some infrastructure investment... If we're reducing fossil fuels and we're getting away from gasoline, there's going to have to be better infrastructure."

"New transmission lines probably going to solve a lot of issues with driving power here."

"Our fleet electrification is really important, so the redundancy and backup at those facilities."

"Potentially updating policies… in order to accommodate the future capacity that's going to be required if we're actually going to meet provincial and federal government targets… Everybody needs to be on the same page, not only from a government perspective, but from a utility perspective because they're going to require those utilities to make those investments. Without the utilities, we have nothing. The infrastructure needs to be there."

Investments to transition from fossil fuels to electricity

Many municipalities report taking steps to shift from natural gas to electricity, through activities such as electrifying transit, fleets, and facilities.

"It's part of our corporate strategy plan. We have green initiatives built within it. We're trying to get to net zero, think it was by 2050."

"There's a strong shift in moving away from carbon intensive to something that's more carbon neutral. And then that comes at the expense of needing huge amount of electrification to run some of those building operating systems… Plan to electrify transit… plan to electrify fleet… plan to electrify facilities."

"On the climate side, we don't have an anti-nuclear bend, but we are looking for less natural gas in the system, and more other sources, recognizing we're got to deal with the peaks, and you have to provide reliable, affordable system."

However, some municipalities note challenges associated with transitioning away from fossil fuels, such as skepticism around the reliability of renewable energy sources and lack of understanding about alternatives like heat pumps.

"There's just an information gap and a knowledge gap. A sense that heat pumps aren't suitable for climate, which is false, or that the electricity isn't as reliable as natural gas. There are some information gaps for sure that Hydro One could maybe help with."

"I think there's skepticism on renewables in terms of their ability to deal with peaks at various points in time… It was like pulling teeth to get people who, long time folks in the electric system, to even kind of buy into renewable energy as an opportunity… We need to ensure that bias isn't kind of setting the direction before the analysis has been done."

Investments in new technology

Several municipalities have already made investments in technologies like solar panels, heat pumps, HVAC replacements, LED lighting, and energy-efficient retrofits or are considering doing so.

"We support our residents with energy efficiency retrofits, and installing heat pumps for example… There's significant cost savings from moving from a propane or electric baseboard to a heat pump."

"We got our roof redone at transit, and we're putting solar panels on that to try to drive our own power and then give it back to the grid… We're doing HVAC replacement… LED lighting conversion, heat pump conversions, those types of things."

"Looking for help to do heat pumps or energy retrofit… People are looking for options for more affordable energy… Interested in understanding what options are and if they can be convinced that it's lower cost and sustainable."

"We're proceeding as a municipality on the basis on taking climate action, and looking at best ways to mitigate greenhouse gases… And so, in that vein, we anticipate an increasing electrification demand, particularly for like home heating as you get more switching and conversion to heat pumps, and supplementing with that type of thing."

One municipality mentioned not planning to invest in these technologies, citing that their current cost of electricity is too low to justify the upfront costs of solar panels.

"My nephew sells solar panels… He looked at my electricity bills and he said, 'Wow there's no way I would be able to sell you your solar panels. It's way too cheap for you to buy electricity.'"

Appendix 4

Hydro One First Nations Leadership In-Depth Interviews

Phase I Report

2028-2032 Joint Rate Application

Prepared for:

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Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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2. Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Inc. (Hydro One), to gain a deeper understanding of the needs and preferences of First Nations communities directly from members of the community in a leadership position, specifically as it relates to Hydro One's Joint Rate Application to the Ontario Energy Board (OEB) covering the years 2028 to 2032.

Approach to First Nations Engagement

Hydro One provided INNOVATIVE with the contact information of leaders in all 89 of the First Nations it serves. INNOVATIVE invited each of the First Nations to schedule a meeting with INNOVATIVE to share their perceptions of their communities' needs and preferences as they relate to Hydro One's Joint Rate Application covering the years 2028 to 2032.

Outreach efforts included Hydro One's Indigenous Relations team pre-socializing the interview opportunity with all First Nations, providing a brief summary of what to expect from the interview, and that INNOVATIVE would be reaching out to them in the coming weeks.

INNOVATIVE sent the initial invitation to all 89 First Nations to participate in an interview on August 26th, 2024. For First Nations that had not yet signed up to participate in an interview, subsequent reminder emails were sent on September 9th, 2024 and September 23rd, 2024. First Nations leaders had the opportunity to book an interview between August 26th and October 10th, 2024. This outreach led to 18 First Nations leadership interviews being completed via videoconference or telephone.

The invitation included a pre-read document that provided background information to participants including a brief summary of what will be asked in the interview, who will be conducting the interview, the next steps in Hydro One's customer engagement, Hydro One's role in Ontario's electricity system, and the amount of the typical On-Reserve First Nations residential customer electricity bill that goes to Hydro One.

Interviews were approximately 45 minutes in length and were conducted by a trained moderator following a discussion guide. In appreciation of the time provided by First Nations leadership, INNOVATIVE provided a $250 cheque for each participating community.

About this Report

This report summarizes the key findings based on these interviews. In general, our approach is to report representative verbatim comments and offer interpretation and/or commentary where necessary. Verbatim responses are shown in blue italics.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used directionally. In interview-based research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view.

3. Key Findings

Several First Nations leaders express overall satisfaction with the services they receive from Hydro One and their relationship to the utility.

Some leaders emphasize their satisfaction with outage response times, local line workers, and other direct relationships with internal contacts at Hydro One, pointing to strong collaboration and communication.

Many First Nations leaders report frequent or prolonged outages, especially in rural and remote reserves.

Several leaders say that outages are common in their community, often due to weather-related events. Leaders identify many aspects of reliability that they feel Hydro One could focus on, including aging infrastructure, resiliency to severe weather, outage response times, and improved communication.

Poor reliability has significant consequences for First Nations – especially related to prolonged outages that impact access to heat, medical equipment for elders, or contribute to food spoilage.

When discussing the impacts of poor reliability, many First Nations leaders identify food storage and security, especially as it relates to traditional hunting practices. Many First Nations also rely primarily on electricity for heat, meaning that prolonged outages can have a significant impact on the health and safety of communities, and especially elders or those with medical needs.

Affordability is a top concern for First Nations leaders.

While some leaders acknowledge the benefit of the First Nations Delivery Credit, the majority still describe electricity costs as a significant burden, especially for low-income households and those on fixed incomes. Many call for greater support or financial relief for customers living on-reserve.

Leaders desire more collaboration with Hydro One and a greater presence in their community.

Many leaders call for an improved relationship with Hydro One, especially related to communication between the Nation and the utility and seek more in-person opportunities to collaborate. Several leaders want Hydro One to provide education around energy use and energy efficiency to leaders and community members.

Most leaders expect significant community, business, and facility growth in their communities in the next five to ten years, resulting in greater demand for electricity.

Some leaders are concerned about the capacity of existing infrastructure to meet this growing demand and delays in service connections for new residences or projects are often cited as a significant barrier.

There is significant interest among First Nations leaders in renewable energy projects, with many already making significant investments.

Communities are actively exploring and implementing solar, biomass, and other renewable energy projects. Many desire Hydro One's guidance and support in this process.

4. Profile & Energy Needs

4.1. Respondent Profile

Communities engaged

Interviews were conducted with leaders representing a diverse range of First Nations, varying from small, remote populations of fewer than 200 on-reserve to larger communities with on-reserve populations up to 1,000 or more, often with more developed infrastructure, including access to more reliable electricity and facilities for larger projects like arenas.

> *"We're a remote community so usage for internet, usage for satellite television, usage for communications, has a huge part on our society. And because of the amount of people living in houses, there's a lot of people sleeping in different shifts, and lots of people staying up at night. So, you end up with, pretty much round-the-clock electricity use in our community."*
>
> *"We have one of the smallest communities in Canada, we only have about 190 people here."*
>
> *"We're on a small island… So, we're considered a remote or semi remote. We have a population of about 200 people on the island. And when it comes to electric electricity, we are probably almost 100% electricity for heating. We do still run wood stoves, but not as much as we used to."*
>
> *"We're a largely urbanized population… living in different urban centers… On reserve, energy requirements are minimal. We don't have any industrial or commercial operations on the reserve."*
>
> *"We have a thriving community here. There's approximately 1000 people in our First Nation territory. We have 2400 acres… We have [REDACTED]… employs about 1100 people."*
>
> *"We're largely urbanized population. We've been flooded off our reserve for the last 100 years here. We're slowly repatriating that that reserve, and physically rebuilding that reserve along with the rest of the First Nations governance and political abilities… So, we actually have very few people living on reserve, less than 10."*
>
> *"The energy demand that we require has been basically addresses, so we converted out single phase power to three phase power in our community. So, we'll be able to accommodate new larger projects like the construction of arenas and so on. Bigger facilities can be built. Our communities in a good position, we're fortunate to be able to get that type of power into our community, which I know that 90% of First Nations across Canada haven't been able to do."*

5. Satisfaction and Relationship with Hydro One

5.1. Overall satisfaction with Hydro One

Satisfaction with Hydro One

Some appreciate Hydro One's responsiveness and the professionalism of their local workers. A few note the limited interaction they have with Hydro One makes it difficult to provide a full assessment, however their sentiment is still favourable.

> *"9 out of 10 I think. I think I talked about it a lot already. You know, I spoke about the geographical and the environmental issues that we would have because of where we are located. That's not their fault, though. Uh, so 9 out of 10."*
>
> *"For the most part, I would say yes. We just went through a contract with Hydro One that employed three to four of our community members and clearing brush, which went good."*
>
> *"Hydro One... the local people that work in the lines... they're very accommodating. Like when power goes off, you know, they're usually here at a very decent time... But it takes a while before power comes on."*
>
> *"I don't think I've had enough interaction with them. Like it's been very limited with just these like almost crisis situations. So, it's hard to say. I don't really deal with hydro that often. Like, it goes off once in a while, but we just wait for it to come back on and there's no issues."*

Dissatisfaction with Hydro One

Meanwhile, others express overall dissatisfaction with the services provided by Hydro One.

> *"I'm not satisfied. We are one of the [isolated] communities that Hydro One doesn't really pay attention to. Many cottages have been added to the system over the years, [but] there's no upgrades on their equipment… They don't respond [to our concerns]. They don't do anything… So if we're gone be serviced as we currently are in 10 years, we got big problems coming up."*
>
> *"People just getting disconnected. No questions asked… [They] don't really tell us right until the last minute."*
>
> *"There's a planning challenge here for me with Hydro One… I don't think we're speaking the same language. It's hard for me to understand what they need and I don't know that I have the technical answers that that I think they want."*
>
> *"We waited for one full year for one building to be connected and it was rental. By the time that they got to connecting, we had to disconnect it because we were done with the rental. So it just doesn't make sense sometimes. Their service response time is not great."*

5.2. How Hydro One can better serve the community

Guidance and education

Most leaders express a strong desire for more active engagement between their communities and Hydro One, particularly in terms of providing guidance and education to members on ways to reduce energy usage.

> *"We need what I would consider kind of like a navigator, someone who can advocate and lead… If there was someone who could kind of nurture or encourage participation and update people, that sort of thing."*

> *"From a First Nation perspective, it's like step up to the plate and share with us what you know, and how we can better manage our power requirements and be able to be in a position to share with you what we're planning. And what kind of advice you may have regarding our plans for development in the future."*

> *"So, I think if they worked with [community energy champion] to provide some info on energy savings initiatives… Maybe also to work with our emergency working group because we're trying to work on a community safety plan, but we haven't really considered the hydro aspect of it."*

> *"Any advice, any ideas, or advising maybe would benefit us in what we use within the buildings to cut on hydro costs… As a bigger agency, or a bigger perspective on the hydro business. That would definitely be beneficial if they worked with everyone, I guess in municipalities, First Nations to advice how they could cut on costs or what route to take to potentially go in that way."*

> *"I think the building of the relationship, the in-person ability to speak to someone who may provide us with a little insight on how the big machine works."*

Vegetation management

Some have concerns regarding vegetation management practices, including the need for timely trimming and the avoidance of chemical sprays, particularly due to perceived environmental and health impacts. There is also a focus on the need for transparency in forestry activities related to new power lines, especially regarding the types of trees removed and the environmental consequences.

> *"With the vegetation a few years ago, I did get them to come after numerous requests to trim the vegetation back, which they did. They did not do it in its entirety and it's time again overdue to trim this vegetation back from the wires."*

> *"It depends if they are going to chemical spray. Absolutely not. We are trying to move to 0 chemicals on our entirety of our traditional land. It's been a real sore point for us for the tree maintenance they do."*

> *"There's a history of sickness in our community and a lot of people have historically blamed that right of way. They said that right up until the 1980s that Hydro One was spraying all types of different pesticides and whatever else he would use to kill the vegetation and without much regard for human life, because we really weren't considered humans till about 60 years ago. I think there's some high rates of cancer even to today."*

> *"When they [Hydro One] go in and they're cutting new lines somewhere, there's issues related to forestry. What kind of trees are they taking down?... But what happens to that? What happens to that*

wood? Where does it go? Who gets it? Is there a process to access it? Those are the kinds of issues. Just from an environmental perspective as well, we need to know, because if it's happening in our harvesting territories, hunting and fishing, we need to understand that the environmental concerns and our issues are being looked after."

5.3. Relationship with Hydro One

Current relationship with Hydro One

Some First Nation communities feel that their relationship with Hydro One is a positive one, with strong communication and support, responsive service, and reliable collaboration that helps resolve their issues efficiently.

"Our current relationship with Hydro One is good. They're responsive to our needs in terms of energy. They work with us. They've been quite helpful in advance in several of the energy demands required for the infrastructure we're doing in our community. So, we haven't had any issues, and I think the way they've approached things up until now have been working."

"We have a really strong relationship, I would say… We have very strong internal contacts with HONI. So that if we did have an issue, if we wanted to, we could go to the highest levels of HONI to get an issue solved. We don't do that because we have good connections in their middle management as well to help rectify issues should they come up or to help fast track something if needed."

"Hydro One… And I'm talking about the construction portion of it, they're very accommodating. Like when the power goes off, they're usually here at a very decent time… they communicate with us really well. Updating us on what they're finding or when they suspect the power is going to come back on. It's not necessarily correct all the time…I think we have a pretty good relationship."

"We do have collaboration and communication with Indigenous relations with Hydro One, and my experience with those individuals are good. And they do work towards trying to resolve issues that we do have and to supply information at request when needed. And it's a good collaboration and communication to this point."

On the other hand, some report frustration with their relationship with Hydro One, citing issues ranging from poor communication, unfulfilled agreements, and uncertainty about who to contact for assistance, resulting in a sense of disconnection and limited progress in their interactions.

"No we don't really have much of a relationship with Hydro One… I mean, we've attempted to do some things with them and whatnot, but we haven't gotten very far… Called partnerships and whatnot, and you know, different work that they're doing outside the community, but because of political things with our neighbor here for [REDACTED], we sort of get pushed out of the way… Well, they get to the table before us, and leave us the crumbs. So yeah, sometimes crumbs are good to pick up, but you're not in the main pool. What are you really there for?"

"At one point we had an agreement in place if they were coming over to [territory], they are to report in here to the office. So, we knew that they were on the [territory] and we wanted to know what they were doing so we could track what is being accomplished. And that went by the wayside. It went on maybe for

a year and then they just dropped that and haven't done that for at least five years…I never know what they're doing over here."

"We have a hard time reaching out… And because we've never met them, they've never reached out or anything."

"The relationship we're having from our community to Hydro One, that's involving [redacted]… And she relays our message to Hydro One, and that's where - and that's not on her part, she represents the community 100% - it's getting back to her and back to us. It's a little weak link there, so that's what we feel. And I went in a different direction, and by going that direction, the message did get to where it's supposed to go. But coming back to us, it was not there. A very weak link there. So, Hydro One's part, it can be improved with the First Nations."

Some leaders express a positive outlook on the development of their relationship with Hydro One, mentioning the progress that has been made and recognition that Hydro One is making efforts to improve the relationship with their community.

"I know the doors are wide open. There's a feeling of camaraderie with Hydro One. There's a feeling of renewed partnership."

"We're just starting to develop some relationships…they do a pretty good job of trying to ensure that they're having patience…we're a First Nations that's in a state of emergency [due to deaths in the community]…They've been patient because every time there's a phone call, a negotiation session, there's another funeral…we're going through so many funerals and it's hard to get the technical expertise and they took a risk on us and [provided us with] a grant…Some really good things that Hydro One has done recently, so I've got to again give them credit where credit's due and that is a positive for us. But we need more of it."

"It's a rebuilding phase. I like how they've come to the table. They have offered us a great…well…grand offer, we still have to work out the details of that… I think they're really trying. So, we're going to try to work together and see what we can come up with."

Desired relationship with Hydro One

Many First Nations leaders express a desire for improved communications from Hydro One and a greater presence in their community.

"I think if Hydro One could be a little bit more present, you know, come to visit us, the leadership... People talk about power; it's usually related to some kind of crisis that they're experiencing. It could be the rates, the cost, or potential cut-offs until a bill is paid."

"I guess a better relationship where they come and speak to us. You know, you have different companies out there, Enbridge and whatnot, that assist you with different things – funding wise and partnerships on this and that. I don't believe we've ever been given that opportunity from Hydro One."

"I think the main thing would just to have, whoever sits on the Indigenous seat there to be in more contact."

"Just better communications I guess and then coming to the nation to sit down and talk with us and tell us what they have to offer that may work for us."

"They could have come to our table a few times, and [asked] 'What can we help you with?' But I've never seen that. We get the odd letter from them on different things. But you know what? Sending me a letter or whatever means nothing to me. You want to talk to me? Come and talk to me."

"Improving communications…helping to partner on the youth crisis center that we're building…we would gladly call it the Hydro One Youth Crisis Center…they're able to sponsor major hocket teams, so we'd love for them to be able to sponsor some of these local community events if possible."

Some leaders focus specifically on Hydro One's role in reconciliation, both culturally and economically.

Cultural Reconciliation: A number of leaders highlight the need for more inclusive partnerships with Hydro One to address the historical impacts on their traditional lands, urging Hydro One to take a deeper, more thoughtful approach to reconciliation.

"Well, for me, I think it'd be being a little more creative and in partnership with First Nations voices and to move the needle on reconciliation... There are impacts not only to the natural environment but to the lands management of the community and our people are very connected to the natural world... If Hydro One was able to understand and build a better perspective on using or considering empowering Indigenous perspective on spirit of the land and those impacts... That would mean a lot."

"There should be more conversation on the accommodation side of things… Accommodation to me is redressing the issue around treaty, the impacts to lands and territories. It's understanding the cumulative effects that not just this industry, but all industries have had on our on our territories and ultimately our peoples. So, like in a perfect world, I think that would be amazing to have that avenue and that support to have those meaningful conversations that have actionable outcomes… I mean you have to have conversation somewhere and keep it moving forward."

"With the legacy issues, there have been improvements. We all know that there is public information that Hydro One is working on new transmission lines that exceed over $100 million. That's part of the policy to have indigenous participation. I mean, that's a start but it still doesn't address the legacy issues. There are definitely cumulative effects that I don't think are taking the right time to appreciate the perspective that indigenous people have, especially in respect to treaty and what that relationship means… Hydro has shifted a policy for their reconciliation action plan, which is positive, but there's still a lot of work to do in terms of fostering a mutually beneficial relationship… It's all growing pains at this point."

Economic Reconciliation: Some leaders specifically point to economic aspects of reconciliation related to the use of traditional lands or resources for electricity infrastructure.

"Lowering the rates. We have that agreement with Ontario that our rates are a little lower than others. But you know, take the rate right off. Let's get rid of the rate. I've heard that from my members. Why do we pay for hydro? It's our resources. And it's hard to argue with them because it's just the way it is."

"Well, I know Hydro One is making millions and billions of dollars every year. They make a lot of money. And the infrastructure they have - they've been able to establish that infrastructure on traditional territory without compensating communities at all. There's no money for lease agreements… Hydro One needs to really look at that and compensate communities accordingly."

"To provide a competitive edge for First Nations or, some would say, to restore historical imbalance as well of their history of, you know, frankly taking advantage of First Nations… There's are ways of providing investments into reconciliation…and we're going to need that as well you know."

"One thing that we don't talk about is like the absolute supply chain in the whole industry… We would like to carve our space in that sort of area of supply chain - in the electrification industry. That to us, is what economic reconciliation looks like. It's about creating quality of life for our people that have been impacted so negatively from industries, government, you name it."

6. Price & Affordability

Electricity costs

Some say that the price of electricity is fair, and that they have benefitted from the First Nations Delivery Credit.

> *"So, like in terms of the on-reserve infrastructure, we have a very unique energy system in that our community buildings are run off renewables and the grid system acts as a backup to those renewables. So, we actually don't pay that much for electricity… Looking in town, from my own perspective, everything is going up in terms of price. Everyone wishes things could be cheaper. But in terms of value for what we're paying for, I think it's at the very least it's fair."*

> *"Now that the delivery charge has been removed, it's certainly been a lot better and easier for our community members to afford to properly heat their houses."*

> *"Something I like for one thing, with the delivery charges and all that, they have been removed, and I think really benefiting our communities."*

However, for many, affordability is still a significant issue, with many First Nation communities struggling with high electricity costs, especially for low-income households.

> *"It's a big impact. Hydro is the same thing... everyone's thinking, all these projects that they put up was supposed to increase the power and to help with the accessibility and affordability of power rates? None of that has happened yet... where are the savings?"*

> *"We have a pretty significant population that is on fixed income... for some of the folks on the lower income levels, if they can save 50 bucks, 100 bucks, it makes a difference in their lives. It certainly does."*

> *"…people deciding whether to pay X amount on hydro this week and get groceries and pay some other bills and... clothes for their kids and feed their kids."*

> *"Once you get out of our community and it goes to Hydro One, the rates are definitely much higher... those fees are probably hurting our community."*

> *"Hydro are a significant cost to the membership and to the band as a whole."*

> *"We have serious levels of poverty here, a lot of it tied into drug problems."*

> *"Affordability is a huge issue, especially with markets, inflation, all of that sort of thing. Things are definitely impacting the folks."*

A few leaders mention that they are exploring various options to help with affordability, such as helping community members apply for the Ontario Electricity Support Program, and looking into alternative energy sources, including local generation.

> *"To lower the electric bills a little bit, I have sent in application for them through the Ontario Electricity Support Program so that takes off a little bit… It depends on your income also with that one. For example, if you make $20,000 or less, and if you have five people, it takes $90 off your hydro bill."*

"We're working on a district biomass unit right now to lower heating costs from the electrical baseboard heating that the member currently have. So that's an ongoing project that's gonna assist with affordability and obviously environmental and everything else."

Impact of electricity bills

Many leaders report that their communities are facing significant financial strain due to high electricity bills, with some even struggling to meet basic needs like food.

"What it impacts are the people that can't afford to turn the light on. The low-income families, the people that are on fixed incomes… Hydro One is continuously contributing to the undermining of the quality of life and standard living in nations by having ridiculous rates for hydro when they are getting lands for free for nothing, for forever. They don't pay for anything."

"Seniors have to run different things and whatnot - just some of the medical needs that they have. So, you know, that sort of thing there, just a lot of cost of hydro."

"There's not too much opportunity here… Community members get impacted in a not so pleasant way when it comes to paying for utilities. I'm not too sure on the numbers but a lot of folks here are on social assistance. So, that's stretched pretty thin when your dollars are very limited. The impacts of your utility bills are essential thing."

"The same impact as food. Things have skyrocketed to the roof…you hear all the time about CEOs getting bonuses of millions and millions and for what? For the expense of us guys starving and suffering and pillaging for scraps. It's a big issue."

"We have a greenhouse…the big challenge that's making the project not viable …they're running four boxes [meters], so that means they're on every bill paying about 50% of that bill is for delivery charges, and it's killing…really hampering the ability of that greenhouse to cover its cost…the goal of our community towards food sovereignty and all these things get people healthy. We have a lot of people here who have diabetes, all kinds of health problems. We need healthy food in the community that's at a decent price. The IESO is trying to help us, but I feel like Hydro isn't really. In fact, I get a lot of complaints from the membership of Hydro giving them a hard time on the bills."

"Very high hydro rates in the community…it's tough when you've got a family of 12-15 living in a house with three bedrooms. How do you teach people about conservation? It's life or death in our communities at times."

Desire for financial support

There is a strong desire for Hydro One to offer more financial support, such as rebates or assistance for low-income individuals and for better access to investment opportunities that could benefit First Nations.

"Anything financial that can help the burden of poverty in First Nations. Reducing rates."

"I think the billing has to be looked at. We have a handful of different bills from Hydro One for the band and I don't understand why it has to be like that. It'd be nice if we could amalgamate all of our band owned properties into consolidated bills, but I don't know how…it's just a headache to try to understand and to keep up with."

"So, with regard to pricing for Hydro, I would love to see some sort of rebate or kick back to the low-income people in the community. That would certainly help."

"So certainly, the investment opportunities with HONI should change... They need to change also not from just a respect to the nations and reconciliation aspect, historical aspect… their competitors from other industries are doing things in terms of economic development that HONI is not doing… selling existing profit, generating assets to First Nations… Additionally, there's other developers that are looking at developing infrastructure projects, energy related or not, that are offering larger investment opportunities for specific project that HONI's offering."

7. Reliability

7.1. Importance of good reliability

Impact on traditional food storage and food security

When asked about the importance of good reliability for their community, many leaders specifically mention negative impacts on food storage and security, with some focusing on traditional hunting practices.

> *"It could be potentially catastrophic for some people here. The difference I think is there's a moose hunt in the fall and a lot of fishing in the summer and in the winter too, through the ice. People are keeping freezers full of food and a lot of people are not buying meat at the grocery store…moose and fish are staples here…if the power goes out for a day or two, you're in big trouble. You start talking about basic food security problems."*

> *"It's a threat to food sources. I mean, refrigerators, freezers, people could lose, you know, groceries. And we all know groceries are super expensive these days. And there's a lot of poverty in communities."*

> *"And you have to worry about your food going bad in your fridge and freezers…that's costly."*

> *"If your freezer's out and your food's spoiling, then you've got to drive another hour to town to go get some more supplies."*

> *"In the summer [when outages happen], you risk losing your food, and your fridge, and your freezer."*

> *"We've lost a lot of meat from freezers not coming back on."*

Heating challenges

Some leaders also report frequent power outages, especially during the wintertime, posing serious heating challenges for homes relying on electric heat.

> *"Big thing is also the power outages. Sometimes it could take 8 hours to get reconnected. A majority of homes in [First Nation] have no secondary heating systems...most homes have electric heat."*

> *"It looks to be anywhere from $7,000 to $8,000 per household for these generators...and to me, keeping people safe, keeping them warm in the winter...that may be the route to go...we'd be spending our own money on that."*

> *"We have a lot of power outages here in the community… The only other business around our area is tourism, camps and summertime fishing. So, there's ongoing power outages during the summertime and wintertime. So, a lot of times over the last 10-15 years, we ended up evacuating people in the wintertime."*

> *"We had an outage last winter and this outage was supposed to last four or five hours and it ended up being eight or ten hours. Now, for people that are in homes that are heated by electricity, that's a big concern. So, we had people cold, we had people scrambling…past six hours in the winter, that's not acceptable."*

Health risks and impact on vulnerable community members

Many are concerned about the outages endangering the health of vulnerable community members, such as the elderly or those with medical needs.

> *"At one time we did have people on oxygen and no power and were running around trying to find emergency power sources, generators or move them to other places...That was bad when they're not well."*

> *"Like you have the younger group that aren't used to being without power… So that's where the panic starts, it's with the younger groups because they don't know how to survive without electricity or anything else."*

> *"We make the best of what we got, and if we have to open up the community center we will, especially if it's cold. The first people we go after is the seniors because they're at the most vulnerable."*

> *"There were a couple times we've been without power for a week. So, we ended up having to transfer a lot of our people, especially our elderly and young kids out into municipalities... The other thing we were trying to do to alleviate, and to assist our people when they encountered long power outages, is we ended up putting in high end propane generators into most of the units in the community. And we focused on our elderly first because we didn't want them without power when temperatures are hitting 30s, it'd be without no air conditioning."*

> *"We have looked into actual generators at certain homes, at senior homes, just to keep the heat going and whatnot."*

7.2. Current state of reliability

Prolonged outages

Several leaders mention that power outages in their communities are common, often due to weather-related events or fallen trees. Some specifically mention "brown outs" or power quality issues in their community.

> *"Three or four times a year. Sometimes a whole day, sometimes more… We have a lot of power outages."*

> *"During the wintertime, about 4 to 5 times every winter. Something like a severe weather knocks out the power."*

> *"There are more numerous during the summer months, could be either a fallen tree or could be other effects that disrupt that service."*

> *"Last weekend it fluctuated a few times. It's something nobody's ever ready for. I am concerned about the short power interruptions where the generators just kick on and then right off again because I believe that that's hard on our generators…I am concerned that it's going to damage the generators"*

> *"Well, they [brownouts] happen. It's been an ongoing thing since I've been there now a little over four years, I guess. Our last one would have been, I think it was June, where we had to post-phone a few meetings and activities that we had a storm."*

"My only grievance is, I can understand the line being down from time to time. Periodically, I'll say, you know, is fair…but at the same time the length of time the line is down is a very big issue."

"There has been an issue quite recently and, in the past, as well. We get hit with a little bit more frequent violent storms… But the issue was the first response, or I mean, the reconnection in our community seemed to be last in the pecking order."

Outage response

Some note that while power outages can be frequent and sometimes lengthy, they still emphasize their satisfaction with Hydro One's response time and online tools.

"They're pretty frequent and they seem to happen more on our side of the boundary than the local community…they typically are resolved within a few hours."

"Where we are, I think everyone accepts that, especially in the winter, there's going to be some service interruptions and generally speaking I think Hydro has been pretty responsive."

"I think reliability in general is at an acceptable level when it comes to number of outages a year. I think there's there may be longer than they should be, but again, that's geography. The crew… got to get on a boat sometimes and we will have outages for 12 hours to 14 hours. Sometimes some things like that. There hasn't been one in the winter since I've been here yet… Maybe in the spring we might have had one. We get wind outages from trees fairly frequently."

"It's been pretty good. If something occurs, power goes down in the middle of January from a blizzard or whatever, I like how you can go online and determine, when the power should be back on."

7.3. Aspects of reliability Hydro One should focus investments on

Reliability areas of focus

Leaders identify many aspects of reliability that Hydro One should focus on, including aging infrastructure, resiliency to severe weather, outage response times, and improved communication.

"It's important to note that being in a First Nation community, infrastructure is not up to the standards… It's very subpar. Our electrical infrastructure feeds into our wastewater program, which is essential service for everybody else, but it seems like for us that we're kind of always just band-aid solutioning things."

"Maybe they could put in a backup power of some kind here. If power goes out, then they'll be here."

"We've had some pretty nasty storms throughout the last couple years here… I think what it boils down to is just manpower in our area, and when things like that happen, there isn't enough… the magnitude of some of the storms that we are getting now, it seems to be worsening throughout the last few years."

"We've been struggling with power at times… We get a little lightening storm and not even some time, we lose power. So, it takes us to restore, sometimes up to two to three days to restore."

"Communication portion, they communicate with us really well, updating us on what they're finding or when they suspect the power is gonna come back on, but the accuracy of it sometimes isn't."

"It's a weak line that goes down several time a year. There are blackouts. There are brownouts, not just for us, but for our neighboring First Nations… And if affects all the business and homes in the heat of the summer, and the cold of the winter."

8. Hydro One Priorities & Future Expectations

8.1. Anticipated changes in electricity use

Community growth

Many leaders expect significant community growth in the upcoming years, resulting in greater demand for electricity. There are some who are concerned about the capacity of existing infrastructure to meet greater demand.

> *"There is a boom in our population, boom in our community. And we were building more homes. We're putting in more infrastructure for housing lots and water lines and everything. And we're still working on it. Just a year and a half ago or something, we just finally got our state-of-the-art water treatment plant going."*

> *"We're trying to do quite a bit of upgrades... but we're just trying to be mindful about, you know, the capacity."*

> *"I'm getting more and more concerned that we're going to have trouble down the line, like, in the near future with is there going to be enough capacity in the line? And we can't afford to pay those kind of contracts like the mining companies…when there's a shortage, those mines are paying the big bucks to have the guaranteed power."*

> *"We have a housing plan. It's very ambitious. They're calling it the 100-unit housing plan. So right now, we're very limited in lots that we can build on… If we have to expand, it would be places that don't have hydro right now. So that would be something that we would have to work with hydro… We're just using our community energy champion to do some of our technical work, but I don't think he's done an energy plan."*

> *"We likely will [be using more electricity in the next 10 years], just like any other community across Canada. We paid for that infrastructure ourselves, Hydro One had no role in financing any of the infrastructure that's required for our growth."*

Business and facility growth

Aside from residential and community growth, many leaders also expect greater demand for electricity related to business and facility growth.

> *"And more and more, especially since the pandemic we've tripled the number of applications that we normally would receive in a quarter for member-owned businesses. And we're seeing new types of businesses come up…[our] economy is growing and diversifying. It's also meaning that there are more and more needs for electricity, and we're already running into some challenges with the amount of power that's available."*

> *"We're expanding all the time right now. We are currently building a big resource center consisting of a public school and the daycare into one facility is currently being built now."*

"There's going to be an increase in demand for sure. We have some projects on the horizon. There's a lot of power that's going to be needed for new homes and new buildings and new facilities and a number of different things."

"We're about to build a multiplex centre…I think it's close to a 12/13 million dollar building it's going to have some substantial hydro needs and we are budgeting of course for the cost of operations and maintenance, but that's going to be something as well that we would love for Hydro One to consider."

"We have a trust which is going to be aimed specifically at growth, infrastructure, for both economic development but also for community needs. So we do see the need for increased demands on hydro…I don't know what upgrading those electrical grids will require."

"We're in the process of building a training and cultural learning center. It's going to be around 15,000 square feet, and that's where part of my concerns are going to be. Like, our community is growing. It's a growing community, and a lot of times we run into energy sources and power outages in our community."

8.2. Investments in alternative sources of energy

Current use of alternative energy sources

Many mention already investing in alternative sources of energy, particularly solar power, to address their energy needs.

"We as a community, we've done solar. We have solar, so we get little rebates and stuff like that."

"Oh yeah. Yeah, we're in a partnership with all the same windmill power anyway. We have been selling energy to the [redacted]. So, yeah, we're doing that anyway. I guess that would be more of a commercial and non-residential application but... so we do have some private, like recreational landowners that have solar energy.. I think it's something that you'll see expand to our homes like people who have travel trailers. I already see panels up in their travel trailers here."

"The solar is totally passive income. It's like the best thing ever. We have a bunch of installations here and we own installations in the South that are just like every month the check comes in. It's the best thing ever."

"Some homes have alternative sources for generated power, but we don't have the number of units to look after everyone's needs."

"So, we were not a grid connected community. We received funding through the small communities' fund to do a solar micro grid and battery system. It's about 93-kilowatt system which actually runs the infrastructure on reserve because we don't have a lot of it either. There are a couple of major facilities that are enough to run on."

"We're always looking at ways to help our members. We do own a solar farm that is roughly 30 miles away from the First Nation. And we have explored doing one that is a little but smaller capacity closer to the First Nation in hopes that we could obviously make a deal again with Hydro."

Meanwhile, others share that they are exploring alternative energy sources, such as solar, wind, and biomass to reduce reliance on external power sources and provide their communities with more affordable and sustainable energy.

> *"We're exploring other ideas…biomass heating distribution system. We're looking at things like that in our new subdivisions that are coming up…of course, there's a cost to everything…but I think for the most part the biomass stuff sounds really good to me for the future. We're also working on solar rooftop projects for all homes to help reduce actual electricity lines coming through."*

> *"We've looked at water source power, we've looked at wind - we're not in a very windy area from what I gather. Solar panels, we're just starting to look at that through these other initiatives that are out there for funding. So, we have proposals for that one. We are always searching for a better way of generating power in the community."*

> *"I'd like to get more solar projects in the community to lower the hydro for everybody. I'm hoping for us to get solar panels done for every house to lower energy costs for every member."*

> *"I'm sure Hydro could help us. Our goal is to embrace energy transition…I think in terms of that relationship, walking together, this is going to be important…I hear about the vehicle transition and all this need for new generation…we're ready to do this stuff, we've got chargers in the community here."*

> *"I'm becoming more and more interested in things like battery storage...we're already into renewables here. We have a company that generates renewable energy here and down South... now there's an old wind project that I'm trying to revive that got squashed right at the last minute when Ford came in."*

Hydro One's role in helping communities meet changing energy needs

Some leaders desire education and assistance programs from Hydro One, particularly around reducing energy usag, energy efficiency, and career opportunities in the energy sector, especially for youth.

> *"It's all about education, understanding systems, understanding what our usage is and what our future projections are for that stuff, and then trying to make something fit that'll work for everyone…I'm sure we have some very interested people that want to participation and check [education from Hydro One] out."*

> *"Thing that Hydro could help us with is understand, as a community and an administration, what do those jobs [with Hydro] look like in the future… getting the youth to understand what the opportunities would look like at Hydro."*

> *"Something that would certainly help that Hydro could do, if there was some sort of assistance program for the youth to enter the trades… I've seen things with Hydro Quebec, where they have impacted the communities with dams, where they've sponsored people to got to school for trades that they need at the dams, and they guarantee the people a job when they're done. That sort of thing would help our community."*

> *"I think if they could like advise us if we're having enough power, because right now, we have one person who knows a little but about electrical work, and they're not certified or anything. So, it would be nice to get some expert advice. We're trying to do quite a bit of upgrades out there, but we're just trying to be mindful about the capacity."*

“If anybody knows power, if it's not Hydro, I don't know who it is. [Would like education on] looking at the different options, looking at how we could reduce our consumption, but still have the use of the power to run our households…Hydro One can play a big role in the whole educational component.”

Some leaders also seek alternative or backup power sources or support with renewable energy projects.

"An alternate source of power, whether it be a big community generator or something, would definitely give us some added comfort. Because we are isolated."

“They can provide us with a backup power source. We’d be happy with that… We can’t afford it.”

“We have an issue with trying to get our solar projects going. We had a project plan for solar panels to go on a school or in community elsewhere… Holding it up is there’s not enough capacity for us to put up solar panels.”

Many claim delays in service connections and project timelines are a significant concern.

"There's more onus on the customer to supply detailed information... And that has certain conditions that you need information to be inputted in order to move on to the next step... It's more of a delay and the timelines are extended within the project to get that set up."

"For project specific, it... carries on and delays... indirect with other contractors and scheduling to complete the project. For example, we have a project that's ongoing right now, but we still do not have a connection."

"Facilitate a new hook up... our poles are in place and it's just running a line to a house... shouldn’t take a couple months to do... Sometimes on new hookups to some of the new homes it’s taken, you know, two to three months when... we should have already been in motion."

“It’s really causing a huge stumbling block to the development of this property…Hydro One is very firm about, there has to be an easement with the town of [community]…it’s really huge in delay in our project and it’s going to get worse.”

“That is one of our biggest complaints is that we do build probably about six or seven houses a year. We’ve been lucky enough to be able to do that, but you’ve got to call [Hydro One] 3-4 months in advance…I think we waited for one full year for one building to be connected….they could really improve the response time pretty substantially.”

“We were trying to get hookups to our new 15 lot subdivision. There were some hiccups and getting the homes moved into right away…it just seemed as though we were jumping through hoops even with our Indigenous liaison…it’s still seemed very slow...it seems like we have to go through a lot of red tape to get the power delivered to these homes.”

9. Appendix 1: Pre-read Document

1

Thank you for taking the time to participate in Hydro One's customer engagement interview.

Hydro One is in the early stages of developing its draft plans covering the years 2028 through 2032.

The purpose of this one-on-one conversation is to begin a dialogue on what you expect from Hydro One as they start developing their Distribution and Transmission system plans for 2028-2032. This includes both the priorities and needs of your community, as well as what you feel Hydro One should be focusing on in the future.

These exploratory conversations are just the first step in an ongoing dialogue. Once Hydro One has developed its draft plans in 2025, you will again be asked to provide feedback.

What will be asked in this interview?

While you may have multiple relationships with Hydro One beyond being a customer (e.g., being a partner in current or future projects), this interview will focus solely on your community's relationship with Hydro One as a **customer**. For instance, in this interview, you will be asked questions about your community's energy needs, what Hydro One can do to better serve your community, what "good" reliability means for your community, and which areas you feel Hydro One should focus more on in the next five to ten years.

The Ontario Energy Board (OEB) expects Hydro One to have an investment plan that responds to customer needs and preferences.

In appreciation for your time, upon completion of this interview, we will provide your community with a $250 donation.

Who will be conducting the interview?

Hydro One has hired an independent research company, Innovative Research Group, to both facilitate and document these conversations. All conversations will be led by a trained researcher who is independent of Hydro One.

Unless you choose otherwise, all your feedback throughout this process will remain completely anonymous to Hydro One.

What are the next steps in Hydro One's customer engagement?

Hydro One plans to gather customer needs and preferences in stages:

- First, identify customer needs and preferences through in-depth conversations with leadership and surveys among on-reserve First Nations customers (**where we are today**)
- Throughout 2025, Hydro One will use this feedback to guide the development of its draft plans.
- Then, later in 2025, Hydro One will return to customers to ensure that their draft plans have found the right balance between investment and outcomes that matter most to customers.
- Finally, again, based on the feedback from customers, Hydro One will revise its plans and submit it to the OEB for final approvals.

Hydro One 2028 – 2032 Rate Application Customer Engagement (Strictly Confidential)

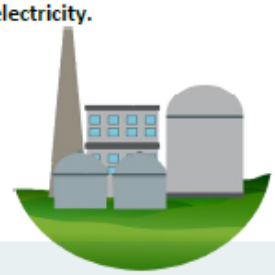
Hydro One's role in Ontario's electricity system

Ontario's electricity system is operated by public, private, and municipal companies across the province. It is made up of three components: generation, transmission and distribution. **Hydro One is Ontario's largest electricity transmission and distribution service provider; it does not generate electricity.**

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources owned by other companies. About half comes from nuclear power. The rest comes from a mix of hydroelectric and natural gas and, to a lesser extent, wind and solar.



Transmission

Hydro One transports electricity across Ontario.

Once electricity is generated, it must be transported to urban, rural, and Indigenous communities across the province. This is done by high voltage transmission lines that serve as highways for electricity. Often these lines are suspended on large steel towers. Hydro One owns and operates almost all of the more than 30,000 km of these lines in Ontario and provides transmission services to most electricity customers in Ontario.



Local Distribution

Hydro One delivers power to homes and businesses in your community.

In your community, Hydro One is also responsible for the last step of the journey: delivering electricity to customers through its local distribution system.

This system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

While there are many distributors in different areas of Ontario, Hydro One builds, operates and maintains the local distribution system that serves you. Hydro One reads meters, calculates and collects bills for all parts of the electricity system and answers customer calls.



How much of the typical electricity bill goes to Hydro One?

- Every item and charge on your bill is mandated by the Ontario government or regulated by the OEB.
- Although Hydro One is responsible for collecting payment for the entire electricity bill, for a typical On-Reserve First Nations residential customer about **44% or $116.41*** is related to the services Hydro One provides per month.
- The portion that is related to Hydro One services consists of: **35% (or $92.14)** for distribution delivery, and **9% (or $24.27)** for transmission delivery. First Nations customers living on-reserve do not pay delivery charges or HST, as they are offset by the **First Nations Delivery Credit**.
- The rest of the bill goes to power generation companies and regulatory agencies.

Appendix 5

Hydro One MNO Leadership In-Depth Interviews

Phase I Report

2028-2032 Joint Rate Application

Prepared for:

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Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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2. Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Networks Inc. (Hydro One), to gain a deeper understanding of the needs and preferences of Métis Nation of Ontario (MNO) citizens directly from citizens in a leadership position, specifically as it relates to Hydro One's Joint Rate Application to the Ontario Energy Board (OEB) covering the years 2028 to 2032.

Approach to MNO Engagement

Hydro One provided INNOVATIVE with the contact information of leaders of all 9 Regional Councils as well as 30 local Community Councils. INNOVATIVE invited each of the Council leaders to schedule a meeting with INNOVATIVE to share their perceptions of their citizens' needs and preferences as they relate to Hydro One's Joint Rate Application covering the years 2028 to 2032.

Outreach efforts included Hydro One's Indigenous Relations team pre-socializing the interview opportunity with MNO leadership and providing a brief summary of what to expect from the interview and that INNOVATIVE would be reaching out to them in the coming weeks.

INNOVATIVE sent the initial invitation to Métis leadership to participate in an interview on September 23rd, 2024. For leaders that had not yet signed up to participate in an interview, a subsequent reminder email was sent on October 7th, 2024. Métis leaders had the opportunity to book an interview between September 23rd and October 10th, 2024. This outreach led to 8 interviews being completed via videoconference or telephone.

The invitation included a pre-read document that provided background information to participants including a brief summary of what will be asked in the interview, who will be conducting the interview, the next steps in Hydro One's customer engagement, Hydro One's role in Ontario's electricity system, and the amount of the typical residential customer electricity bill that goes to Hydro One.

Interviews were approximately 45 minutes in length and were conducted by a trained moderator following a discussion guide. In appreciation of the time provided by MNO leadership, INNOVATIVE provided a $250 cheque.

About this Report

This report summarizes the key findings based on these interviews. In general, our approach is to report representative verbatim comments and offer interpretation and/or commentary where necessary. Verbatim responses are shown in blue italics.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used directionally. In interview-based research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view.

3. Key Findings

Leaders are generally satisfied with the reliability that citizens experience, though more rural areas are more likely to be impacted by frequent or extended outages.

Most leaders express general satisfaction with reliability, especially in more urban areas. Some leaders with citizens in rural and remote areas identify issues with more frequent or prolonged outages, which have significant impacts on food spoilage, medical equipment, and heating.

Most Métis leaders report a very limited relationship with Hydro One and desire more collaboration and direct communication between Hydro One and Métis leaders and citizens.

For most leaders, there is a desire for more consistent and direct communication with Hydro One. Many identified a need for a more collaborative relationship through community events, open houses, or educational initiatives.

Affordability is a significant concern, especially for seniors and citizens in low-income households.

Many leaders raise affordability concerns, emphasizing the impacts of electricity bills on citizens. Several leaders call for greater financial support for Métis citizens when it comes to electricity bills, focusing on citizens most impacted by the costs of their bill.

Some Métis leaders have concerns around vegetation management, specifically regarding chemical spraying.

Leaders emphasize the impact of spraying on traditional harvesting practices and express a preference for mechanical clearing and improved communication around the timing of tree and vegetation trimming.

Many Métis leaders expect growing energy demand in their communities.

This growing energy demand is expected as a result of residential growth, industrial growth, and the changing ways citizens are using electricity.

4. Profile & Energy Needs

4.1. Respondent Profile

Communities Engaged

Interviews were conducted with leaders representing Métis regions across Ontario, with populations ranging from approximately 220 to up to 7,000 citizens. These communities span both urban and rural areas, with varying levels of distribution service from Hydro One. When discussing their membership, some leaders emphasize growing affordability issues.

> *"I would say probably more than half of our citizens [are served by Hydro One]."*
>
> *"We've got a fair mix of people who live in town and their heat sources, usually propane or electric, and then the people who live out of town. I think most of us are wood stoves."*
>
> *"Well, for people, we have in between roughly say 500 and 700…in there somewhere…I would say over 90% [are served by Hydro One]."*
>
> *"The average household or average couple has 1.2 kids. Indigenous families have 2.6 to 2.8 almost three kids per household. So is that difference in demographic will impact a household—more kids, more laundry, right? More laundry, more hydro."*
>
> *"We do have a section of our citizenship that is marginalized, working for minimum wage, having issues going month to month as cost of living is up tremendously over the last couple of years. One income family with children can barely getting by."*
>
> *"It's huge [the territory]. I have 1,500 citizens in my catchment…I think we all pay to Hydro One."*
>
> *"We have about 220 citizens here. We had to revamp and eliminate a lot of citizens that were unverified…I think Hydro One is the only [distributor]."*

5. Satisfaction and Relationship with Hydro One

5.1. Overall satisfaction with Hydro One

Satisfaction related to reliability

Métis leaders largely attribute satisfaction with services to their reliability experience. Some Métis leaders note improvement in reliability over time and recognize the importance of the services Hydro One provides.

> *"Over the past 10 years, I would say things have improved dramatically... We still get some blackouts out of the mine, but it wasn't near as much as it was."*
>
> *"When you turn the lights on, the lights work. That's invaluable. You don't really realize how much you need hydro until the hydro goes out and then you would probably pay whatever you need to get it back. So, I think you know it's kind of just like a monopoly we need it. So you're going to pay what you have to pay to get it."*
>
> *"It was pretty good as far as that's concerned. I've got nothing bad to say about Hydro One."*
>
> *"Is it satisfactory to me? Yes, because I'm getting hydro on a regular basis. I'm paying what I can afford."*

Areas of Dissatisfaction

Some other Métis leaders express dissatisfaction with Hydro One for a variety of reasons, including issues with communication, a lack of clarity on where customers should go for support, and vegetation management issues.

> *"[When] they were fixing hydro poles at the end of the road and they just come snap your power out for the entire day. Maybe some sort of e-mail to a customer saying, 'hey, we're going to be doing work down this road. [You] might experience power outages.' But instead, I barely woke up, turn the TV on. 10 minutes later, it was out. And it was out the entire day, and I didn't know why until I actually went down the road to ask the workers... Maybe just some sort of communication to keep you in the loop so you feel like you're valued instead of just 'Oh, well, you get the power when you get the power. You don't when you don't.'"*
>
> *"I don't know if those customers are aware of what [contacts] Hydro [One] has. It's not like they've got a fridge magnet [that] says, 'for all things Hydro, call this number,' right?... How do I tell them who to call?"*
>
> *"They complain about [spraying] because it affects their way of life, for harvesting... If you're used to trapping in your area, why should you go another couple 100 miles just to trap, it's not worth it, right?"*

5.2. How Hydro One can better serve the community

Vegetation management

Some leaders express concern over vegetation management practices, specifically related to chemical spraying. They emphasize the impact of spraying on Métis traditional harvesting practices and express a preference for mechanical clearing.

> *"Being Indigenous means we collect medicines and foods off of those lines sometimes. It's nice to know if they're marked that they're chemically clean. It'd be nice to know the schedule when they tend to go and do mechanical clearing, because if there are plants that are at that seasonal time of the year when they're ready to be harvested, we would have that ability to go in ahead of them and harvest them."*

> *"We don't like that pesticide or herbicide, because it was killing everything. The trappers were getting angry because there were no more animals around there. There wasn't even a flyer. Nothing. And other provinces have gotten rid of that. They don't use it anymore. So anyway, so they said, 'OK, we're not going to use it because of your concerns.' And then they use something else. But it still had Garlon pour in it. They just renamed it."*

> *"There's nothing controversial about what they're doing, except for that spraying. And that's about the only thing that we have a problem with. Until that's resolved, it's always going to be a problem with citizens."*

Community engagement

Many leaders have a desire for a stronger relationship with Hydro One, including regular, direct communication through community events, open houses, or educational initiatives.

> *"Say an annual fish fry, for instance... and last year was our biggest one, which I think was roughly 175 people plus other local businesses like say, Bruce Nuclear. Like all the surrounding businesses are starting to come up. And [they] put tables at our events so that it gets the word out as well. So it's not just like a faceless company, right? There's more interactions and stuff like that. So maybe if they started to partake in some of our events. And then they would actually get to hear from our people directly."*

> *"Being more involved with us, even if it's just to have like a meet and greet or an information session. If there's information that they would like to get out just to invite our people [to] have a little sit down. They can explain some things or what they plan on doing. They kind of just do what they want when they want and you figure out after."*

> *"I can put the QR code for them to scan and to do that survey for Hydro One. They just got to ask. And I think that [it] would be a lot better to hear individually from all those people."*

> *"Maybe there's a newsletter they can stick in there and give some trivia pieces about hydro and how it relates to everything."*

> *"Having some open houses [so] that where people could come in and ask most people about Hydro One, they wouldn't be able to tell you very much. Huge company. They know this much about it, right? The education about a big company might help people to not be so frustrated and mad at their bill."*

"To get my citizens to events, I have all kinds of big draws. I have monthly draws. We give away all kinds of $1000 attendance prizes. We have... $500 gas cards. Nothing, right? All you have to do is click register if you're in an account holder with them and they pull five names every month."

Greater financial support

Many leaders express issues around affordability of electricity for citizens and some specifically mention the role of Hydro One in providing greater financial support to those most impacted by the cost of their electricity bills.

"They can give them, you know, a $50 credit every month to help towards that bill. Maybe there has to be something like that, or someone whose income's $20,000 a year, having to decide am I eating or am I going to be cold."

"It'd be nice to have a program for Indigenous people through Hydro One that helps subsidize some of the lower income families... I have a role in in putting our citizens in contact with the proper staff to be able to get their assistance. Whatever program that MNO are running or mainstream programming."

"It's hard. It's extremely hard, especially for seniors. I have a job. It's great. I'll pay my bill. But when you're [a] senior, you're already cutting... They don't really think [about] seniors and people that are on very low income. They shouldn't be paying the same as what we're paying."

"The big one that is a concern for many people is if you're struggling to pay your hydro bill. [If] you are First Nations and you live on reserve, you can access a pot of funding from Hydro One. But if you're Métis, you can't."

"You don't get people who want to even sign up for their citizenship because it doesn't get him a break on hydro. It doesn't get him a break on their taxes. They still have to pay all of their taxes. Not like if they lived on a reserve."

"When I lived in Alberta, I could access a utilities bank if I needed to, like you could go there like a food bank, but if you need help paying your utility. They have that out there. We don't [have] that here. So if you're not making your payments, you're getting cut off."

"The only thing that I have heard from constituents was the price of hydro. If there was a way that they could work something out... that there would be some sort of like discount or back pay at the end of the year kind of thing. Basically all, it's just prices."

5.3. Relationship with Hydro One

Current relationship with Hydro One

When asked about their current relationship with Hydro One, most leaders say that they do not have a strong relationship or communicate regularly with the utility in their role within the Métis Nation of Ontario.

"Well, personally I don't have much of a relationship with Hydro One."

"It's amicable. We have not met as often as I think we need to, and that is mostly due to COVID. We used to have a multi-disciplinary meeting about once a year…and those haven't happened probably since 2019, maybe 2018? I don't know if we're going to get back on track with that…they're usually good gatherings and good information."

"We did a deal with them, but our relationship with Hydro One was very, very contentious for quite a while…we kicked them out of a room at one point."

"I'm not overly happy with the fact that I was told at one point previously that Hydro One already has its agreements with First Nations [while we are in ongoing negotiations]."

"To be honest, I am new to this role…so I personally have never had any interactions with Hydro One at all with my council."

"I don't really have communication with them…just when there's an outage, I get a notice that there is going to be an outage."

Desired relationship with Hydro One

Many leaders call for greater engagement with Hydro One and project involvement on par with First Nations. Some note challenges in addressing the dispersed Métis population, as well as perceived inequities in economic opportunities and project involvement compared to other Indigenous groups.

"If you have a duty to consult and measure impacts and benefits, you have to do that with all Indigenous groups, whether it's Inuit, First Nations or Métis. Hydro One said, 'Oh, it's real easy to do reserves, because that's a postal code. Basically, we can just slam it all down at once and get it done.' It's a little more difficult [for us]. We're scattered over large geography. You'd have to basically register with them that you are Indigenous and then they would have to settle. But they're not talking to us about that. So there's an unfairness from Hydro One and other distributors."

"Hydro [One] said there is going to be no economic development for any group. Didn't matter what group you were, there was going to be no economic development. 3 weeks later they are announcing cross Ontario that they're giving the First Nations 51% of this project. Three weeks. Three weeks after we were told nothing. Zero. Nada. Nobody's getting anything."

"They didn't say, 'hey, we want to change the name of this project, and here's what your options are.' We were just told this is the name of the line. I mean, I know First Nation groups that weren't happy with it... We are one of the three Indigenous groups in Canada, and we have to be treated very similarly... If we had a treaty, we would have our impact to rights be on par with the First Nations. But until we have a treaty with Canada, they keep thinking that they can just keep pushing us off to the side."

"We need to be treated fairly, equitably and fairly as our as our brothers and sisters are."

Many leaders are open and willing to work with Hydro One to build and maintain a proactive and supportive relationship.

"If there's a way possible for us to move forward together, I think that would be great cause. Again, it shows that they're trying to get more involved with the community and we'd be more than happy to work with them on any process, like even getting information out. If they want to do like the fixing... 'your hydro will be down while,' we can put that to our people in the area... We'd be willing to."

"Electricity grid and service providers might want to at some point time get together and do the same thing and say, 'hey, let's give one number out to our customers if they have to call, they will be redirected by somebody on who answers that call and tell you who to get a hold of, right?"

6. Price & Affordability

Affordability

Many raise significant concerns around the affordability of electricity bills, emphasizing the financial burden it places on citizens, especially for those living in rural areas, seniors, and low-income households.

> *"[Affordability] is a huge issue... I think we spend a disproportionate amount of it on our hydro and if you're like me, I live out in the middle of nowhere. I don't have any other utilities."*
>
> *"[Hydro One can] slash their bills by 90%."*
>
> *"Over the last year, we've had several citizens that have come to us asking for help paying their bills. Specifically, their hydro bill because, it's too unaffordable."*
>
> *"The colder the winter, the more you heat, the more you pay. You have to take it from someplace else to be able to pay that bill. So that's generally the food on your table, right?... [So] you're not going to eat healthy because you can't afford a healthy meal."*
>
> *"With the prices today, I keep the furnace off, I keep air conditioning off. I keep my lights off. We do so much in the dark because it's not affordable otherwise... We shouldn't have to be that cheap with the use of hydro to exist. There are people that are less fortunate in wages that keep their hydro off even more than that because they can't afford those bills. People, people have already cut down."*
>
> *"If there was some affordability, why should I have to keep my house at 58°? Because I can't afford a hydro bill. If it's at 70°, where I'd be comfortable or 68°, that would be comfortable. [But] I'm keeping it down, pushing it down to 60°. Well, that's not reasonable."*
>
> *"Reducing cost... I know that it's repetitious, but it's cost. Cost is what affects my community members the most right now."*

Billing

Some share that billing clarity could be improved. Some also note that seniors find bills difficult to understand.

> *"But you have lots of seniors. So people who are not understanding the words or the way that they're explaining and the bill is just downright terrible."*
>
> *"We're at the whim of whatever they want to charge…if you look at when your bill comes, they're changing you for delivery here and delivery there. And I'm like, 'the stuff's in the pipe'. Whether you use this much or this little, they charge you the same no matter what you do…I would like an explanation of why we have to pay 3 delivery charges, you know, to come from that pipe... So I think a little bit more detailed explanation that's user friendly."*
>
> *"They say square cubic foot…you know, and all that. Like what does that mean to a senior that you've used this much…where are they getting this from?...I feel sorry for especially the seniors because they really don't know."*
>
> *"The bill is really only 20% of what we are actually using…everything else, you know, just started being astronomical. I honestly believe we're being gouged…and it's taking advantage of people."*

"People think when they hear in the news that hydro is only going up 3%, they don't understand that's the production of the electricity. The delivery can also go up 3% and since they're both 50% of your bill, your bill is really going up 5%. I think the corporations need to be clear on what the total impact of your bill will be. Not trying to pull the wool over people's eyes."

7. Reliability

7.1. Importance of good reliability

Impacts of poor reliability

Leaders identify a range of impacts related to poor reliability and especially extended outages, highlighting issues related to food spoilage, medical equipment, and heat.

> *"After that big snowstorm... there was a lot of people that were coming to me going. 'I need a generator because I lost all the food in my fridge. I lost everything. I didn't have heat.'"*

> *"But if it's not mostly the older people who we'd be worried about because they wouldn't be able to feed themselves, take their medication, or even like the ones who would have sleep apnea, couldn't use their machines, right?"*

> *"I know that the longer power outages are about 12 hours. And that's a pretty long time, especially if you're one of my citizens who's on an oxygen machine and you're relying on that power and you don't have that backup... And so there are some people that have come to rely on me providing my personal backup generator during power outages because they've got either older freezers that don't do well when they're turning off and on, and they don't want to lose their meat or they have the oxygen machines or other medical equipment that they need to have plugged in."*

> *"Hydro, for the most part, you get a three, 4–5-hour outage. Nothing to worry about. If it looks like it's going to be more than five hours, you have to start thinking about the meats in your fridges and freezers and whatever else."*

7.2. Current state of reliability

General satisfaction in reliability

Leaders are generally satisfied with the reliability of Hydro One's service to their citizens, expressing that they do not often experience reliability issues.

> *"[Citizens] don't ever say it's not reliable. They just say it's too expensive."*

> *"When I look at reliability, it's there. I don't think there's an issue with that. It comes down to cost and how affordable is it for our citizens."*

> *"The reliability's pretty consistent. There are some interruptions, but [that is] what happens with anything right?"*

> *"Other than the old homes with the old wiring, I would say that I really don't have flickering unless the light bulb's about to bust."*

> *"Overall, is it reliable? Yes. Do I think that they could do better informing a proper outage that they know in advance? Yes."*

Urban and rural differences

For some, reliability is considered less dependable in rural areas compared to urban centers, with rural and remote citizens more likely to report frequent or prolonged outages.

> *"[Reliability] just depends on what grid you're in for. For me, any sort of storm, it'll go out right away because of where I am. But the ones who are in the bigger cities never really seem to have a problem because they're on a whole different power grid."*

> *"Most of them, they know the area where they live. They know when there's an outage, it could be significant being six or eight hours or more versus, you know, living in town. You might have a two-to-four-hour window of concern. So, most of them have been prepared. They have that survival mentality already that power could go out. So, they've got the equipment to get through it."*

> *"Work quicker to restore power because when they're taking away resources from [redacted] to send them down to [redacted] during an outage for both communities. Because there is a more urban area, they're more prioritized over the rural areas. And I don't think that that's fair."*

> *"We had a really bad snowstorm three years ago, where we had 4 1/2 feet of snow dumped on us and my road. For three days, every single one of my neighbors down my road lost their power. Large amount of them were citizens. I was the only one who had no issues because I wasn't on the grid. But for some people they were without power for a week or so."*

8. Hydro One Priorities & Future Expectations

8.1. Anticipated changes in electricity use

Community growth

Many leaders anticipate growing use of electricity in their communities due to population growth, particularly in more rural areas.

> *"Immigration [is] stronger than it's ever been. We're seeing more diverse cultures settling in our area. Housing construction is way up... The next census should see a significant growth in our town."*

> *"Where I live now, they're starting to take the farmland outside of the that's roughly around the city and they're about to turn those into apartment buildings... Growth is booming, that's for sure."*

> *"I see lots of people, city people, moving to the small rural areas… people are selling their homes in the city, in Toronto, and all over and moving to these tiny towns."*

Business and industry growth

In line with expected community growth, many leaders also expect expanding housing construction, urban development, and growing economic activity as a result of expanded business and industry activity.

> *"With the mining industry in this area, because that's the one of the main employers, there are a number of new properties coming into existence... The demand for workers is going to be there. So the growth is going to be there."*

> *"[Redacted] itself is growing, but a lot of this area is dependent on the mines at [redacted]. In [redacted] was a very small community. People work logging in forestry. [Redacted] is mostly the hospital, government or education."*

> *"With the amount of mines that we're hoping to open and stuff like that in the area, they're going to chew up a really big part of whatever power that they can do. I think Hydro [One] needs to up their game, make things more efficient in... how they're producing power. I think they could. I think they can squeeze way more out of what they're doing and become that much more efficient."*

General increasing energy demand

In addition to population and industry growth, some leaders share that rising consumption habits and increasing demand for electric vehicle charging infrastructure are contributing to higher energy usage. Some mention that climate change and fluctuating weather patterns, including prolonged extreme heat, are further driving rising demand.

> *"The rationale for why it's going up is going to be electric vehicles. Everything else is getting more energy efficient. So the promotion of electric vehicles and charging stations. You see them popping up in every community. Now they are a dime a dozen…so those types of things are part of the growth factor."*

"[With] the climate change,... last summer we had several days where it was over 40 for a week, and that was a lot on the grid when you're trying to power all those air conditioners. So that's also another thing is with the fluctuating weather."

"In terms of power consumption, [it] is mainly going to be that everybody needs that bigger TV. Everybody wants to plug absolutely everything in all the time."

"Even though I do follow time of [use], I do everything I can to reduce my power output, input and stuff like that. I know that I'm going to increase how much power I use. It's inevitable."

"I think with the amount of power that everybody is going to be using, I think that they I think that hydro really needs to keep [up with] their maintenance."

8.2. Investments in alternative sources of energy

Renewable uptake and energy-conscious behaviours

Some leaders note uptake of renewable energy options like solar and identify growing trends in energy-conscious behaviours to reduce usage.

"I think they're trying to go, 'greener,' right? They're trying to do the solar panels and that stuff. I don't know how much of it would [change] because the more you look into [it], you realize more [that] it's not really worth it. The trade off the wind, propellers, turbines, etc. and the animals that kills really isn't worth what people are getting. Because they don't work half the time, right?"

"People who live in the more rural areas where they do have a fair amount of sunshine, they set their solar panels up where they built their house…[One of my friends] did that. All his solar panels and everything are all set up... He's getting the batteries the whole 9 yards.."

"The usage stays the same. I think people are being a little more cautious keeping the lights down, even though with the LED bulbs today you're using very little electricity. You know those that heat by electricity? Keep that heat down one or two degrees. You put a sweater on instead of putting the heat up and so on."

Hydro One's role in helping communities meet changing energy needs

Leaders look to Hydro One to take a leadership role in addressing the rising climate change concerns by continuously modernizing infrastructure and investing in renewable energy sources.

"People's concerns are absolutely right about climate change, something that needs to be taken very seriously. And I think that the more modern techniques and the more modern your infrastructure is, the better chance of its survival."

"I think that we need the introduction of not just hydro dams, but the increase of power has to come from renewables... I think in the far north where all these communities are on diesel, we need to remove them from diesel because of climate change. They need to get on the small nuclear reactors. I honestly don't think there's enough sunlight in the day, and winds are not as consistent."

"Nuclear produced electricity is the most expensive out there right now... But over the 60-year period that cost [would] drop because the return is greater over time.?"

9. Appendix 1: Pre-read Document

Thank you for taking the time to participate in Hydro One's customer engagement interview.

Hydro One is in the early stages of developing its draft plans covering the years 2028 through 2032.

The purpose of this one-on-one conversation is to begin a dialogue on what you expect from Hydro One as they start developing their Distribution and Transmission system plans for 2028-2032. This includes both the priorities and needs of your members, as well as what you feel Hydro One should be focusing on in the future.

These exploratory conversations are just the first step in an ongoing dialogue. Once Hydro One has developed its draft plans in 2025, you will again be asked to provide feedback.

What will be asked in this interview?

While you may have multiple relationships with Hydro One beyond being a customer (e.g., being a partner in current or future projects), this interview will focus solely on your and your members' relationship with Hydro One as a **customer**. For instance, in this interview, you will be asked questions about your members' energy needs, what Hydro One can do to better serve your members, what "good" reliability means for your members and which areas you feel Hydro One should focus more on in the next five to ten years.

The Ontario Energy Board (OEB) expects Hydro One to have an investment plan that responds to customer needs and preferences.

In appreciation for your time, upon completion of this interview, you will be provided with a $250 donation to support one of the Métis Nation of Ontario's programs.

Who will be conducting the interview?

Hydro One has hired an independent research company, Innovative Research Group, to both facilitate and document these conversations. All conversations will be led by a trained researcher who is independent of Hydro One.

Unless you choose otherwise, all your feedback throughout this process will remain completely anonymous to Hydro One.

What are the next steps in Hydro One's customer engagement?

Hydro One plans to gather customer needs and preferences in stages:

- First, identify customer needs and preferences through in-depth conversations with leadership and surveys among Hydro One customers (**where we are today**)
- Throughout 2025, Hydro One will use this feedback to guide the development of its draft plans.
- Then, later in 2025, Hydro One will return to customers to ensure that their draft plans have found the right balance between investment and outcomes that matter most to customers.
- Finally, again, based on the feedback from customers, Hydro One will revise its plans and submit it to the OEB for final approvals.

Hydro One's role in Ontario's electricity system

Ontario's electricity system is operated by public, private, and municipal companies across the province. It is made up of three components: generation, transmission and distribution. **Hydro One is Ontario's largest electricity transmission and distribution service provider; it does not generate electricity.**

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources owned by other companies. About half comes from nuclear power. The rest comes from a mix of hydroelectric and natural gas and, to a lesser extent, wind and solar.



Transmission

Hydro One transports electricity across Ontario.

Once electricity is generated, it must be transported to urban, rural, and Indigenous communities across the province. This is done by high voltage transmission lines that serve as highways for electricity. Often these lines are suspended on large steel towers. Hydro One owns and operates almost all of the more than 30,000 km of these lines in Ontario and provides transmission services to most electricity customers in Ontario.



Local Distribution

Hydro One delivers power to homes and businesses in many communities.

In many communities across each of the 9 Métis Nation of Ontario regions, Hydro One is also responsible for the last step of the journey: delivering electricity to customers through its local distribution system.

This system includes transformer stations that decrease the voltage of the electricity so it can be used safely in homes and businesses.

There are many distributors in different areas of Ontario serving Métis membership, and Hydro One builds, operates and maintains the local distribution system in many communities. Hydro One reads meters, calculates and collects bills for all parts of the electricity system and answers customer calls.



How much of the typical electricity bill goes to Hydro One?

- Every item and charge on your bill is mandated by the Ontario government or regulated by the OEB.
- Although Hydro One is responsible for collecting payment for the entire electricity bill from its distribution customers, for a typical residential customer about **34% or $57.72*** goes to Hydro One per month.
- The portion that goes to Hydro One consists of: **24% (or $41.18^)** for distribution services, and **10% (or $16.54)** for transmission services.
- The rest of the bill goes to power generation companies, taxes and regulatory agencies.

*Before Ontario Electricity Rebate of 19.3%.

^Distribution portion of the delivery charges include Distribution Rate Protection savings.

Appdendix 6

2028-2032 Joint Rate Application
Phase I: Planning Placemat



Hydro One Phase I Customer Engagement

Planning Placemat (Identifying Customer Needs and Preferences)

Between August and December 2024, INNOVATIVE engaged with customers, community leaders, and stakeholder groups to identify general customer needs and preferences, and to gather feedback on a series of high-level investment trade-offs covering both the distribution and transmission systems.
This planning placemat summarizes the quantitative feedback received from customers through an online survey. The online survey was customized for different customer types and rate classes with estimated bill impacts provided. Where appropriate, results are weighted by region and consumption to ensure they are representative of Hydro One's broader customer base.

Customer Type Unweighted n (weighted in brackets)	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve n=426 (400)	Small Business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
What are customer needs? **Most customers do not identify any specific needs. Among those who do, the top responses include decreased outages, lower rates, address/proactive tree trimming, communications during outages, and improving customer service.**							
Customer Needs (%) indicates share of customers within the customer group providing the response. Results are based on an open-ended question asking customers what they would like Hydro One to do to improve its services. Top-3 most common responses are shown.	Decrease outages (9%)	Lower rates (7%)	Lower rates (10%)	Decrease outages (9%)	Decrease outages (15%)		Improve customer service (19%)
	Lower rates (9%)	Decrease outages (6%)	Decrease outages (5%)	Improve customer service (4%)	Communication during outages (10%)		Decrease outages (13%)
	Address/proactive tree trimming (7%)	Improve outage response times (3%)	Address/proactive tree trimming (4%)	Upgrade/better maintain infrastructure (3%)	Building capacity/ addressing growth (7%)		Improve information sharing (7%)
What outcomes do customers prioritize? **Reasonable rates and reliable electricity are top priorities for all customer types. Meeting growing demand for electricity is a top priority for C&I, Large Dx, and Other LDC Residential customers.**							
General Priorities (%) indicates total share of customers within the customer group that select the priority in their top-3 outcomes. Only the 3 most frequently selected priorities are shown.	Reasonable rates (80%)	Reasonable rates (76%)	Reasonable rates (82%)	Reasonable rates (83%)	Reasonable rates (75%)	Reasonable rates (76%)	Reliable electricity (81%)
	Reliable electricity (69%)	Reliable electricity (49%)	Reliable electricity (52%)	Reliable electricity (67%)	Reliable electricity (69%)	Meeting growing demand (59%)	Reasonable rates (61%)
	Ensuring safety (40%)	Ensuring safety (38%)	Enhancing the grid for new tech (37%)	Meeting growing demand (39%)	Meeting growing demand (43%)	Reliable electricity (57%)	Ensuring safety (53%)
What reliability outcomes do customers prioritize? **Both the length and number of outages are important priorities across all customer types. For all customer types, the length of outages <u>not</u> caused by severe weather is within their top-3 priorities.**							
Reliability Priorities (%) indicates total share of customers within the customer group that select the priority in their top-3 outcomes. Only the 3 most frequently selected priorities are shown.	Length of outages caused by severe weather (63%)	Length of outages caused by severe weather (59%)	Length of outages caused by severe weather (60%)	Number of outages <u>not</u> caused by severe weather (61%)	Number of outages <u>not</u> caused by severe weather (57%)	Length of outages caused by severe weather (65%)	Number of outages <u>not</u> caused by severe weather (65%)
	Length of outages <u>not</u> caused by severe weather (57%)	Communications during outages/ETOR (54%)	Number of outages <u>not</u> caused by severe weather (57%)	Length of outages <u>not</u> caused by severe weather (60%)	Momentary interruptions in power (57%)	Number of outages <u>not</u> caused by severe weather (59%)	Length of outages <u>not</u> caused by severe weather (58%)
	Number of outages <u>not</u> caused by severe weather (52%)	Length of outages <u>not</u> caused by severe weather (52%)	Length of outages <u>not</u> caused by severe weather (54%)	Length of outages caused by severe weather (49%)	Length of outages <u>not</u> caused by severe weather (46%)	Length of outages <u>not</u> caused by severe weather (59%)	Number of outages caused by severe weather (50%)

*Local distribution company

Hydro One Phase I Customer Engagement

Planning Placemat (Identifying Customer Needs and Preferences)

Customer Type Unweighted n (weighted in brackets)	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers	
	Residential n=6,053 (5,000)	First Nations On-Reserve n=426 (400)	Small Business n=477 (450)	Commercial & Industrial n=311 (300)	Large Dx Accounts n=61	Other LDC* Residential n=1,019 (1,000)	Large Tx Accounts n=72
Distribution Investment Trade-Offs							
High-Level Reliability							
A majority of customers want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid. Across customer types, a plurality of customers want Hydro One to make investments to improve reliability rather than maintain reliability.							
Improve reliability	68%	48%	58%	55%	75%		
Maintain reliability	19%	28%	21%	27%	16%		
Defer investments	7%	11%	11%	9%	3%		
Targeted Reliability Improvements							
A majority of customers want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.							
Make targeted investments	78%	66%	73%	70%	87%		
Minimize investments	12%	19%	16%	15%	10%		
Responding to Severe Weather							
A majority of customers want Hydro One to make investments to make the system more resilient to severe weather. Across customer types, a plurality want Hydro One to proactively invest rather than make the investments as part of ongoing replacement.							
Proactively invest	64%	45%	62%	51%	67%		
As part of ongoing replacement	23%	28%	23%	32%	23%		
Minimize investments	7%	17%	8%	8%	5%		
Enabling Economic Growth							
A plurality of customers want Hydro One to make proactive investments to enable anticipated growth and accommodate new connections and service upgrades in a timely manner.							
Proactively invest	52%	50%	48%	44%	62%		
Only as growth materializes	34%	29%	35%	34%	31%		
Evolving Customer Requests & System Visibility							
A majority of customers want Hydro One to make proactive investments in technology to accommodate customer requests and improve system visibility.							
Proactively invest	69%	57%	63%	61%	77%		
Limit/delay investments	20%	28%	25%	22%	16%		
Transmission Investment Trade-Offs							
Transmission Renewal							
A majority of customers want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.							
Increase reliability	48%	37%	43%	30%	41%	37%	56%
Maintain reliability	34%	38%	36%	45%	46%	35%	36%
Accept more risk	10%	12%	11%	12%	8%	20%	3%

*Local distribution company

Note that "don't know" is not shown on investment trade-off questions.

Appendix 7

INNOVATIVE RESEARCH GROUP

2028-2032 Joint Rate Application
Phase I: Customer Engagement Report

hydro one



April 2025

Report Navigation

2028-2032 Joint Rate Application

Phase I Customer Engagement Report

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Hydro One 2028-2032 Joint Rate Application Customer Engagement (Phase I)

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Networks Inc. (Hydro One), to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of online surveys conducted as part of Phase I of this customer engagement for the 2028-2032 joint rate application.

Report Overview

In Phase I, Hydro One and INNOVATIVE set out to develop an understanding of current customer needs and preferences, as well as gain some preliminary insights on more specific investment areas that could be further explored in Phase II. Investment trade-off questions were asked relating to both the distribution and transmission systems.

A key principle of this phase uses random-sampling research methods to ensure a representative sample of customers were engaged, ensuring the generalizability of the findings.

The online survey was customized for different customer types, and this report contains separate sections for each: **Residential & Seasonal**, **First Nations On-Reserve**, **Small Business (GS<50)**, **Commercial & Industrial**, **Large Distribution Accounts**, **Large Transmission Accounts**, and **Other LDC Residential**.

Introduction
Segmenting Customers

Customer Segmentation

In addition to segmenting customers based on where they reside or operate in Hydro One's service territory, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within, and what is outside of Hydro One's influence or control.

Segmentation, where possible, is used throughout this report to look beyond the topline numbers and to analyze the results for key segments:

1. **Region:** Using customer data provided by Hydro One, we split customers into five regions for analysis; West, Central, Central East, East, and North based on Hydro One's service zones.

2. **Consumption Quartiles**: For residential, First Nations On-Reserve, small business (GS<50), and commercial & industrial customers, results are also shown by consumption quartiles. For low-volume customers, this is based on how much electricity the customer consumes in an average month (in kWh). For commercial & industrial customers, this is based on customer demand in an average month (in kW). This is used to ensure that no one customer consumption/demand profile is over or underrepresented in the survey results.

3. **Bill Impact on Finances**: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement(s):

    a) Residential/First Nations On-Reserve: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

    b) Small Business/Commercial & Industrial*: The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

4. **Vulnerable Consumers**: For residential and First Nations On-Reserve customers, using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Ontario Electricity Support Program (OESP)* criteria.

Understanding Segmentation

Segmentation is an effective way to look past the topline numbers and dig deeper into the needs and preferences of the customer segments outlined above. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel based on perceptions that may be outside of the utility's influence or control.

INNOVATIVE RESEARCH GROUP

Sample Validation

Overview and Methodology

Section 1



Overview and Methodology

Research Objectives

Research Objectives

As part of its Phase I Customer Engagement, Torys LLP, on behalf of its client Hydro One, commissioned INNOVATIVE to conduct parallel telephone and online surveys among low-volume customer types.

Running parallel telephone and online surveys serves two primary purposes

Online surveys are conducted to gather feedback and insights on preferences and needs from customers. It is important to establish a baseline level of knowledge of the electricity system among customers in order to gather informed feedback on customer needs and preferences. The most effective way to present this information is through an online survey. Feedback from these surveys will help Hydro One's planners inform the design of the utility's draft investment plan, which will be share with customers in Phase II of the customer engagement.

Parallel telephone "reference surveys" are conducted to ensure that customers reached by email are representative of the broader population of Hydro One customers reached via telephone. Not all customers have provided their email address to Hydro One, but all have phone numbers. Understanding the differences between customers with a known email address (email sample) and the broader customer base (reached via telephone) is a critical step for understanding how representative the email sample is of the broader customer base. This approach allows for weighting adjustments to be made to the online survey results when significant differences are found between the two samples that meaningfully impact the overall results.

Benefits of Utilizing an Online Methodology

Online surveys allow us to provide the context and information needed for customers to give meaningful input into their needs, preferences, and evaluation of Hydro One's draft investment plan that will be presented in Phase II of the customer engagement. Benefits of utilizing an online methodology include:

- Better presentation of information through the use of visuals (e.g. diagrams and pictures)
- Ability to ask more questions, as respondents are more likely to spend a longer time participating in an online survey than on the phone
- Flexibility for customers to complete the survey at their own pace

Overview and Methodology

Overview of Approach

INNOVATIVE undertook a rigorous "sample validation" process to understand whether and where differences existed between customers who have provided their email to Hydro One and the full population of customers. Telephone reference surveys were conducted for all low-volume customer types, namely residential (both primary and seasonal), First Nations On-Reserve, and small business (GS>50kW).

Since email addresses were available for all Large Distribution Accounts (LDA) and nearly all Commercial and Industrial (C&I) and Large Transmission Accounts (LTX), telephone reference surveys were not conducted among those customer groups.

Overview of Approach

The sample validation portion of this report takes several steps to validate the sample across customer types, both when a telephone reference survey was conducted and when it was not.

1. **Use complete customer lists to compare known sample variables between those with an email address and the full population of customers.** This allows us to identify systematic differences between those with an email on file and the full population of customers regarding known characteristics (rate class, region, and consumption) that may impact outcomes. All samples except Large Distribution Accounts (LDA) and Large Transmission Accounts (LTX) are weighted by region and consumption quartile to ensure representativeness.
2. **For customer types where parallel telephone and online surveys were conducted, we compare responses on core demographics, firmographics, and controls that may impact outcomes.** This allows us to identify differences between online and telephone respondents on self-reported demographics, firmographics, and controls.
3. **Based on the above exercise, we identify any sample differences that may be corrected for with weighting.** We focus on differences that meaningfully impact the overall results of the online surveys.

Overview and Methodology

Survey Methodologies

The sample validation portion of this report documents the results of several telephone reference surveys and online surveys conducted by INNOVATIVE among selected customer groups. Below, an overview of survey methodology is provided. All surveys listed below follow a random sampling methodology where customers are randomly selected to be invited to participate.

Telephone Reference Surveys

The **residential telephone survey** was fielded from November 13th, 2024, to November 24th, 2024, among a random sample of n=1,011 primary residential and seasonal customers. The sample is weighted proportionately to n=1,000 by region, consumption quartile, and customer type.

The **First Nations On-Reserve telephone survey** was fielded from November 14th, 2024, to November 19th, 2024, among a random sample of n=204 First Nations On-Reserve residential customers. The sample is weighted proportionately to n=200 by region and consumption quartile.

The **small business (GS<50) telephone survey** was fielded from November 13th, 2024, to November 21st, 2024, among a random sample of n=401 small business customers. The sample is weighted proportionately to n=400 by region and consumption quartile.

Online Surveys

The **residential online survey** was fielded from November 12th, 2024, to December 4th, 2024, among a random sample of n=6,053 primary residential and seasonal customers. The sample is weighted proportionately to n=5,000 by region, consumption quartile, and customer type.

The **First Nations On-Reserve online survey** was fielded from November 14th, 2024, to December 5th, 2024, among a random sample of n=426 First Nations On-Reserve residential customers. The sample is weighted proportionately to n=400 by region and consumption quartile.

The **small business (GS<50) online survey** was fielded from November 12th, 2024, to December 3rd, 2024, among a random sample of n=477 small business customers. The sample is weighted proportionately to n=450 by region and consumption quartile.

Note: *Graphs and tables may not always total 100% due to rounding. Values greater than any error in data. Sums are added before rounding numbers.*

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Sample Validation

Comparing Known Sample Variables



Comparing Known Sample Variables

Overall Customer Email Coverage

Overall Customer Email Coverage

The table below summarizes the email coverage of each of Hydro One's customer types.

Rate Class	Total Records (Meters)	Unique customers*	Customers with an email	Email coverage (out of unique customers)
Residential	1,193,492	1,078,621	766,702	**71.1%**
Seasonal	136,763	102,349	68,663	**67.1%**
First Nations On-Reserve	20,801	17,276	11,552	**66.9%**
Small Business	113,709	63,122	45,571	**72.2%**
Commercial & Industrial	7,453	5,154	4,827	**93.7%**
Large Distribution	289	276	276	**100.0%**
Large Transmission	249	197	195	**99.0%**

*Unique *customers* from the complete list of Hydro One's records (individual meters) are identified by cross-referencing available contact information to identify customers with multiple meters. Customers are assigned to their highest-order rate class in the following order (Large Transmission Account, Large Distribution Account, Commercial & Industrial, Small Business (GS<50kW), First Nations On-Reserve, Residential, Seasonal). For customers with multiple records within the same rate class, the record with the highest average monthly consumption is used for the purpose of assigning sample variables.

Comparing Known Sample Variables

Regional Distribution by Customer Type (Con't)

Comparing Known Sample Variables

The information below compares the sample of each customer type with email addresses to the total customer accounts of that customer type across regions.

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

(1) Regional Distribution by Customer Type

Using service zones, areas are grouped into five distinct regions within Hydro One's service territory.

Distributions of region are similar (+/- 4%) across residential, seasonal, and First Nations On-Reserve customer types. Any differences are accounted for by making weighting adjustments based on region.

Customer Type	Region	Share of full population	Share of email sample	Difference
Residential	Central	26%	26%	**0%**
	Central East	31%	31%	**0%**
	East	16%	17%	**+1%**
	North	11%	10%	**-1%**
	West	16%	15%	**-1%**
Seasonal	Central	39%	40%	**+1%**
	Central East	32%	32%	**0%**
	East	6%	6%	**0%**
	North	16%	15%	**0%**
	West	7%	6%	**0%**
First Nations On-Reserve	Central	26%	24%	**-1%**
	Central East	14%	15%	**0%**
	East	1%	1%	**0%**
	North	48%	50%	**+2%**
	West	11%	10%	**-2%**

Comparing Known Sample Variables

Regional Distribution by Customer Type

(1) Regional Distribution by Customer Type

Using service zones, areas are grouped into five distinct regions within Hydro One's service territory.

Distributions of region are similar (+-/ 4%) small business (GS<50) and commercial & industrial customer types. Any differences are accounted for by making weighting adjustments based on region.

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Customer Type*	Region	Share of full population	Share of email sample	Difference
Small Business (GS<50)	Central	24%	25%	**+1%**
	Central East	27%	27%	**0%**
	East	14%	15%	**+1%**
	North	15%	14%	**0%**
	West	21%	20%	**-1%**
Commercial & Industrial	Central	25%	25%	**0%**
	Central East	22%	22%	**0%**
	East	12%	12%	**0%**
	North	11%	12%	**0%**
	West	28%	29%	**0%**

Note: LDA and LTX customers are not shown as all, or nearly all customers have an email on file.

Comparing Known Sample Variables

Distribution of Consumption Quartile by Customer Type

Comparing Known Sample Variables

The information below compares the sample of each customer type with email addresses to the total customer accounts across average monthly consumption (low-volume) or demand (commercial & industrial).

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

(2) Distribution of Consumption Quartile by Customer Type

Within each customer type, customers are grouped into four equal quartiles based on average monthly consumption (measured in kWh) for low-volume customers and average monthly demand (measured in kW) for commercial & industrial customers.

Distributions of consumption quartile are similar (+/- 4%) for residential and First Nations On-Reserve customers. Seasonal customers with an email on file skew towards higher consumption. Any differences are accounted for by making weighting adjustments based on consumption quartile.

Customer Type	Region	Share of full population	Share of email sample	Difference
Residential	First	25%	23%	**-1%**
	Second	25%	24%	**0%**
	Third	25%	25%	**0%**
	Fourth	25%	26%	**+1%**
	Average Monthly Consumption (kWh)	931.9	953.0	**+2%**
Seasonal	First	25%	20%	**-4%**
	Second	25%	23%	**-1%**
	Third	25%	26%	**+1%**
	Fourth	25%	29%	**+4%**
	Average Monthly Consumption (kWh)	422.3	475.9	**+13%**
First Nations On-Reserve	First	25%	23%	**-2%**
	Second	25%	24%	**0%**
	Third	25%	25%	**0%**
	Fourth	25%	27%	**+2%**
	Average Monthly Consumption (kWh)	1,217.5	1,258.7	**+3%**

Comparing Known Sample Variables

Distribution of Consumption Quartile by Customer Type

(2) Distribution of Consumption Quartile by Customer Type

Within each customer type, customers are grouped into four equal quartiles based on average monthly consumption (measured in kWh) for low-volume customers and average monthly demand (measured in kW) for commercial & industrial customers.

Distributions of consumption quartile are similar (+/- 4%) for commercial & industrial customers. Small business (GS<50) customers with an email on file skew towards higher consumption. Any differences are accounted for by making weighting adjustments based on consumption quartile.

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Customer Type	Region	Share of full population	Share of email sample	Difference
Small Business (GS<50)	First	25%	22%	-3%
	Second	25%	24%	-1%
	Third	25%	25%	0%
	Fourth	25%	28%	+3%
	Average Monthly Consumption (kWh)	2,481.6	2,773.1	+12%
Commercial & Industrial	First	25%	25%	0%
	Second	25%	25%	0%
	Third	25%	25%	0%
	Fourth	25%	25%	0%
	Average Monthly Demand (kW)	143.3	146.2	+2%

Note: LDA and LTX customers are not shown as all or nearly all customers have an email on file.

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Sample Validation

Reference Surveys: Comparing Telephone and Online



Reference Surveys
Comparing Telephone and Online

Comparing Telephone and Online

For residential (including seasonal), First Nations On-Reserve, and small business (GS<50) customers, parallel telephone and online surveys were conducted to identify differences between online and telephone respondents on self-reported demographics, firmographics, and controls. The following tables outline similarities and differences across each of the customer groups where parallel telephone and online surveys were conducted.

Summary of Residential Sample Validation

Comparing the results of the telephone reference survey and the online survey across basic demographics, familiarity and satisfaction, outage experience, and environmental controls reveals minor differences between the two samples with some notable differences on age and highest level of education.

On education, telephone respondents are more likely to have their highest level of education at the high school or less level and online respondents are more likely to have their highest level of education at the college/trades level. Additionally, online respondents skew slightly younger than telephone respondents.

The online results are not weighted by education or age as doing so does not meaningfully impact the overall results.

Demographics

Gender	Telephone	Online	Difference
Men	54%	51%	-3%
Women	46%	45%	-1%
Prefer to self-describe	-	<1%	-

Age	Telephone	Online	Difference
18 to 34	5%	6%	0%
35 to 44	10%	11%	+1%
45 to 54	11%	14%	+2%
55 to 64	20%	25%	+5%
65 to 74	28%	28%	0%
75+	20%	13%	-7%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

Demographics (Con't)

Education	Telephone	Online	Difference
High school or less	29%	15%	-13%
College/Trades	33%	42%	+9%
University	35%	37%	+2%

Household Size	Telephone	Online	Difference
Single person household	20%	14%	-5%
2 people	43%	49%	+5%
3 people	14%	13%	-1%
4 people	10%	13%	+3%
5 people	6%	5%	-1%
6 people	3%	2%	-1%
7+ people	2%	1%	0%

After Tax Household Income	Telephone	Online	Difference
$38,000 or less	13%	9%	-4%
$38,001 to $54,000	9%	10%	0%
$54,001 to $65,000	10%	8%	-2%
$65,001 to $71,000	6%	8%	+1%
Over $71,000	42%	42%	0%

LEAP/OESP Qualification	Telephone	Online	Difference
LEAP/OESP qualified	24%	19%	-5%
Income <$71k, not qualified	15%	15%	+1%
Income >$71k, not qualified	42%	42%	0%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

Demographics (Con't)

Employment Status	Telephone	Online	Difference
Self-employed	7%	9%	+2%
Employed full-time	29%	33%	+4%
Employed part-time	3%	4%	+1%
Seasonal employment	0%	1%	0%
Currently unemployed	2%	1%	-1%
Student	0%	0%	0%
Retired	51%	46%	-5%
Homemaker	1%	1%	0%
Disability/sick leave	2%	2%	0%
Parental leave	0%	0%	0%

Identification as Indigenous	Telephone	Online	Difference
First Nations	1%	1%	0%
Métis	1%	2%	0%
Inuk (Inuit)	0%	0%	0%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

Familiarity and Satisfaction

Familiarity with Hydro One's Role	Telephone	Online	Difference
Very familiar with Hydro One's role and could explain the details to others	26%	16%	-10%
Somewhat familiar with Hydro One's role, but could not explain all the details to others	43%	53%	+10%
Have heard of some of the terms, but knew very little about Hydro One's role	16%	22%	+6%
Knew nothing about Hydro One's role	9%	8%	-1%
Familiar (Very + Somewhat)	69%	69%	0%

Satisfaction with Hydro One	Telephone	Online	Difference
Very satisfied	51%	49%	-2%
Somewhat satisfied	34%	36%	+2%
Neither satisfied nor dissatisfied	6%	9%	+3%
Somewhat dissatisfied	5%	5%	-1%
Very dissatisfied	2%	1%	-1%
Satisfied (Very + Somewhat)	85%	85%	0%
Dissatisfied (Very + Somewhat)	8%	6%	-1%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

Bill Familiarity and Outage Experience

Familiarity with Bill	Telephone	Online	Difference
Very familiar	17%	13%	-5%
Somewhat familiar	30%	31%	+1%
Not very familiar	22%	28%	+6%
Not familiar at all	26%	27%	+1%
Familiar (Very + Somewhat)	47%	44%	-3%

Outages in Past 12 Months	Telephone	Online	Difference
None	15%	14%	-2%
1 outage	11%	8%	-4%
2 outages	16%	17%	1%
3+ outages	51%	48%	-3%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

Environmental Controls

Bill has a major impact on my finances	Telephone	Online	Difference
Strongly agree	19%	18%	-1%
Somewhat agree	28%	33%	+5%
Somewhat disagree	23%	25%	+2%
Strongly Disagree	21%	21%	-1%
Don't know/No opinion	8%	3%	-5%
Agree (Strongly + Somewhat)	47%	51%	+3%
Disagree (Strongly + Somewhat)	44%	46%	+2%

Consumers are well-protected with respect to price, reliability, and quality	Telephone	Online	Difference
Strongly agree	12%	9%	-3%
Somewhat agree	41%	44%	+3%
Somewhat disagree	14%	24%	+11%
Strongly Disagree	9%	12%	+3%
Don't know/No opinion	24%	11%	-13%
Agree (Strongly + Somewhat)	53%	53%	0%
Disagree (Strongly + Somewhat)	23%	36%	+14%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

Summary of First Nations On-Reserve Sample Validation

Comparing results of the telephone reference survey and the online survey across basic demographics, familiarity and satisfaction, outage experience, and environmental controls reveals minor differences between the two samples with some notable differences on age and highest level of education.

As is the case with the Residential & Seasonal results, telephone respondents are more likely to have their highest level of education at the high school or less level and online respondents are more likely to have their highest level of education at the college/trades level. Additionally, First Nations On-Reserve online respondents skew slightly younger than telephone respondents.

The online results are not weighted by education or age as doing so does not meaningfully impact the overall results.

Demographics

Gender	Telephone	Online	Difference
Men	37%	37%	0%
Women	63%	60%	-4%
Prefer to self-describe	-	-	-

Age	Telephone	Online	Difference
18 to 34	9%	8%	-1%
35 to 44	10%	16%	+6%
45 to 54	17%	26%	+9%
55 to 64	26%	26%	+1%
65 to 74	24%	19%	-5%
75+	13%	5%	-8%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

First Nations On-Reserve

Demographics (Con't)

Education	Telephone	Online	Difference
High school or less	38%	26%	-13%
College/Trades	38%	50%	+13%
University	21%	19%	-3%

Household Size	Telephone	Online	Difference
Single person household	24%	15%	-8%
2 people	31%	33%	+1%
3 people	15%	19%	+4%
4 people	14%	18%	+3%
5 people	6%	10%	+4%
6 people	6%	2%	-3%
7+ people	5%	2%	-2%

After Tax Household Income	Telephone	Online	Difference
$38,000 or less	33%	31%	-2%
$38,001 to $54,000	16%	13%	-3%
$54,001 to $65,000	9%	10%	+1%
$65,001 to $71,000	6%	6%	-1%
Over $71,000	24%	23%	-1%

LEAP/OESP Qualification	Telephone	Online	Difference
LEAP/OESP qualified	53%	47%	-6%
Income <$71k, not qualified	11%	12%	+1%
Income >$71k, not qualified	24%	23%	-1%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

Demographics (Con't)

Employment Status	Telephone	Online	Difference
Self-employed	7%	4%	-4%
Employed full-time	37%	47%	+10%
Employed part-time	3%	4%	0%
Seasonal employment	-	3%	+3%
Term employment	-	1%	+1%
Currently unemployed	9%	5%	-5%
Student	-	1%	+1%
Retired	31%	24%	-7%
Homemaker	2%	1%	-1%
Disability/sick leave	7%	6%	-1%
Parental leave	<1%	<1%	0%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

First Nations On-Reserve

Familiarity and Satisfaction

Familiarity with Hydro One's Role	Telephone	Online	Difference
Very familiar with Hydro One's role and could explain the details to others	15%	16%	+1%
Somewhat familiar with Hydro One's role, but could not explain all the details to others	44%	43%	-1%
Have heard of some of the terms, but knew very little about Hydro One's role	15%	26%	+11%
Knew nothing about Hydro One's role	14%	13%	-1%
Familiar (Very + Somewhat)	59%	59%	0%

Satisfaction with Hydro One	Telephone	Online	Difference
Very satisfied	51%	55%	+4%
Somewhat satisfied	35%	34%	-1%
Neither satisfied nor dissatisfied	5%	8%	+3%
Somewhat dissatisfied	3%	1%	-2%
Very dissatisfied	2%	1%	-1%
Satisfied (Very + Somewhat)	85%	89%	+3%
Dissatisfied (Very + Somewhat)	6%	3%	-3%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

Bill Familiarity and Outage Experience

Familiarity with Bill	Telephone	Online	Difference
Very familiar	35%	29%	-6%
Somewhat familiar	34%	35%	+1%
Not very familiar	9%	15%	+6%
Not familiar at all	15%	20%	+5%
Familiar (Very + Somewhat)	69%	64%	-5%

Outages in Past 12 Months	Telephone	Online	Difference
None	9%	11%	+2%
1 outage	11%	4%	-7%
2 outages	17%	20%	+3%
3+ outages	58%	43%	-15%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

First Nations On-Reserve

Environmental Controls

Bill has a major impact on my finances	Telephone	Online	Difference
Strongly agree	18%	22%	+4%
Somewhat agree	32%	39%	+7%
Somewhat disagree	18%	20%	+1%
Strongly Disagree	21%	12%	-9%
Don't know/No opinion	11%	7%	-3%
Agree (Strongly + Somewhat)	50%	61%	+11%
Disagree (Strongly + Somewhat)	39%	32%	-7%

Consumers are well-protected with respect to price, reliability, and quality	Telephone	Online	Difference
Strongly agree	16%	13%	-3%
Somewhat agree	43%	44%	+1%
Somewhat disagree	5%	22%	+17%
Strongly Disagree	6%	8%	+1%
Don't know/No opinion	29%	14%	-15%
Agree (Strongly + Somewhat)	59%	56%	-2%
Disagree (Strongly + Somewhat)	12%	30%	+18%

Note: 'Prefer not to say' not shown.

Reference Surveys
Comparing Telephone and Online

Summary of Small Business (GS<50) Sample Validation

Comparing the results of the telephone reference survey and the online survey across basic firmographics, familiarity and satisfaction, outage experience, and environmental controls reveals minor differences between the two samples.

While telephone respondents are less likely to say they are familiar with the share of their bill that goes to Hydro One than online respondents, the online results are not weighted by familiarity with the share of their bill that goes to Hydro One as doing so does not meaningfully impact the overall results.

Firmographics

Business Sector	Telephone	Online	Difference
Commercial	20%	19%	0%
Manufacturing/Industrial	10%	10%	0%
Data Centre	1%	-	-1%
Hospitality	5%	10%	+5%
Restaurant/Tavern	4%	3%	-2%
Retail	12%	9%	-3%
Warehouse	2%	3%	1%
Real estate	6%	6%	-1%
Agriculture	15%	14%	-1%
Non-Profit/Charity	3%	2%	-1%
Healthcare	2%	3%	+1%
Government	1%	<1%	-1%
Automotive/Transportation	5%	1%	-5%
Church/Place of Worship	3%	1%	-1%
Consulting/Professional services	3%	1%	-2%
Other services	4%	3%	-1%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

Firmographics (Con't)

Business Size	Telephone	Online	Difference
1 person	11%	12%	+1%
2 to 5 people	44%	48%	+4%
6 to 10 people	18%	14%	-4%
11 to 25 people	16%	12%	-5%
26 to 50 people	5%	4%	-1%
More than 50 people	3%	4%	+1%

Familiarity and Satisfaction

Familiarity with Hydro One's Role	Telephone	Online	Difference
Very familiar with Hydro One's role and could explain the details to others	23%	18%	-5%
Somewhat familiar with Hydro One's role, but could not explain all the details to others	41%	53%	+12%
Have heard of some of the terms, but knew very little about Hydro One's role	18%	22%	+3%
Knew nothing about Hydro One's role	10%	5%	-5%
Familiar (Very + Somewhat)	65%	71%	+6%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

Familiarity and Satisfaction (Con't)

Satisfaction with Hydro One	Telephone	Online	Difference
Very satisfied	47%	41%	-6%
Somewhat satisfied	32%	38%	+6%
Neither satisfied nor dissatisfied	12%	13%	+1%
Somewhat dissatisfied	4%	4%	0%
Very dissatisfied	1%	3%	+2%
Satisfied (Very + Somewhat)	80%	79%	0%
Dissatisfied (Very + Somewhat)	5%	8%	+2%

Bill Familiarity and Outage Experience

Familiarity with Bill	Telephone	Online	Difference
Very familiar	13%	15%	+2%
Somewhat familiar	26%	36%	+9%
Not very familiar	22%	27%	+4%
Not familiar at all	31%	22%	-9%
Familiar (Very + Somewhat)	39%	51%	+11%

Outages in Past 12 Months	Telephone	Online	Difference
None	23%	14%	-8%
1 outage	13%	8%	-5%
2 outages	11%	18%	+6%
3+ outages	46%	47%	+1%

Note: 'Prefer not to say' and 'Don't know' not shown.

Reference Surveys
Comparing Telephone and Online

Environmental Controls

Bill has a major impact on the bottom line of my organization	Telephone	Online	Difference
Strongly agree	25%	26%	+2%
Somewhat agree	33%	35%	+2%
Somewhat disagree	16%	20%	+4%
Strongly Disagree	13%	13%	0%
Don't know/No opinion	13%	6%	-7%
Agree (Strongly + Somewhat)	58%	61%	+3%
Disagree (Strongly + Somewhat)	29%	33%	+4%

Consumers are well-protected with respect to price, reliability, and quality	Telephone	Online	Difference
Strongly agree	10%	9%	0%
Somewhat agree	38%	40%	+2%
Somewhat disagree	13%	25%	+12%
Strongly Disagree	9%	16%	+7%
Don't know/No opinion	30%	10%	-21%
Agree (Strongly + Somewhat)	48%	49%	+2%
Disagree (Strongly + Somewhat)	22%	41%	+19%

Note: 'Prefer not to say' not shown.

INNOVATIVE RESEARCH GROUP

Residential & Seasonal Customers

Online Survey Results

Section 2



Online Survey
Survey Design & Methodology

Field Dates

The **Residential and Seasonal Online Surveys** were sent to a random selection of Hydro One residential and seasonal customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **November 12th and December 4th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the residential survey was sent to **44,567** customers and the seasonal survey was sent to **4,004** customers from *customerexperience@hydroone.com*. Reminder emails were sent on November 18th, November 27th, and December 2nd, 2024 to those who had not yet completed the survey.

Residential & Seasonal Online Survey Completes

A total of **6,053** (unweighted) Hydro One residential and seasonal customers completed the online survey.

Sample Weighting

The residential and seasonal online survey sample was weighted down to n=5,000 proportionately by consumption quartile, region, and customer type (primary residential vs. seasonal) in order to be representative of the broader Hydro One customer base.

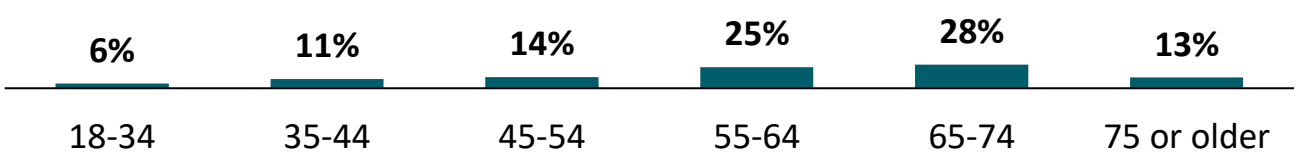
The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	186 (175)	205 (183)	187 (191)	195 (183)	786 (743)
Central	376 (340)	411 (331)	419 (332)	442 (355)	1,674 (1,378)
Central East	432 (381)	479 (387)	481 (382)	473 (371)	1,890 (1,541)
East	240 (181)	250 (189)	271 (195)	254 (190)	1,029 (767)
North	145 (155)	188 (143)	159 (134)	175 (134)	673 (571)
Total	1,380 (1,233)	1,533 (1,233)	1,517 (1,233)	1,539 (1,233)	6,053 (5,000)

Note: *Graphs and tables may not always total 100% due to rounding values other than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Demographic Breakdown

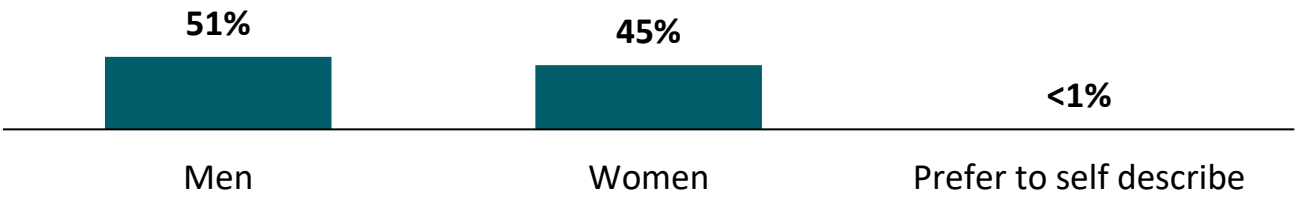
Q Age



"Prefer not to say" (3%) not shown.

n=5,000

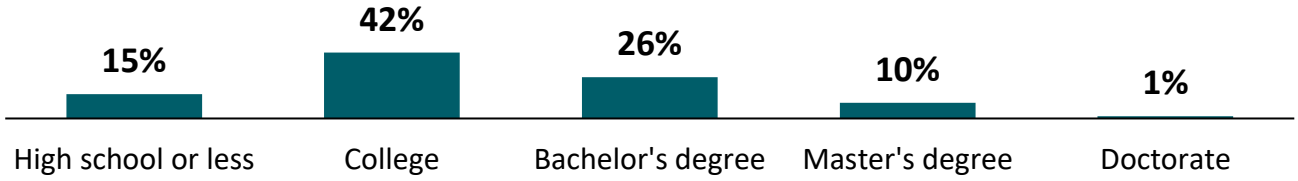
Q Gender



"Prefer not to say" (4%) not shown.

n=5,000

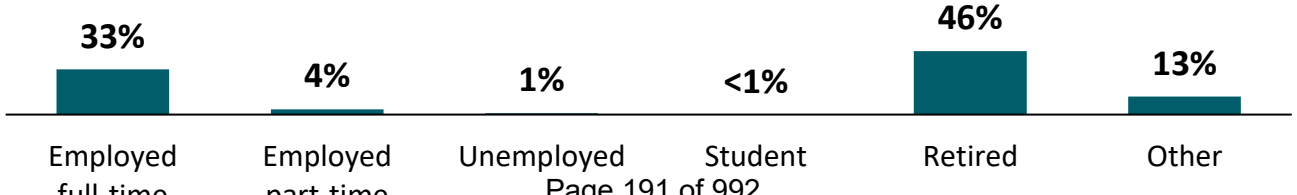
Q Education



"Other" (2%) and "Prefer not to say" (4%) not shown.

n=5,000

Q Employment Status



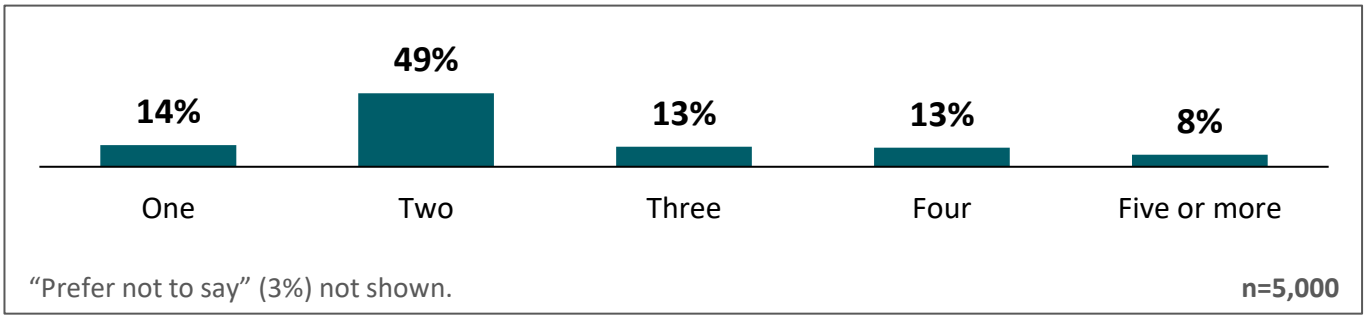
"Prefer not to say" (3%) not shown.

n=5,000

Demographic Breakdown
Continued

Residential & Seasonal

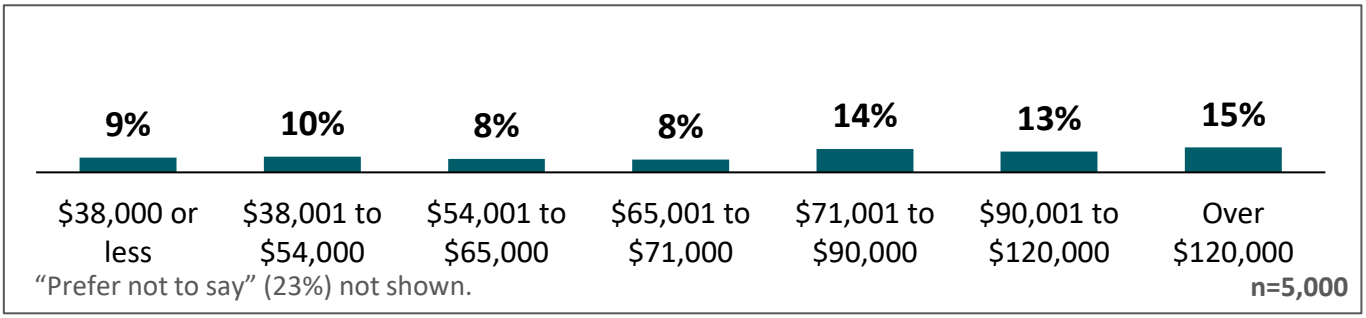
Q Household Size



"Prefer not to say" (3%) not shown.

n=5,000

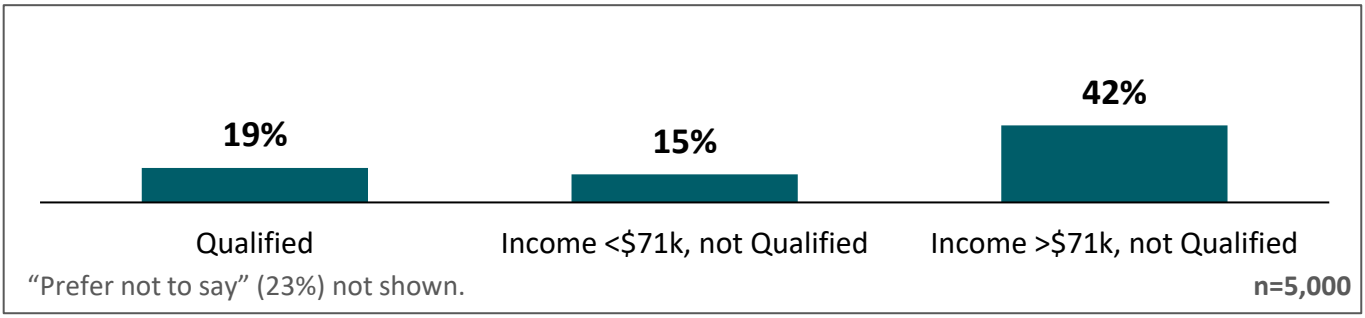
Q After Tax Household Income



"Prefer not to say" (23%) not shown.

n=5,000

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (23%) not shown.

n=5,000

INNOVATIVE RESEARCH GROUP

Demographic Breakdown
Continued

Residential & Seasonal

Are you:

Q First Nations



"Prefer not to say" (5%) not shown.

n=5,000

Q Métis



"Prefer not to say" (5%) not shown.

n=5,000

Q Inuk



"Prefer not to say" (5%) not shown.

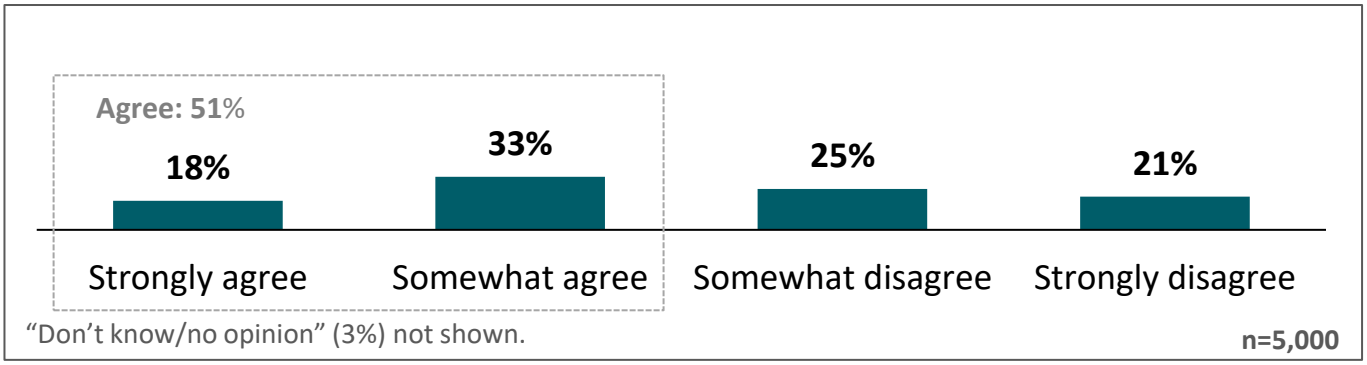
n=5,000

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Environmental Controls

To what extent do you agree or disagree with the following statements?

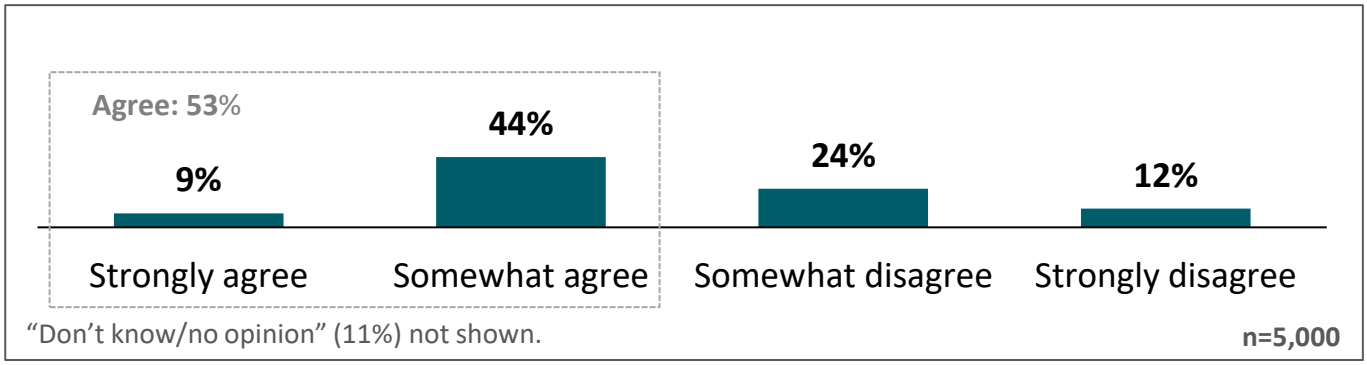
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (3%) not shown.

n=5,000

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (11%) not shown.

n=5,000

Residential & Seasonal Customers

Familiarity & Experience

Preamble:

Before we begin, this survey has **three key objectives**.

First, **Hydro One** wants to better understand your experiences as a customer.

Second, **Hydro One** wants your input on some of the investment areas they could focus on in the future.

Third, **Hydro One** wants to learn a little bit more about their customers. This will help them ensure that they are receiving feedback that represents a wide range of customers.

First, let's talk about your experience.

While you might have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a [residential/seasonal] customer.

Familiarity & Experience

Familiarity with Hydro One's Role in the System

Residential & Seasonal

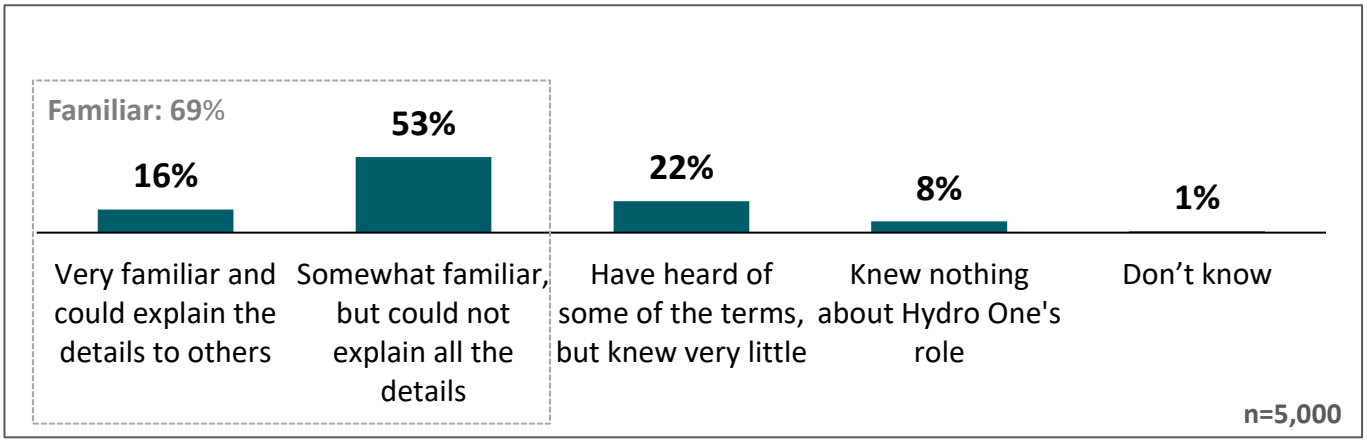
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which takes electricity from transmission lines and brings it to your [home/seasonal property] through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Very familiar	16%	18%	14%	16%	18%	16%	17%
Somewhat familiar	52%	56%	54%	54%	51%	55%	51%
Knew very little	22%	19%	22%	21%	23%	22%	23%
Knew nothing	8%	6%	9%	9%	7%	7%	7%
Don't know	1%	1%	1%	1%	1%	1%	2%
Familiar (Very + Somewhat)	**68%**	**74%**	**68%**	**70%**	**69%**	**71%**	**68%**

Familiarity & Experience

Familiarity with Hydro One's Role in the System

Residential & Seasonal

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	16%	12%	16%	19%	16%	17%
Somewhat familiar	53%	51%	53%	53%	50%	56%
Knew very little	22%	26%	22%	21%	24%	20%
Knew nothing	8%	10%	9%	6%	9%	6%
Don't know	1%	2%	<1%	1%	1%	1%
Familiar (Very + Somewhat)	**69%**	**62%**	**69%**	**72%**	**66%**	**72%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very familiar	14%	15%	17%	19%
Somewhat familiar	53%	52%	54%	52%
Knew very little	23%	23%	21%	21%
Knew nothing	9%	8%	7%	7%
Don't know	1%	1%	1%	1%
Familiar (Very + Somewhat)	**67%**	**68%**	**71%**	**71%**

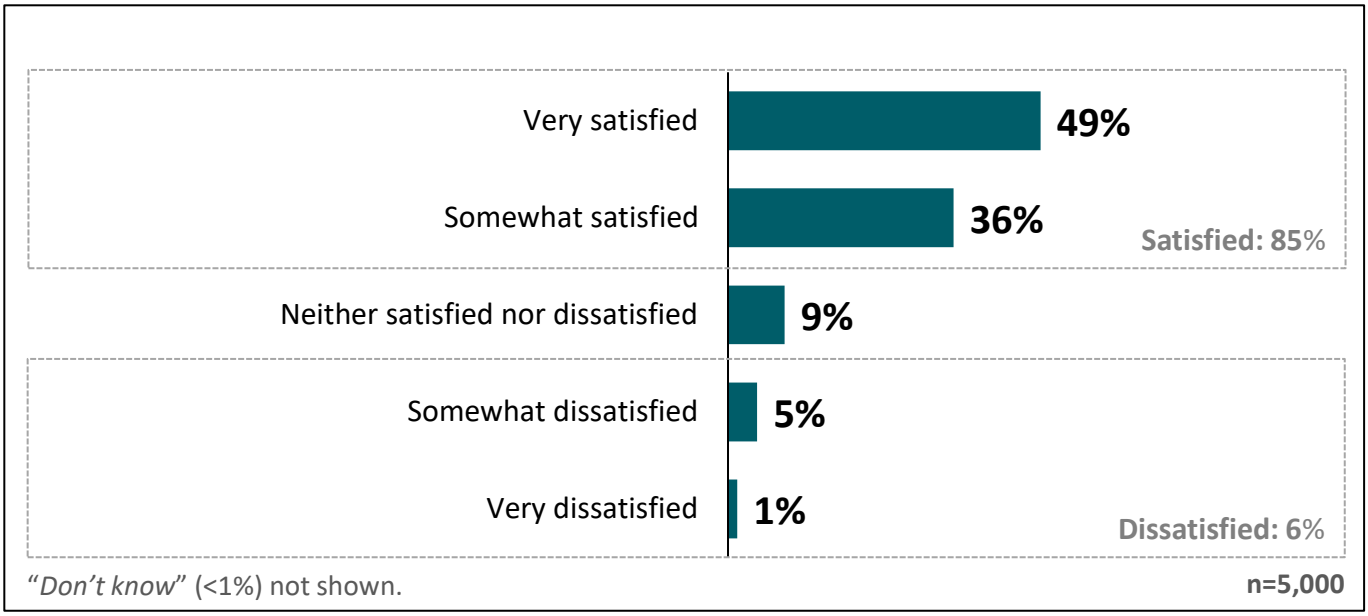
Familiarity & Experience

Overall Satisfaction with Hydro One

Residential & Seasonal

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Q Overall, how satisfied or dissatisfied are you with the service you receive from **Hydro One**?



"*Don't know*" (<1%) not shown.

n=5,000

	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Very satisfied	50%	40%	50%	46%	51%	54%	45%
Somewhat satisfied	35%	40%	34%	38%	36%	32%	37%
Neither	9%	11%	9%	10%	8%	9%	9%
Somewhat dissatisfied	4%	6%	6%	5%	4%	4%	6%
Very dissatisfied	1%	3%	2%	2%	1%	1%	3%
Don't know	<1%	--	<1%	<1%	<1%	1%	1%
Satisfied (Very + Somewhat)	**85%**	**80%**	**84%**	**84%**	**87%**	**86%**	**81%**
Dissatisfied (Very + Somewhat)	**6%**	**9%**	**7%**	**6%**	**5%**	**5%**	**8%**

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Familiarity & Experience

Overall Satisfaction with Hydro One

Residential & Seasonal

Q Overall, how satisfied or dissatisfied are you with the service you receive from **Hydro One**?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very satisfied	49%	50%	55%	48%	43%	56%
Somewhat satisfied	36%	35%	33%	37%	38%	33%
Neither	9%	9%	7%	9%	11%	7%
Somewhat dissatisfied	5%	5%	4%	4%	6%	3%
Very dissatisfied	1%	1%	1%	1%	2%	1%
Don't know	<1%	1%	<1%	<1%	<1%	<1%
Satisfied (Very + Somewhat)	**85%**	**85%**	**88%**	**86%**	**81%**	**89%**
Dissatisfied (Very + Somewhat)	**6%**	**6%**	**5%**	**6%**	**8%**	**4%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very satisfied	54%	51%	47%	45%
Somewhat satisfied	32%	34%	38%	38%
Neither	9%	9%	9%	9%
Somewhat dissatisfied	4%	4%	5%	6%
Very dissatisfied	1%	2%	2%	1%
Don't know	<1%	<1%	<1%	<1%
Satisfied (Very + Somewhat)	**86%**	**85%**	**85%**	**84%**
Dissatisfied (Very + Somewhat)	**5%**	**6%**	**6%**	**7%**

Familiarity & Experience

How can Hydro One improve services?

Residential & Seasonal

Q Is there anything in particular you would like **Hydro One** to do to improve its services to you?

Response	%
Decrease outages/interruptions	9.2%
Lower rates/decrease bills	9.0%
Address/proactive tree trimming	6.6%
Satisfied with services/no issues	4.3%
Improve communication during outages	2.8%
Bury power lines/better line maintenance	2.6%
Upgrade/better maintain infrastructure	1.6%
Improve response time for outages	0.9%
Billing improvements - timing/payments/bill format	0.7%
Energy alternatives/green energy options	0.7%
Improve customer service	0.6%
Improve general communication	0.5%
More information/visibility into usage	0.5%
Provide incentives/rebates	0.5%
Improve website/app	0.5%
Find efficiencies/costs savings	0.4%
More transparency around costs	0.3%
Building capacity/addressing growth	0.2%
Other	1.0%
None/Don’t know	57.0%

Note: Only responses >0.1% shown

Familiarity & Experience

Bill Familiarity

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

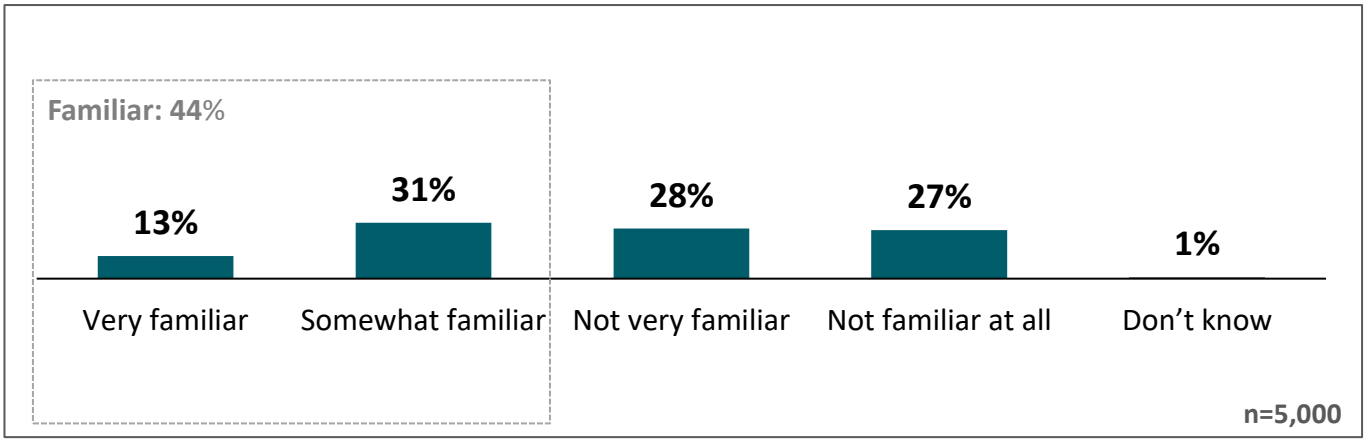
Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to **Hydro One**. As of October 1st, 2024, for a typical **[residential/seasonal]** customer, about **[bill percentage]** or **[bill amount]** goes to **Hydro One** per month. This amount is split into **[distribution amount]** for distribution and **[transmission amount]** for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Bill Legend

Customer Group	[bill percentage]	[bill amount]	[distribution amount]	[transmission amount]
Residential	32%	$46	$33	$13
Seasonal	45%	$61	$55	$6

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Hydro One**?



Familiarity & Experience

Bill Familiarity

Residential & Seasonal

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Hydro One**?

	Overall	Customer Type: Residential	Customer Type: Seasonal	Region: West	Region: Central	Region: Central East	Region: East	Region: North
Very familiar	13%	12%	16%	12%	13%	14%	11%	13%
Somewhat familiar	31%	31%	32%	32%	34%	27%	34%	32%
Not very familiar	28%	28%	27%	29%	27%	29%	29%	25%
Not familiar at all	27%	28%	24%	26%	26%	29%	26%	29%
Don't know	1%	1%	1%	1%	<1%	1%	<1%	1%
Familiar (Very + Somewhat)	**44%**	**44%**	**48%**	**44%**	**46%**	**41%**	**45%**	**45%**

	LEAP/OESP Qualification: Qualified	LEAP/OESP Qualification: <$71k Not Qualified	LEAP/OESP Qualification: >$71k Not Qualified	Bill Impact: Major Impact	Bill Impact: No Major Impact
Very familiar	11%	13%	14%	13%	13%
Somewhat familiar	29%	29%	32%	32%	31%
Not very familiar	28%	28%	28%	29%	27%
Not familiar at all	30%	30%	25%	26%	28%
Don't know	1%	<1%	1%	1%	1%
Familiar (Very + Somewhat)	**40%**	**42%**	**46%**	**44%**	**44%**

Familiarity & Experience

Bill Familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Hydro One**?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Very familiar	13%	13%	13%	12%	13%
Somewhat familiar	31%	30%	31%	32%	32%
Not very familiar	28%	26%	27%	28%	30%
Not familiar at all	27%	29%	29%	27%	24%
Don't know	1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**44%**	**44%**	**43%**	**44%**	**45%**

Familiarity & Experience

Familiarity with Rate Applications

Residential & Seasonal

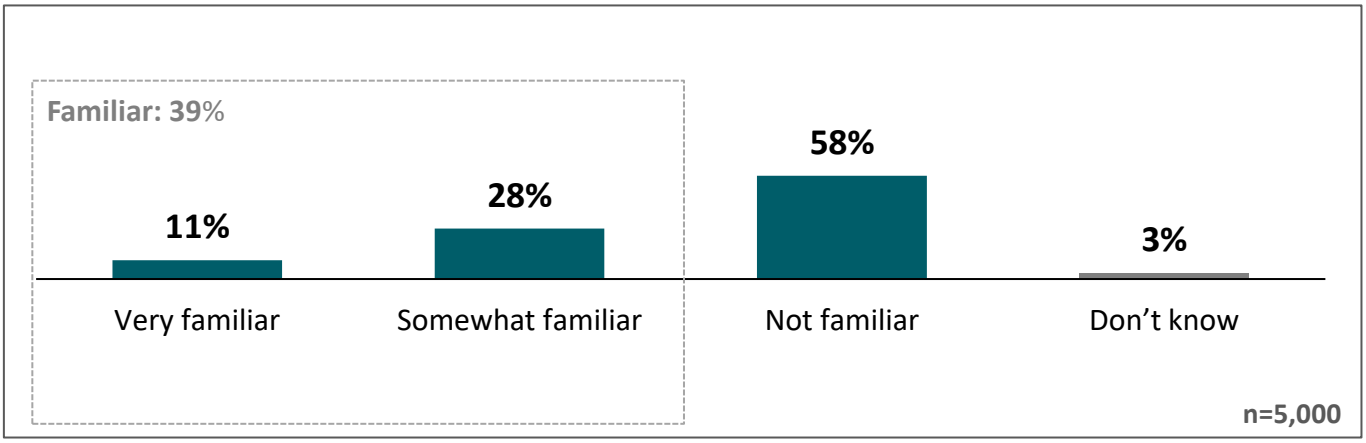
Hydro One is funded by the rates paid by its customers.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Very familiar	10%	13%	10%	10%	11%	10%	12%
Somewhat familiar	28%	31%	30%	29%	26%	29%	28%
Not familiar	58%	54%	58%	57%	59%	58%	57%
Don't know	3%	3%	2%	3%	4%	3%	3%
Familiar (Very + Somewhat)	**38%**	**44%**	**39%**	**40%**	**37%**	**39%**	**40%**

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Familiarity & Experience

Familiarity with Rate Applications

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	11%	8%	9%	13%	11%	10%
Somewhat familiar	28%	25%	28%	29%	27%	30%
Not familiar	58%	63%	60%	56%	58%	57%
Don't know	3%	5%	3%	3%	4%	3%
Familiar (Very + Somewhat)	**39%**	**33%**	**37%**	**41%**	**38%**	**40%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very familiar	10%	10%	12%	11%
Somewhat familiar	27%	30%	29%	27%
Not familiar	60%	56%	57%	59%
Don't know	3%	3%	2%	4%
Familiar (Very + Somewhat)	**37%**	**40%**	**41%**	**37%**

INNOVATIVE RESEARCH GROUP

Residential & Seasonal Customers

Customer Priorities



Customer Priorities
Response Labels Legend

Residential & Seasonal

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 8 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity	Providing reliable electricity to my [home/seasonal property]
Enhancing Hydro One's customer service	Enhancing Hydro One's customer service
Offering programs to help manage usage	Offering programs that can help customers better manage their electricity usage
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Enhancing the grid for new technologies	Enhancing the grid so that customers can connect new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

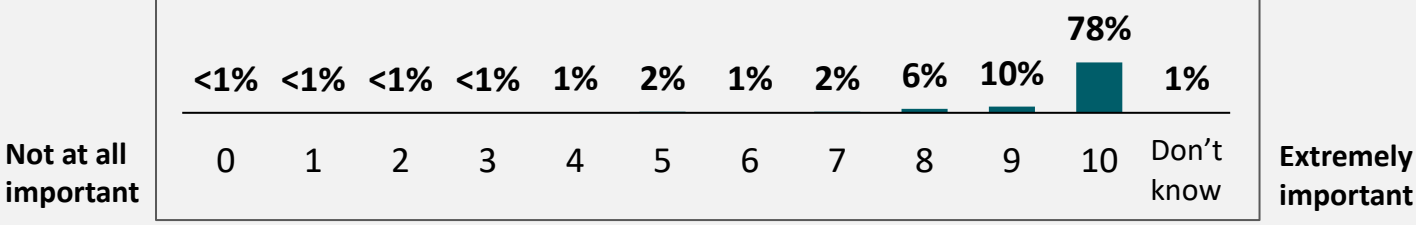
Customer Priorities

Importance of Customer Priorities

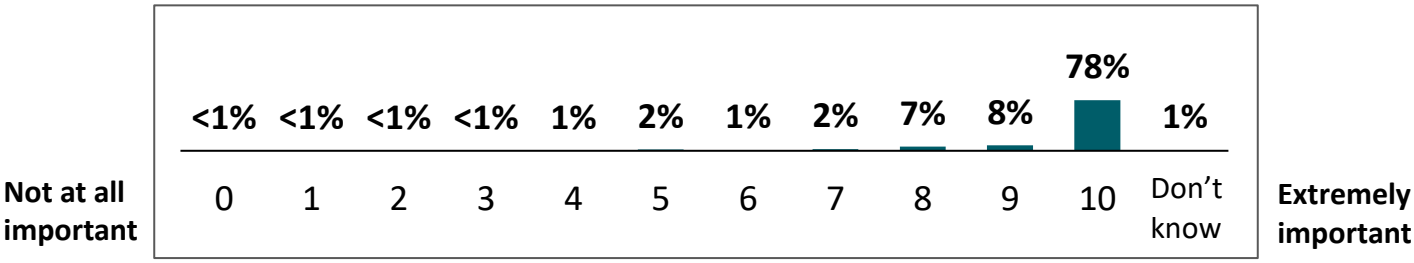
Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

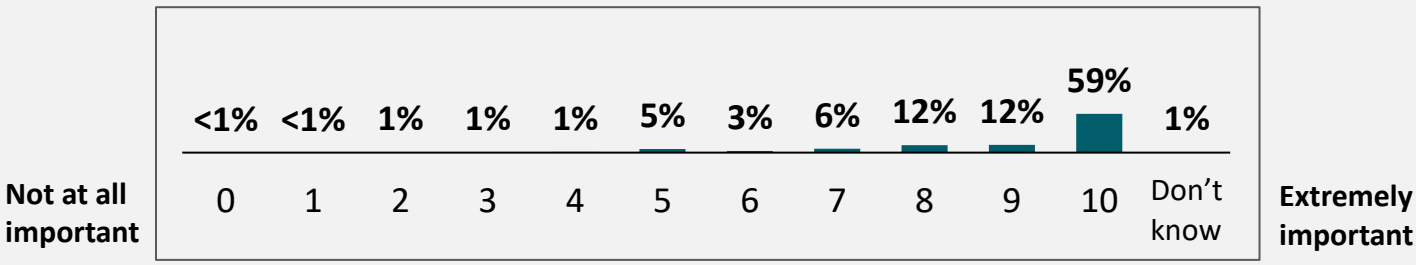
Providing reliable electricity [average = **9.5**]



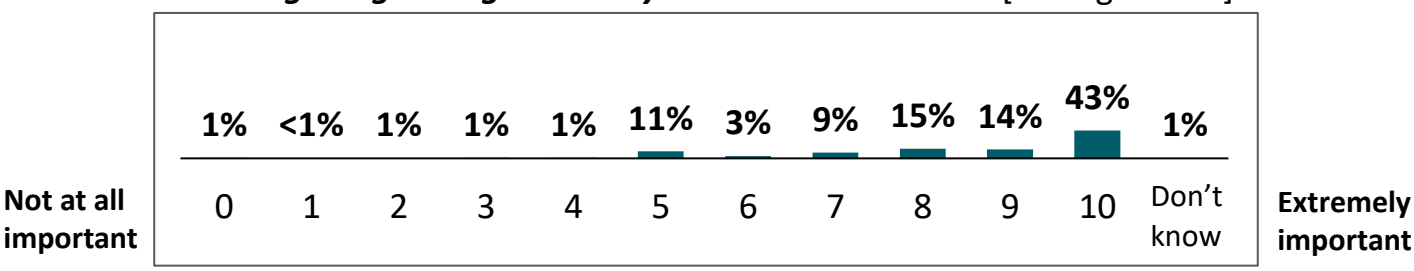
Delivering electricity at reasonable rates [average = **9.5**]



Ensuring the safety of electricity infrastructure [average = **8.9**]



Meeting the growing electricity need [average = **8.2**]



Note: Priority labels have been shortened for brevity. See slide 50 for full label text.
"Don't know" not included in calculation of means.

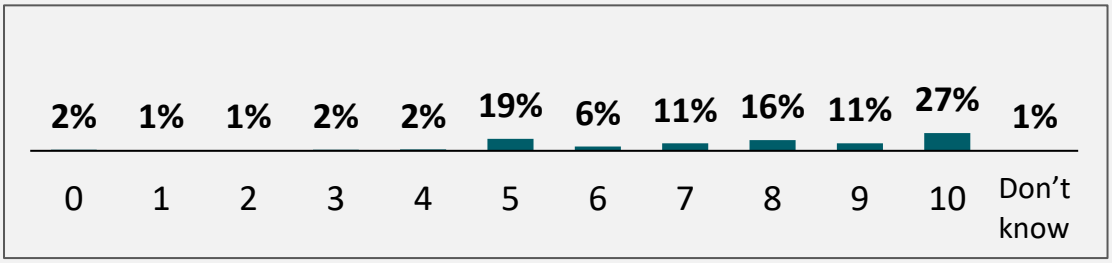
Customer Priorities

Importance of Customer Priorities (Cont'd)

Residential & Seasonal

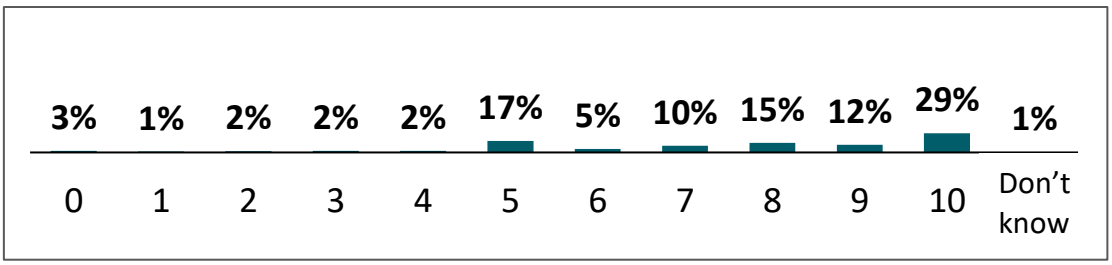
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

Enhancing Hydro One's customer service [average = **7.4**]



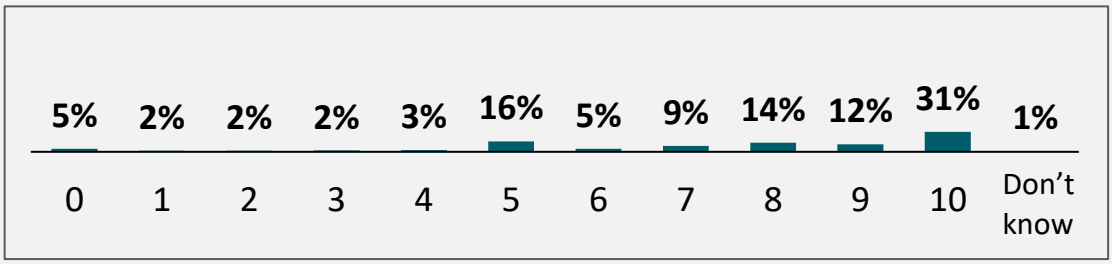
Not at all important **Extremely important**

Offering programs to help manage usage [average = **7.3**]



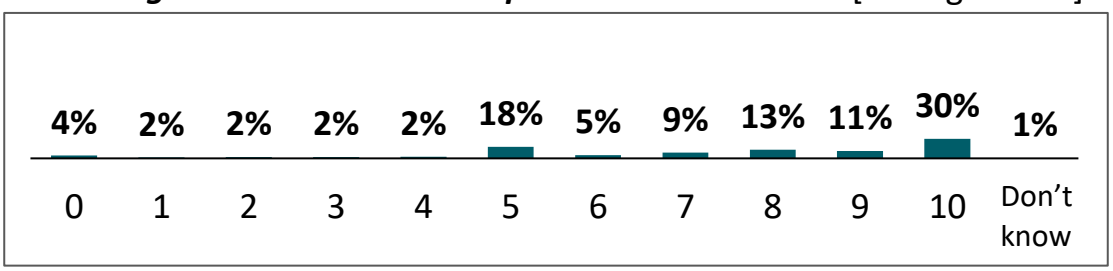
Not at all important **Extremely important**

Enhancing the grid for new technologies [average = **7.2**]



Not at all important **Extremely important**

Reducing the environmental impact [average = **7.2**]



Not at all important **Extremely important**

Note: Priority labels have been shortened for brevity. See slide 50 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Importance of Customer Priorities – Average Scores

Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		Customer Type		Region				
Average Score	**Overall**	**Residential**	**Seasonal**	**West**	**Central**	**Central East**	**East**	**North**
Providing reliable electricity	9.5	9.5	9.2	9.5	9.5	9.5	9.5	9.5
Delivering electricity at reasonable rates	9.5	9.5	9.5	9.4	9.5	9.5	9.5	9.5
Ensuring the safety of electricity infrastructure	8.9	8.9	8.7	8.9	8.9	9.0	8.9	8.8
Meeting the growing electricity need	8.2	8.3	7.7	8.3	8.2	8.3	8.3	8.0
Enhancing Hydro One's customer service	7.4	7.5	7.1	7.4	7.4	7.5	7.4	7.3
Offering programs to help manage usage	7.3	7.4	6.6	7.3	7.3	7.5	7.3	7.2
Enhancing the grid for new technologies	7.2	7.3	6.6	6.9	7.3	7.4	7.3	7.1
Reducing the environmental impact	7.2	7.2	6.9	6.9	7.2	7.4	7.2	7.1

Note: Priority labels have been shortened for brevity. See slide 50 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Importance of Customer Priorities – Average Scores

Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		LEAP/OESP Qualification			Bill Impact	
Average Score	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Providing reliable electricity	9.5	9.4	9.5	9.5	9.5	9.6
Delivering electricity at reasonable rates	9.5	9.5	9.6	9.4	9.6	9.3
Ensuring the safety of electricity infrastructure	8.9	8.9	9.0	8.8	8.8	9.0
Meeting the growing electricity need	8.2	8.2	8.4	8.2	8.2	8.3
Enhancing Hydro One's customer service	7.4	7.6	7.5	7.2	7.6	7.2
Offering programs to help manage usage	7.3	7.9	7.5	7.1	7.6	7.1
Enhancing the grid for new technologies	7.2	7.2	7.3	7.4	7.1	7.4
Reducing the environmental impact	7.2	7.4	7.5	7.0	7.0	7.4

Note: Priority labels have been shortened for brevity. See slide 50 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Importance of Customer Priorities – Average Scores

Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

Average Score	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Providing reliable electricity	9.5	9.5	9.5	9.4	9.5
Delivering electricity at reasonable rates	9.5	9.5	9.5	9.5	9.5
Ensuring the safety of electricity infrastructure	8.9	9.0	9.0	8.8	8.9
Meeting the growing electricity need	8.2	8.4	8.3	8.1	8.2
Enhancing Hydro One's customer service	7.4	7.6	7.5	7.3	7.4
Offering programs to help manage usage	7.3	7.4	7.3	7.3	7.4
Enhancing the grid for new technologies	7.2	7.3	7.2	7.1	7.4
Reducing the environmental impact	7.2	7.6	7.2	6.9	7.0

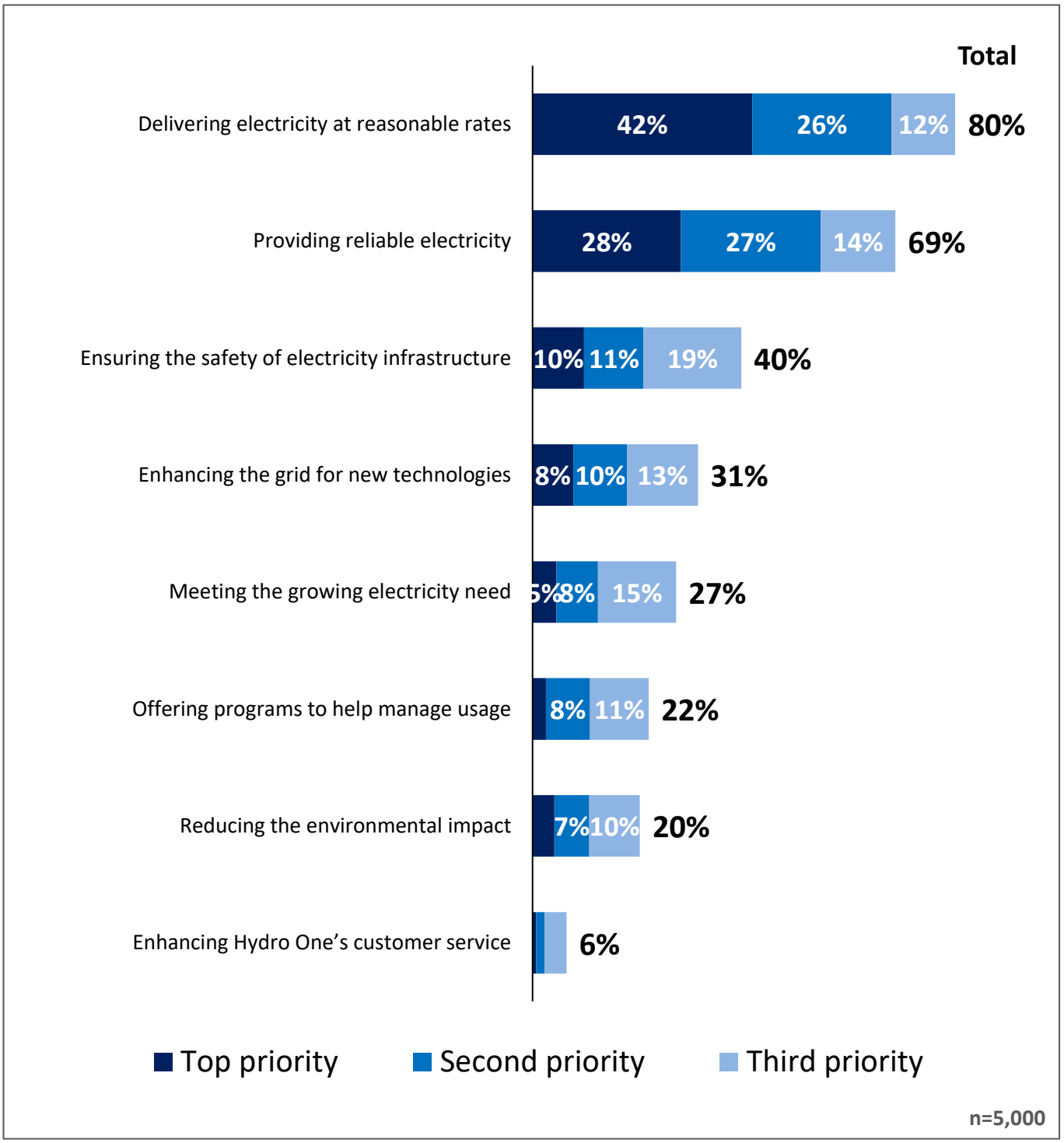
Note: Priority labels have been shortened for brevity. See slide 50 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Residential & Seasonal

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 50 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Residential & Seasonal

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Overall	Customer Type: Residential	Customer Type: Seasonal	Region: West	Region: Central	Region: Central East	Region: East	Region: North
Delivering electricity at reasonable rates	80%	80%	82%	82%	80%	79%	79%	83%
Providing reliable electricity	69%	68%	76%	65%	70%	68%	71%	70%
Ensuring the safety of electricity infrastructure	40%	40%	39%	40%	38%	39%	40%	44%
Enhancing the grid for new technologies	31%	32%	30%	30%	32%	32%	33%	28%
Meeting the growing electricity need	27%	27%	26%	32%	26%	27%	29%	22%
Offering programs to help manage usage	22%	23%	16%	22%	22%	23%	22%	21%
Reducing the environmental impact	20%	20%	19%	17%	21%	22%	20%	19%
Enhancing Hydro One's customer service	6%	6%	9%	6%	7%	6%	5%	8%

Note: Priority labels have been shortened for brevity. See slide 50 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Residential & Seasonal

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

		LEAP/OESP Qualification			Bill Impact	
% who select as top 3 priority	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	80%	82%	81%	78%	86%	74%
Providing reliable electricity	69%	62%	67%	71%	67%	71%
Ensuring the safety of electricity infrastructure	40%	43%	40%	38%	39%	40%
Enhancing the grid for new technologies	31%	28%	33%	35%	28%	35%
Meeting the growing electricity need	27%	25%	28%	28%	24%	30%
Offering programs to help manage usage	22%	27%	22%	21%	27%	17%
Reducing the environmental impact	20%	20%	22%	21%	18%	23%
Enhancing Hydro One's customer service	6%	7%	6%	6%	8%	5%

Note: Priority labels have been shortened for brevity. See slide 50 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Residential & Seasonal

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Delivering electricity at reasonable rates	80%	77%	82%	81%	81%
Providing reliable electricity	69%	67%	68%	69%	71%
Ensuring the safety of electricity infrastructure	40%	42%	40%	40%	36%
Enhancing the grid for new technologies	31%	29%	30%	32%	35%
Meeting the growing electricity need	27%	29%	28%	26%	26%
Offering programs to help manage usage	22%	21%	21%	24%	22%
Reducing the environmental impact	20%	23%	20%	18%	20%
Enhancing Hydro One's customer service	6%	6%	7%	7%	6%

Note: Priority labels have been shortened for brevity. See slide 50 for full label text. "Don't know" not shown.

Customer Priorities

Other Priorities

Residential & Seasonal

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Reasonable/affordable rates	6.4%
Having alternative energy/sustainable sources/green technology	3.3%
Enhancing the grid/infrastructure	2.9%
Improving reliability/less outages	2.8%
Burying lines underground/removing hydro poles	1.4%
Reducing environmental impacts	1.3%
Tree trimming/removal	1.1%
Meeting growing needs for electricity	0.9%
Incentives for seniors/subsidy programs	0.8%
Electric vehicle (EV) infrastructure investment	0.7%
Support/incentives for new technologies or energy efficiency efforts	0.7%
Prioritizing safety	0.6%
Information/programs to manage electricity usage	0.6%
Withstanding extreme weather	0.5%
Improving customer service/communication	0.5%
Affordable renewable energy	0.4%
Focus on nuclear energy/power	0.4%
Reducing length of outages	0.1%
Other	2.7%
None/Don't know	72.1%

Note: Only responses >0.1% shown

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Residential & Seasonal Customers

Reliability Experience

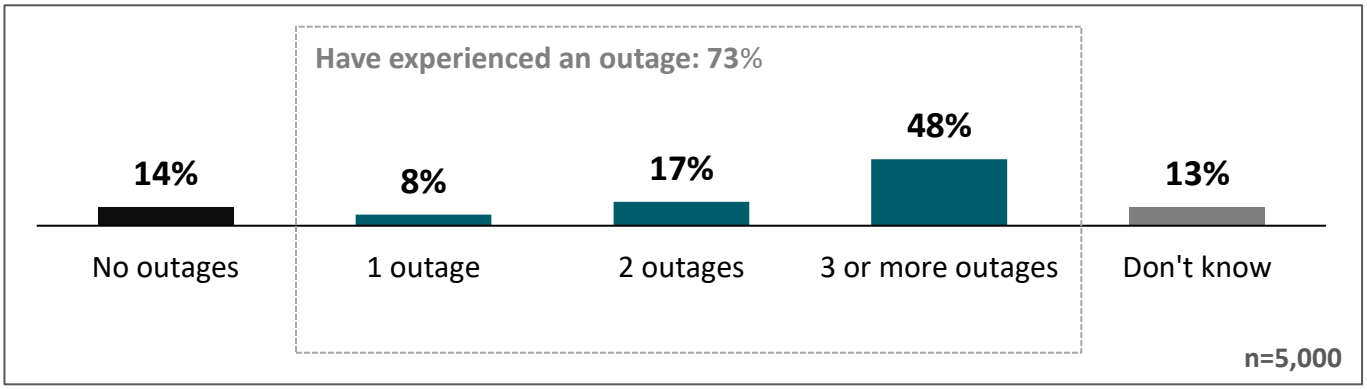


Reliability Experience
Number of Outages Experienced

Residential & Seasonal

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at [home/your seasonal property] **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
No outages	14%	6%	13%	9%	17%	16%	12%
1 outage	8%	5%	9%	6%	9%	9%	5%
2 outages	18%	10%	19%	16%	18%	19%	14%
3 or more outages	46%	62%	46%	56%	42%	41%	56%
Don't know	13%	17%	13%	12%	15%	14%	12%
Have experienced at least 1 outage	**73%**	**77%**	**74%**	**78%**	**69%**	**70%**	**76%**

Reliability Experience
Number of Outages Experienced

Residential & Seasonal

Q Have you experienced any power outages at [home/your seasonal property] **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
No outages	14%	17%	17%	11%	14%	13%
1 outage	8%	8%	10%	8%	7%	9%
2 outages	17%	16%	19%	17%	16%	19%
3 or more outages	48%	41%	42%	53%	49%	47%
Don't know	13%	17%	13%	10%	14%	12%
Have experienced at least 1 outage	**73%**	**66%**	**71%**	**78%**	**71%**	**75%**

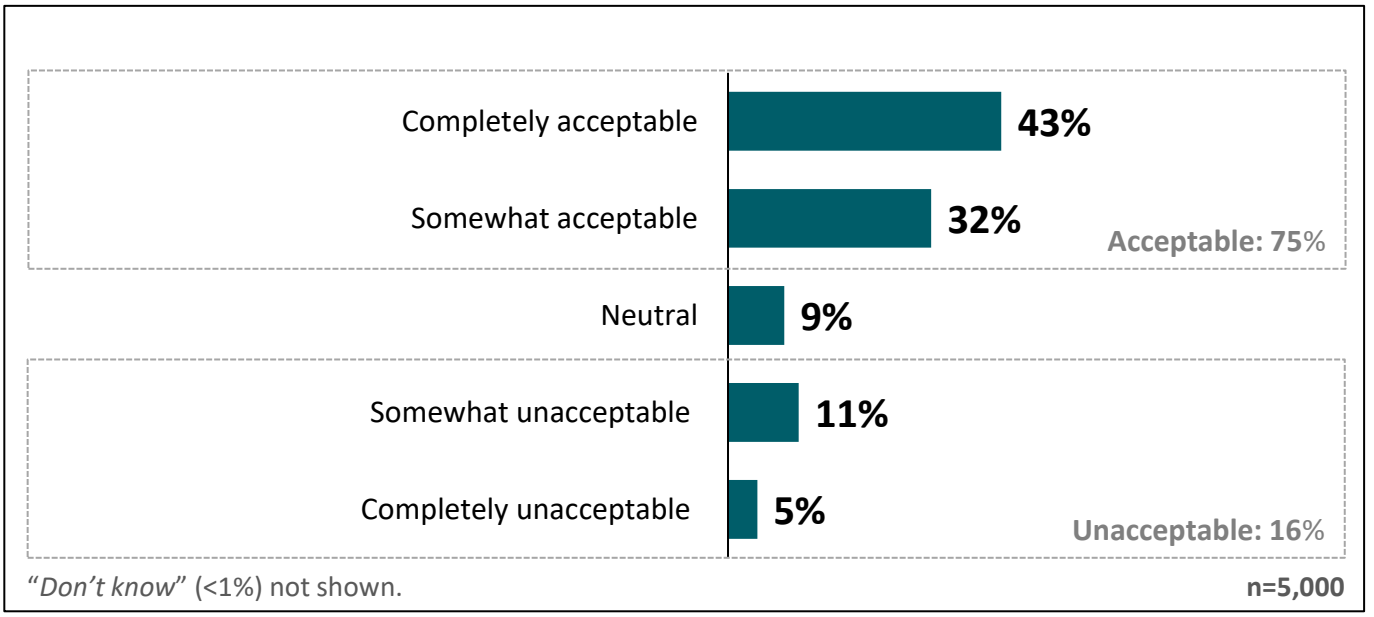
	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
No outages	18%	14%	12%	10%
1 outage	9%	9%	8%	6%
2 outages	18%	17%	18%	16%
3 or more outages	38%	46%	51%	57%
Don't know	17%	14%	12%	11%
Have experienced at least 1 outage	**66%**	**72%**	**77%**	**79%**

Reliability Experience

Current Reliability of Electricity Service

Residential & Seasonal

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (<1%) not shown. **n=5,000**

	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Completely acceptable	45%	29%	42%	39%	46%	49%	38%
Somewhat acceptable	32%	36%	33%	33%	31%	30%	32%
Neutral	9%	11%	8%	9%	9%	9%	10%
Somewhat unacceptable	10%	19%	13%	14%	8%	8%	14%
Completely unacceptable	5%	4%	5%	5%	5%	4%	5%
Don't know	<1%	<1%	<1%	<1%	1%	<1%	<1%
Acceptable (Completely + Somewhat)	**76%**	**66%**	**74%**	**72%**	**78%**	**79%**	**71%**
Unacceptable (Completely + Somewhat)	**15%**	**23%**	**18%**	**19%**	**13%**	**12%**	**19%**

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Reliability Experience

Current Reliability of Electricity Service

Residential & Seasonal

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Completely acceptable	43%	46%	48%	42%	40%	46%
Somewhat acceptable	32%	31%	30%	33%	34%	30%
Neutral	9%	8%	7%	9%	9%	8%
Somewhat unacceptable	11%	10%	9%	12%	11%	11%
Completely unacceptable	5%	5%	5%	4%	5%	4%
Don't know	<1%	1%	<1%	<1%	<1%	1%
Acceptable (Completely + Somewhat)	**75%**	**77%**	**78%**	**75%**	**74%**	**76%**
Unacceptable (Completely + Somewhat)	**16%**	**14%**	**15%**	**16%**	**16%**	**15%**

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Completely acceptable	49%	42%	43%	37%
Somewhat acceptable	30%	33%	29%	36%
Neutral	7%	9%	9%	9%
Somewhat unacceptable	8%	11%	13%	14%
Completely unacceptable	5%	4%	6%	4%
Don't know	1%	<1%	<1%	<1%
Acceptable (Completely + Somewhat)	**80%**	**75%**	**73%**	**73%**
Unacceptable (Completely + Somewhat)	**12%**	**15%**	**18%**	**18%**

Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights
Improving communications during outages	Improving communications during outages, including estimated restoration times

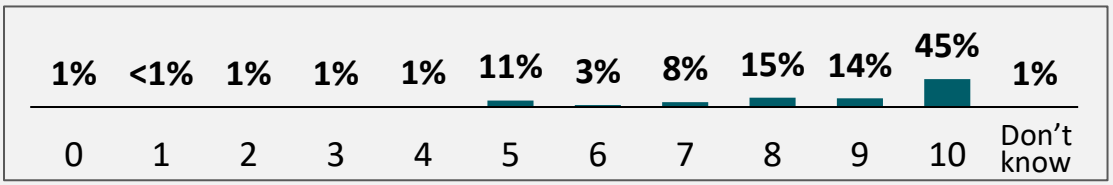
Reliability Experience

Importance of Reliability Priorities

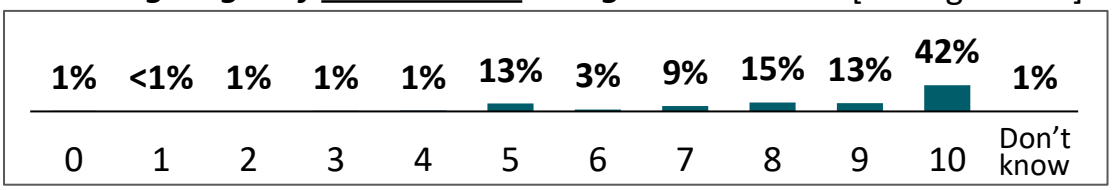
Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

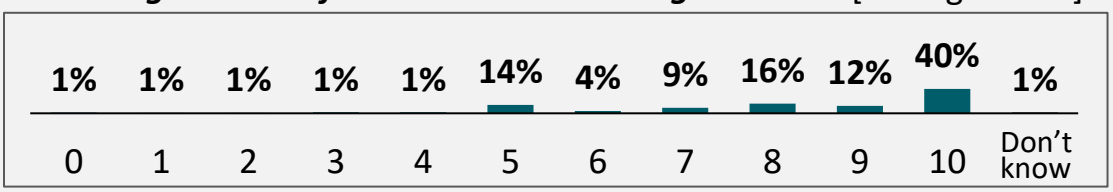
Reducing length of weather-caused outages [average = **8.4**]



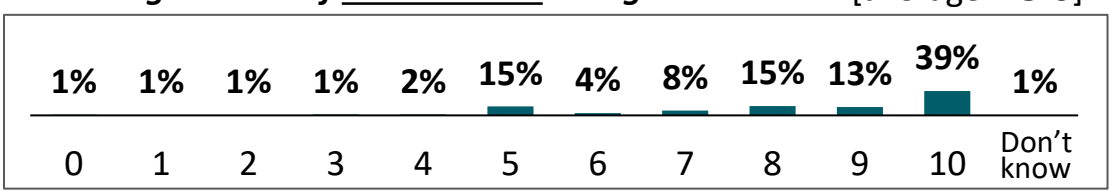
Reducing length of non-weather outages [average = **8.2**]



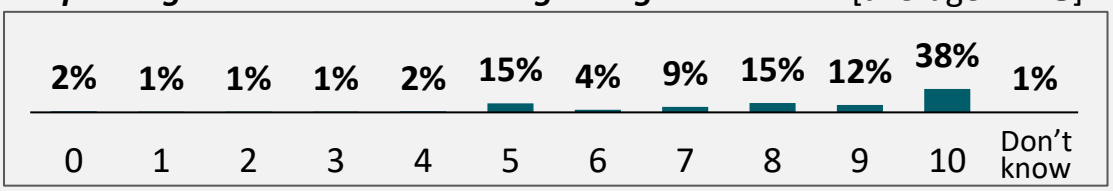
Reducing number of weather-caused outages [average = **8.0**]



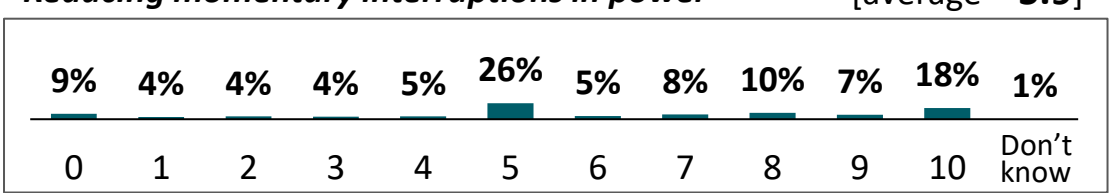
Reducing number of non-weather outages [average = **8.0**]



Improving communications during outages [average = **7.8**]



Reducing momentary interruptions in power [average = **5.9**]



Note: Priority labels have been shortened for brevity. See slide 66 for full label text.
"Don't know" not included in calculation of means.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Customer Type		Region				
Average Score	**Overall**	**Residential**	**Seasonal**	**West**	**Central**	**Central East**	**East**	**North**
Reducing length of weather-caused outages	8.4	8.4	8.3	8.3	8.3	8.4	8.5	8.3
Reducing length of non-weather outages	8.2	8.2	8.3	8.3	8.2	8.2	8.2	8.0
Reducing number of weather-caused outages	8.0	8.0	8.0	7.9	8.0	8.1	8.2	7.8
Reducing number of non-weather outages	8.0	8.0	8.0	8.1	8.1	8.0	8.0	7.8
Improving communications during outages	7.8	7.9	7.4	8.0	7.8	7.9	8.0	7.7
Reducing momentary interruptions in power	5.9	6.0	5.0	6.4	5.8	5.7	5.8	5.7

Note: Priority labels have been shortened for brevity. See slide 66 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		LEAP/OESP Qualification			Bill Impact	
Average Score	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Reducing length of weather-caused outages	8.4	8.3	8.4	8.3	8.5	8.3
Reducing length of non-weather outages	8.2	8.3	8.1	8.1	8.3	8.0
Reducing number of weather-caused outages	8.0	8.0	8.1	7.9	8.1	7.9
Reducing number of non-weather outages	8.0	8.1	7.8	8.0	8.2	7.8
Improving communications during outages	7.8	8.0	7.9	7.7	8.1	7.6
Reducing momentary interruptions in power	5.9	6.1	5.6	5.7	6.2	5.5

Note: Priority labels have been shortened for brevity. See slide 66 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Residential & Seasonal

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Consumption Quartiles			
Average Score	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**
Reducing length of weather-caused outages	8.4	8.4	8.4	8.3	8.4
Reducing length of non-weather outages	8.2	8.2	8.2	8.1	8.2
Reducing number of weather-caused outages	8.0	8.0	8.1	8.0	8.1
Reducing number of non-weather outages	8.0	8.0	8.1	7.9	8.1
Improving communications during outages	7.8	7.9	7.9	7.8	7.8
Reducing momentary interruptions in power	5.9	5.8	5.9	5.8	5.9

Note: Priority labels have been shortened for brevity. See slide 66 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

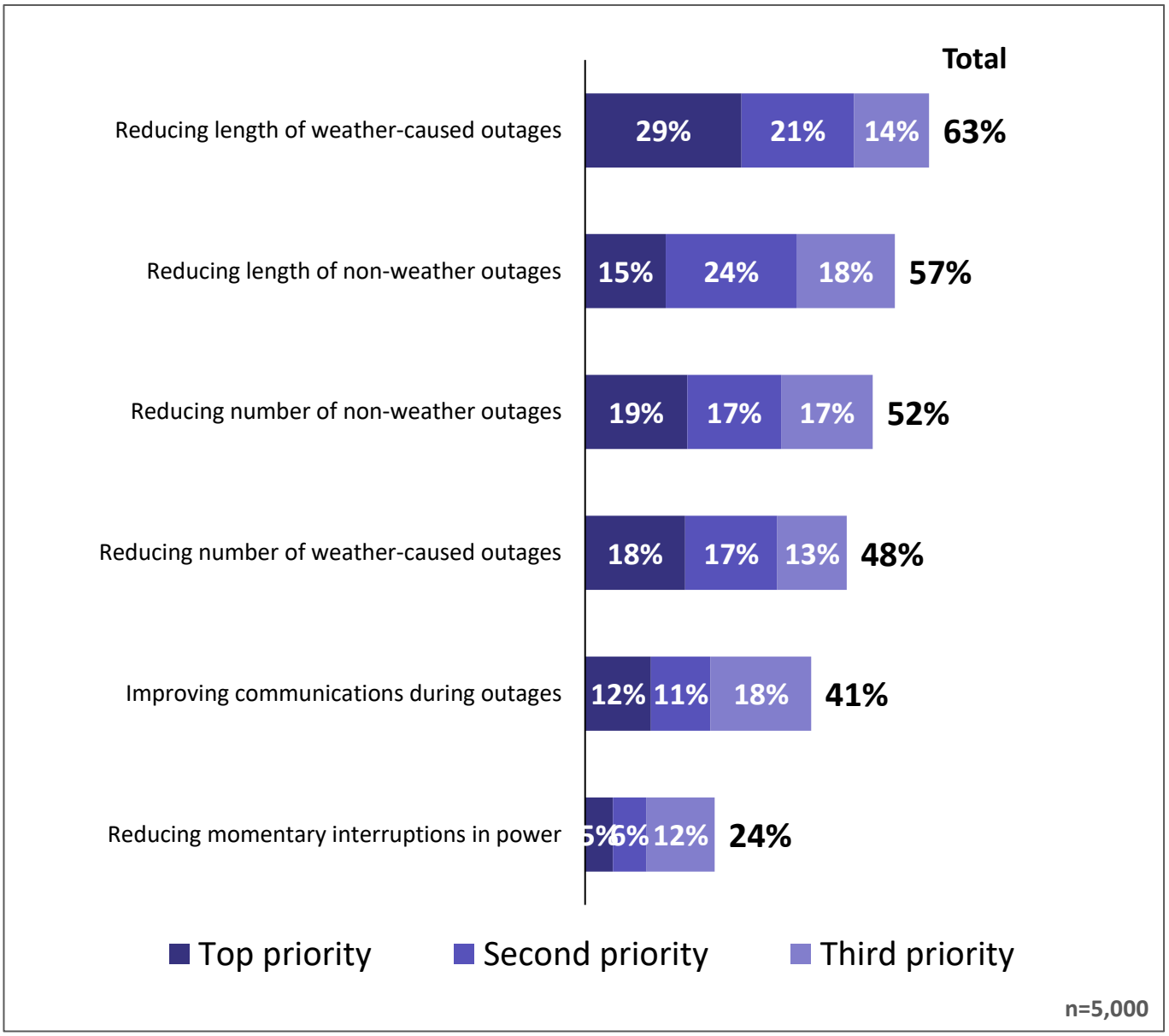
Reliability Experience

Ranking Reliability Priorities

Residential & Seasonal

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?



Note: Priority labels have been shortened for brevity. See slide 66 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Residential & Seasonal

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Customer Type		Region				
% who select as top 3 priority	**Overall**	**Residential**	**Seasonal**	**West**	**Central**	**Central East**	**East**	**North**
Reducing length of weather-caused outages	63%	62%	66%	57%	63%	66%	65%	59%
Reducing length of non-weather outages	57%	56%	60%	58%	56%	57%	53%	60%
Reducing number of non-weather outages	52%	52%	57%	53%	55%	51%	50%	52%
Reducing number of weather-caused outages	48%	47%	50%	44%	50%	47%	51%	44%
Improving communications during outages	41%	42%	35%	44%	38%	42%	42%	42%
Reducing momentary interruptions in power	24%	25%	15%	28%	25%	21%	21%	25%

Note: Priority labels have been shortened for brevity. See slide 66 for full label text. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Residential & Seasonal

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		LEAP/OESP Qualification			Bill Impact	
% who select as top 3 priority	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Reducing length of weather-caused outages	63%	59%	63%	65%	61%	65%
Reducing length of non-weather outages	57%	55%	55%	58%	57%	56%
Reducing number of non-weather outages	52%	49%	52%	55%	51%	54%
Reducing number of weather-caused outages	48%	45%	49%	49%	46%	49%
Improving communications during outages	41%	45%	44%	40%	44%	39%
Reducing momentary interruptions in power	24%	27%	22%	22%	26%	21%

Note: Priority labels have been shortened for brevity. See slide 66 for full label text. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Residential & Seasonal

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Consumption Quartiles			
% who select as top 3 priority	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**
Reducing length of weather-caused outages	63%	60%	63%	64%	65%
Reducing length of non-weather outages	57%	56%	58%	56%	56%
Reducing number of non-weather outages	52%	53%	52%	53%	52%
Reducing number of weather-caused outages	48%	44%	49%	47%	50%
Improving communications during outages	41%	45%	41%	41%	37%
Reducing momentary interruptions in power	24%	21%	23%	25%	26%

Note: Priority labels have been shortened for brevity. See slide 66 for full label text. "Don't know" not shown.

INNOVATIVE RESEARCH GROUP

Residential & Seasonal Customers

Investment Priorities



Investment Priorities

High-Level Reliability

Now let's turn to the next topic – investment trade-offs. There are **6** investment areas that **Hydro One** would like your input on.

You do not need to be a system planner or engineer to answer these questions. The trade-offs will focus on what outcomes matter most to you as a customer – balancing investment outcomes and cost to you.

First, we would like to talk about the local distribution system, which takes electricity from transmission lines and brings it to your [home/seasonal property] through a network of wires, poles and other equipment.

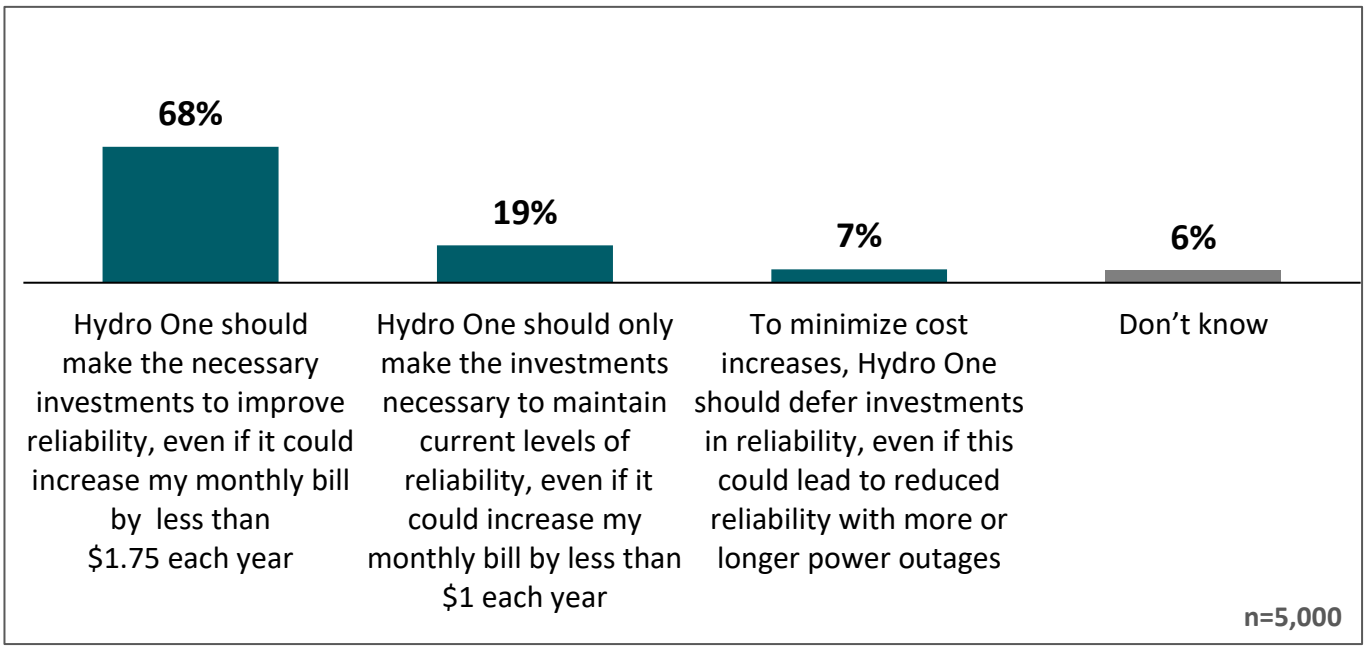
The first category is related to the reliability you experience.

On average, between 2019 and 2023, the typical **Hydro One** customer has experienced about 3.8 outages per year, resulting in a total of 16.6 hours without power.

It's important to keep in mind that these are system averages, and that your actual experience may be different.

Hydro One has historically identified investments in maintaining or improving reliability by taking into consideration the overall age, health, and likelihood of failure of equipment.

Q Based on your own reliability experience, which of the following is closest to your point of view?



Investment Priorities
High-Level Reliability

Residential & Seasonal

Q Based on your own reliability experience, which of the following is closest to your point of view?

		Customer Type		Region				
	Overall	Residential	Seasonal	West	Central	Central East	East	North
Necessary investments to improve reliability	68%	68%	73%	69%	69%	68%	68%	67%
Necessary investments to maintain reliability	19%	19%	17%	17%	19%	19%	20%	18%
Defer investments	7%	7%	5%	8%	6%	7%	6%	8%
Don't know	6%	6%	5%	6%	6%	6%	7%	7%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Necessary investments to improve reliability	60%	70%	74%	57%	79%
Necessary investments to maintain reliability	22%	19%	17%	23%	14%
Defer investments	10%	6%	6%	11%	3%
Don't know	8%	5%	3%	8%	4%

Note: Response labels have been shortened for brevity. See slide 76 for full label text.

Investment Priorities

High-Level Reliability

Residential & Seasonal

Q Based on your own reliability experience, which of the following is closest to your point of view?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Necessary investments to improve reliability	68%	66%	70%	67%	71%
Necessary investments to maintain reliability	19%	20%	19%	18%	17%
Defer investments	7%	7%	5%	8%	6%
Don't know	6%	7%	6%	7%	5%

Note: Response labels have been shortened for brevity. See slide 76 for full label text.

Investment Priorities

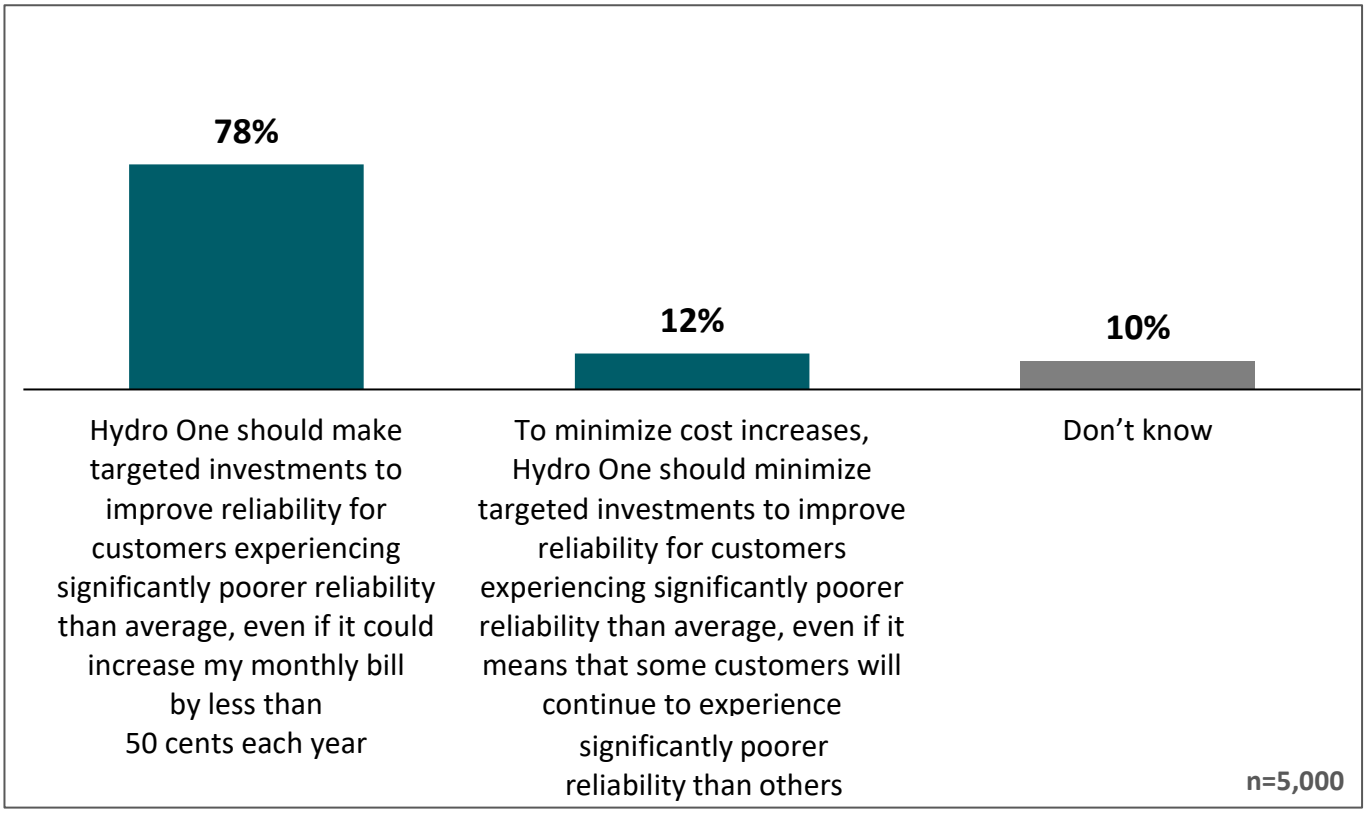
Targeted Reliability

The second category is related to more targeted improvements to reliability.

Hydro One customers experience different levels of reliability, depending on where they live, the design of the system and the condition of the equipment supplying them.

While some **Hydro One** customers didn't experience any outages in 2022 or 2023, others were without power more than 10 times per year. Similarly, the total length of time that customers were without power ranges from less than one hour to more than 50 hours per year.

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?



Investment Priorities
Targeted Reliability

Residential & Seasonal

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?

	Overall	Customer Type: Residential	Customer Type: Seasonal	Region: West	Region: Central	Region: Central East	Region: East	Region: North
Targeted investments to improve reliability	78%	78%	80%	78%	77%	78%	79%	78%
Minimize targeted investments	12%	13%	11%	14%	13%	13%	9%	12%
Don't know	10%	10%	9%	8%	10%	9%	12%	11%

	LEAP/OESP Qualification: Qualified	LEAP/OESP Qualification: <$71k Not Qualified	LEAP/OESP Qualification: >$71k Not Qualified	Bill Impact: Major Impact	Bill Impact: No Major Impact
Targeted investments to improve reliability	73%	80%	82%	70%	86%
Minimize targeted investments	14%	12%	12%	18%	7%
Don't know	13%	9%	6%	12%	7%

	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Targeted investments to improve reliability	76%	80%	76%	79%
Minimize targeted investments	13%	11%	14%	12%
Don't know	11%	9%	10%	9%

Note: Response labels have been shortened for brevity. See slide 79 for full label text.

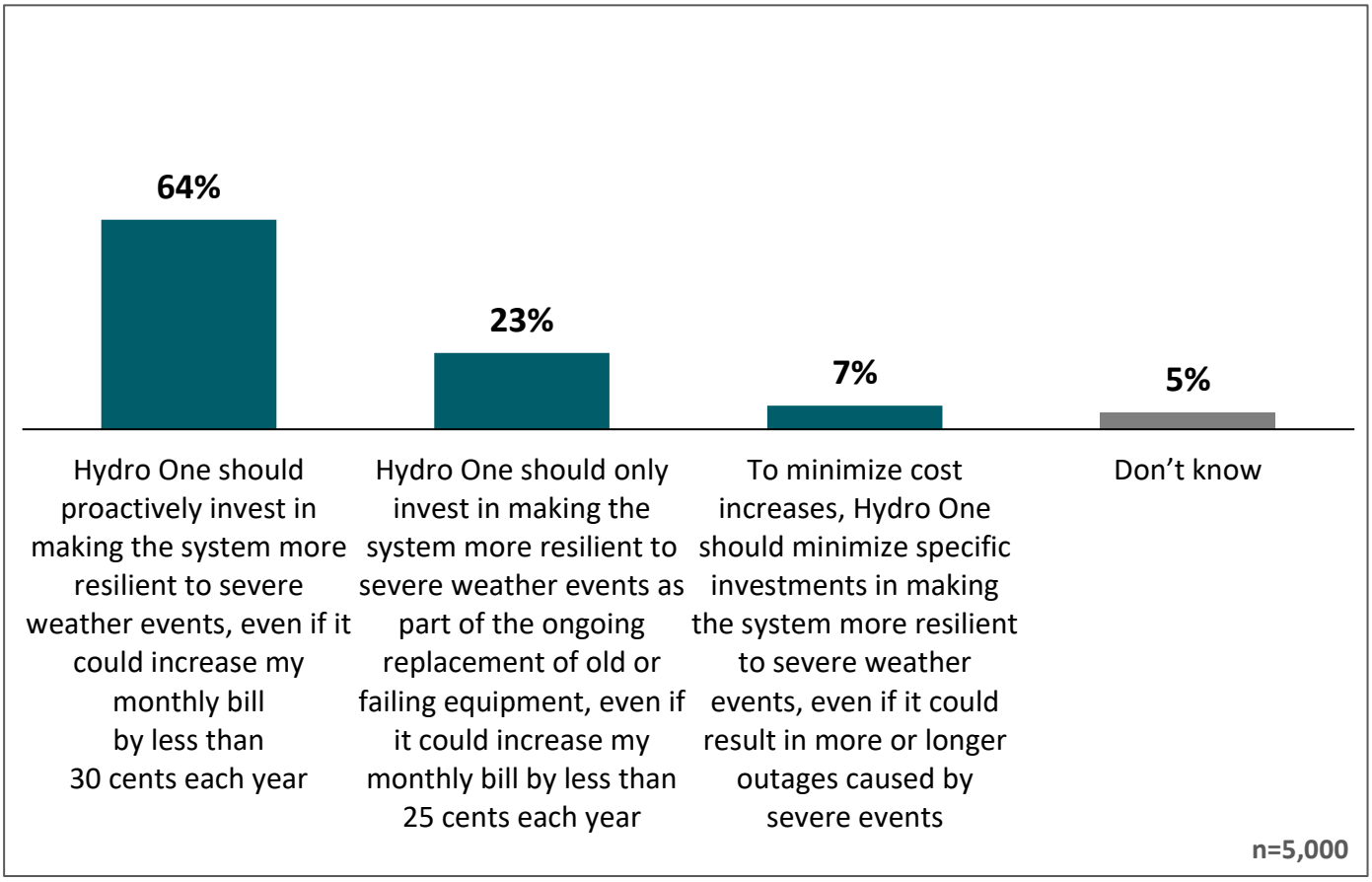
Investment Priorities

Responding to Severe Weather

On average, between 2019 and 2023, **severe weather events**, such as ice storms, windstorms or thunderstorms, have contributed to 51% of all hours that the typical customer has been without power per year.

While some of these outages may be inevitable, **Hydro One** could make additional investments to make the system more resilient to these types of events. These investments could help either reduce the number of outages caused by severe weather events or improve restoration times when these outages do occur.

Q Based on this, which of the following is closest to your point of view?



Investment Priorities

Responding to Severe Weather

Residential & Seasonal

Q Based on this, which of the following is closest to your point of view?

	Overall	Customer Type		Region				
		Residential	Seasonal	West	Central	Central East	East	North
Proactively invest in resiliency	64%	64%	68%	62%	64%	66%	65%	62%
Invest as part of ongoing replacement	23%	23%	23%	26%	24%	22%	22%	24%
Minimize specific investments	7%	8%	4%	8%	7%	7%	6%	8%
Don't know	5%	5%	5%	4%	5%	5%	6%	6%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactively invest in resiliency	57%	64%	69%	53%	76%
Invest as part of ongoing replacement	27%	25%	21%	29%	18%
Minimize specific investments	10%	7%	6%	11%	3%
Don't know	7%	3%	3%	7%	3%

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Proactively invest in resiliency	62%	65%	64%	66%
Invest as part of ongoing replacement	24%	24%	24%	21%
Minimize specific investments	8%	6%	8%	8%
Don't know	6%	5%	4%	5%

Note: Response labels have been shortened for brevity. See slide 81 for full label text.

Investment Priorities
Growth

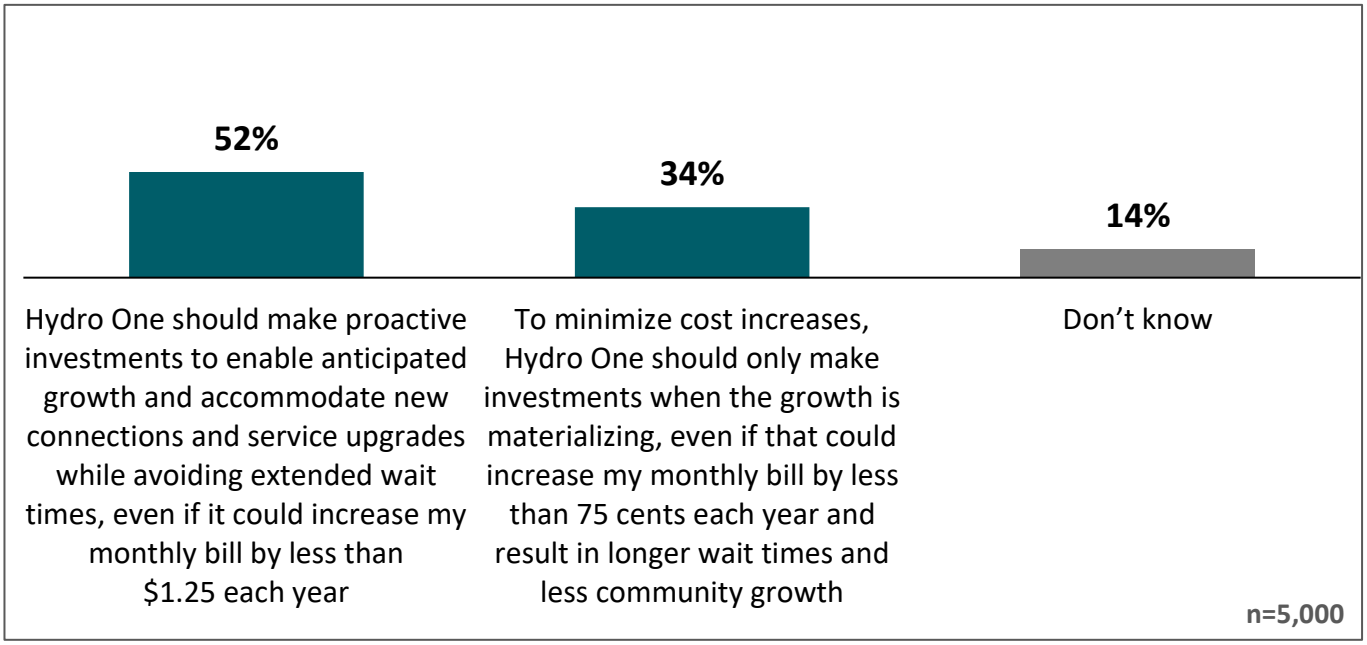
Electricity demand is on the rise across Ontario. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Hydro One** to make significant investments in the grid.

Increased growth can result in longer wait times to connect new homes or businesses to the system or facilitate upgrades for existing customers if insufficient capacity is available.

For instance, as increasing growth occurs, some new businesses may be asked to wait up to 2 years or longer for their facility to be connected to the **Hydro One** grid.

However, **Hydro One** could make proactive investments to enable anticipated growth and allow new homes or businesses to connect to the system in a timely manner, and to not delay service upgrades for existing customers.

Q Based on this, which is closest to your point of view?



Investment Priorities
Growth

Residential & Seasonal

Q Based on this, which is closest to your point of view?

	Overall	Customer Type: Residential	Customer Type: Seasonal	Region: West	Region: Central	Region: Central East	Region: East	Region: North
Proactive investments to enable growth	52%	52%	48%	52%	51%	51%	53%	50%
Only make investments as growth materializes	34%	34%	39%	34%	35%	35%	33%	35%
Don't know	14%	14%	13%	14%	14%	13%	14%	16%

	LEAP/OESP Qualification: Qualified	LEAP/OESP Qualification: <$71k Not Qualified	LEAP/OESP Qualification: >$71k Not Qualified	Bill Impact: Major Impact	Bill Impact: No Major Impact
Proactive investments to enable growth	48%	57%	56%	42%	62%
Only make investments as growth materializes	33%	32%	34%	41%	27%
Don't know	19%	11%	9%	17%	11%

	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Proactive investments to enable growth	50%	52%	49%	55%
Only make investments as growth materializes	34%	33%	38%	33%
Don't know	16%	15%	13%	12%

Note: Response labels have been shortened for brevity. See slide 83 for full label text.

Investment Priorities

Evolving Customer Requests & System Visibility

Residential & Seasonal

Beyond residential and industrial growth, customers are increasingly requesting information and upgrades related to new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers.

Whether or not you are actively considering these types of technologies for yourself, **Hydro One** needs to be prepared to accommodate these types of customer requests, not just today, but over the next 5 to 10 years.

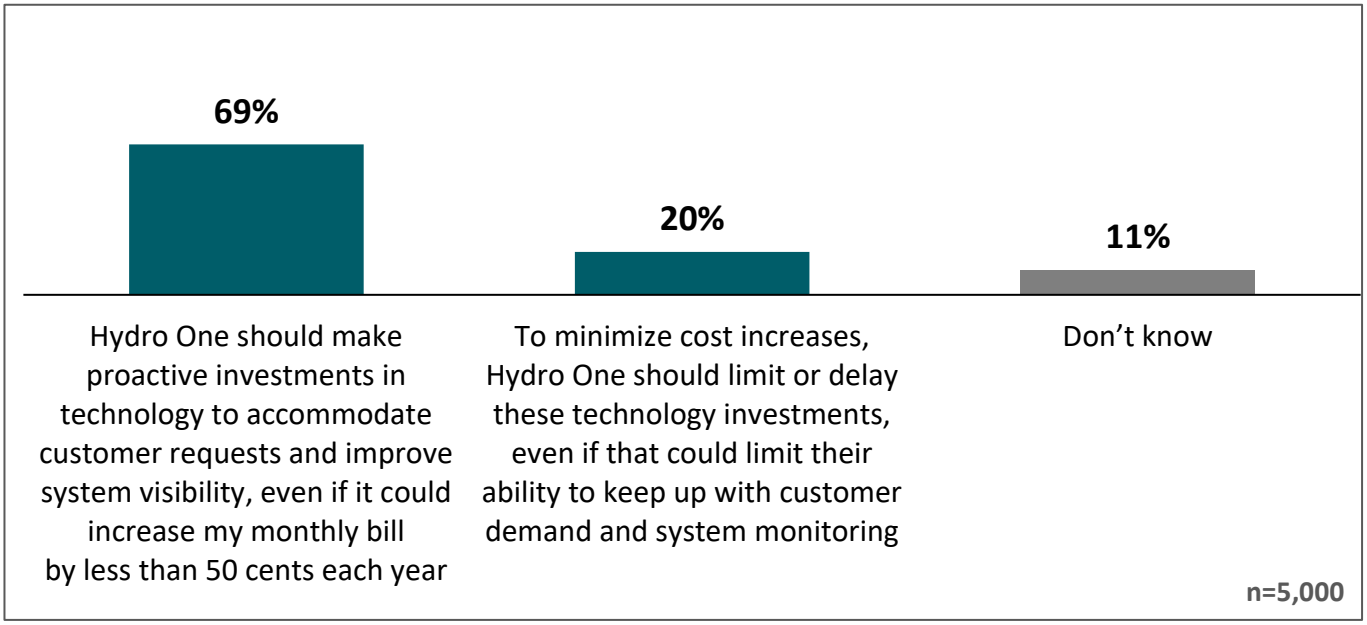
While **Hydro One** has an obligation to make certain investments to accommodate customer requests, planners have identified incremental investments that can help:

- Ensure that **Hydro One's** grid is ready to accommodate if and when customers request to connect new technologies.

- Give the **Hydro One** control room more "visibility" into exactly where and how much electricity is being used in real-time, helping make more informed decisions on managing electricity demand and equipment maintenance or upgrades.

As the pace of change and customer needs are rapidly evolving, delaying or limiting these investments means that **Hydro One** could struggle to keep up with customer demand for connecting new technology and lack the precision to monitor the grid as new technology adoption increases.

Q With regards to these investments, which of the following is closest to your point of view?



INNOVATIVE RESEARCH GROUP

Investment Priorities

Evolving Customer Requests & System Visibility

Residential & Seasonal

Q With regards to these investments, which of the following is closest to your point of view?

		Customer Type		Region				
	Overall	Residential	Seasonal	West	Central	Central East	East	North
Proactive investments in technology	69%	69%	70%	67%	69%	70%	69%	67%
Limit or delay technology investments	20%	20%	20%	21%	20%	18%	20%	21%
Don't know	11%	12%	9%	11%	11%	11%	11%	12%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactive investments in technology	66%	72%	73%	60%	78%
Limit or delay technology investments	21%	18%	19%	27%	13%
Don't know	13%	10%	8%	14%	9%

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Proactive investments in technology	68%	68%	68%	72%
Limit or delay technology investments	18%	21%	21%	18%
Don't know	13%	11%	11%	10%

Note: Response labels have been shortened for brevity. See slide 85 for full label text.

Investment Priorities

Transmission Renewal

Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

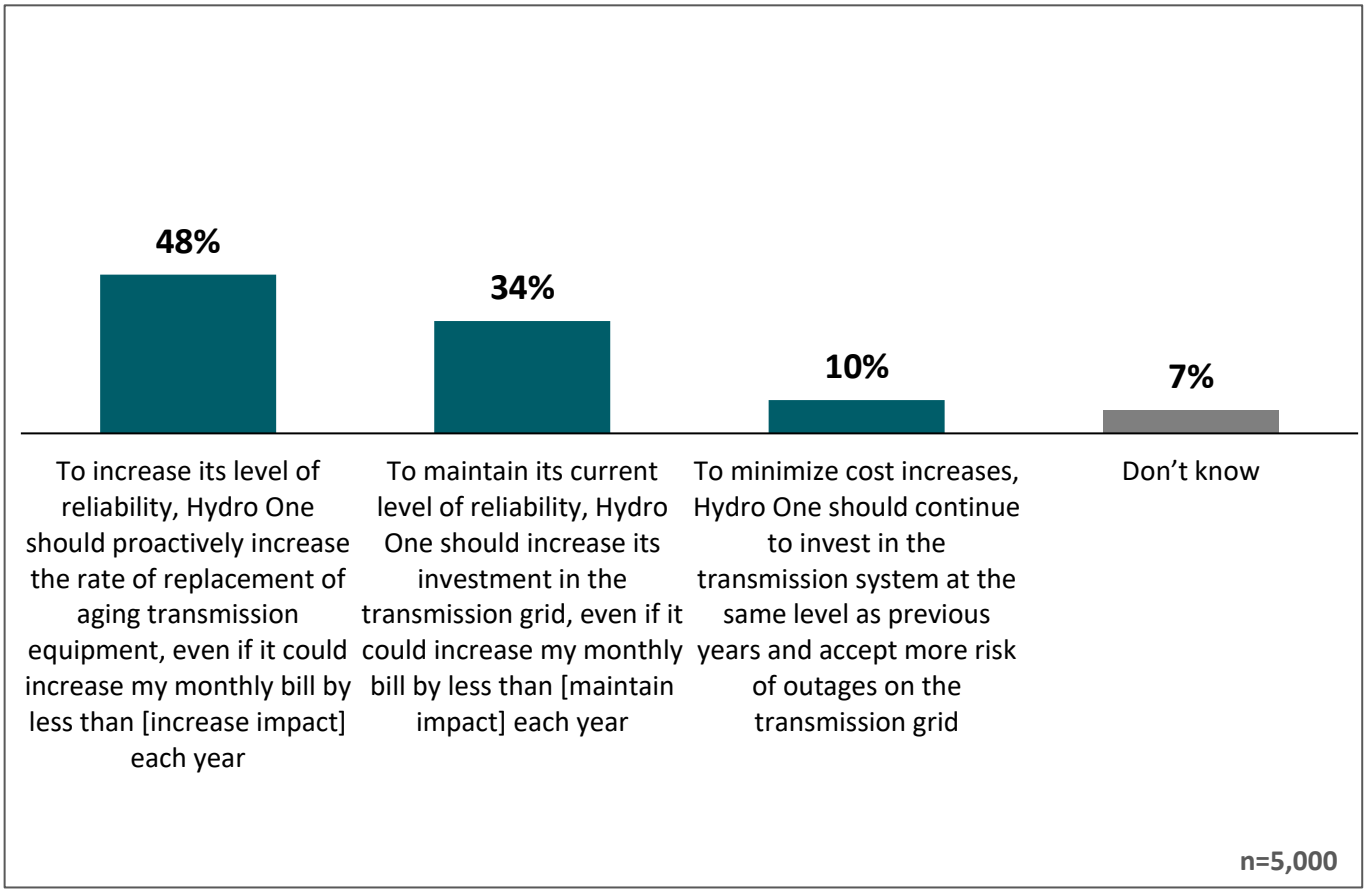
Investment Priorities
Transmission Renewal

Residential & Seasonal

Q With this in mind, what is closest to your point of view?

Transmission Renewal Legend

Customer Group	[maintain impact]	[increase impact]
Residential	85 cents	30 cents
Seasonal	45 cents	15 cents



INNOVATIVE RESEARCH GROUP

Investment Priorities
Transmission Renewal

Residential & Seasonal

Q With this in mind, what is closest to your point of view?

		Customer Type		Region				
	Overall	Residential	Seasonal	West	Central	Central East	East	North
Proactively increase investment to increase reliability	48%	48%	54%	49%	49%	49%	48%	43%
Increase investment to maintain current reliability	34%	35%	32%	34%	32%	34%	36%	37%
Continue to invest at the same level	10%	10%	9%	10%	11%	10%	9%	11%
Don't know	7%	7%	5%	6%	8%	6%	7%	9%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactively increase investment to increase reliability	44%	48%	53%	37%	60%
Increase investment to maintain current reliability	33%	38%	34%	38%	31%
Continue to invest at the same level	14%	9%	9%	16%	4%
Don't know	10%	5%	4%	9%	5%

Note: Response labels have been shortened for brevity. See slide 88 for full label text.

Investment Priorities
Transmission Renewal

Residential & Seasonal

Q With this in mind, what is closest to your point of view?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Proactively increase investment to increase reliability	48%	47%	48%	47%	52%
Increase investment to maintain current reliability	34%	35%	36%	34%	33%
Continue to invest at the same level	10%	10%	9%	12%	9%
Don't know	7%	8%	7%	7%	7%

Note: Response labels have been shortened for brevity. See slide 88 for full label text.

First Nations On-Reserve Customers

Online Survey Results

Section 3



Field Dates

The **First Nations On-Reserve Customer Online Surveys** was sent to a random selection of Hydro One on-reserve customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **November 14th and December 5th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the survey was sent to **6,293** customers from *customerexperience@hydroone.com*. Reminder emails were sent on November 21st, November 28th, and December 4th, 2024 to those who had not yet completed the survey.

First Nations On-Reserve Customer Online Survey Completes

A total of **426** (unweighted) Hydro One on-reserve customers completed the online survey.

Sample Weighting

The First Nations On-Reserve Customer online survey sample was weighted down to n=400 proportionately by consumption quartiles and region in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

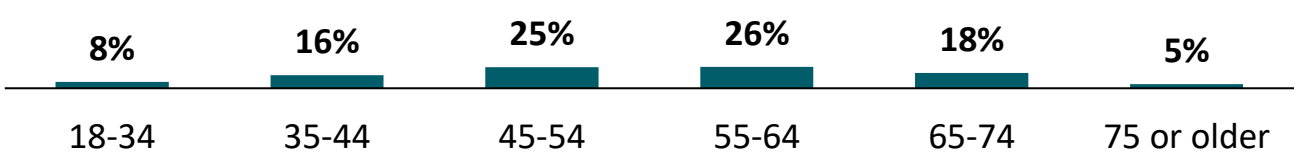
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	7 (10)	9 (12)	11 (13)	9 (9)	37 (45)
Central	43 (36)	26 (29)	24 (22)	14 (17)	107 (104)
East/Central East	30 (17)	32 (17)	16 (15)	10 (11)	91 (60)
North	34 (35)	48 (42)	53 (49)	51 (62)	191 (191)
Total	114 (99)	115 (99)	104 (99)	84 (99)	426 (400)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Demographic Breakdown

First Nations On-Reserve

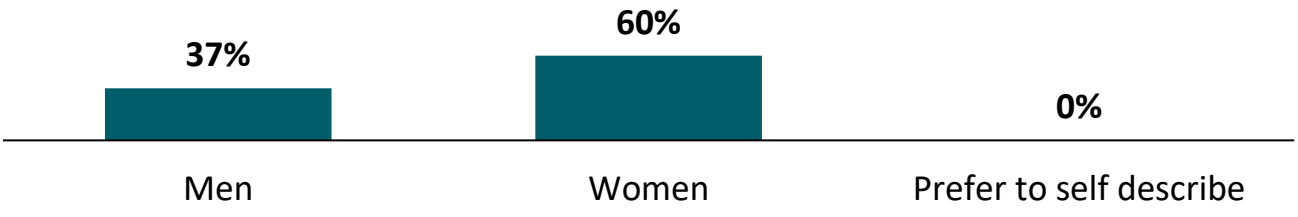
Q Age



"Prefer not to say" (2%) not shown.

n=400

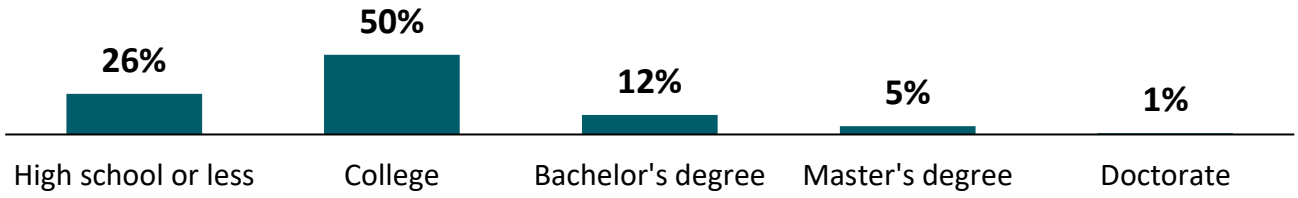
Q Gender



"Prefer not to say" (4%) not shown.

n=400

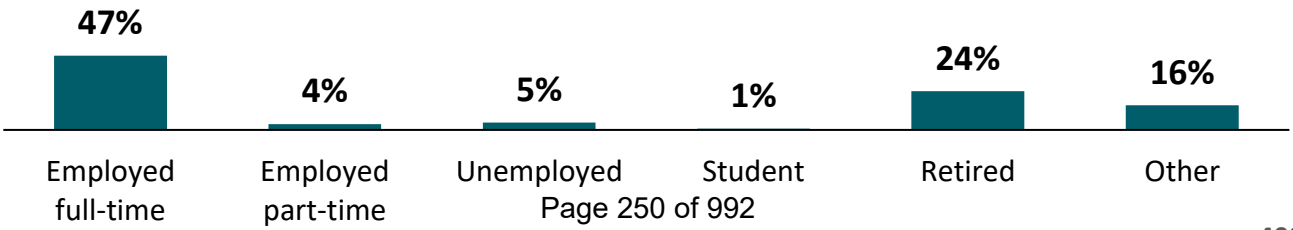
Q Education



"Other" (1%) and "Prefer not to say" (5%) not shown.

n=400

Q Employment Status



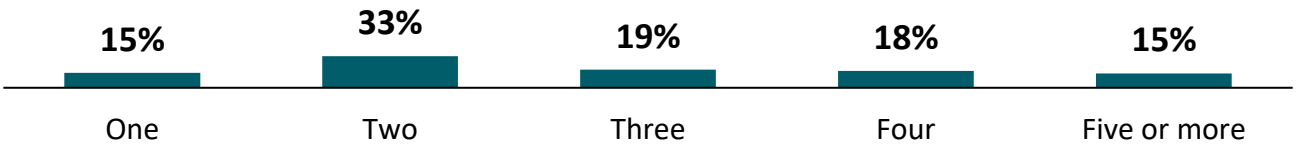
"Prefer not to say" (4%) not shown.

n=400

Demographic Breakdown
Continued

First Nations On-Reserve

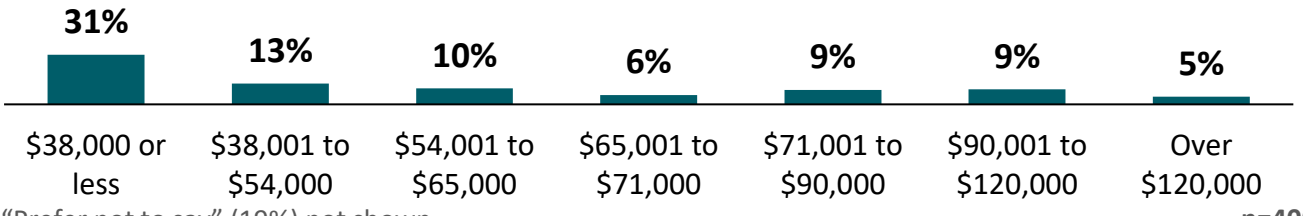
Q Household Size



"Prefer not to say" (1%) not shown.

n=400

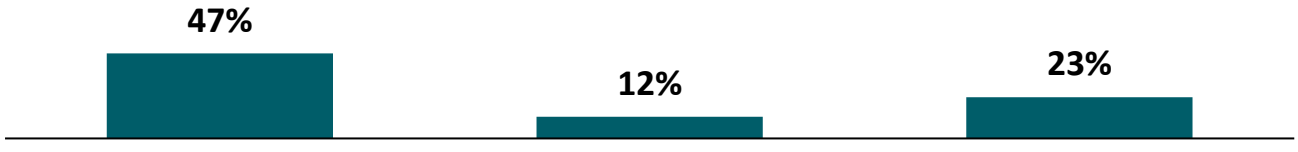
Q After Tax Household Income



"Prefer not to say" (19%) not shown.

n=400

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (19%) not shown.

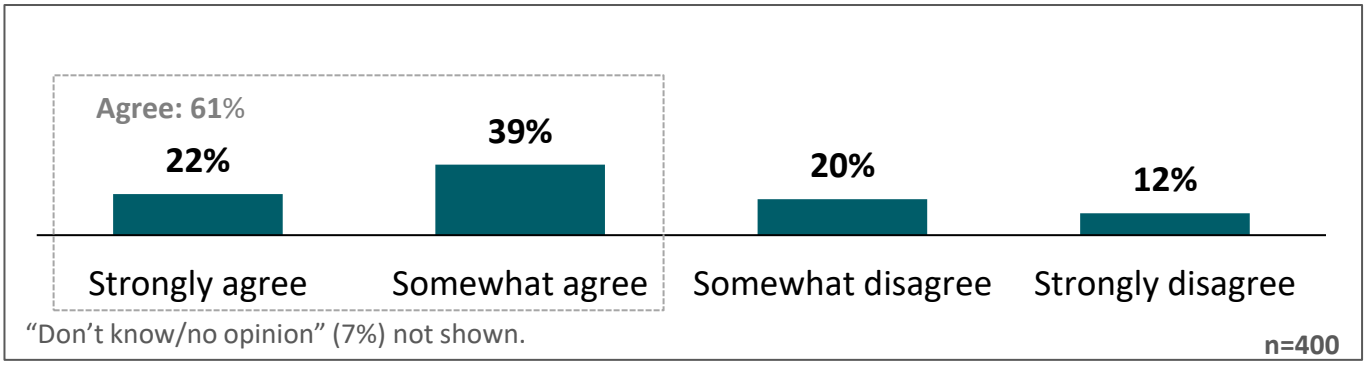
n=400

INNOVATIVE RESEARCH GROUP

Environmental Controls

To what extent do you agree or disagree with the following statements?

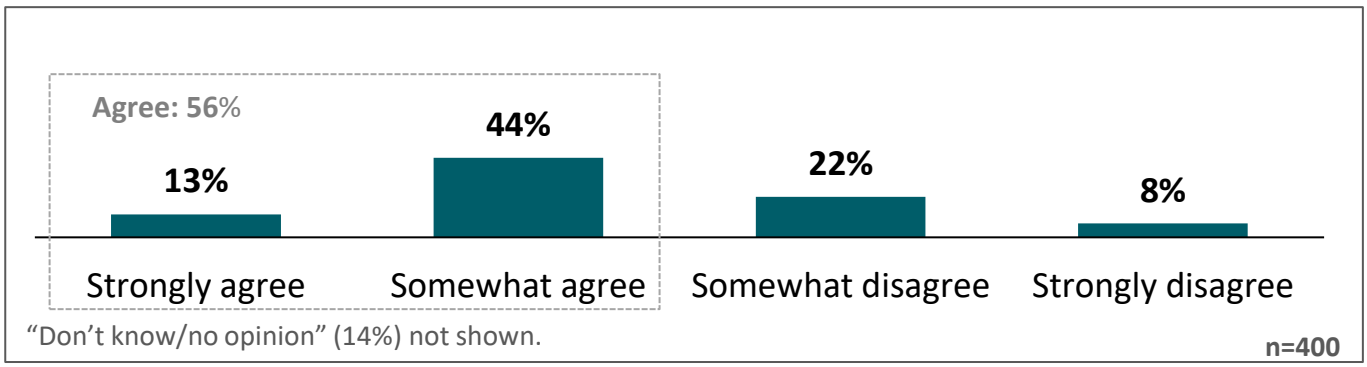
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (7%) not shown.

n=400

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (14%) not shown.

n=400

First Nations On-Reserve Customers

Familiarity & Experience

Preamble:

Before we begin, this survey has **three key objectives**.

First, **Hydro One** wants to better understand your experiences as a customer.

Second, **Hydro One** wants your input on some of the investment areas they could focus on in the future.

Third, **Hydro One** wants to learn a little bit more about their customers. This will help them ensure that they are receiving feedback that represents a wide range of customers.

First, let's talk about your experience.

While you might have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a residential customer.

Familiarity & Experience

Familiarity with Hydro One's Role in the System

First Nations On-Reserve

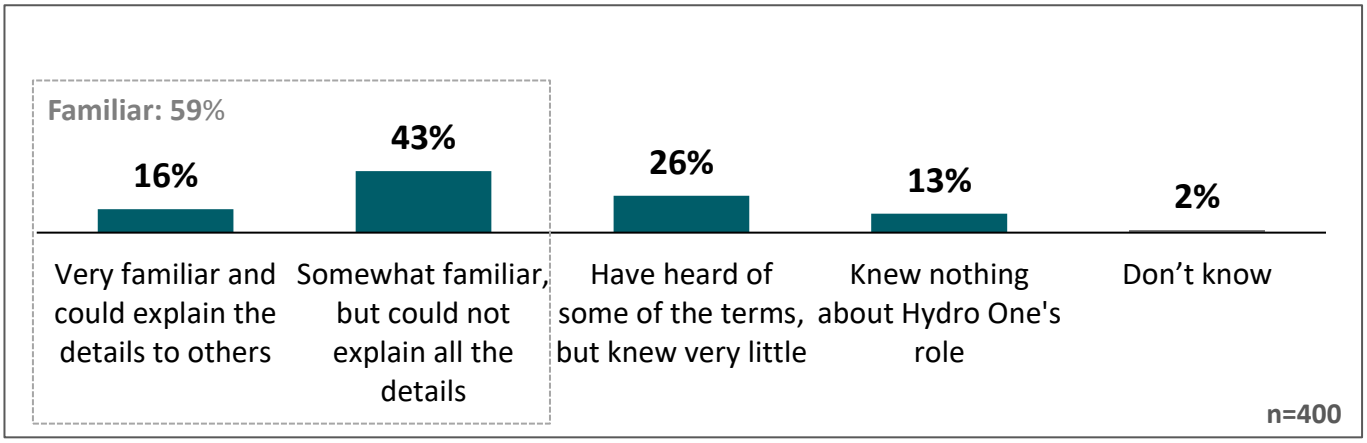
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which takes electricity from transmission lines and brings it to your home through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	West	Central	East/Central East	North
Very familiar	19%	14%	11%	19%
Somewhat familiar	32%	46%	53%	40%
Knew very little	42%	24%	20%	25%
Knew nothing	7%	14%	12%	15%
Don't know	--	1%	3%	2%
Familiar (Very + Somewhat)	**51%**	**61%**	**64%**	**59%**

Familiarity & Experience

Familiarity with Hydro One's Role in the System

First Nations On-Reserve

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	16%	16%	8%	19%	17%	16%
Somewhat familiar	43%	42%	53%	42%	43%	43%
Knew very little	26%	21%	25%	29%	26%	25%
Knew nothing	13%	18%	12%	10%	13%	14%
Don't know	2%	3%	2%	1%	2%	2%
Familiar (Very + Somewhat)	**59%**	**58%**	**61%**	**60%**	**59%**	**59%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very familiar	6%	17%	21%	21%
Somewhat familiar	50%	37%	47%	38%
Knew very little	28%	29%	21%	24%
Knew nothing	15%	13%	10%	15%
Don't know	1%	3%	2%	1%
Familiar (Very + Somewhat)	**56%**	**54%**	**67%**	**59%**

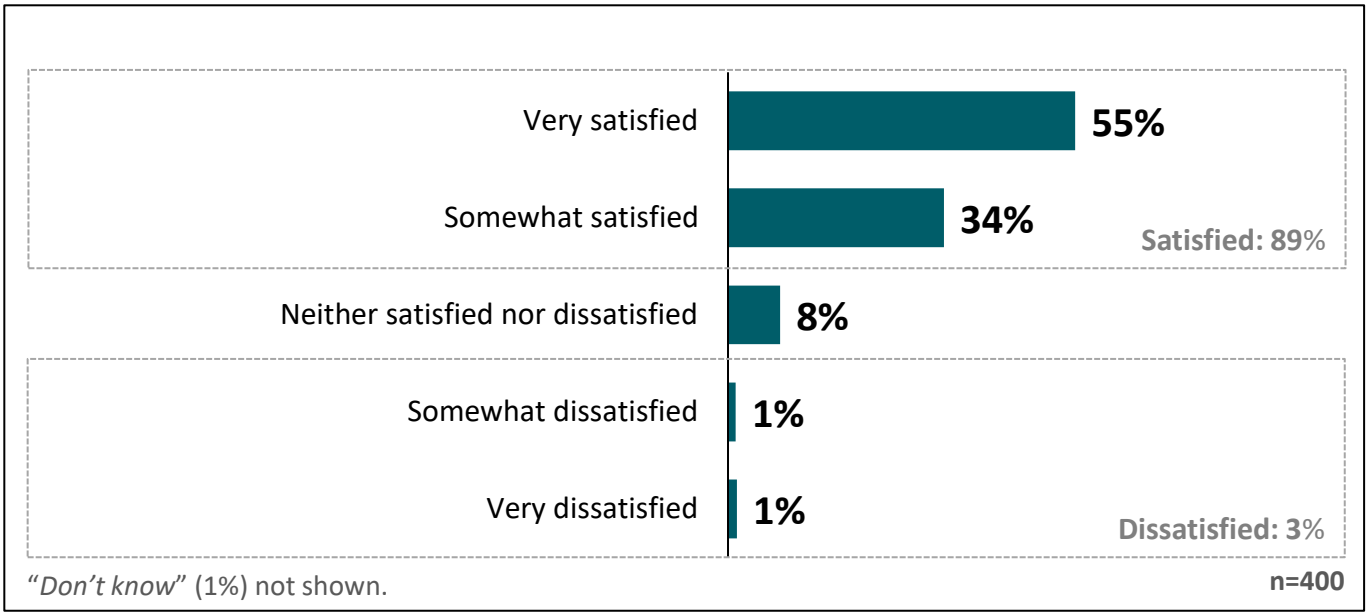
Familiarity & Experience

Overall Satisfaction with Hydro One

First Nations On-Reserve

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Q Overall, how satisfied or dissatisfied are you with the service you receive from **Hydro One**?



"*Don't know*" (1%) not shown.

n=400

Region

	West	Central	East/Central East	North
Very satisfied	59%	62%	57%	49%
Somewhat satisfied	31%	28%	36%	37%
Neither	5%	8%	4%	10%
Somewhat dissatisfied	3%	--	1%	2%
Very dissatisfied	2%	--	2%	2%
Don't know	--	1%	--	1%
Satisfied (Very + Somewhat)	**90%**	**91%**	**92%**	**86%**
Dissatisfied (Very + Somewhat)	**5%**	**--**	**3%**	**3%**

Familiarity & Experience

Overall Satisfaction with Hydro One

Q Overall, how satisfied or dissatisfied are you with the service you receive from **Hydro One**?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very satisfied	55%	60%	46%	50%	55%	54%
Somewhat satisfied	34%	28%	48%	36%	32%	36%
Neither	8%	8%	6%	9%	8%	8%
Somewhat dissatisfied	1%	1%	--	2%	1%	1%
Very dissatisfied	1%	2%	--	2%	2%	1%
Don't know	1%	<1%	--	--	1%	--
Satisfied (Very + Somewhat)	**89%**	**89%**	**94%**	**86%**	**87%**	**91%**
Dissatisfied (Very + Somewhat)	**3%**	**3%**	--	**4%**	**3%**	**1%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very satisfied	55%	54%	60%	49%
Somewhat satisfied	39%	38%	23%	36%
Neither	4%	8%	11%	11%
Somewhat dissatisfied	2%	--	2%	1%
Very dissatisfied	1%	--	3%	2%
Don't know	--	--	1%	1%
Satisfied (Very + Somewhat)	**94%**	**92%**	**84%**	**84%**
Dissatisfied (Very + Somewhat)	**2%**	**--**	**5%**	**4%**

Familiarity & Experience

How can Hydro One improve services?

First Nations On-Reserve

Q Is there anything in particular you would like **Hydro One** to do to improve its services to you?

Response	%
Lower rates/decrease bills	7.0%
Satisfied with services/no issues	6.3%
Decrease outages/interruptions	5.6%
Improve response time for outages	2.8%
Improve communication during outages	2.4%
Address/proactive tree trimming	2.4%
Improve customer service	2.0%
Bury power lines/better line maintenance	1.8%
Improve infrastructure	1.3%
Find efficiencies/costs savings/lower operating costs	0.7%
Improve general communication	0.6%
Billing improvements - timing/payments/bill format	0.5%
More information/transparency/ability to track usage	0.5%
Building capacity/addressing growth	0.2%
Energy alternatives/green energy options	0.1%
Other	3.2%
None/Don’t know	62.5%

Note: Only responses >0.1% shown

Familiarity & Experience

Bill Familiarity

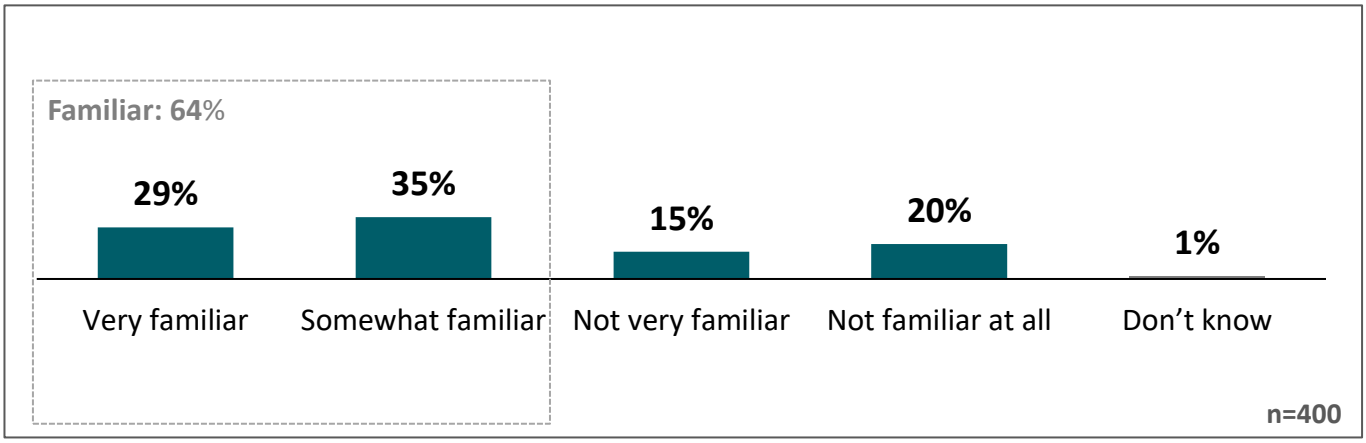
Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, the portion of your bill that goes to **Hydro One**, covering distribution and transmission delivery services, is offset by the **First Nations Delivery Credit**.

As of October 1st, 2024, for a typical On-Reserve First Nations residential customer, the bill credit offsets approximately **26%** of the total bill, or **$53** per month, related to the services **Hydro One** provides. This amount is split into **$33** for distribution delivery and **$20** for transmission delivery.

The rest of your bill payment goes to power generation companies and regulatory agencies.

Q Before this survey, how familiar were you with the **First Nations Delivery Credit**, which offsets the amount of your electricity bill that covers **Hydro One's** services?



Region

	West	Central	East/Central East	North
Very familiar	32%	28%	34%	27%
Somewhat familiar	35%	37%	32%	34%
Not very familiar	19%	15%	12%	16%
Not familiar at all	11%	19%	20%	22%
Don't know	3%	1%	2%	1%
Familiar (Very + Somewhat)	**67%**	**65%**	**67%**	**61%**

Familiarity & Experience

Bill Familiarity

Q Before this survey, how familiar were you with the **First Nations Delivery Credit**, which offsets the amount of your electricity bill that covers **Hydro One's** services?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	29%	25%	37%	27%	29%	30%
Somewhat familiar	35%	38%	31%	31%	33%	37%
Not very familiar	15%	17%	10%	18%	16%	14%
Not familiar at all	20%	19%	23%	19%	21%	18%
Don't know	1%	1%	--	4%	1%	2%
Familiar (Very + Somewhat)	**64%**	**63%**	**67%**	**59%**	**62%**	**67%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very familiar	31%	25%	30%	32%
Somewhat familiar	34%	34%	39%	32%
Not very familiar	13%	17%	12%	18%
Not familiar at all	21%	21%	17%	18%
Don't know	1%	3%	2%	--
Familiar (Very + Somewhat)	**65%**	**59%**	**69%**	**64%**

Familiarity & Experience

Familiarity with Rate Applications

First Nations On-Reserve

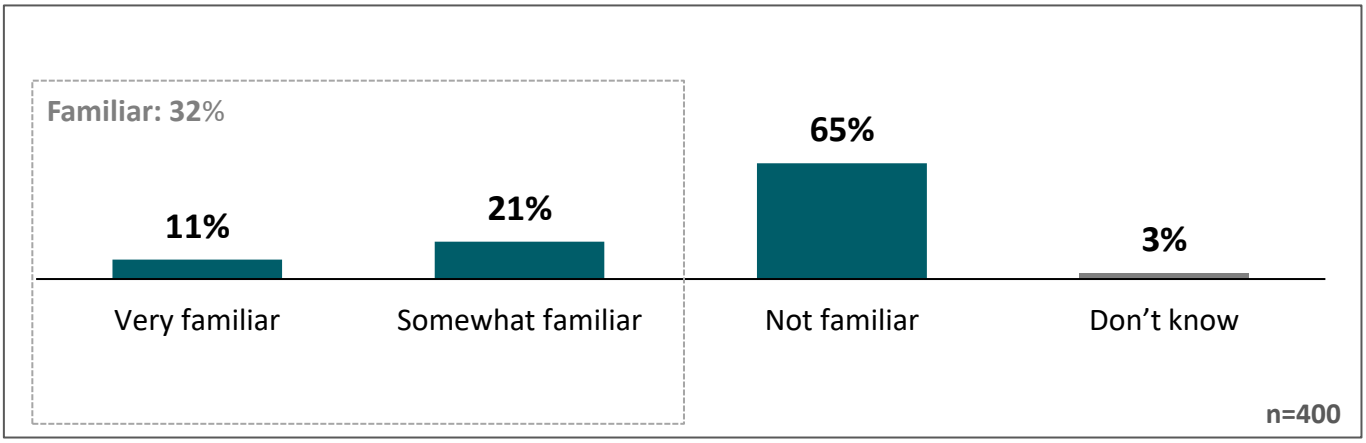
Hydro One is funded by the rates paid by its customers.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



Region

	West	Central	East/Central East	North
Very familiar	11%	9%	11%	12%
Somewhat familiar	17%	20%	18%	23%
Not familiar	70%	68%	70%	60%
Don't know	2%	3%	2%	4%
Familiar (Very + Somewhat)	**28%**	**29%**	**28%**	**35%**

Familiarity & Experience

Familiarity with Rate Applications

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	11%	9%	8%	14%	11%	11%
Somewhat familiar	21%	25%	26%	17%	25%	15%
Not familiar	65%	61%	64%	68%	62%	70%
Don't know	3%	4%	2%	2%	3%	4%
Familiar (Very + Somewhat)	**32%**	**35%**	**34%**	**30%**	**36%**	**26%**

	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
Very familiar	7%	12%	10%	14%
Somewhat familiar	18%	24%	25%	17%
Not familiar	68%	63%	61%	66%
Don't know	6%	1%	3%	4%
Familiar (Very + Somewhat)	**26%**	**36%**	**36%**	**31%**

First Nations On-Reserve Customers

Customer Priorities



Customer Priorities

Response Labels Legend

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 8 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity	Providing reliable electricity to my home
Enhancing Hydro One's customer service	Enhancing Hydro One's customer service
Offering programs to help manage usage	Offering programs that can help customers better manage their electricity usage
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Enhancing the grid for new technologies	Enhancing the grid so that customers can connect new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

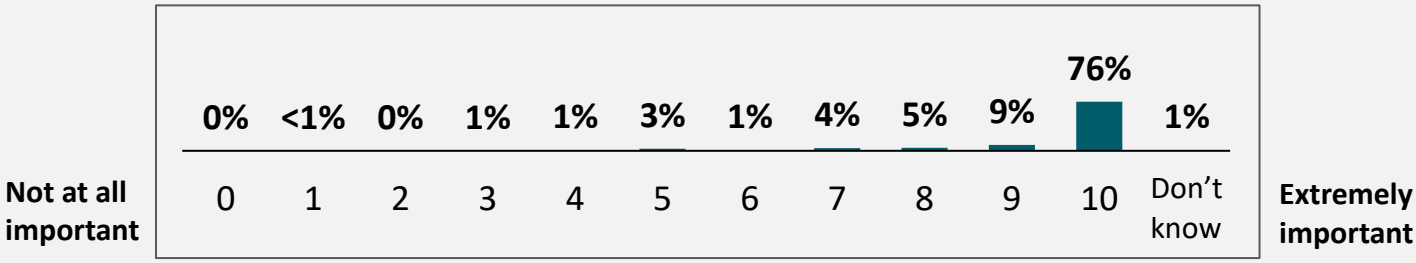
Customer Priorities

Importance of Customer Priorities

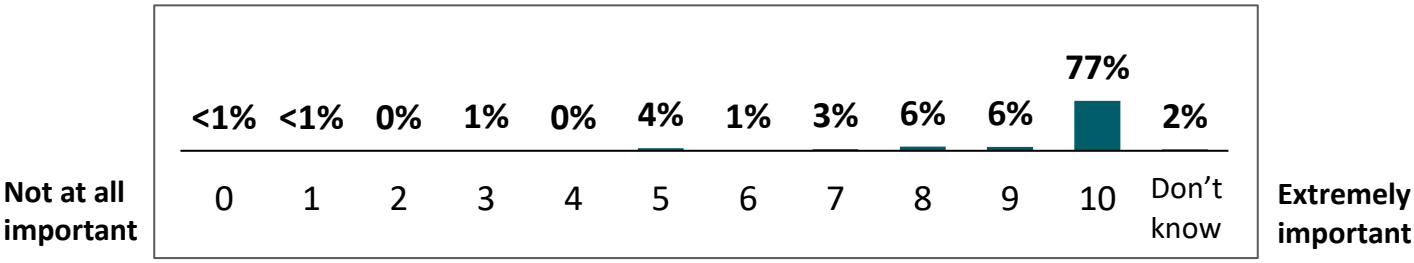
First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

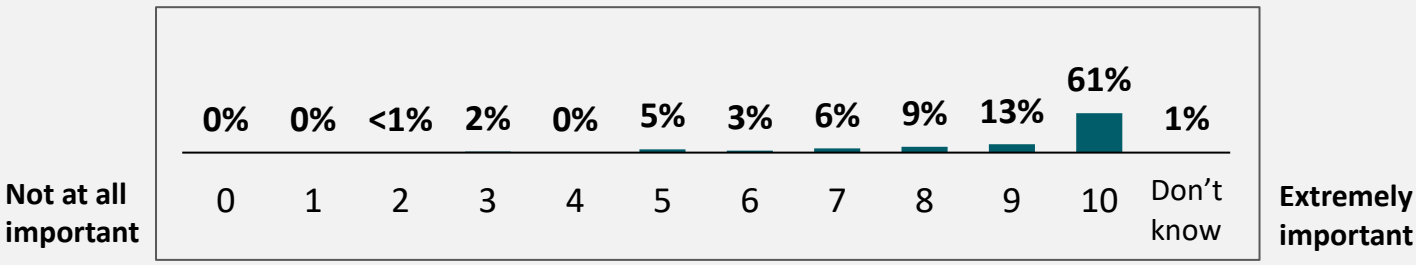
Providing reliable electricity [average = **9.4**]



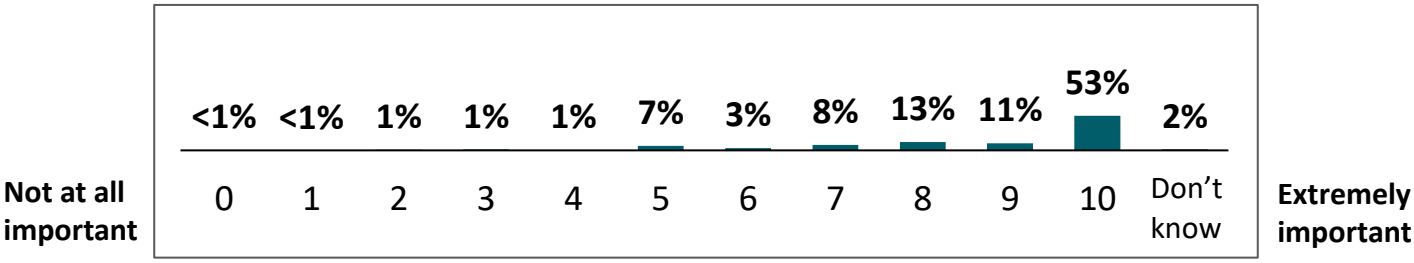
Delivering electricity at reasonable rates [average = **9.4**]



Ensuring the safety of electricity infrastructure [average = **9.0**]



Meeting the growing electricity need [average = **8.7**]



Note: Priority labels have been shortened for brevity. See slide 107 for full label text.
"Don't know" not included in calculation of means.

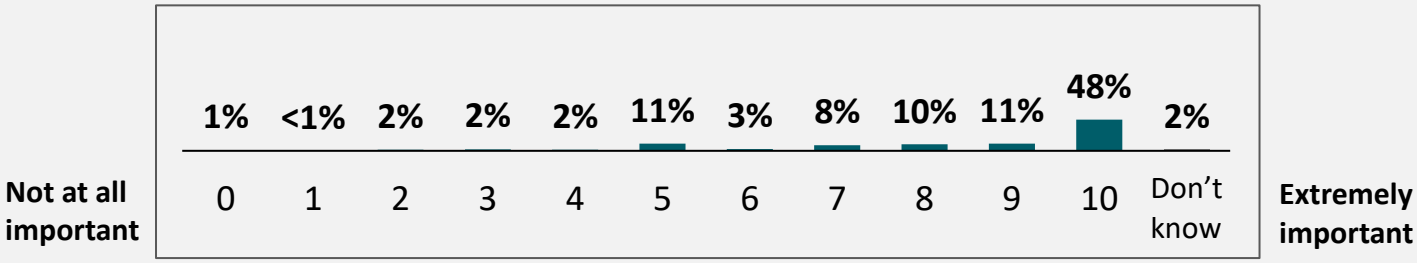
Customer Priorities

Importance of Customer Priorities (Cont'd)

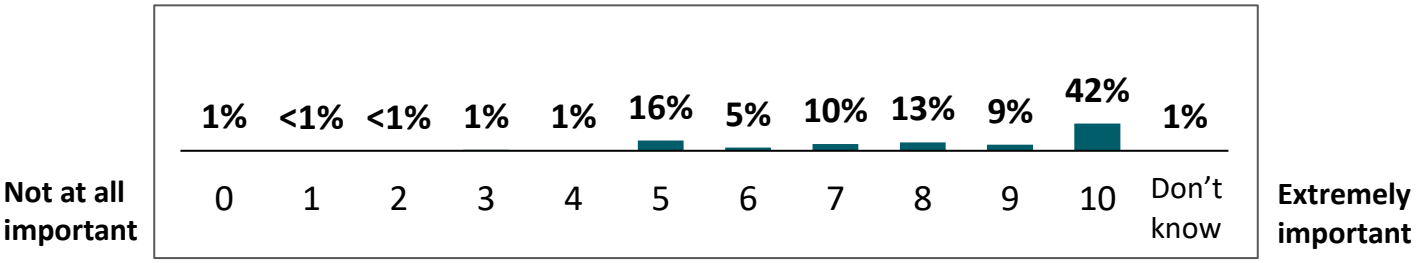
First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

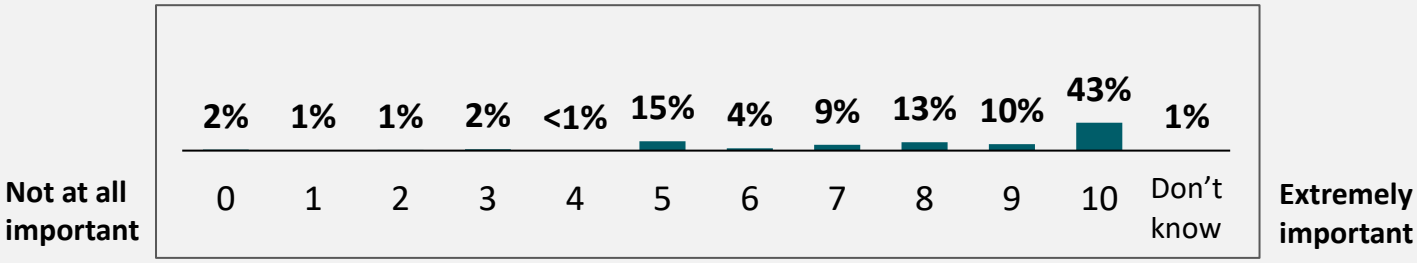
Reducing the environmental impact [average = **8.2**]



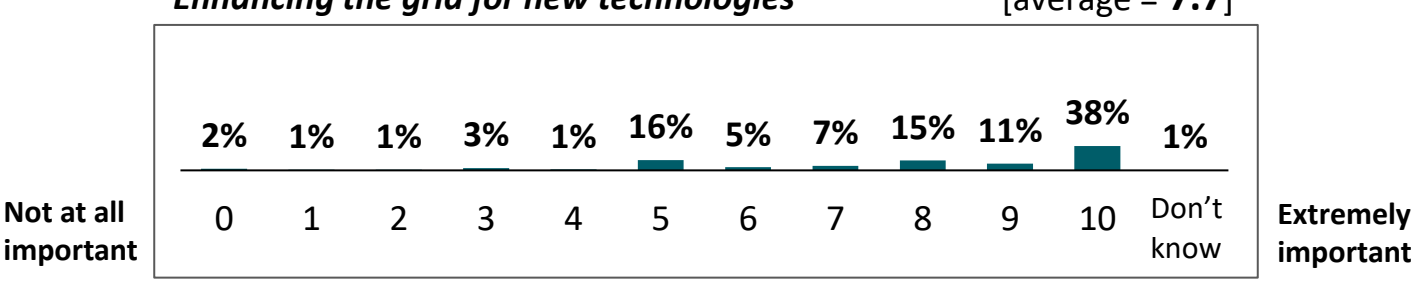
Enhancing Hydro One's customer service [average = **8.0**]



Offering programs to help manage usage [average = **8.0**]



Enhancing the grid for new technologies [average = **7.7**]



Note: Priority labels have been shortened for brevity. See slide 107 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Importance of Customer Priorities – Average Scores

First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		Region			
Average Score	**Overall**	**West**	**Central**	**East/Central East**	**North**
Providing reliable electricity	9.4	9.6	9.3	9.6	9.3
Delivering electricity at reasonable rates	9.4	9.6	9.3	9.7	9.3
Ensuring the safety of electricity infrastructure	9.0	9.3	9.0	9.1	8.9
Meeting the growing electricity need	8.7	8.8	8.7	8.5	8.6
Reducing the environmental impact	8.2	8.1	8.1	7.9	8.3
Enhancing Hydro One's customer service	8.0	8.6	7.9	7.4	8.2
Offering programs to help manage usage	8.0	8.3	7.8	8.0	8.0
Enhancing the grid for new technologies	7.7	8.2	7.7	7.1	7.8

Note: Priority labels have been shortened for brevity. See slide 107 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Importance of Customer Priorities – Average Scores

First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		LEAP/OESP Qualification			Bill Impact	
Average Score	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Providing reliable electricity	9.4	9.3	9.5	9.3	9.3	9.4
Delivering electricity at reasonable rates	9.4	9.3	9.4	9.5	9.4	9.3
Ensuring the safety of electricity infrastructure	9.0	9.0	8.7	9.0	9.0	8.9
Meeting the growing electricity need	8.7	8.6	8.7	8.6	8.7	8.6
Reducing the environmental impact	8.2	8.1	8.2	8.2	8.4	7.9
Enhancing Hydro One's customer service	8.0	8.0	8.2	7.9	8.2	7.7
Offering programs to help manage usage	8.0	8.2	7.8	7.8	8.3	7.6
Enhancing the grid for new technologies	7.7	7.5	8.3	7.8	7.8	7.5

Note: Priority labels have been shortened for brevity. See slide 107 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Importance of Customer Priorities – Average Scores

First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

	Consumption Quartiles				
Average Score	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**
Providing reliable electricity	9.4	9.6	9.4	9.6	8.9
Delivering electricity at reasonable rates	9.4	9.6	9.3	9.4	9.2
Ensuring the safety of electricity infrastructure	9.0	9.2	8.9	9.2	8.5
Meeting the growing electricity need	8.7	8.9	8.6	8.6	8.4
Reducing the environmental impact	8.2	8.7	8.0	8.1	8.1
Enhancing Hydro One's customer service	8.0	8.4	7.9	8.0	7.9
Offering programs to help manage usage	8.0	8.6	7.8	8.2	7.5
Enhancing the grid for new technologies	7.7	7.8	7.6	8.1	7.3

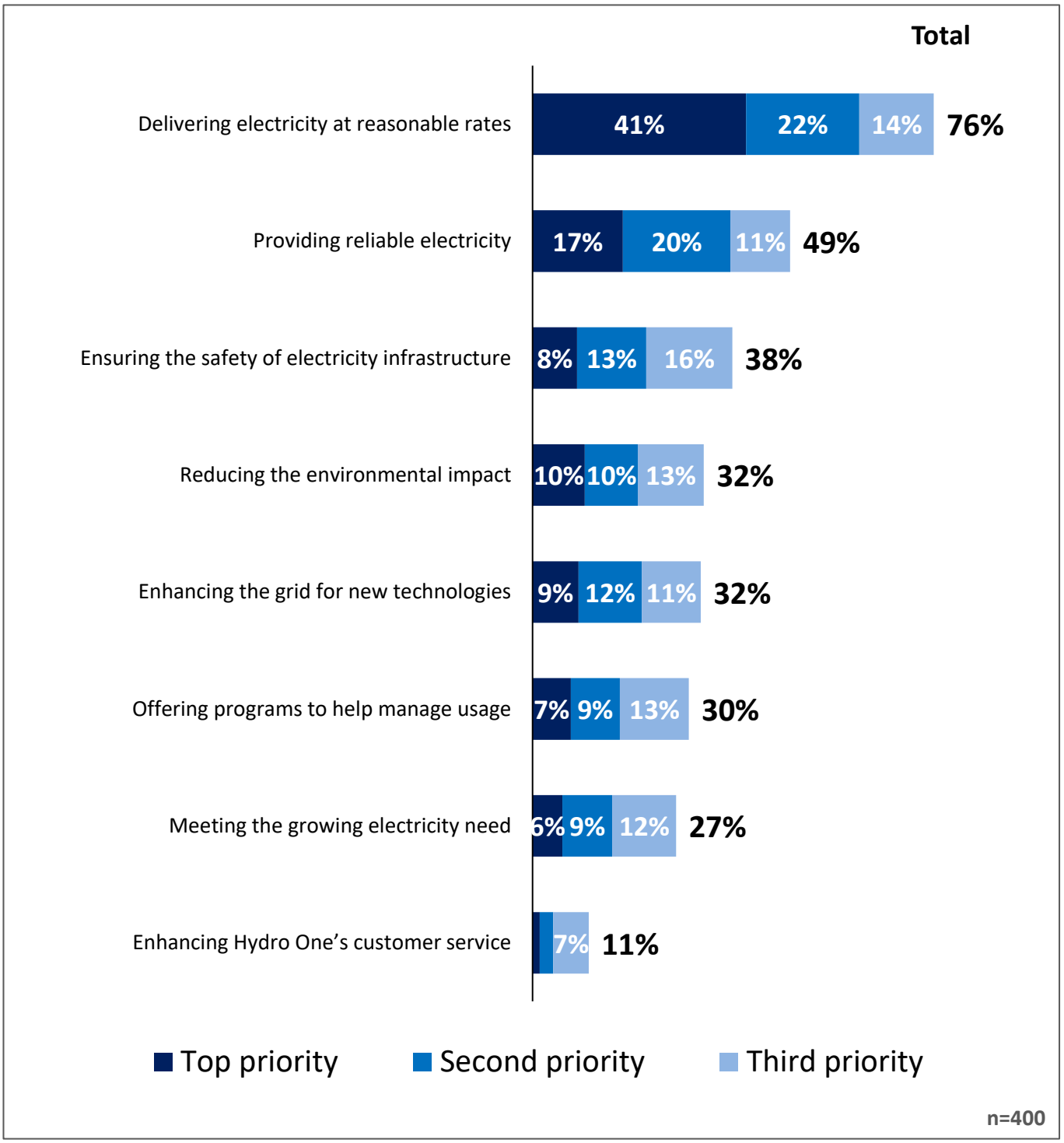
Note: Priority labels have been shortened for brevity. See slide 107 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

First Nations On-Reserve

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 107 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

First Nations On-Reserve

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Overall	Region: West	Region: Central	Region: East/Central East	Region: North
Delivering electricity at reasonable rates	76%	86%	77%	83%	72%
Providing reliable electricity	49%	54%	45%	52%	49%
Ensuring the safety of electricity infrastructure	38%	40%	39%	42%	35%
Reducing the environmental impact	32%	31%	32%	28%	34%
Enhancing the grid for new technologies	32%	31%	29%	33%	33%
Offering programs to help manage usage	30%	22%	34%	28%	30%
Meeting the growing electricity need	27%	23%	37%	29%	22%
Enhancing Hydro One's customer service	11%	11%	7%	5%	14%

Note: Priority labels have been shortened for brevity. See slide 107 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

First Nations On-Reserve

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

		LEAP/OESP Qualification			Bill Impact	
% who select as top 3 priority	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	76%	78%	80%	70%	81%	68%
Providing reliable electricity	49%	48%	40%	57%	45%	54%
Ensuring the safety of electricity infrastructure	38%	39%	33%	36%	38%	38%
Reducing the environmental impact	32%	28%	41%	33%	29%	38%
Enhancing the grid for new technologies	32%	28%	44%	34%	32%	32%
Offering programs to help manage usage	30%	34%	26%	28%	31%	28%
Meeting the growing electricity need	27%	27%	25%	26%	28%	27%
Enhancing Hydro One's customer service	11%	10%	11%	16%	11%	10%

Note: Priority labels have been shortened for brevity. See slide 107 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

First Nations On-Reserve

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Delivering electricity at reasonable rates	76%	75%	78%	77%	75%
Providing reliable electricity	49%	45%	59%	48%	45%
Ensuring the safety of electricity infrastructure	38%	34%	43%	42%	33%
Reducing the environmental impact	32%	42%	26%	31%	30%
Enhancing the grid for new technologies	32%	35%	24%	35%	33%
Offering programs to help manage usage	30%	35%	26%	28%	31%
Meeting the growing electricity need	27%	28%	25%	23%	32%
Enhancing Hydro One's customer service	11%	6%	13%	9%	15%

Note: Priority labels have been shortened for brevity. See slide 107 for full label text. "Don't know" not shown.

Customer Priorities

Other Priorities

First Nations On-Reserve

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Reasonable/affordable rates	6.2%
Enhancing the grid/infrastructure	4.3%
Having alternative energy/sustainable sources/green technology	4.1%
Incentives for seniors/subsidy programs	3.8%
Reducing environmental impacts	2.0%
Improving reliability/less outages	2.0%
Burying lines underground/removing hydro poles	1.8%
Tree trimming/removal	1.1%
Meeting growing needs for electricity	1.1%
Electric vehicle (EV) infrastructure investment	0.8%
Information/programs to manage electricity usage	0.5%
Withstanding extreme weather	0.4%
Support/incentives for new technologies or energy efficiency efforts	0.3%
Reducing length of outages	0.3%
Affordable renewable energy	0.2%
Prioritizing safety	0.1%
Other	3.8%
None/Don’t know	67.5%

Note: Only responses >0.1% shown

First Nations On-Reserve Customers

Reliability Experience

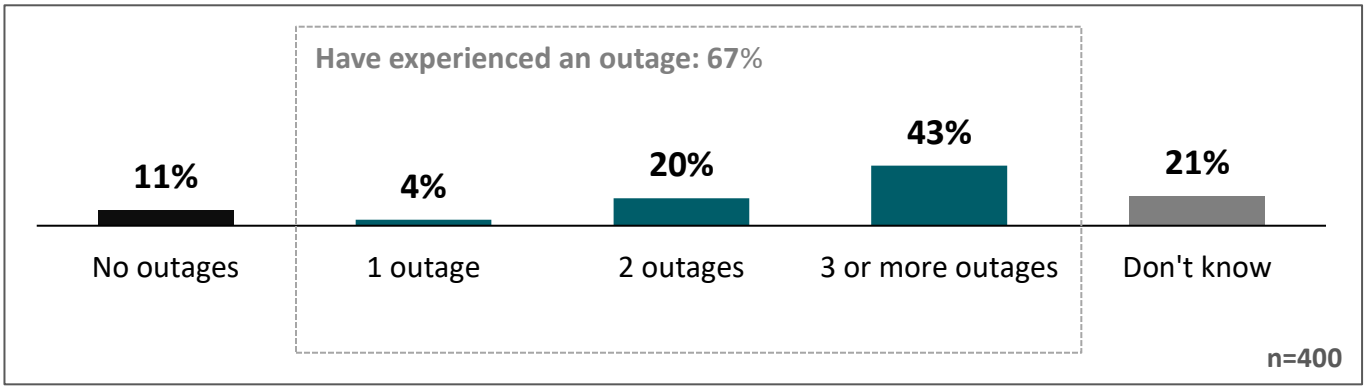


Reliability Experience
Number of Outages Experienced

First Nations On-Reserve

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at your home **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



Region

	West	Central	East/Central East	North
No outages	3%	22%	14%	7%
1 outage	--	8%	3%	3%
2 outages	27%	23%	18%	17%
3 or more outages	60%	30%	42%	47%
Don't know	10%	17%	23%	26%
Have experienced at least 1 outage	**88%**	**61%**	**63%**	**67%**

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Reliability Experience
Number of Outages Experienced

Q Have you experienced any power outages at your home **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
No outages	11%	11%	10%	9%	14%	7%
1 outage	4%	4%	8%	3%	3%	6%
2 outages	20%	18%	14%	26%	19%	20%
3 or more outages	43%	40%	45%	53%	44%	42%
Don't know	21%	27%	22%	9%	20%	24%
Have experienced at least 1 outage	**67%**	**62%**	**68%**	**81%**	**66%**	**69%**

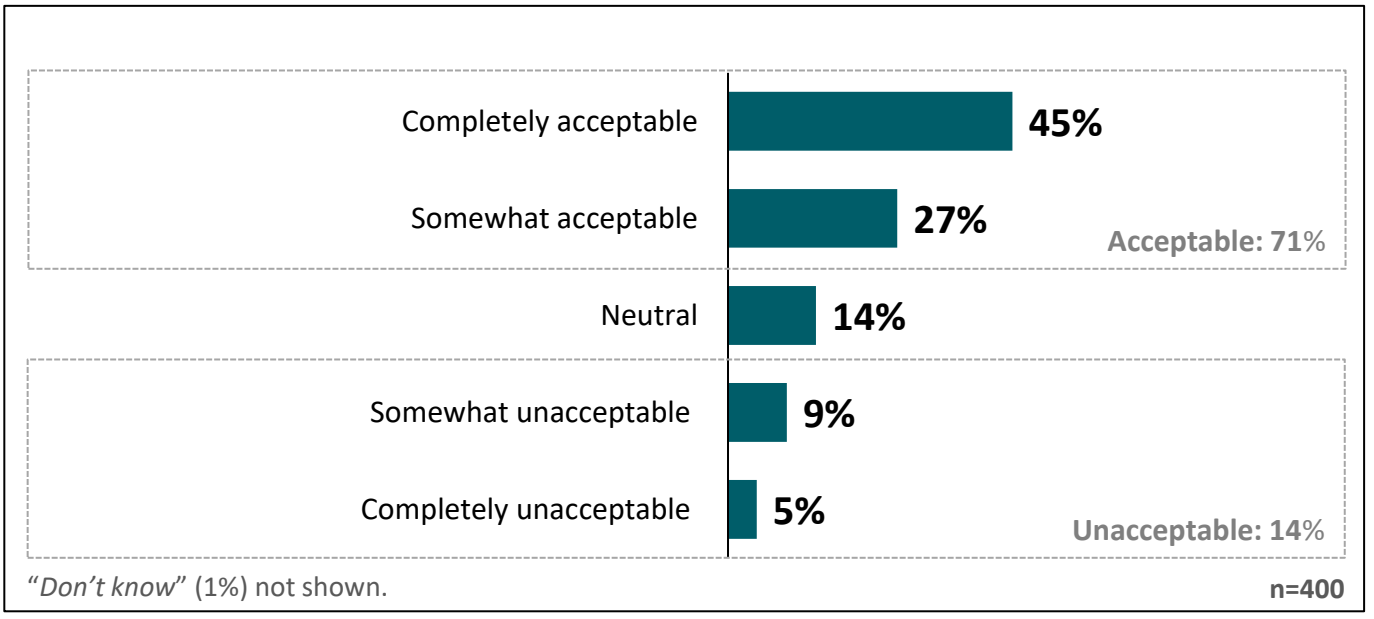
	Consumption Quartiles			
	Low	**Medium-Low**	**Medium-High**	**High**
No outages	13%	18%	9%	6%
1 outage	7%	5%	1%	2%
2 outages	23%	21%	18%	18%
3 or more outages	39%	40%	49%	46%
Don't know	18%	17%	23%	28%
Have experienced at least 1 outage	**69%**	**65%**	**68%**	**66%**

Reliability Experience

Current Reliability of Electricity Service

First Nations On-Reserve

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (1%) not shown.

n=400

Region

	West	Central	East/Central East	North
Completely acceptable	20%	53%	48%	45%
Somewhat acceptable	33%	30%	25%	24%
Neutral	21%	9%	10%	16%
Somewhat unacceptable	13%	6%	7%	11%
Completely unacceptable	13%	2%	7%	3%
Don't know	--	--	2%	1%
Acceptable (Completely + Somewhat)	**53%**	**83%**	**73%**	**69%**
Unacceptable (Completely + Somewhat)	**27%**	**8%**	**14%**	**14%**

Reliability Experience

Current Reliability of Electricity Service

First Nations On-Reserve

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Completely acceptable	45%	49%	40%	37%	43%	47%
Somewhat acceptable	27%	23%	35%	29%	27%	26%
Neutral	14%	15%	10%	13%	15%	12%
Somewhat unacceptable	9%	7%	10%	14%	9%	10%
Completely unacceptable	5%	5%	4%	5%	5%	4%
Don't know	1%	<1%	1%	1%	1%	1%
Acceptable (Completely + Somewhat)	**71%**	**72%**	**75%**	**66%**	**71%**	**73%**
Unacceptable (Completely + Somewhat)	**14%**	**13%**	**13%**	**19%**	**14%**	**14%**

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Completely acceptable	54%	47%	41%	37%
Somewhat acceptable	26%	23%	26%	32%
Neutral	11%	13%	15%	17%
Somewhat unacceptable	4%	15%	10%	9%
Completely unacceptable	5%	2%	7%	4%
Don't know	1%	--	2%	1%
Acceptable (Completely + Somewhat)	**80%**	**70%**	**66%**	**69%**
Unacceptable (Completely + Somewhat)	**9%**	**17%**	**17%**	**13%**

Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights
Improving communications during outages	Improving communications during outages, including estimated restoration times

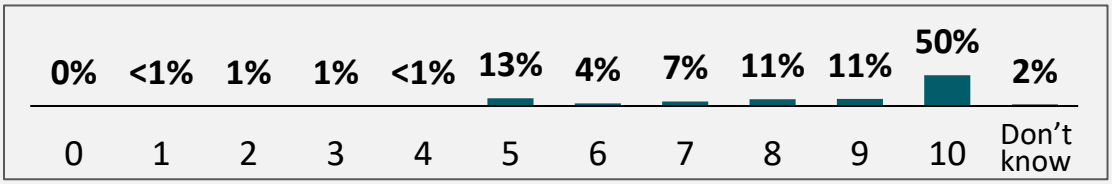
Reliability Experience

Importance of Reliability Priorities

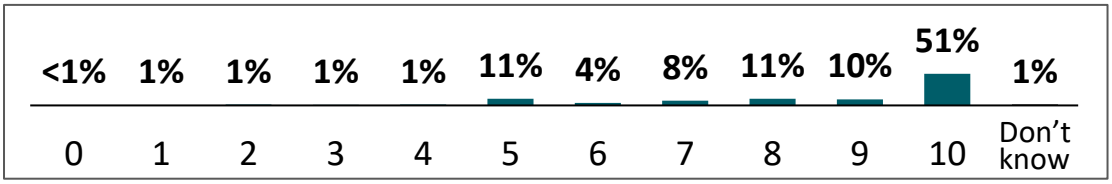
First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

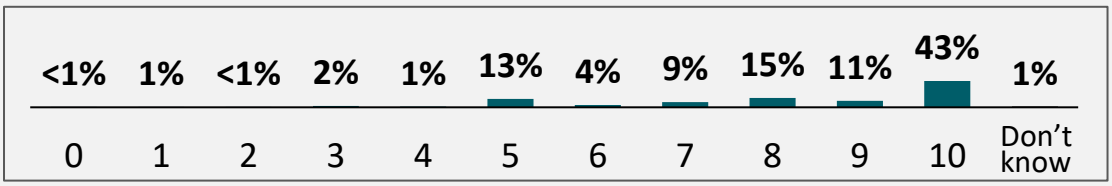
Reducing length of weather-caused outages [average = **8.5**]



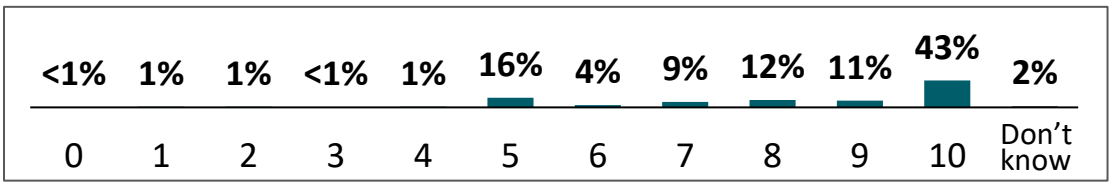
Improving communications during outages [average = **8.4**]



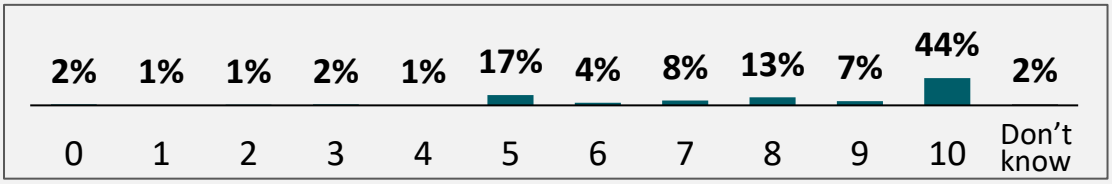
Reducing length of non-weather outages [average = **8.1**]



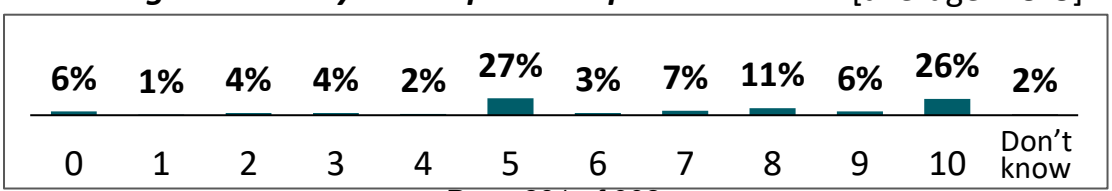
Reducing number of weather-caused outages [average = **8.1**]



Reducing number of non-weather outages [average = **7.9**]



Reducing momentary interruptions in power [average = **6.6**]



Note: Priority labels have been shortened for brevity. See slide 123 for full label text.
"Don't know" not included in calculation of means.

Reliability Experience

Importance of Reliability Priorities – Average Scores

First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

	Region				
Average Score	**Overall**	**West**	**Central**	**East/Central East**	**North**
Reducing length of weather-caused outages	8.5	8.9	8.2	8.7	8.4
Improving communications during outages	8.4	8.8	8.1	8.2	8.6
Reducing length of non-weather outages	8.1	7.8	8.1	8.5	8.1
Reducing number of weather-caused outages	8.1	8.7	8.1	8.1	7.9
Reducing number of non-weather outages	7.9	7.5	7.9	8.3	7.9
Reducing momentary interruptions in power	6.6	6.9	6.1	6.7	6.7

Note: Priority labels have been shortened for brevity. See slide 123 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		LEAP/OESP Qualification			Bill Impact	
Average Score	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Reducing length of weather-caused outages	8.5	8.5	8.4	8.2	8.7	8.1
Improving communications during outages	8.4	8.6	8.3	8.0	8.7	8.0
Reducing length of non-weather outages	8.1	8.2	8.1	7.9	8.4	7.7
Reducing number of weather-caused outages	8.1	8.1	7.7	7.9	8.4	7.6
Reducing number of non-weather outages	7.9	8.0	7.7	7.7	8.2	7.4
Reducing momentary interruptions in power	6.6	6.6	6.8	6.1	7.0	5.8

Note: Priority labels have been shortened for brevity. See slide 123 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

First Nations On-Reserve

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

Average Score	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Reducing length of weather-caused outages	8.5	8.7	8.4	8.6	8.2
Improving communications during outages	8.4	8.5	8.4	8.5	8.3
Reducing length of non-weather outages	8.1	8.5	8.2	8.0	7.9
Reducing number of weather-caused outages	8.1	8.4	8.0	8.3	7.9
Reducing number of non-weather outages	7.9	8.2	7.9	8.0	7.5
Reducing momentary interruptions in power	6.6	7.0	6.3	7.0	6.0

Note: Priority labels have been shortened for brevity. See slide 123 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

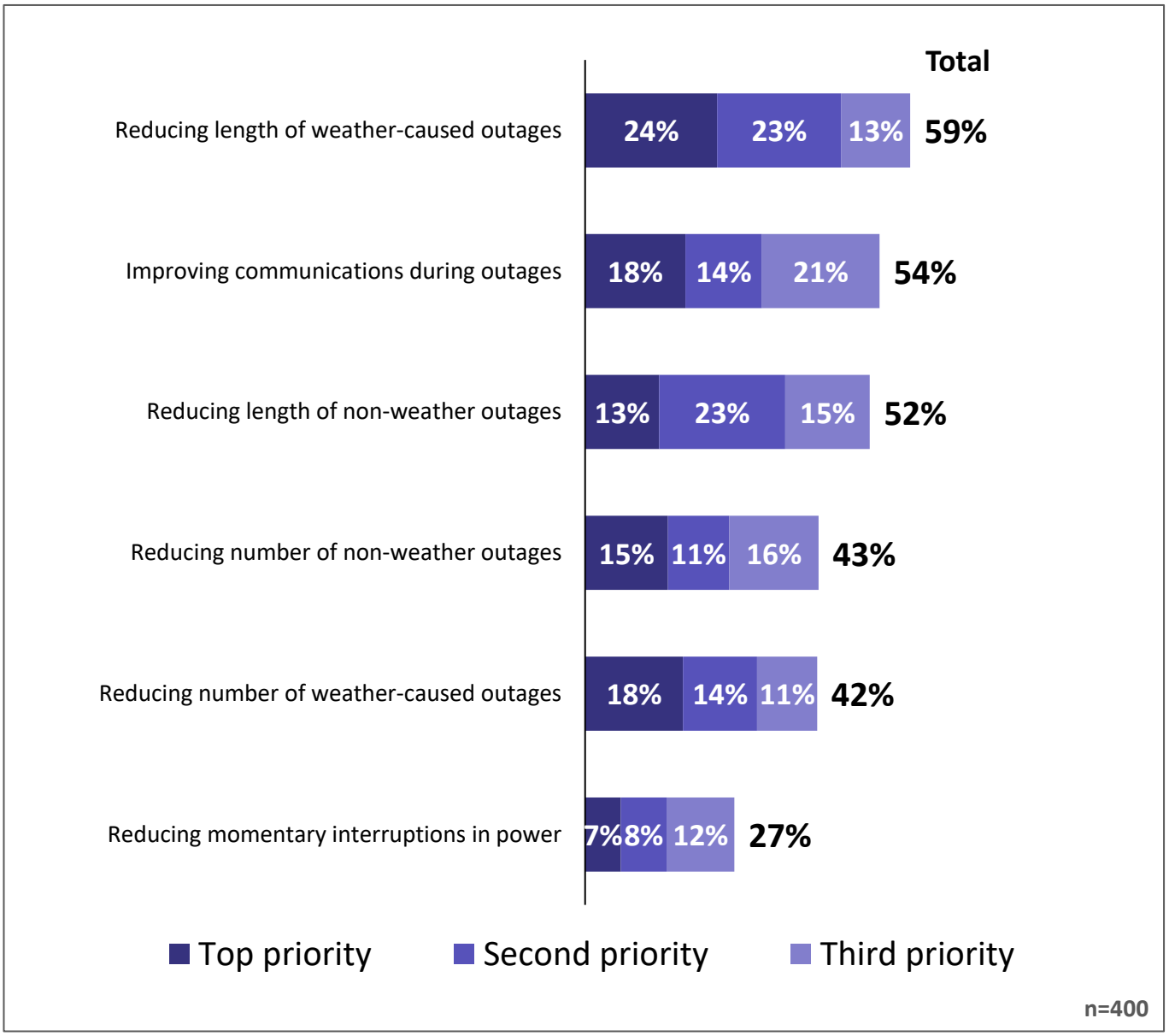
Reliability Experience

Ranking Reliability Priorities

First Nations On-Reserve

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?



Note: Priority labels have been shortened for brevity. See slide 123 for full label text.
"Don't know" not shown.

Reliability Experience
Ranking Reliability Priorities

First Nations On-Reserve

Q Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Region			
% who select as top 3 priority	**Overall**	**West**	**Central**	**East/Central East**	**North**
Reducing length of weather-caused outages	59%	79%	61%	60%	54%
Improving communications during outages	54%	47%	51%	53%	57%
Reducing length of non-weather outages	52%	46%	49%	57%	53%
Reducing number of non-weather outages	43%	38%	46%	44%	41%
Reducing number of weather-caused outages	42%	53%	45%	39%	39%
Reducing momentary interruptions in power	27%	26%	30%	27%	26%

Note: Priority labels have been shortened for brevity. See slide 123 for full label text. "Don't know" not shown.

Reliability Experience
Ranking Reliability Priorities

First Nations On-Reserve

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		LEAP/OESP Qualification			Bill Impact	
% who select as top 3 priority	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Reducing length of weather-caused outages	59%	58%	48%	63%	61%	57%
Improving communications during outages	54%	51%	63%	58%	57%	48%
Reducing length of non-weather outages	52%	54%	51%	48%	52%	52%
Reducing number of non-weather outages	43%	37%	51%	50%	43%	42%
Reducing number of weather-caused outages	42%	45%	38%	38%	46%	36%
Reducing momentary interruptions in power	27%	32%	25%	25%	28%	27%

Note: Priority labels have been shortened for brevity. See slide 123 for full label text. "Don't know" not shown.

Reliability Experience
Ranking Reliability Priorities

First Nations On-Reserve

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Consumption Quartiles			
% who select as top 3 priority	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**
Reducing length of weather-caused outages	59%	59%	70%	54%	55%
Improving communications during outages	54%	54%	49%	57%	55%
Reducing length of non-weather outages	52%	56%	56%	47%	50%
Reducing number of non-weather outages	43%	45%	51%	43%	31%
Reducing number of weather-caused outages	42%	36%	43%	42%	49%
Reducing momentary interruptions in power	27%	29%	20%	33%	28%

Note: Priority labels have been shortened for brevity. See slide 123 for full label text. "Don't know" not shown.

First Nations On-Reserve Customers

Investment Priorities



Investment Priorities

High-Level Reliability

First Nations On-Reserve

Now let's turn to the next topic – investment trade-offs. There are **6** investment areas that **Hydro One** would like your input on.

You do not need to be a system planner or engineer to answer these questions. The trade-offs will focus on what outcomes matter most to you as a customer – balancing investment outcomes and cost to you.

The costs outlined in the following questions are for illustrative purposes only. Because the portion of your bill that goes to **Hydro One** is offset by the First Nations Delivery Credit, these costs would not be reflected on your bill, but still represent the true cost of the choices.

First, we would like to talk about the local distribution system, which takes electricity from transmission lines and brings it to your home through a network of wires, poles and other equipment.

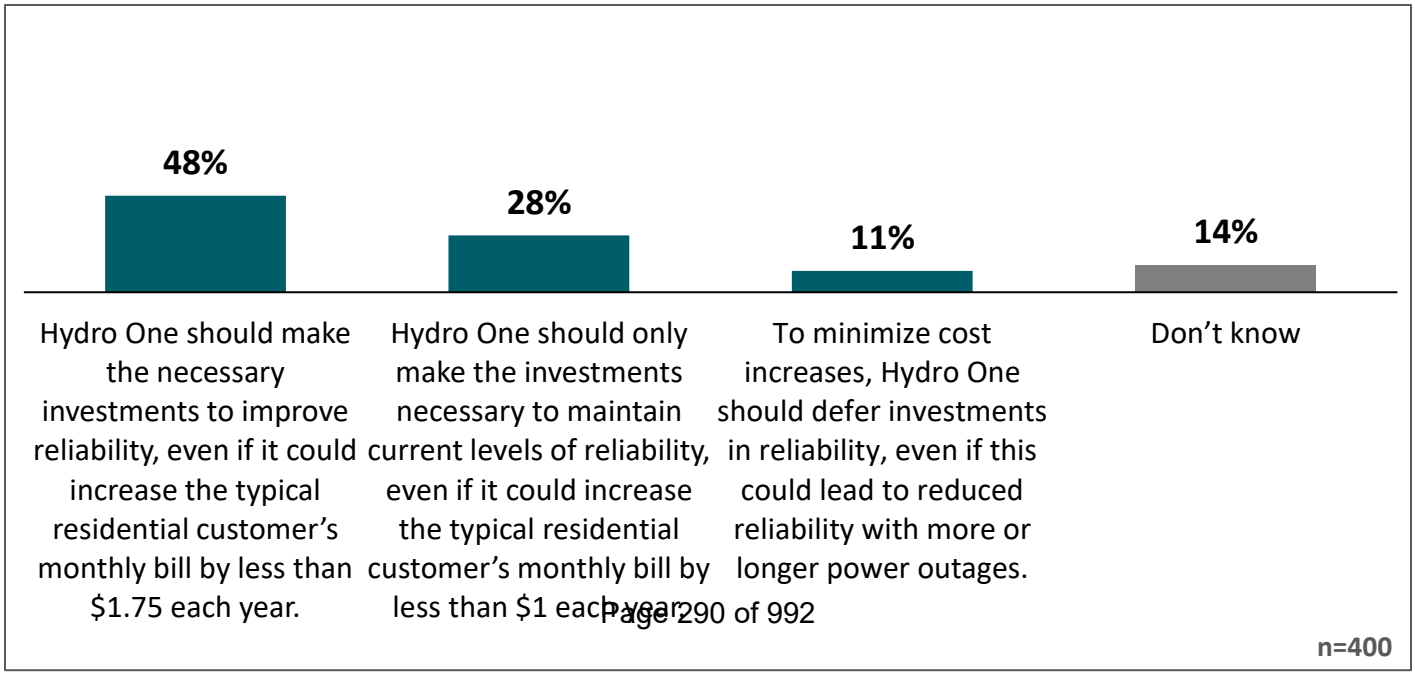
The first category is related to the reliability you experience.

On average, between 2019 and 2023, the typical **Hydro One** customer has experienced about 3.8 outages per year, resulting in a total of 16.6 hours without power.

It's important to keep in mind that these are system averages, and that your actual experience may be different.

Hydro One has historically identified investments in maintaining or improving reliability by taking into consideration the overall age, health, and likelihood of failure of equipment.

Q Based on your own reliability experience, which of the following is closest to your point of view?



Investment Priorities
High-Level Reliability

Q Based on your own reliability experience, which of the following is closest to your point of view?

		Region			
	Overall	West	Central	East/Central East	North
Necessary investments to improve reliability	48%	43%	51%	49%	47%
Necessary investments to maintain reliability	28%	31%	30%	35%	24%
Defer investments	11%	24%	5%	7%	11%
Don't know	14%	3%	13%	10%	17%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Necessary investments to improve reliability	45%	49%	56%	41%	58%
Necessary investments to maintain reliability	27%	25%	30%	31%	23%
Defer investments	12%	11%	5%	13%	7%
Don't know	15%	15%	9%	15%	12%

Note: Response labels have been shortened for brevity. See slide 133 for full label text.

Investment Priorities
High-Level Reliability

First Nations On-Reserve

Q Based on your own reliability experience, which of the following is closest to your point of view?

	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Necessary investments to improve reliability	48%	45%	46%	60%	41%
Necessary investments to maintain reliability	28%	33%	34%	17%	27%
Defer investments	11%	7%	10%	9%	16%
Don't know	14%	15%	10%	14%	16%

Note: Response labels have been shortened for brevity. See slide 133 for full label text.

Investment Priorities

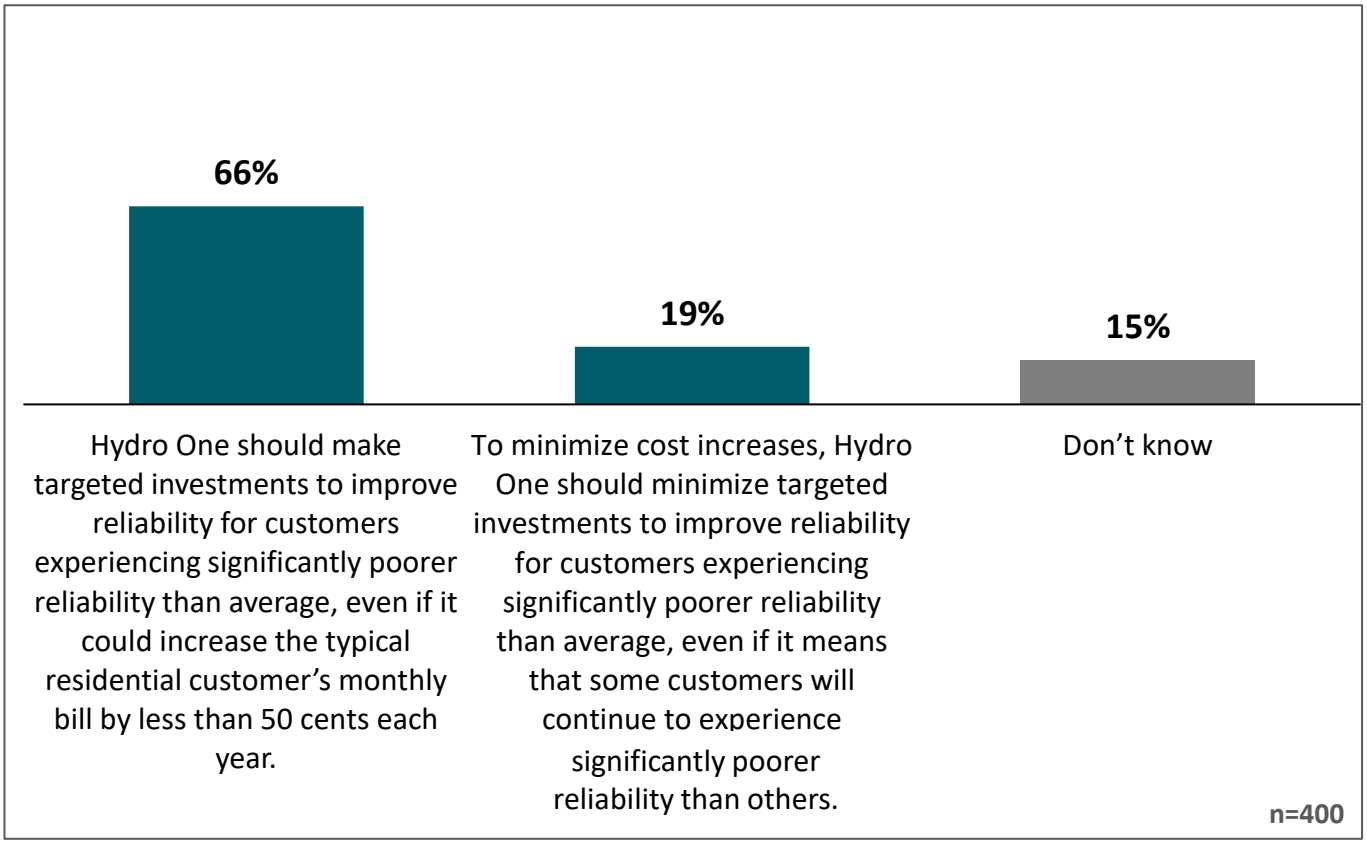
Targeted Reliability

The second category is related to more targeted improvements to reliability.

Hydro One customers experience different levels of reliability, depending on where they live, the design of the system and the condition of the equipment supplying them.

While some **Hydro One** customers didn't experience any outages in 2022 or 2023, others were without power more than 10 times per year. Similarly, the total length of time that customers were without power ranges from less than one hour to more than 50 hours per year.

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?



Investment Priorities
Targeted Reliability

First Nations On-Reserve

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?

Region

	Overall	West	Central	East/Central East	North
Targeted investments to improve reliability	66%	65%	75%	70%	60%
Minimize targeted investments	19%	15%	15%	16%	23%
Don't know	15%	19%	10%	14%	17%

LEAP/OESP Qualification / Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Targeted investments to improve reliability	59%	66%	77%	63%	70%
Minimize targeted investments	22%	22%	13%	23%	13%
Don't know	18%	12%	10%	13%	17%

Consumption Quartiles

	Low	Medium-Low	Medium-High	High
Targeted investments to improve reliability	72%	58%	75%	60%
Minimize targeted investments	15%	19%	16%	25%
Don't know	13%	23%	9%	14%

Note: Response labels have been shortened for brevity. See slide 136 for full label text.

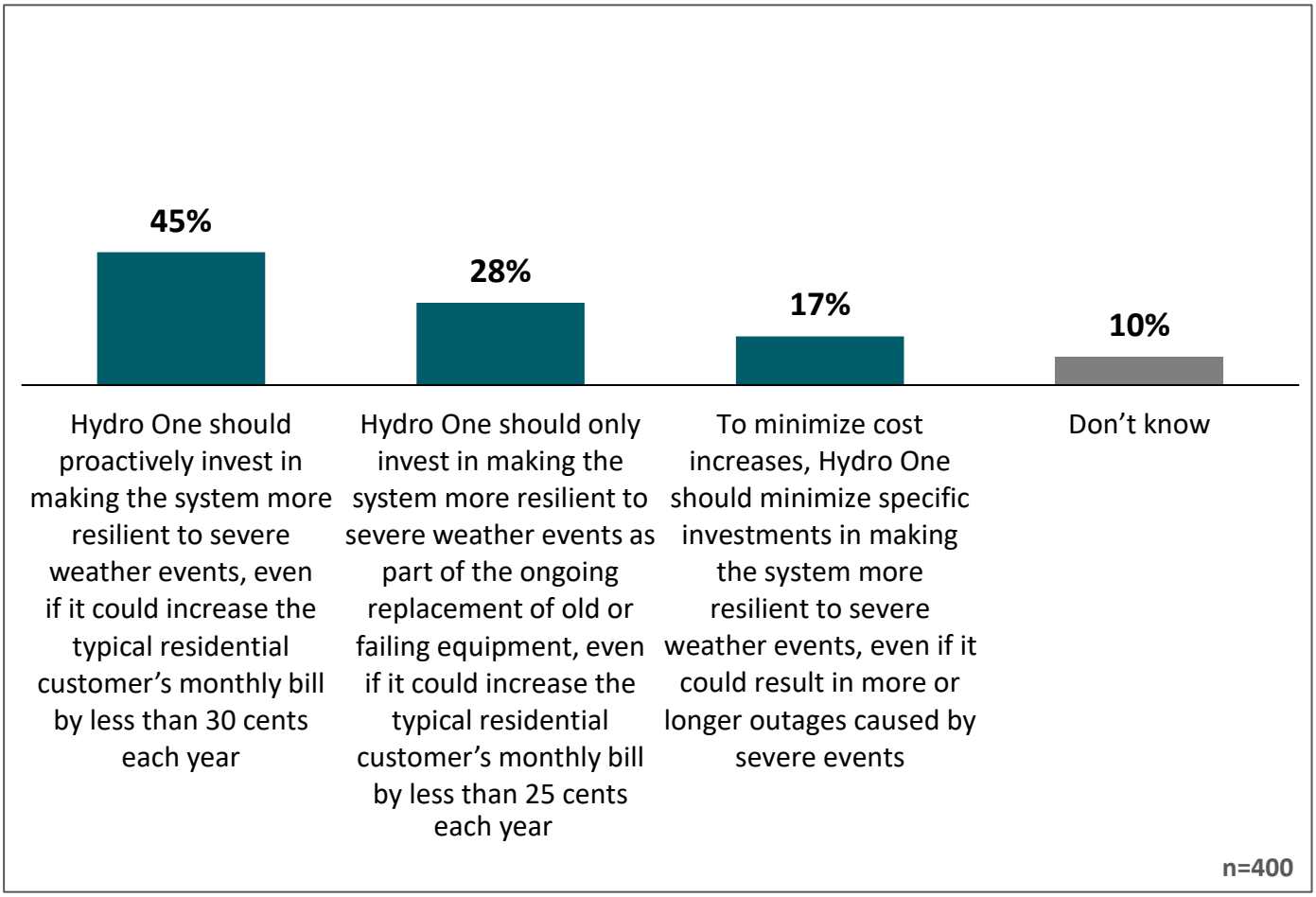
Investment Priorities

Responding to Severe Weather

On average, between 2019 and 2023, **severe weather events**, such as ice storms, windstorms or thunderstorms, have contributed to 51% of all hours that the typical customer has been without power per year.

While some of these outages may be inevitable, **Hydro One** could make additional investments to make the system more resilient to these types of events. These investments could help either reduce the number of outages caused by severe weather events or improve restoration times when these outages do occur.

Q Based on this, which of the following is closest to your point of view?



Investment Priorities

Responding to Severe Weather

First Nations On-Reserve

Q Based on this, which of the following is closest to your point of view?

Region

	Overall	West	Central	East/Central East	North
Proactively invest in resiliency	45%	49%	48%	47%	43%
Invest as part of ongoing replacement	28%	30%	27%	35%	26%
Minimize specific investments	17%	16%	14%	12%	20%
Don't know	10%	5%	11%	6%	11%

LEAP/OESP Qualification / Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactively invest in resiliency	44%	48%	49%	42%	51%
Invest as part of ongoing replacement	27%	25%	30%	30%	26%
Minimize specific investments	17%	18%	15%	20%	12%
Don't know	11%	8%	6%	9%	11%

Consumption Quartiles

	Low	Medium-Low	Medium-High	High
Proactively invest in resiliency	48%	44%	49%	42%
Invest as part of ongoing replacement	27%	31%	27%	27%
Minimize specific investments	16%	14%	16%	20%
Don't know	10%	10%	8%	11%

Note: Response labels have been shortened for brevity. See slide 138 for full label text.

Investment Priorities
Growth

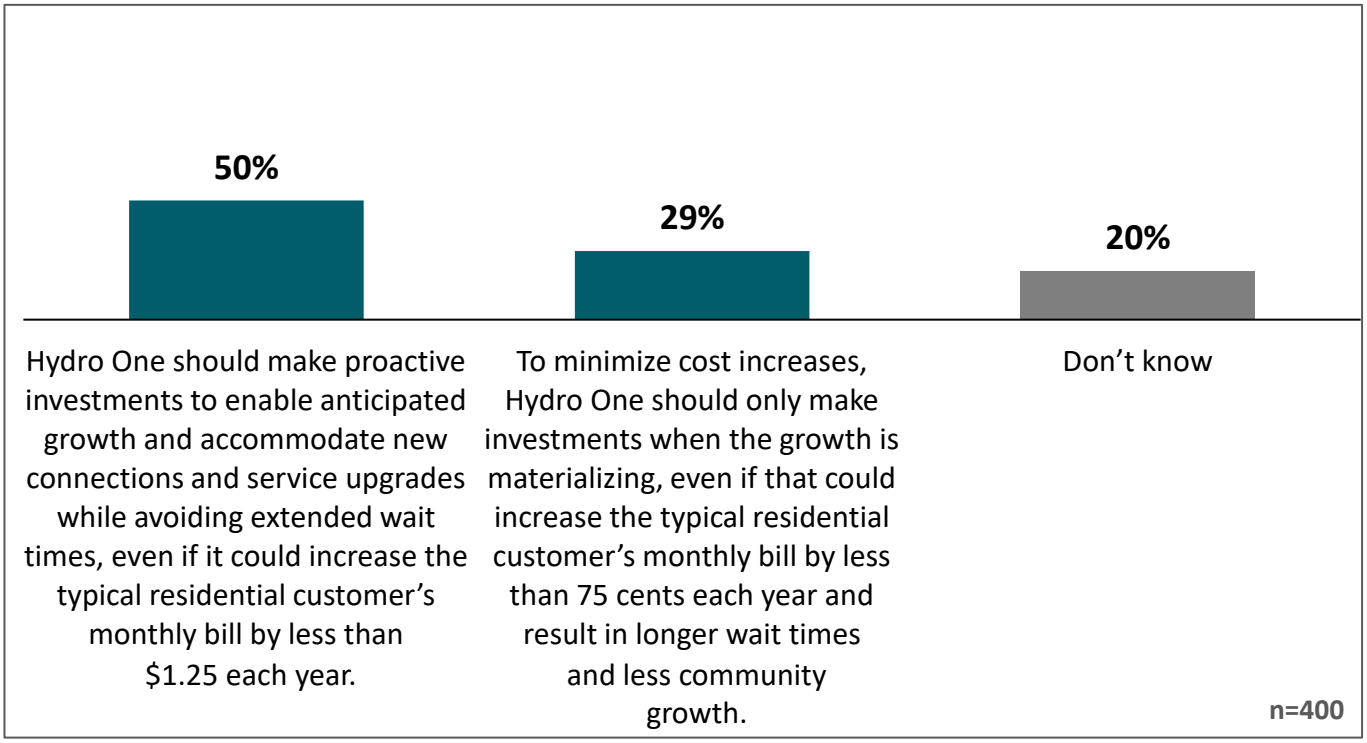
Electricity demand is on the rise across Ontario. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Hydro One** to make significant investments in the grid.

Increased growth can result in longer wait times to connect new homes or businesses to the system or facilitate upgrades for existing customers if insufficient capacity is available.

For instance, as increasing growth occurs, some new businesses may be asked to wait up to 2 years or longer for their facility to be connected to the **Hydro One** grid.

However, **Hydro One** could make proactive investments to enable anticipated growth and allow new homes or businesses to connect to the system in a timely manner, and to not delay service upgrades for existing customers.

Q Based on this, which is closest to your point of view?



Investment Priorities
Growth

First Nations On-Reserve

Q Based on this, which is closest to your point of view?

Region

	Overall	West	Central	East/Central East	North
Proactive investments to enable growth	50%	44%	59%	47%	49%
Only make investments as growth materializes	29%	32%	26%	36%	28%
Don't know	20%	25%	15%	18%	23%

LEAP/OESP Qualification / Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactive investments to enable growth	49%	49%	58%	50%	51%
Only make investments as growth materializes	27%	40%	29%	32%	25%
Don't know	24%	11%	14%	19%	23%

Consumption Quartiles

	Low	Medium-Low	Medium-High	High
Proactive investments to enable growth	47%	47%	61%	45%
Only make investments as growth materializes	27%	35%	25%	30%
Don't know	26%	17%	14%	25%

Note: Response labels have been shortened for brevity. See slide 140 for full label text.

Investment Priorities

Evolving Customer Requests & System Visibility

First Nations On-Reserve

Beyond residential and industrial growth, customers are increasingly requesting information and upgrades related to new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers.

Whether or not you are actively considering these types of technologies for yourself, **Hydro One** needs to be prepared to accommodate these types of customer requests, not just today, but over the next 5 to 10 years.

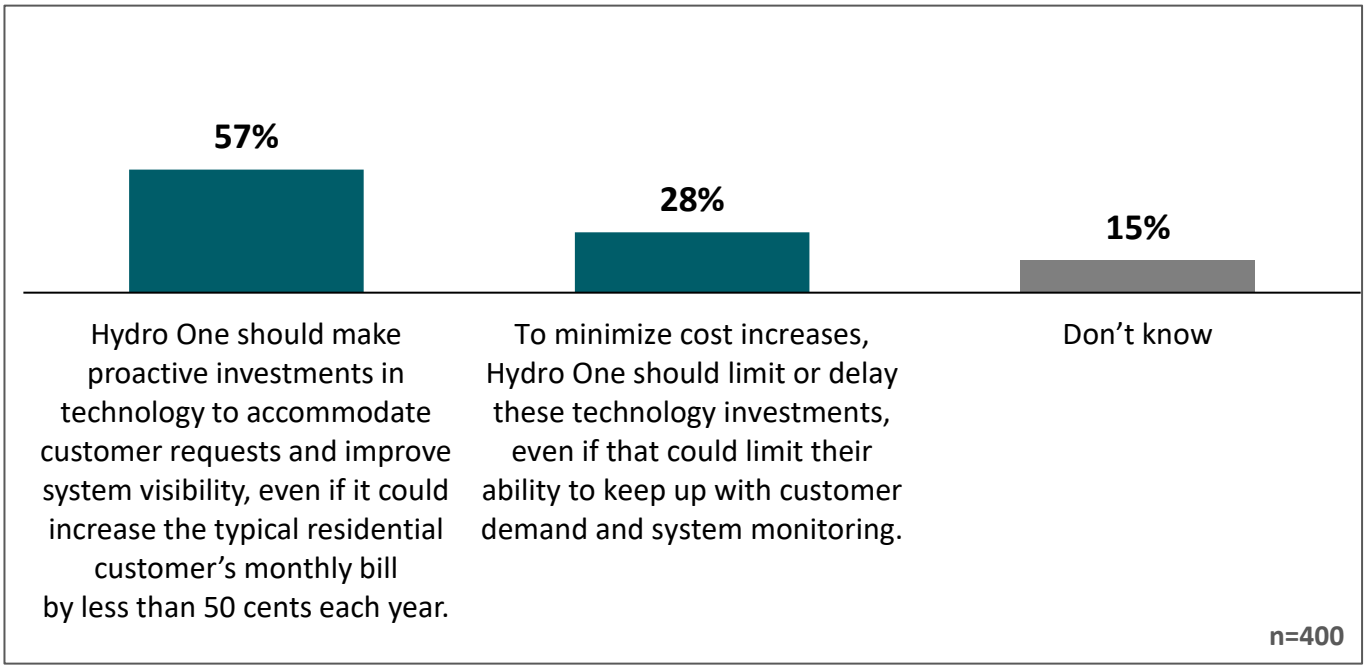
While **Hydro One** has an obligation to make certain investments to accommodate customer requests, planners have identified incremental investments that can help:

- Ensure that **Hydro One's** grid is ready to accommodate if and when customers request to connect new technologies.

- Give the **Hydro One** control room more "visibility" into exactly where and how much electricity is being used in real-time, helping make more informed decisions on managing electricity demand and equipment maintenance or upgrades.

As the pace of change and customer needs are rapidly evolving, delaying or limiting these investments means that **Hydro One** could struggle to keep up with customer demand for connecting new technology and lack the precision to monitor the grid as new technology adoption increases.

Q With regards to these investments, which of the following is closest to your point of view?



INNOVATIVE RESEARCH GROUP

Investment Priorities

Evolving Customer Requests & System Visibility

First Nations On-Reserve

Q With regards to these investments, which of the following is closest to your point of view?

Region

	Overall	West	Central	East/Central East	North
Proactive investments in technology	57%	49%	58%	63%	57%
Limit or delay technology investments	28%	40%	31%	22%	25%
Don't know	15%	11%	11%	14%	18%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactive investments in technology	48%	67%	74%	56%	59%
Limit or delay technology investments	36%	24%	19%	32%	22%
Don't know	16%	10%	8%	13%	19%

Consumption Quartiles

	Low	Medium-Low	Medium-High	High
Proactive investments in technology	60%	58%	61%	50%
Limit or delay technology investments	22%	35%	26%	30%
Don't know	18%	7%	13%	20%

Note: Response labels have been shortened for brevity. See slide 142 for full label text.

Investment Priorities

Transmission Renewal

First Nations On-Reserve

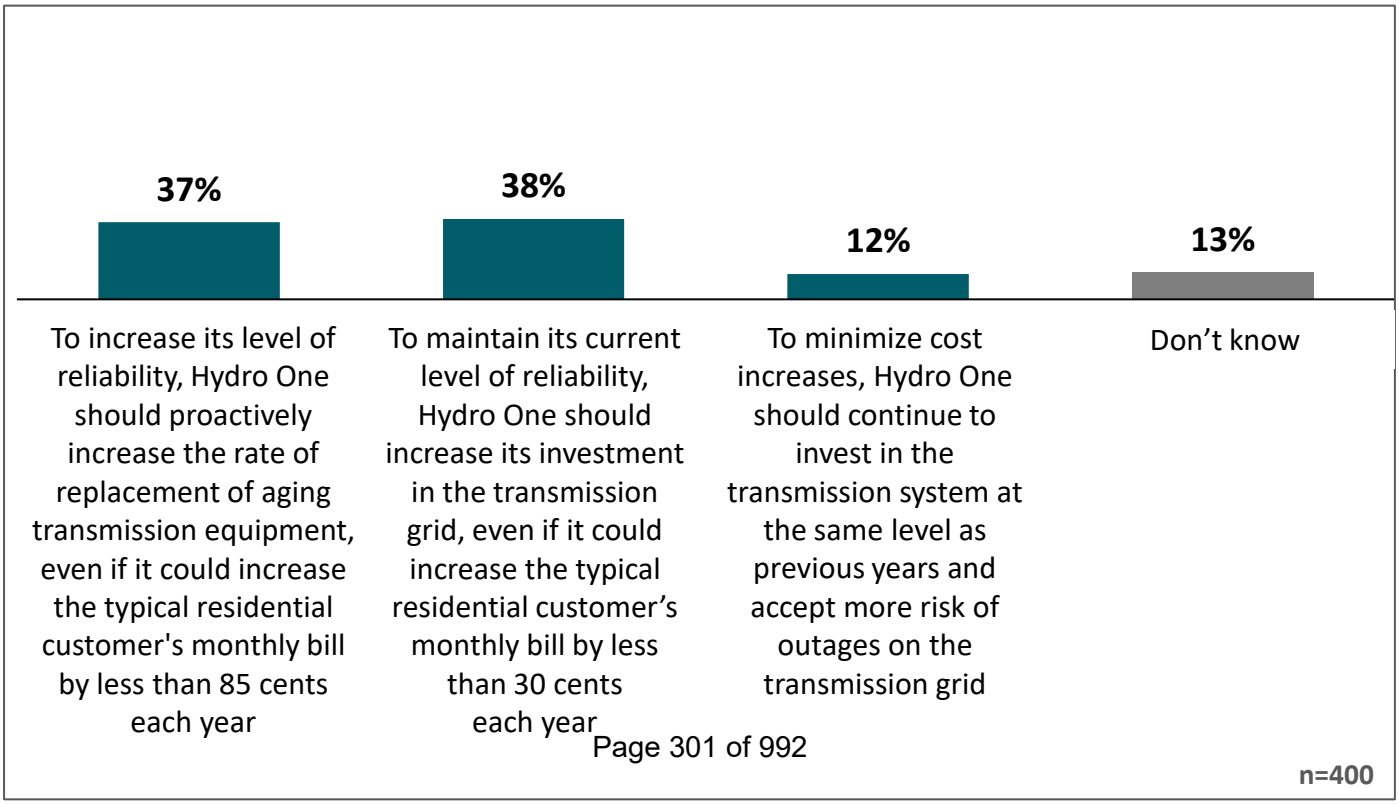
Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

Q With this in mind, what is closest to your point of view?



n=400

Investment Priorities
Transmission Renewal

First Nations On-Reserve

Q With this in mind, what is closest to your point of view?

		Region			
	Overall	West	Central	East/Central East	North
Proactively increase investment to increase reliability	37%	32%	41%	37%	35%
Increase investment to maintain current reliability	38%	41%	37%	40%	38%
Continue to invest at the same level	12%	15%	12%	16%	10%
Don't know	13%	11%	10%	8%	17%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactively increase investment to increase reliability	34%	31%	51%	34%	41%
Increase investment to maintain current reliability	35%	49%	40%	39%	38%
Continue to invest at the same level	15%	10%	4%	14%	9%
Don't know	17%	10%	5%	13%	13%

Note: Response labels have been shortened for brevity. See slide 144 for full label text.

Investment Priorities
Transmission Renewal

First Nations On-Reserve

Q With this in mind, what is closest to your point of view?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Proactively increase investment to increase reliability	37%	40%	37%	47%	24%
Increase investment to maintain current reliability	38%	32%	43%	35%	43%
Continue to invest at the same level	12%	15%	9%	7%	17%
Don't know	13%	13%	11%	11%	17%

Note: Response labels have been shortened for brevity. See slide 144 for full label text.

INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Survey Results

Section 4



Field Dates

The **Small Business (GS<50) Online Survey** was sent to a random selection of Hydro One small business customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **November 12th and December 3rd, 2024**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the small business survey was sent to **7,875** customers from *customerexperience@hydroone.com*. Reminder emails were sent on November 18th, November 27th and December 2nd, 2024 to those who had not yet completed the survey.

Small Business Online Survey Completes

A total of **477** (unweighted) Hydro One small business customers completed the online survey.

Sample Weighting

The small business online survey sample was weighted down to n=450 proportionately by consumption quartile and region in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

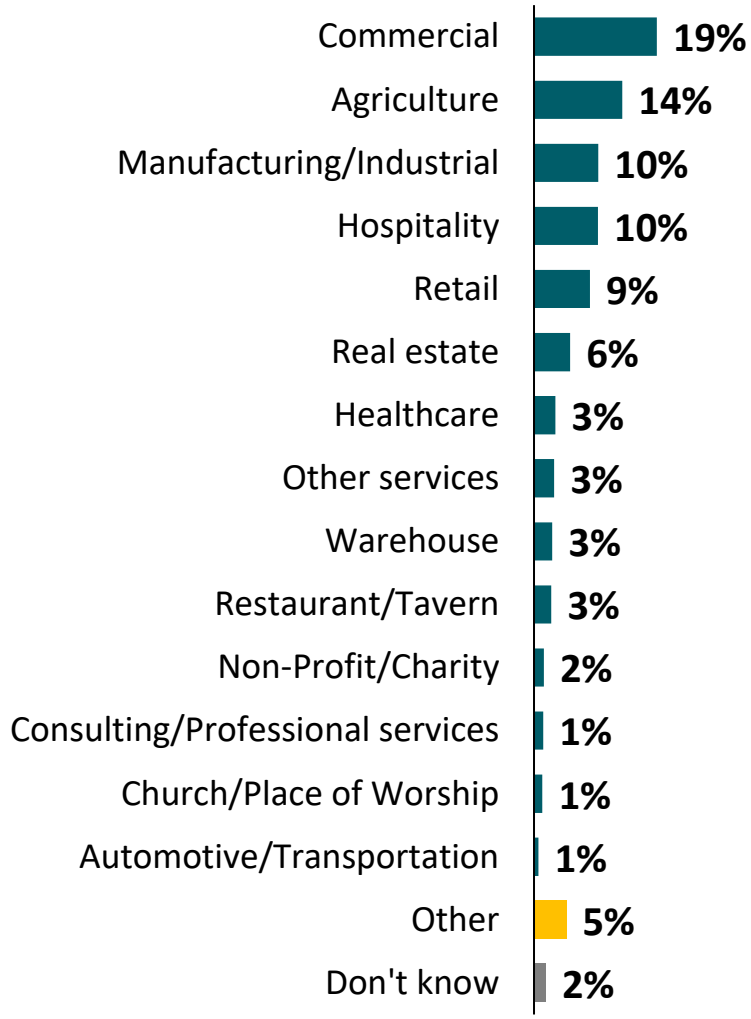
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	31 (25)	27 (23)	17 (23)	32 (24)	107 (94)
Central	25 (27)	26 (27)	27 (27)	20 (27)	98 (108)
Central East	39 (29)	41 (30)	25 (31)	27 (29)	133 (119)
East	24 (16)	17 (17)	16 (16)	18 (15)	75 (64)
North	22 (16)	10 (15)	18 (16)	14 (18)	64 (66)
Total	141 (112)	121 (112)	103 (112)	111 (112)	477 (450)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographic Breakdown

Small Business

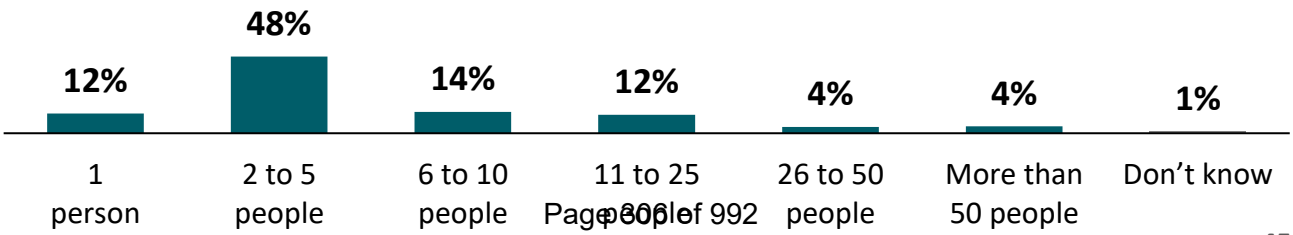
Q Business Sector



"Prefer not to say" (8%) not shown.

n=450

Q Business Size



"Prefer not to say" (4%) not shown.

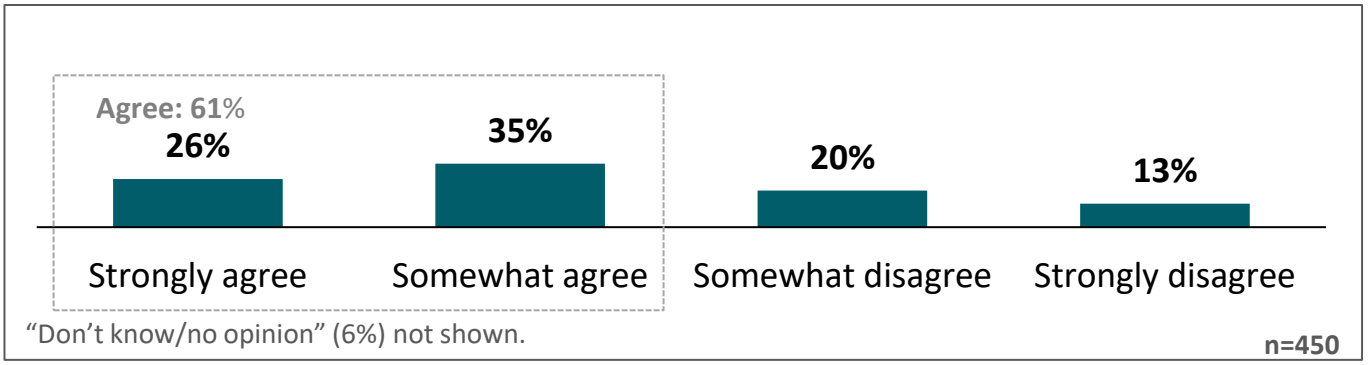
n=450

Environmental Controls

Small Business

To what extent do you agree or disagree with the following statements?

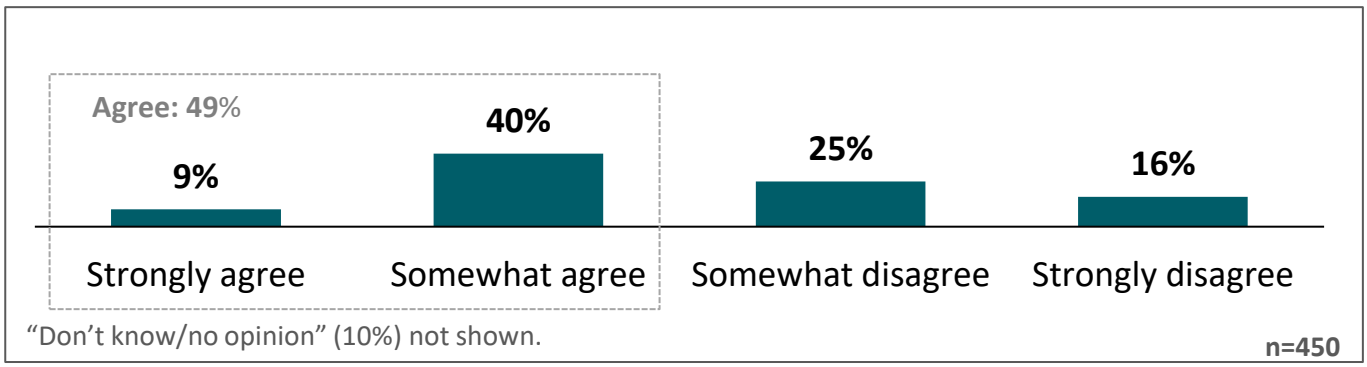
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (6%) not shown.

n=450

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (10%) not shown.

n=450

INNOVATIVE RESEARCH GROUP

Small Business Customers

Familiarity & Experience

Preamble:

Before we begin, this survey has **three key objectives**.

First, **Hydro One** wants to better understand your experiences as a customer.

Second, **Hydro One** wants your input on some of the investment areas they could focus on in the future.

Third, **Hydro One** wants to learn a little bit more about their customers. This will help them ensure that they are receiving feedback that represents a wide range of customers.

First, let's talk about your experience.

While you might have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a small business customer.

Familiarity & Experience

Familiarity with Hydro One's Role in the System

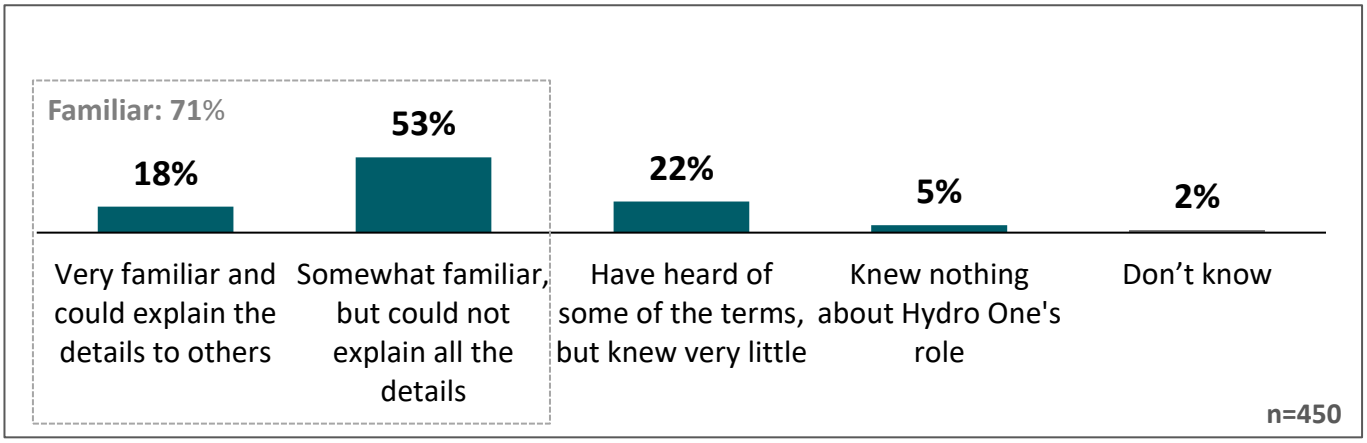
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	West	Central	Central East	East	North
Very familiar	19%	17%	13%	20%	27%
Somewhat familiar	57%	53%	54%	52%	45%
Knew very little	18%	21%	29%	16%	20%
Knew nothing	5%	6%	4%	11%	2%
Don't know	1%	2%	1%	1%	6%
Familiar (Very + Somewhat)	**76%**	**70%**	**66%**	**72%**	**72%**

Familiarity & Experience

Familiarity with Hydro One's Role in the System

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very familiar	18%	17%	19%	20%	17%	19%	18%
Somewhat familiar	53%	55%	56%	53%	47%	53%	52%
Knew very little	22%	19%	19%	20%	29%	21%	22%
Knew nothing	5%	7%	5%	5%	4%	5%	6%
Don't know	2%	2%	2%	1%	3%	2%	2%
Familiar (Very + Somewhat)	**71%**	**72%**	**74%**	**74%**	**64%**	**72%**	**69%**

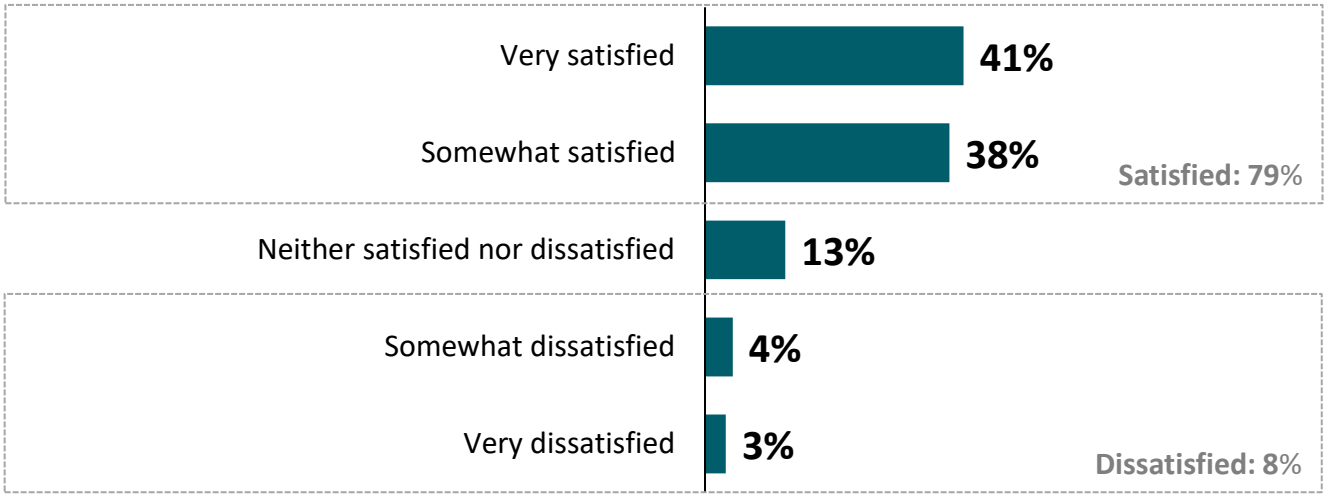
Familiarity & Experience

Overall Satisfaction with Hydro One

Small Business

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from **Hydro One**?



"*Don't know*" (1%) not shown.

n=450

Region

	West	Central	Central East	East	North
Very satisfied	34%	36%	48%	42%	44%
Somewhat satisfied	43%	42%	32%	34%	42%
Neither	15%	12%	12%	12%	11%
Somewhat dissatisfied	5%	3%	6%	5%	2%
Very dissatisfied	3%	4%	2%	6%	1%
Don't know	--	2%	--	--	--
Satisfied (Very + Somewhat)	**76%**	**78%**	**80%**	**76%**	**86%**
Dissatisfied (Very + Somewhat)	**8%**	**7%**	**8%**	**11%**	**4%**

INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Overall Satisfaction with Hydro One

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from **Hydro One**?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very satisfied	41%	45%	41%	34%	42%	39%	43%
Somewhat satisfied	38%	37%	41%	42%	33%	40%	36%
Neither	13%	9%	11%	16%	14%	12%	14%
Somewhat dissatisfied	4%	5%	5%	3%	4%	4%	5%
Very dissatisfied	3%	3%	1%	5%	4%	5%	1%
Don't know	1%	1%	--	--	1%	<1%	1%
Satisfied (Very + Somewhat)	**79%**	**82%**	**83%**	**76%**	**76%**	**79%**	**79%**
Dissatisfied (Very + Somewhat)	**8%**	**8%**	**6%**	**8%**	**9%**	**8%**	**6%**

Familiarity & Experience

How can Hydro One improve services?

Q Is there anything in particular you would like **Hydro One** to do to improve its services to your organization?

Response	%
Lower rates/decrease bills	9.9%
Decrease outages/interruptions	5.5%
Address/proactive tree trimming	4.3%
Upgrade/better maintain infrastructure	3.1%
Satisfied with services/no issues	3.1%
Improve communication during outages	2.1%
Bury power lines/better line maintenance	2.1%
Improve customer service	2.1%
Billing improvements - timing/payments/bill format	1.8%
Improve general communication	1.6%
Improve response time for outages	1.3%
Energy alternatives/green energy options	1.2%
Improve website/app	1.1%
Provide incentives/rebates	0.6%
Find efficiencies/costs savings	0.3%
Building capacity/addressing growth	0.2%
More information/visibility into usage	0.2%
More transparency around costs	0.2%
Other	2.8%
None/Don’t know	56.6%

Note: Only responses >0.1% shown

Familiarity & Experience

Bill Familiarity

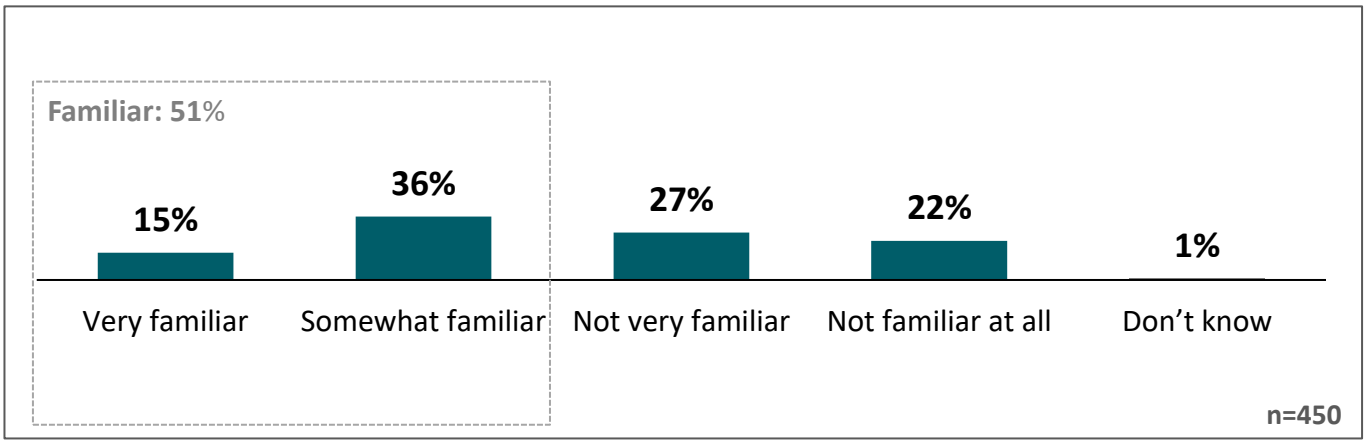
Small Business

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to **Hydro One**. As of October 1st, 2024, for a typical small business customer, about **40%** or **$174** goes to Hydro One per month. This amount is split into **$144** for distribution and **$30** for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.*

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Hydro One**?



Region

	West	Central	Central East	East	North
Very familiar	16%	17%	15%	14%	14%
Somewhat familiar	43%	37%	29%	29%	40%
Not very familiar	25%	24%	33%	26%	22%
Not familiar at all	15%	21%	22%	32%	24%
Don't know	1%	1%	1%	--	--
Familiar (Very + Somewhat)	**59%**	**54%**	**44%**	**43%**	**53%**

Note: *Organizations who do not pay HST see the following:
The rest of your bill payment goes to power generation companies and regulatory agencies

Familiarity & Experience

Bill Familiarity

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Hydro One**?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very familiar	15%	10%	16%	17%	17%	14%	17%
Somewhat familiar	36%	37%	32%	41%	34%	39%	31%
Not very familiar	27%	28%	25%	29%	24%	26%	27%
Not familiar at all	22%	25%	26%	13%	23%	20%	25%
Don't know	1%	--	1%	--	2%	1%	1%
Familiar (Very + Somewhat)	**51%**	**47%**	**48%**	**58%**	**51%**	**53%**	**48%**

Familiarity & Experience

Familiarity with Rate Applications

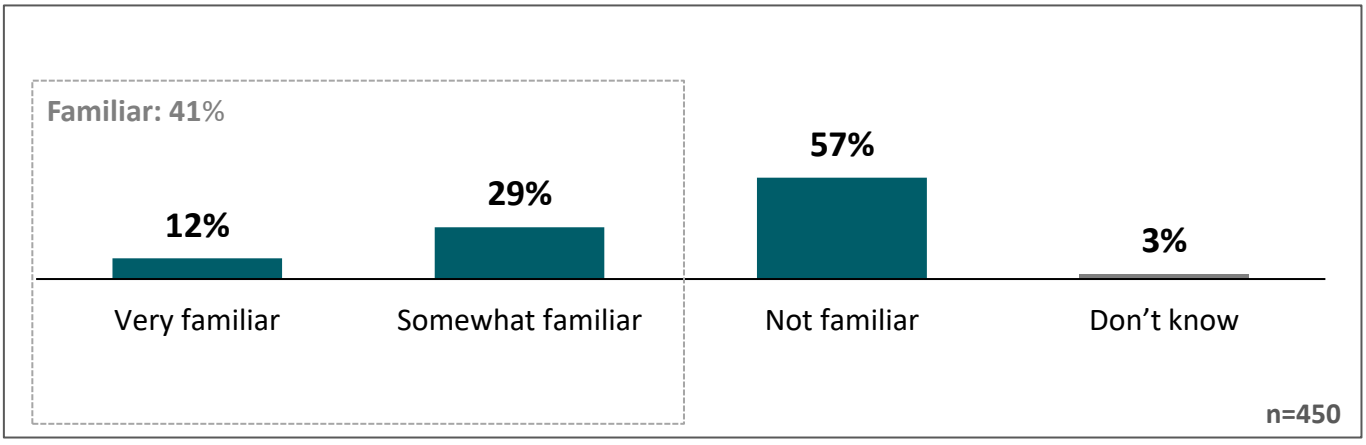
Hydro One is funded by the rates paid by its customers.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



Region

	West	Central	Central East	East	North
Very familiar	10%	14%	12%	15%	7%
Somewhat familiar	37%	24%	25%	31%	30%
Not familiar	53%	60%	58%	51%	61%
Don't know	1%	1%	5%	3%	2%
Familiar (Very + Somewhat)	**46%**	**38%**	**37%**	**46%**	**37%**

Familiarity & Experience

Familiarity with Rate Applications

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very familiar	12%	10%	12%	14%	11%	11%	13%
Somewhat familiar	29%	30%	28%	32%	25%	28%	30%
Not familiar	57%	58%	58%	54%	57%	58%	55%
Don't know	3%	2%	2%	--	7%	4%	1%
Familiar (Very + Somewhat)	**41%**	**40%**	**40%**	**46%**	**36%**	**39%**	**43%**

INNOVATIVE RESEARCH GROUP

Small Business Customers

Customer Priorities



Customer Priorities

Response Labels Legend

Small Business

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 8 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity	Providing reliable electricity to my organization
Enhancing Hydro One's customer service	Enhancing Hydro One's customer service
Offering programs to help manage usage	Offering programs that can help customers better manage their electricity usage
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Enhancing the grid for new technologies	Enhancing the grid so that customers can connect new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

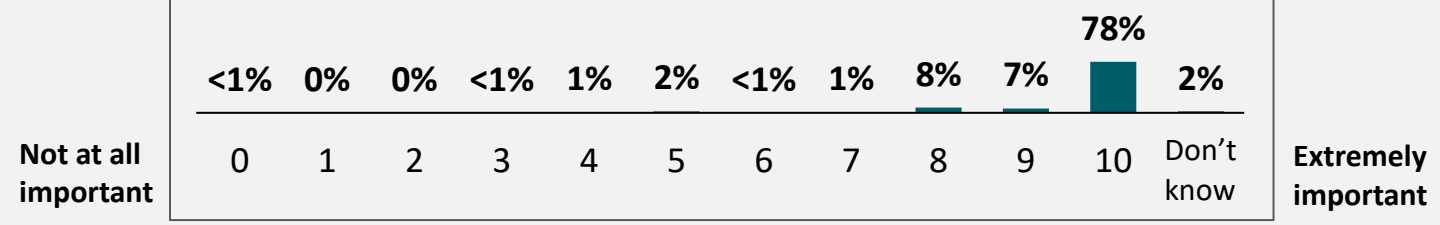
Customer Priorities

Importance of Customer Priorities

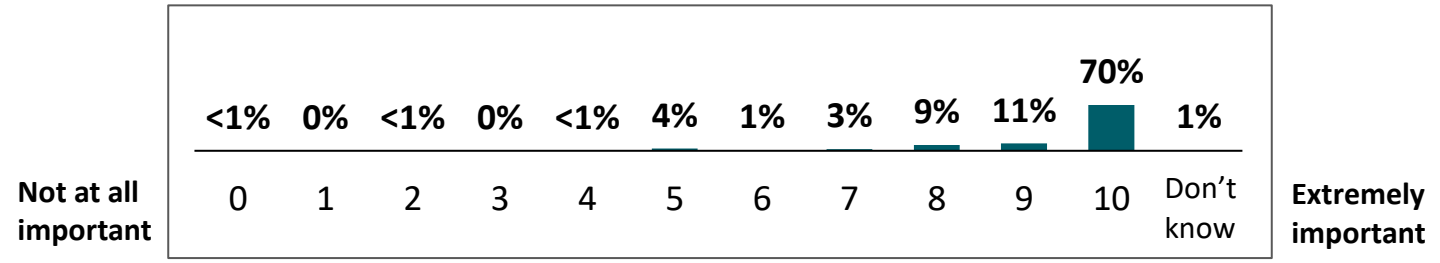
Small Business

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

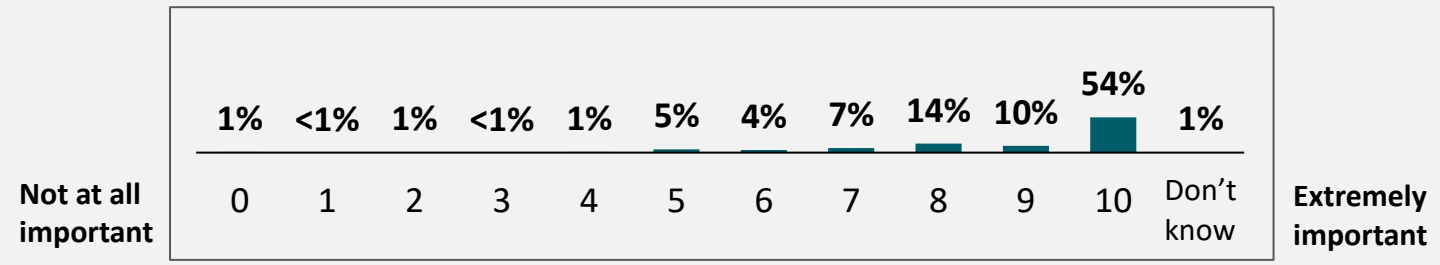
Delivering electricity at reasonable rates [average = **9.5**]



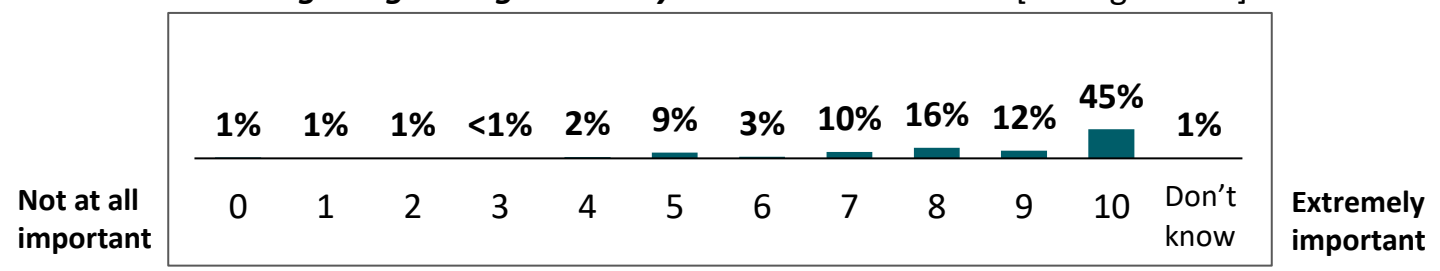
Providing reliable electricity [average = **9.3**]



Ensuring the safety of electricity infrastructure [average = **8.7**]



Meeting the growing electricity need [average = **8.3**]



Note: Priority labels have been shortened for brevity. See slide 162 for full label text.
"Don't know" not included in calculation of means.

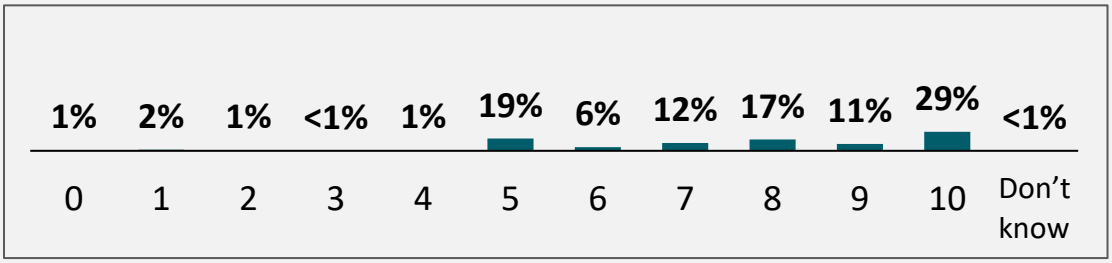
Customer Priorities

Importance of Customer Priorities (Cont'd)

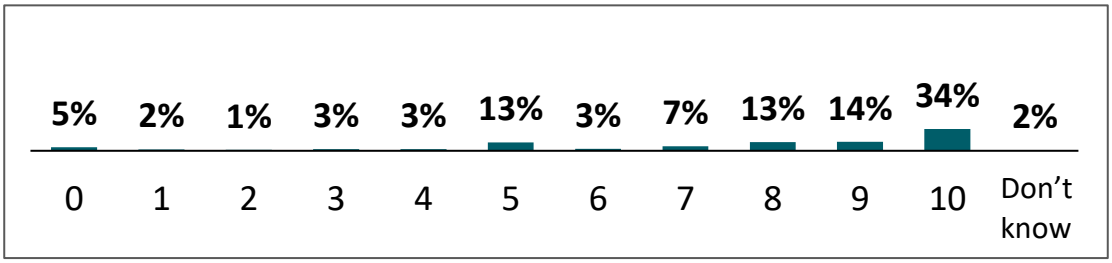
Small Business

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

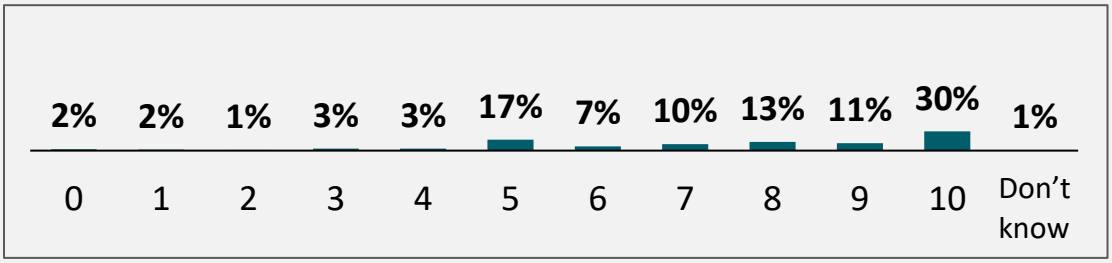
Enhancing Hydro One's customer service [average = **7.6**]



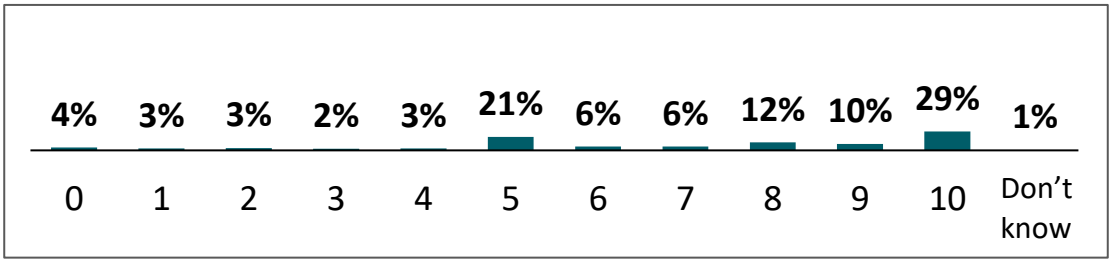
Enhancing the grid for new technologies [average = **7.4**]



Offering programs to help manage usage [average = **7.3**]



Reducing the environmental impact [average = **6.9**]



Note: Priority labels have been shortened for brevity. See slide 162 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Small Business

Importance of Customer Priorities – Average Scores

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		Region				
Average Score	**Overall**	**West**	**Central**	**Central East**	**East**	**North**
Delivering electricity at reasonable rates	9.5	9.4	9.6	9.5	9.6	9.6
Providing reliable electricity	9.3	9.2	9.4	9.4	9.4	9.2
Ensuring the safety of electricity infrastructure	8.7	8.4	8.8	8.6	8.6	8.9
Meeting the growing electricity need	8.3	8.4	8.6	8.2	8.4	7.9
Enhancing Hydro One's customer service	7.6	7.3	7.4	7.7	7.5	7.9
Enhancing the grid for new technologies	7.4	7.1	7.9	6.8	7.6	7.7
Offering programs to help manage usage	7.3	6.8	7.5	7.4	7.3	7.5
Reducing the environmental impact	6.9	6.5	7.3	6.7	7.1	7.2

Note: Priority labels have been shortened for brevity. See slide 162 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Small Business

Importance of Customer Priorities – Average Scores

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		Consumption Quartiles				Bill Impact	
Average Score	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	9.5	9.5	9.6	9.5	9.5	9.6	9.5
Providing reliable electricity	9.3	9.1	9.2	9.3	9.6	9.3	9.3
Ensuring the safety of electricity infrastructure	8.7	8.7	8.9	8.6	8.5	8.6	8.7
Meeting the growing electricity need	8.3	8.3	8.5	8.3	8.2	8.2	8.4
Enhancing Hydro One's customer service	7.6	7.7	7.7	7.3	7.5	7.6	7.4
Enhancing the grid for new technologies	7.4	7.5	7.6	7.2	7.2	7.4	7.2
Offering programs to help manage usage	7.3	7.3	7.3	7.2	7.4	7.4	7.2
Reducing the environmental impact	6.9	7.0	7.0	6.9	6.7	6.9	7.0

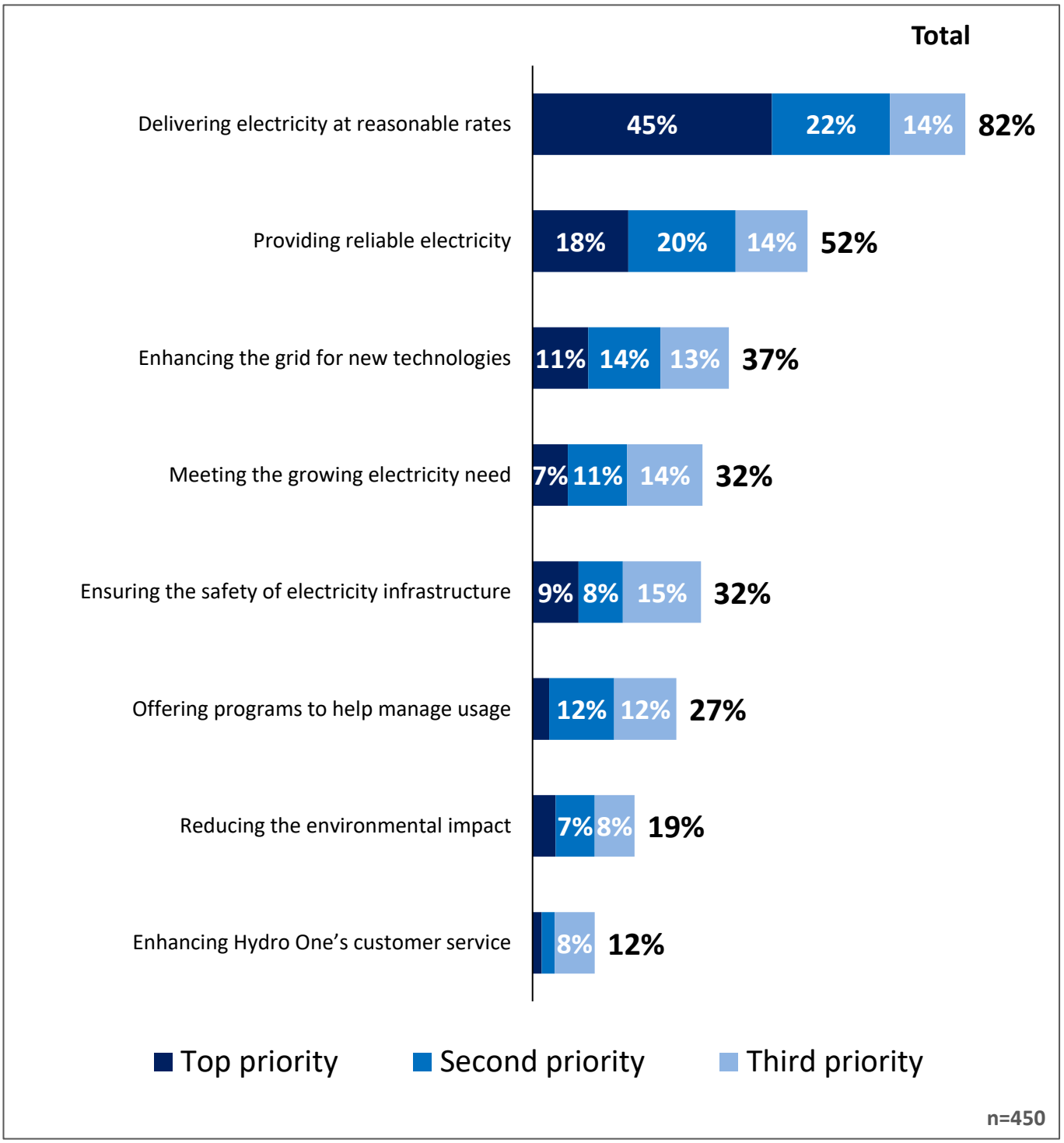
Note: Priority labels have been shortened for brevity. See slide 162 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Small Business

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 162 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Small Business

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Region					
	Overall	West	Central	Central East	East	North
Delivering electricity at reasonable rates	82%	81%	78%	84%	85%	87%
Providing reliable electricity	52%	59%	50%	51%	50%	50%
Enhancing the grid for new technologies	37%	36%	42%	36%	40%	32%
Meeting the growing electricity need	32%	38%	33%	36%	24%	25%
Ensuring the safety of electricity infrastructure	32%	27%	32%	30%	38%	36%
Offering programs to help manage usage	27%	21%	28%	29%	29%	30%
Reducing the environmental impact	19%	17%	19%	22%	19%	19%
Enhancing Hydro One's customer service	12%	11%	12%	11%	8%	18%

Note: Priority labels have been shortened for brevity. See slide 162 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Small Business

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

		Consumption Quartiles				Bill Impact	
% who select as top 3 priority	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	82%	81%	84%	79%	86%	85%	78%
Providing reliable electricity	52%	51%	45%	52%	61%	53%	51%
Enhancing the grid for new technologies	37%	38%	38%	40%	33%	39%	35%
Meeting the growing electricity need	32%	36%	32%	30%	32%	29%	38%
Ensuring the safety of electricity infrastructure	32%	30%	39%	33%	27%	30%	35%
Offering programs to help manage usage	27%	28%	26%	25%	29%	30%	23%
Reducing the environmental impact	19%	20%	19%	24%	14%	19%	20%
Enhancing Hydro One's customer service	12%	11%	12%	11%	14%	13%	10%

Note: Priority labels have been shortened for brevity. See slide 162 for full label text. "Don't know" not shown.

Customer Priorities

Other Priorities

Small Business

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Reasonable/affordable rates	8.4%
Enhancing the grid/infrastructure	5.3%
Improving reliability/less outages	3.0%
Having alternative energy/sustainable sources/green technology	2.9%
Burying lines underground/removing hydro poles	1.5%
Meeting growing needs for electricity	1.2%
Tree trimming/removal	0.9%
Improving customer service/communication	0.9%
Reducing environmental impacts	0.8%
Information/programs to manage electricity usage	0.8%
Incentives for seniors/subsidy programs	0.6%
Focus on nuclear energy/power	0.4%
Withstanding extreme weather	0.4%
Prioritizing safety	0.3%
Affordable renewable energy	0.3%
Support/incentives for new technologies or energy efficiency efforts	0.2%
Other	3.1%
None/Don’t know	68.9%

Note: Only responses >0.1% shown

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Small Business Customers

Reliability Experience



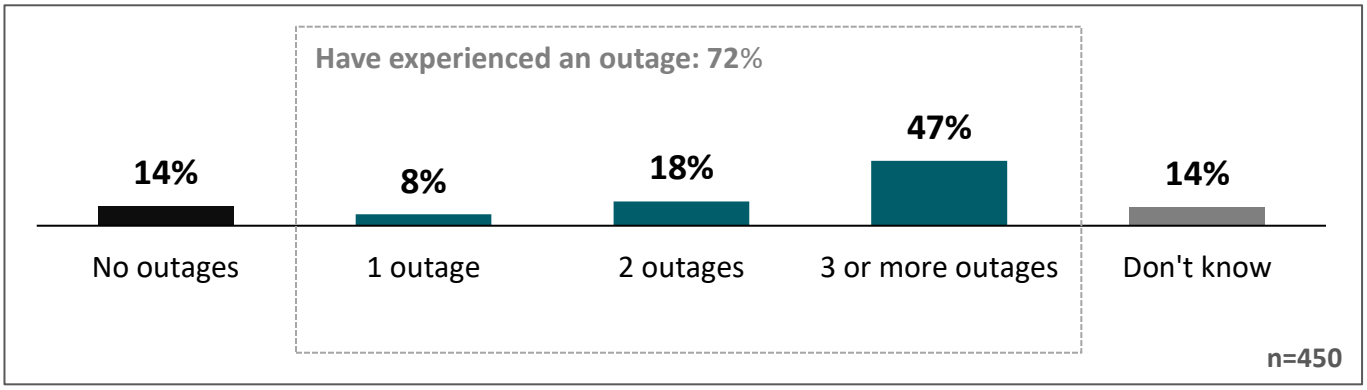
Reliability Experience

Number of Outages Experienced

Small Business

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at your organization **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



Region

	West	Central	Central East	East	North
No outages	9%	12%	19%	14%	17%
1 outage	6%	8%	10%	11%	7%
2 outages	19%	15%	19%	22%	12%
3 or more outages	56%	51%	35%	40%	55%
Don't know	11%	14%	17%	14%	10%
Have experienced at least 1 outage	**80%**	**74%**	**64%**	**73%**	**73%**

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Reliability Experience
Number of Outages Experienced

Small Business

Q Have you experienced any power outages at your organization **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

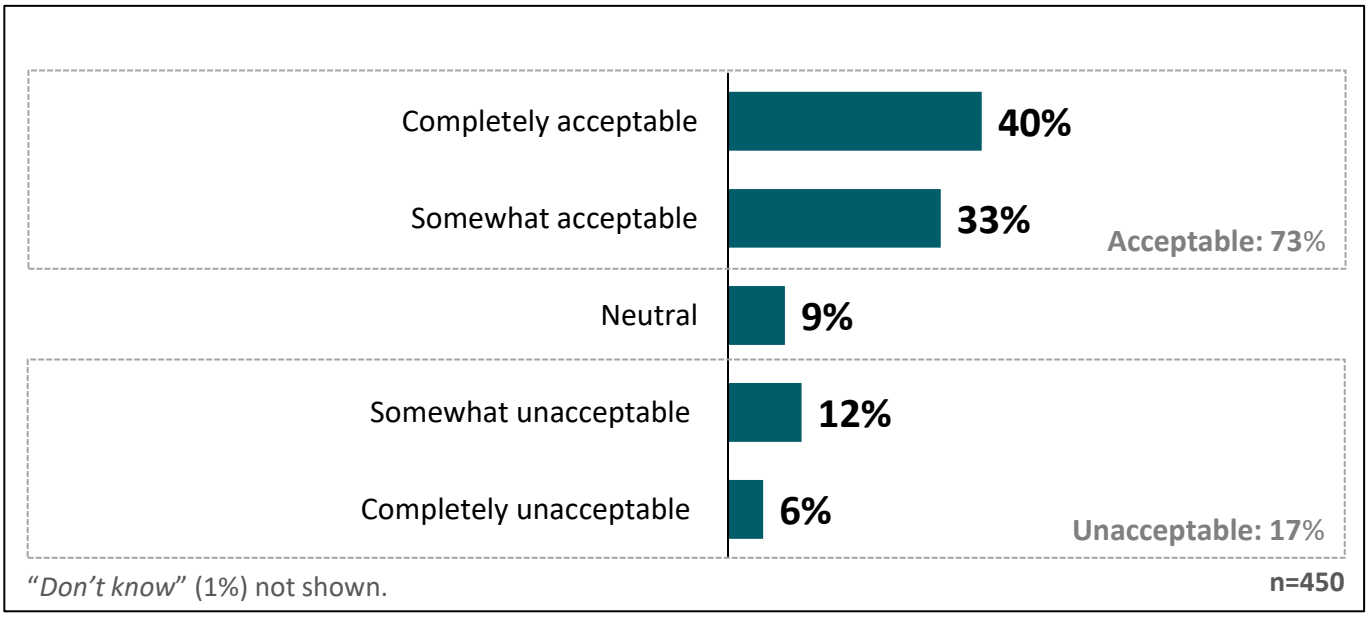
		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
No outages	14%	12%	15%	11%	19%	11%	19%
1 outage	8%	8%	8%	7%	10%	7%	11%
2 outages	18%	20%	15%	16%	20%	16%	19%
3 or more outages	47%	44%	49%	55%	39%	54%	35%
Don't know	14%	16%	13%	12%	13%	12%	16%
Have experienced at least 1 outage	**72%**	**72%**	**72%**	**78%**	**69%**	**77%**	**65%**

Reliability Experience

Current Reliability of Electricity Service

Small Business

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (1%) not shown.

n=450

Region

	West	Central	Central East	East	North
Completely acceptable	33%	37%	45%	47%	39%
Somewhat acceptable	35%	38%	32%	22%	38%
Neutral	9%	6%	11%	6%	12%
Somewhat unacceptable	15%	11%	7%	20%	9%
Completely unacceptable	7%	7%	6%	4%	3%
Don't know	--	1%	--	2%	--
Acceptable (Completely + Somewhat)	**68%**	**75%**	**77%**	**69%**	**77%**
Unacceptable (Completely + Somewhat)	**22%**	**18%**	**12%**	**23%**	**11%**

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Reliability Experience

Current Reliability of Electricity Service

Small Business

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?

		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Completely acceptable	40%	39%	41%	40%	40%	37%	44%
Somewhat acceptable	33%	38%	31%	33%	32%	36%	30%
Neutral	9%	8%	8%	12%	9%	9%	9%
Somewhat unacceptable	12%	11%	13%	11%	11%	11%	12%
Completely unacceptable	6%	5%	6%	4%	7%	7%	3%
Don't know	1%	--	1%	--	1%	--	1%
Acceptable (Completely + Somewhat)	**73%**	**76%**	**72%**	**73%**	**72%**	**73%**	**74%**
Unacceptable (Completely + Somewhat)	**17%**	**16%**	**19%**	**16%**	**18%**	**18%**	**16%**

INNOVATIVE RESEARCH GROUP

Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights
Improving communications during outages	Improving communications during outages, including estimated restoration times

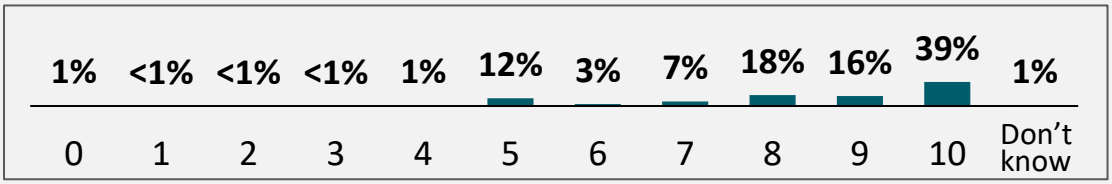
Reliability Experience

Importance of Reliability Priorities

Small Business

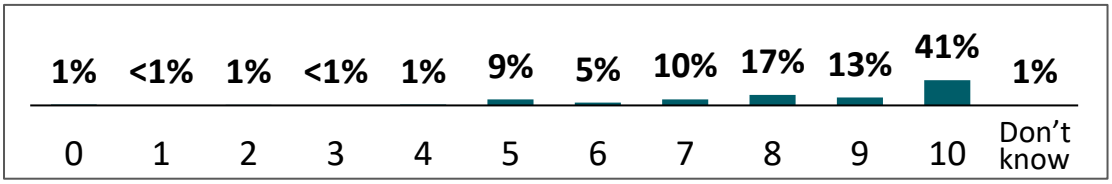
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

Reducing length of non-weather outages [average = **8.2**]



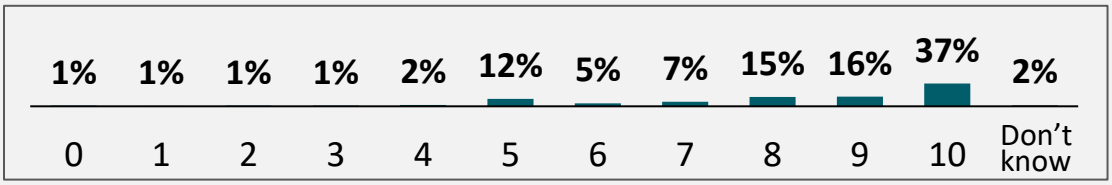
Not at all important — Extremely important

Reducing length of weather-caused outages [average = **8.2**]



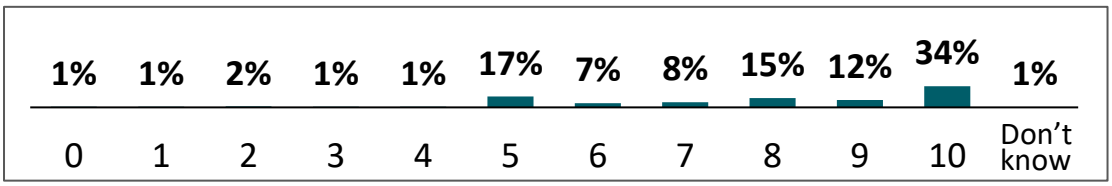
Not at all important — Extremely important

Reducing number of non-weather outages [average = **8.0**]



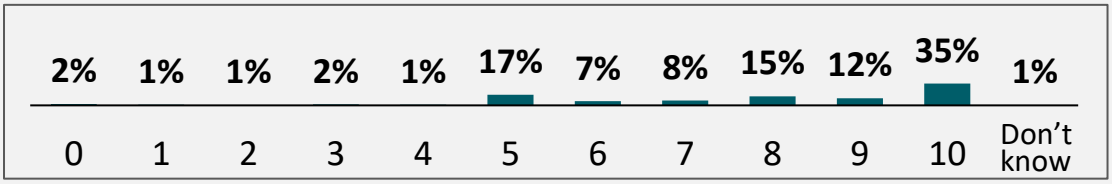
Not at all important — Extremely important

Reducing number of weather-caused outages [average = **7.7**]



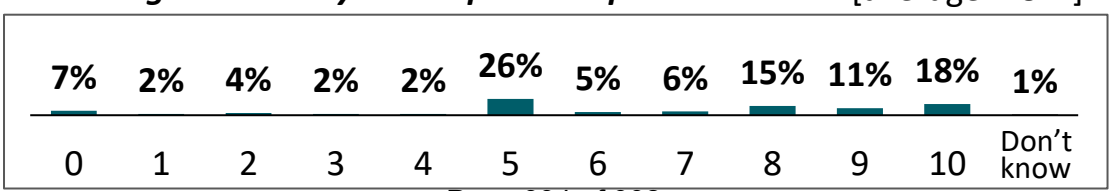
Not at all important — Extremely important

Improving communications during outages [average = **7.7**]



Not at all important — Extremely important

Reducing momentary interruptions in power [average = **6.4**]



Not at all important — Extremely important

Note: Priority labels have been shortened for brevity. See slide 176 for full label text.
"Don't know" not included in calculation of means.

Reliability Experience

Small Business

Importance of Reliability Priorities – Average Scores

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Region				
Average Score	**Overall**	**West**	**Central**	**Central East**	**East**	**North**
Reducing length of non-weather outages	8.2	8.2	8.4	8.1	8.1	8.2
Reducing length of weather-caused outages	8.2	8.1	8.2	8.1	8.1	8.4
Reducing number of non-weather outages	8.0	8.0	8.3	7.9	7.9	7.9
Reducing number of weather-caused outages	7.7	7.7	7.8	7.4	7.8	8.2
Improving communications during outages	7.7	7.7	7.5	7.7	7.5	8.2
Reducing momentary interruptions in power	6.4	6.9	6.3	6.1	5.7	6.9

Note: Priority labels have been shortened for brevity. See slide 176 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Small Business

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Consumption Quartiles				Bill Impact	
Average Score	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Reducing length of non-weather outages	8.2	8.1	8.0	8.3	8.5	8.3	8.1
Reducing length of weather-caused outages	8.2	8.0	8.1	8.2	8.4	8.2	8.1
Reducing number of non-weather outages	8.0	7.8	7.8	8.1	8.3	8.3	7.6
Reducing number of weather-caused outages	7.7	7.7	7.8	7.6	7.8	7.9	7.5
Improving communications during outages	7.7	7.7	7.4	8.0	7.7	7.9	7.4
Reducing momentary interruptions in power	6.4	6.1	6.3	6.5	6.5	6.6	6.0

Note: Priority labels have been shortened for brevity. See slide 176 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

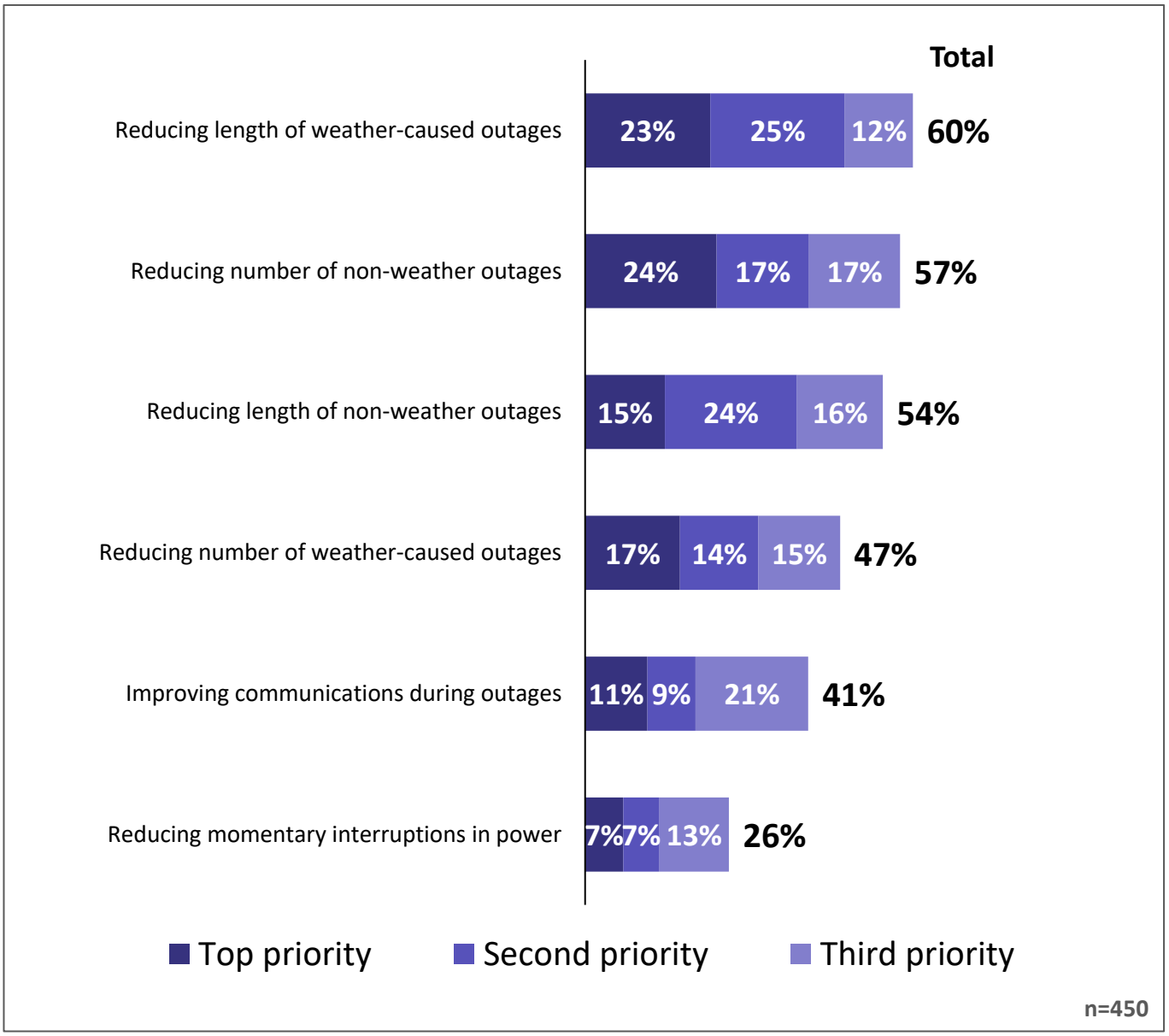
Reliability Experience

Ranking Reliability Priorities

Small Business

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?



Note: Priority labels have been shortened for brevity. See slide 176 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Small Business

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Region				
% who select as top 3 priority	**Overall**	**West**	**Central**	**Central East**	**East**	**North**
Reducing length of weather-caused outages	60%	54%	59%	66%	52%	65%
Reducing number of non-weather outages	57%	58%	59%	54%	60%	59%
Reducing length of non-weather outages	54%	52%	61%	54%	52%	50%
Reducing number of weather-caused outages	47%	43%	45%	48%	57%	41%
Improving communications during outages	41%	44%	37%	45%	35%	40%
Reducing momentary interruptions in power	26%	32%	24%	21%	24%	33%

Note: Priority labels have been shortened for brevity. See slide 176 for full label text. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Small Business

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Consumption Quartiles				Bill Impact	
% who select as top 3 priority	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Reducing length of weather-caused outages	60%	63%	63%	54%	59%	57%	65%
Reducing number of non-weather outages	57%	57%	51%	62%	59%	60%	53%
Reducing length of non-weather outages	54%	53%	51%	61%	53%	57%	50%
Reducing number of weather-caused outages	47%	45%	50%	46%	44%	46%	48%
Improving communications during outages	41%	44%	41%	41%	36%	39%	43%
Reducing momentary interruptions in power	26%	25%	28%	26%	26%	28%	23%

Note: Priority labels have been shortened for brevity. See slide 176 for full label text. "Don't know" not shown.

INNOVATIVE RESEARCH GROUP

Small Business Customers

Investment Priorities



Investment Priorities

High-Level Reliability

Now let's turn to the next topic – investment trade-offs. There are **6** investment areas that **Hydro One** would like your input on.

You do not need to be a system planner or engineer to answer these questions. The trade-offs will focus on what outcomes matter most to you as a customer – balancing investment outcomes and cost to you.

First, we would like to talk about the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

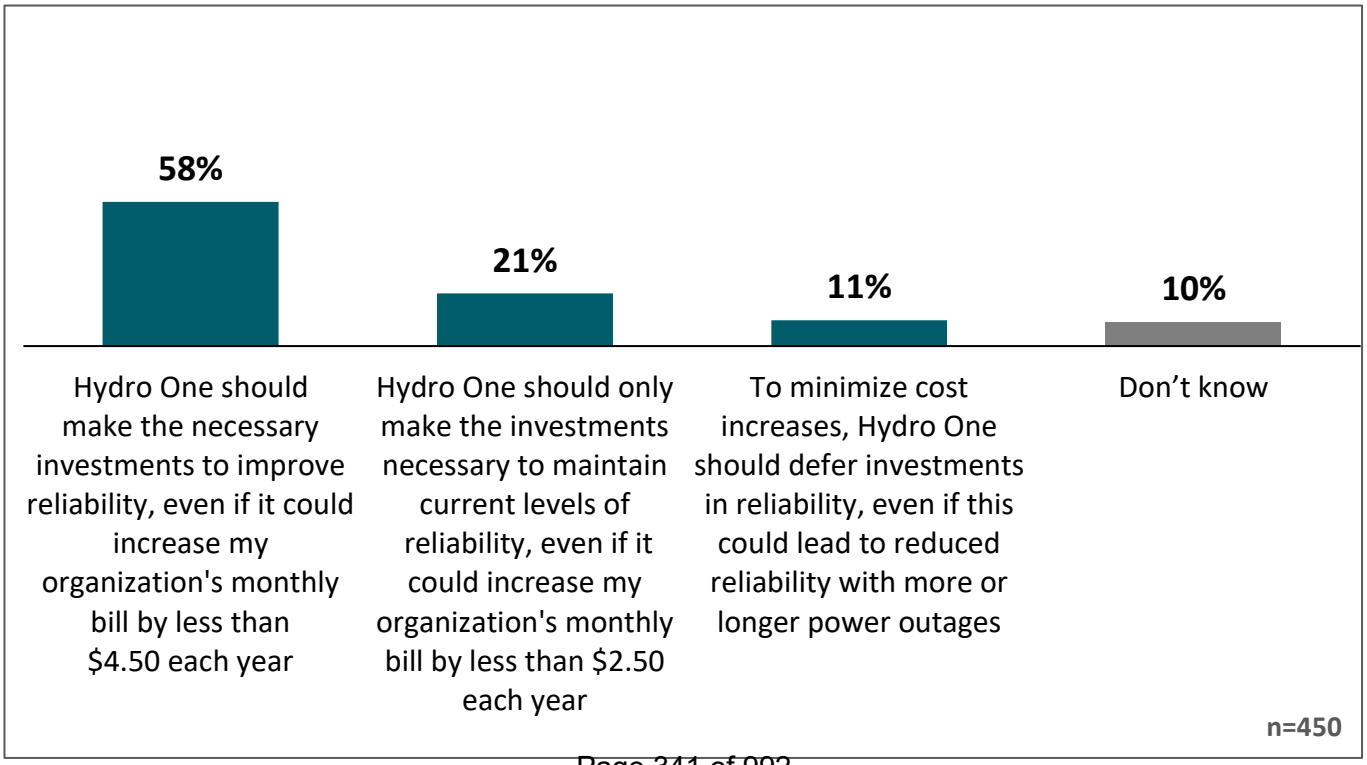
The first category is related to the reliability you experience.

On average, between 2019 and 2023, the typical **Hydro One** customer has experienced about 3.8 outages per year, resulting in a total of 16.6 hours without power.

It's important to keep in mind that these are system averages, and that your actual experience may be different.

Hydro One has historically identified investments in maintaining or improving reliability by taking into consideration the overall age, health, and likelihood of failure of equipment.

Q Based on your own reliability experience, which of the following is closest to your point of view?



Investment Priorities

High-Level Reliability

Small Business

Q Based on your own reliability experience, which of the following is closest to your point of view?

		Region				
	Overall	West	Central	Central East	East	North
Necessary investments to improve reliability	58%	61%	59%	63%	59%	46%
Necessary investments to maintain reliability	21%	20%	24%	20%	22%	22%
Defer investments	11%	8%	13%	8%	9%	16%
Don't know	10%	11%	4%	9%	10%	17%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Necessary investments to improve reliability	61%	58%	58%	57%	53%	67%
Necessary investments to maintain reliability	20%	21%	25%	20%	23%	19%
Defer investments	10%	12%	7%	14%	14%	6%
Don't know	9%	9%	11%	10%	11%	8%

Note: Response labels have been shortened for brevity. See slide 184 for full label text.

Investment Priorities

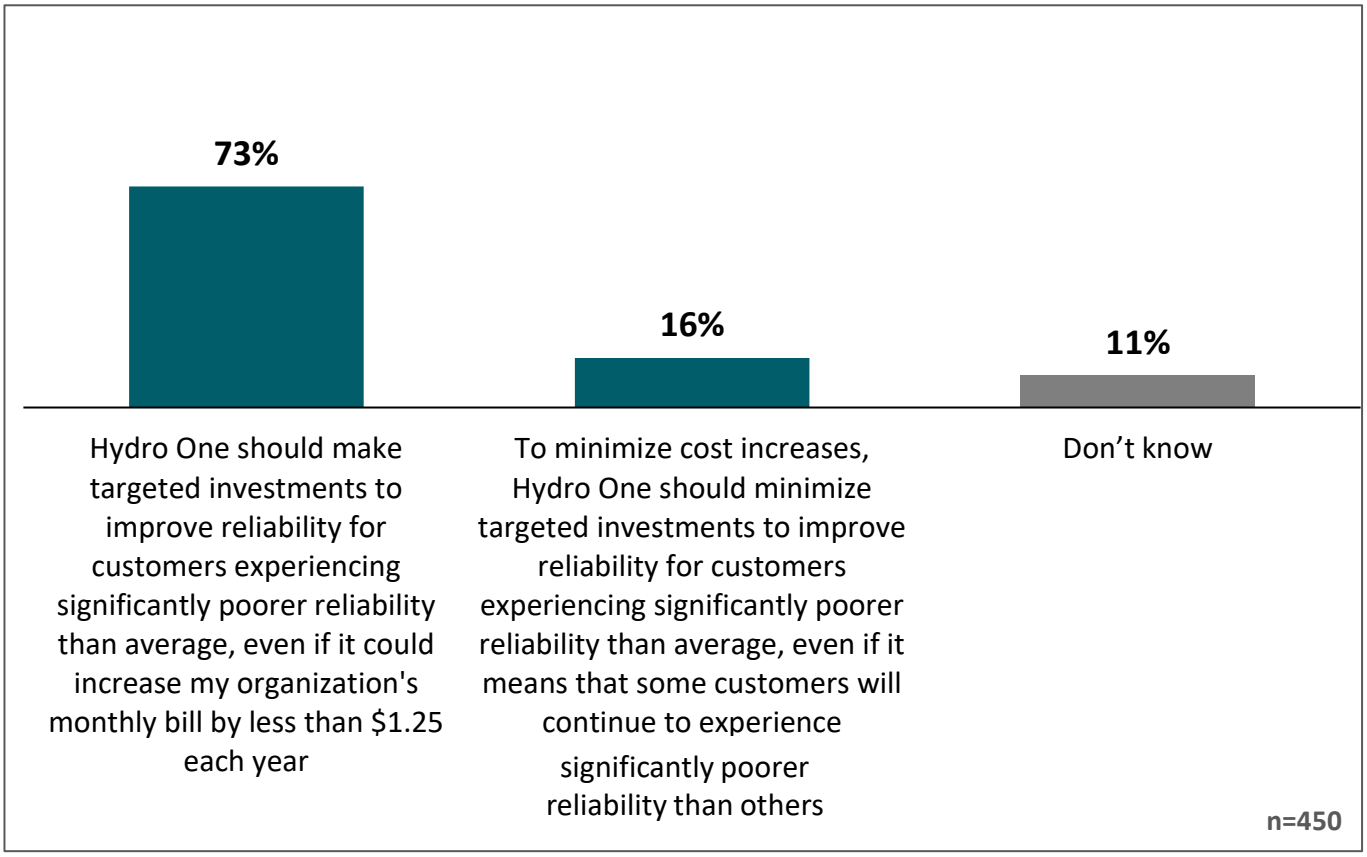
Targeted Reliability

The second category is related to more targeted improvements to reliability.

Hydro One customers experience different levels of reliability, depending on where they live, the design of the system and the condition of the equipment supplying them.

While some **Hydro One** customers didn't experience any outages in 2022 or 2023, others were without power more than 10 times per year. Similarly, the total length of time that customers were without power ranges from less than one hour to more than 50 hours per year.

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?



Investment Priorities
Targeted Reliability

Small Business

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?

		Region				
	Overall	West	Central	Central East	East	North
Targeted investments to improve reliability	73%	72%	77%	73%	71%	71%
Minimize targeted investments	16%	15%	15%	17%	22%	14%
Don't know	11%	14%	7%	10%	8%	15%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Targeted investments to improve reliability	71%	75%	71%	75%	71%	76%
Minimize targeted investments	19%	14%	17%	15%	17%	16%
Don't know	10%	11%	12%	9%	12%	8%

Note: Response labels have been shortened for brevity. See slide 186 for full label text.

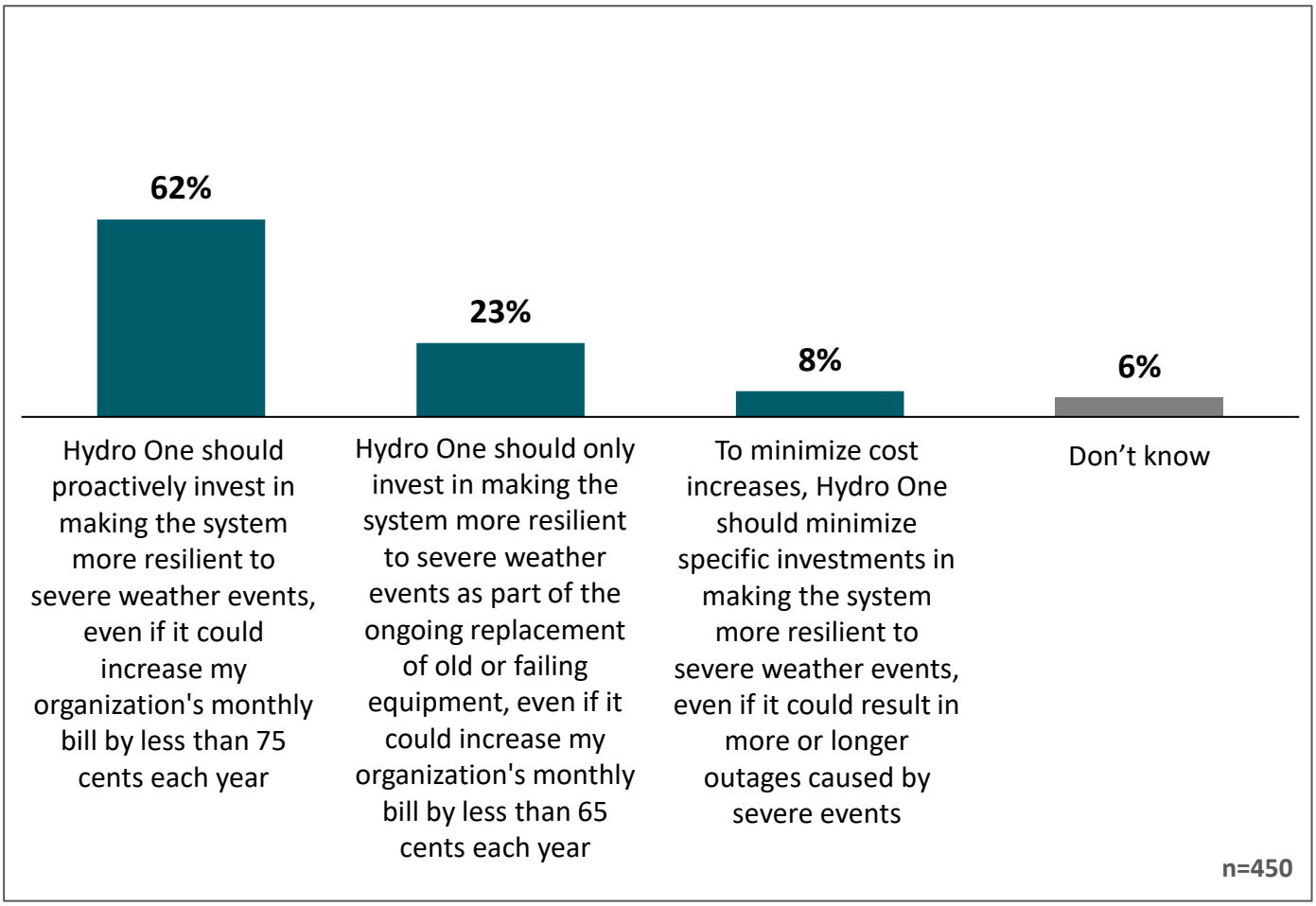
Investment Priorities

Responding to Severe Weather

On average, between 2019 and 2023, **severe weather events**, such as ice storms, windstorms or thunderstorms, have contributed to 51% of all hours that the typical customer has been without power per year.

While some of these outages may be inevitable, **Hydro One** could make additional investments to make the system more resilient to these types of events. These investments could help either reduce the number of outages caused by severe weather events or improve restoration times when these outages do occur.

Q Based on this, which of the following is closest to your point of view?



Investment Priorities

Responding to Severe Weather

Small Business

Q Based on this, which of the following is closest to your point of view?

	Overall	Region				
		West	Central	Central East	East	North
Proactively invest in resiliency	62%	63%	69%	68%	58%	45%
Invest as part of ongoing replacement	23%	22%	20%	19%	26%	36%
Minimize specific investments	8%	9%	6%	8%	10%	9%
Don't know	6%	7%	4%	5%	7%	10%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Proactively invest in resiliency	65%	61%	62%	61%	58%	69%
Invest as part of ongoing replacement	21%	25%	24%	23%	27%	18%
Minimize specific investments	6%	8%	9%	9%	9%	7%
Don't know	7%	6%	4%	7%	6%	6%

Note: Response labels have been shortened for brevity. See slide 186 for full label text.

Investment Priorities

Growth

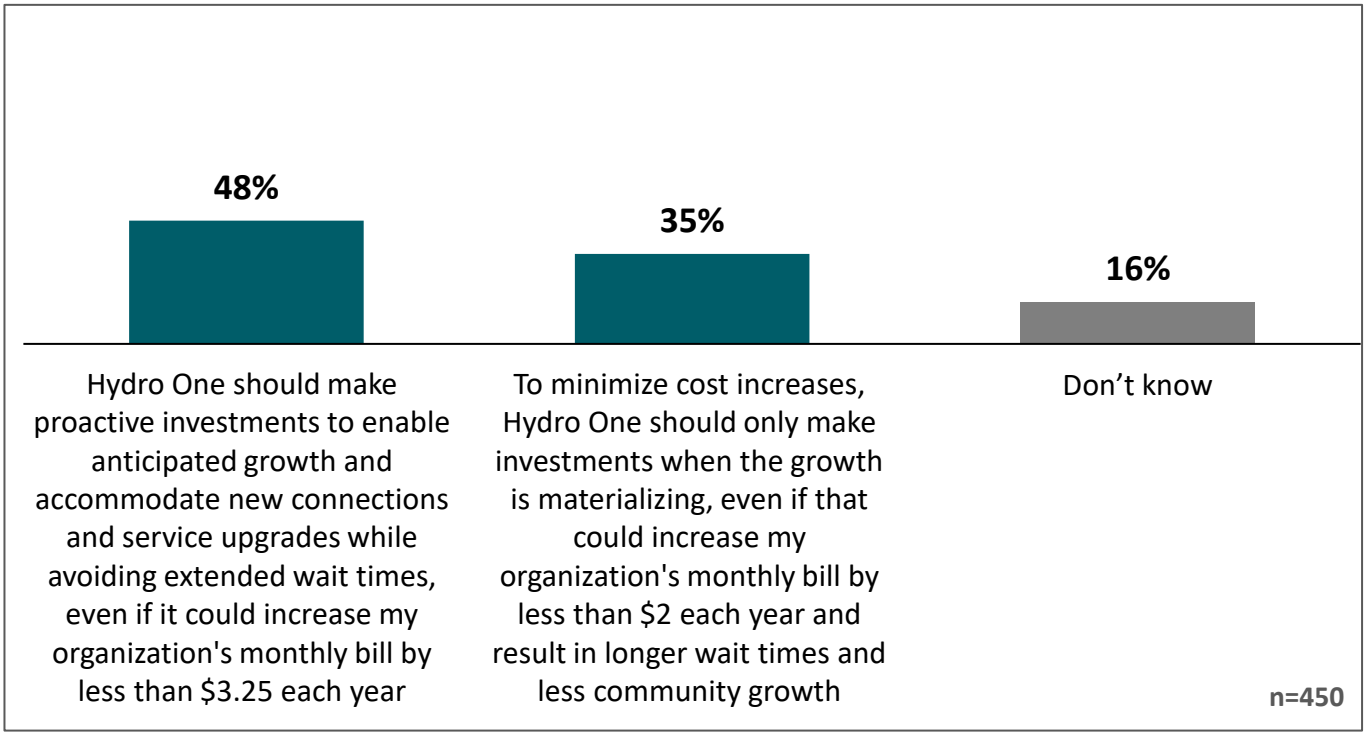
Electricity demand is on the rise across Ontario. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Hydro One** to make significant investments in the grid.

Increased growth can result in longer wait times to connect new homes or businesses to the system or facilitate upgrades for existing customers if insufficient capacity is available.

For instance, as increasing growth occurs, some new businesses may be asked to wait up to 2 years or longer for their facility to be connected to the **Hydro One** grid.

However, **Hydro One** could make proactive investments to enable anticipated growth and allow new homes or businesses to connect to the system in a timely manner, and to not delay service upgrades for existing customers.

Q Based on this, which is closest to your point of view?



Investment Priorities
Growth

Q Based on this, which is closest to your point of view?

	Region					
	Overall	West	Central	Central East	East	North
Proactive investments to enable growth	48%	50%	47%	46%	53%	47%
Only make investments as growth materializes	35%	31%	38%	36%	38%	35%
Don't know	16%	19%	15%	18%	10%	18%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Proactive investments to enable growth	51%	47%	45%	51%	42%	59%
Only make investments as growth materializes	35%	38%	36%	32%	39%	29%
Don't know	14%	15%	19%	17%	19%	12%

Note: Response labels have been shortened for brevity. See slide 190 for full label text.

Investment Priorities

Evolving Customer Requests & System Visibility

Small Business

Beyond residential and industrial growth, customers are increasingly requesting information and upgrades related to new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers.

Whether or not you are actively considering these types of technologies for yourself, **Hydro One** needs to be prepared to accommodate these types of customer requests, not just today, but over the next 5 to 10 years.

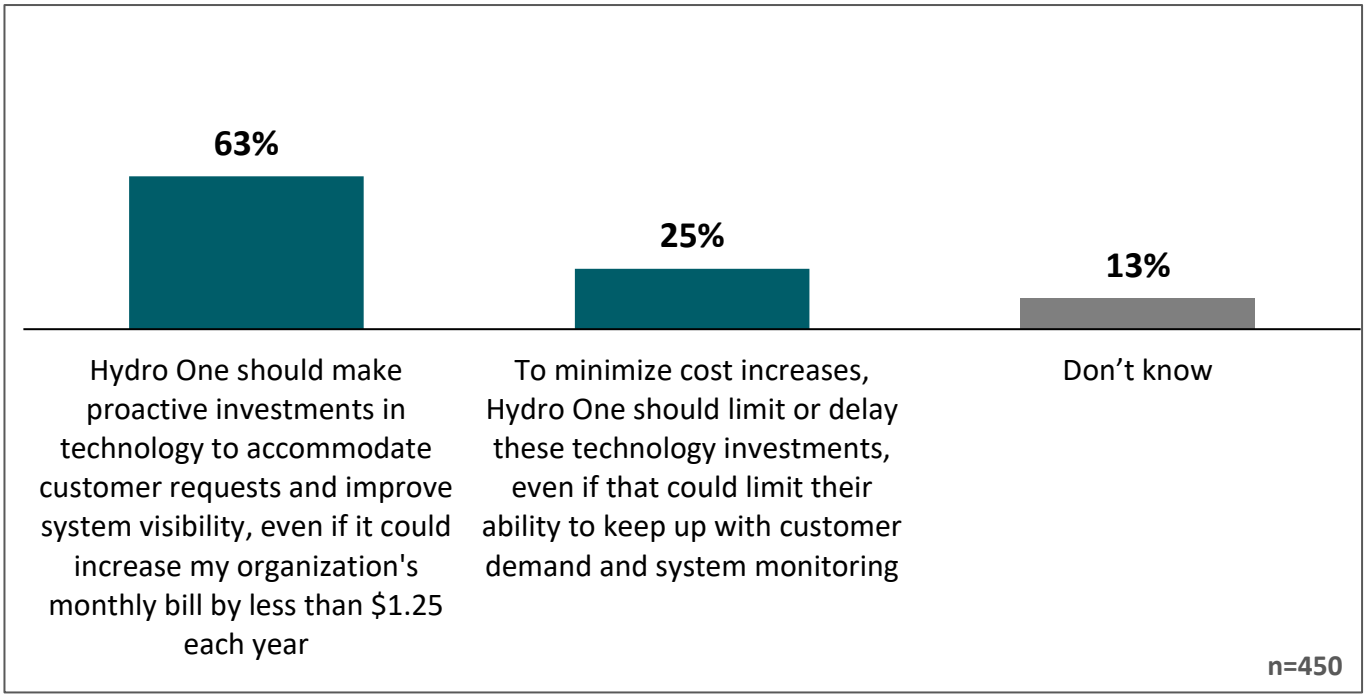
While **Hydro One** has an obligation to make certain investments to accommodate customer requests, planners have identified incremental investments that can help:

- Ensure that **Hydro One's** grid is ready to accommodate if and when customers request to connect new technologies.

- Give the **Hydro One** control room more "visibility" into exactly where and how much electricity is being used in real-time, helping make more informed decisions on managing electricity demand and equipment maintenance or upgrades.

As the pace of change and customer needs are rapidly evolving, delaying or limiting these investments means that **Hydro One** could struggle to keep up with customer demand for connecting new technology and lack the precision to monitor the grid as new technology adoption increases.

Q With regards to these investments, which of the following is closest to your point of view?



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Investment Priorities

Evolving Customer Requests & System Visibility

Small Business

Q With regards to these investments, which of the following is closest to your point of view?

	Overall	Region				
		West	Central	Central East	East	North
Proactive investments in technology	63%	67%	64%	62%	61%	58%
Limit or delay technology investments	25%	26%	26%	22%	26%	25%
Don't know	13%	8%	10%	16%	13%	17%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Proactive investments in technology	67%	62%	61%	60%	59%	68%
Limit or delay technology investments	20%	28%	27%	25%	26%	22%
Don't know	12%	10%	12%	15%	15%	9%

Note: Response labels have been shortened for brevity. See slide 192 for full label text.

Investment Priorities

Transmission Renewal

Small Business

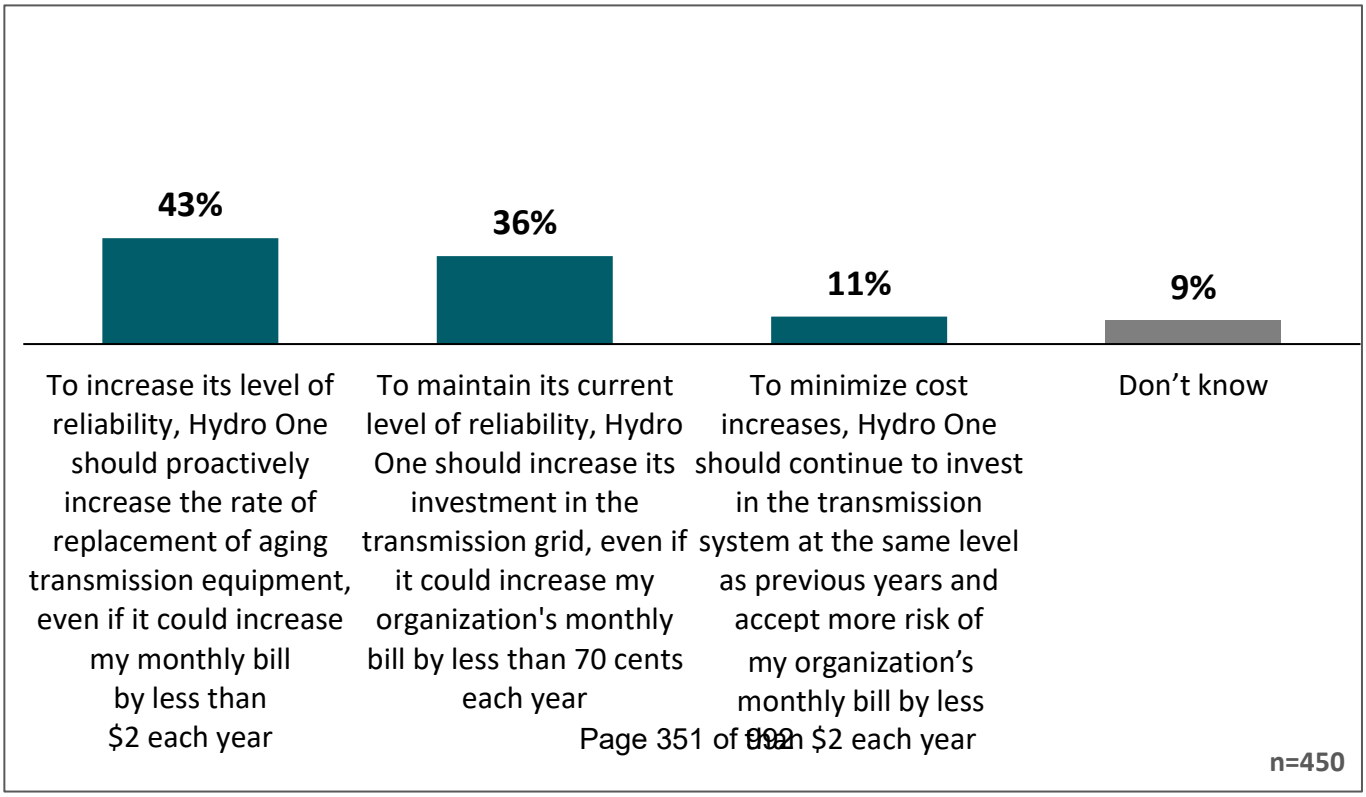
Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

Q With this in mind, what is closest to your point of view?



Investment Priorities
Transmission Renewal

Q With this in mind, what is closest to your point of view?

	Region					
	Overall	West	Central	Central East	East	North
Proactively increase investment to increase reliability	43%	42%	46%	50%	35%	37%
Increase investment to maintain current reliability	36%	37%	35%	32%	42%	36%
Continue to invest at the same level	11%	10%	11%	9%	11%	17%
Don't know	9%	11%	7%	9%	12%	10%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Proactively increase investment to increase reliability	47%	49%	40%	37%	35%	56%
Increase investment to maintain current reliability	36%	31%	37%	40%	39%	32%
Continue to invest at the same level	9%	12%	11%	13%	15%	6%
Don't know	8%	8%	12%	10%	11%	6%

Note: Response labels have been shortened for brevity. See slide 194 for full label text.

INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Online Survey Results

Section 5



Field Dates

The **Commercial & Industrial Online Survey** was sent to all Hydro One commercial & industrial customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **November 13th and December 13th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly demand, region and rate class. Customers were sent a survey that reflects their rate class (Sub Transmission low, medium, high, or General Service Demand).

In total, the commercial & industrial survey was sent to **4,827** customers from *customerexperience@hydroone.com*. Reminder emails were sent on November 20th, November 27th, December 4th and December 10th, 2024, to those who had not yet completed the survey.

Commercial & Industrial Online Survey Completes

A total of **311** (unweighted) Hydro One commercial & industrial customers completed the online survey.

Sample Weighting

The commercial & industrial online survey sample was weighted down to n=300 proportionately by consumption quartiles and region in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

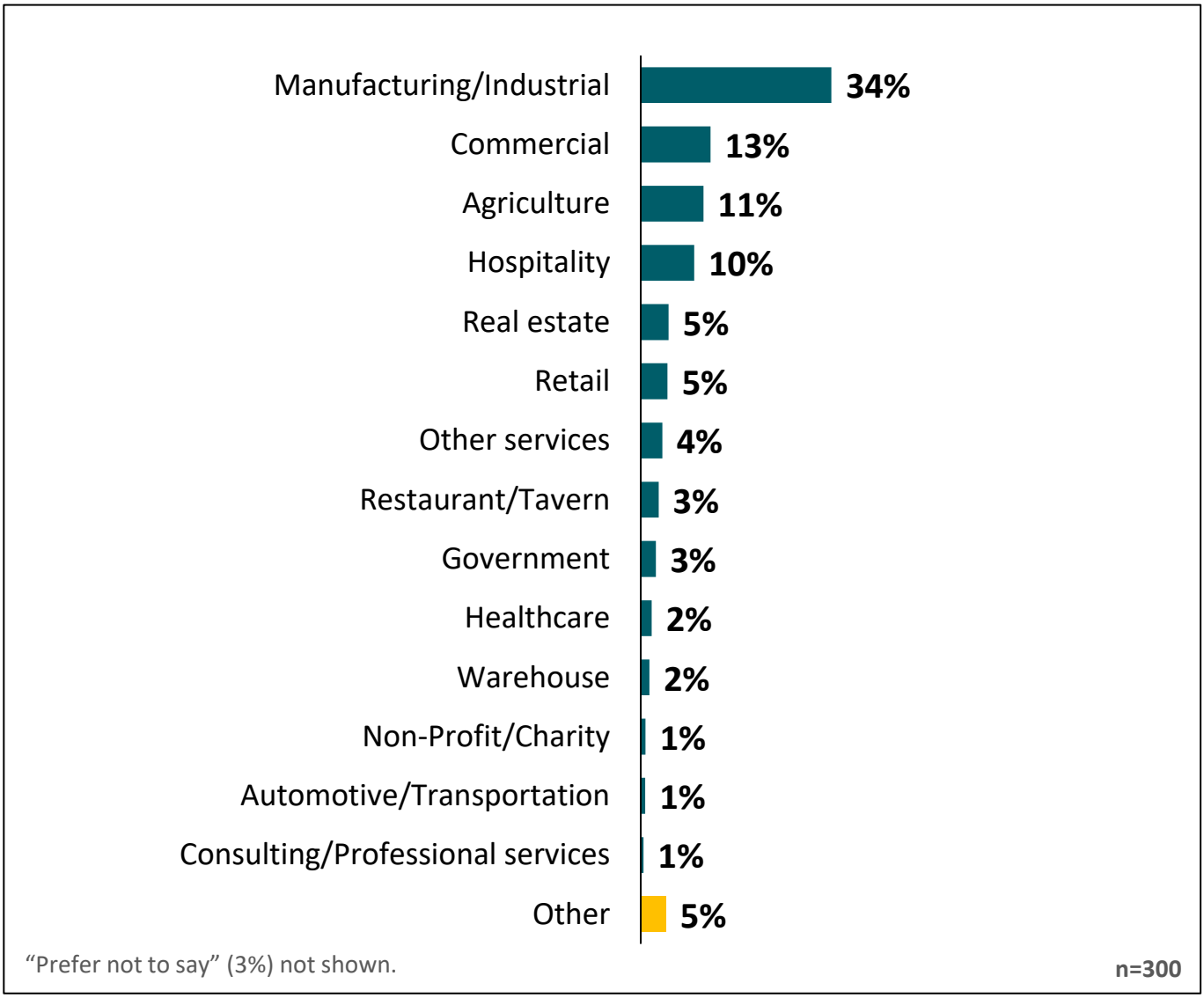
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	19 (18)	35 (26)	28 (20)	24 (21)	106 (86)
Central	17 (22)	22 (24)	21 (21)	13 (15)	73 (82)
Central East	15 (18)	12 (11)	19 (17)	18 (19)	64 (66)
East	6 (7)	7 (7)	8 (7)	7 (7)	28 (28)
North	9 (8)	7 (5)	9 (9)	10 (12)	35 (34)
Total	67 (75)	85 (75)	86 (75)	73 (75)	311 (300)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographic Breakdown

Commercial & Industrial

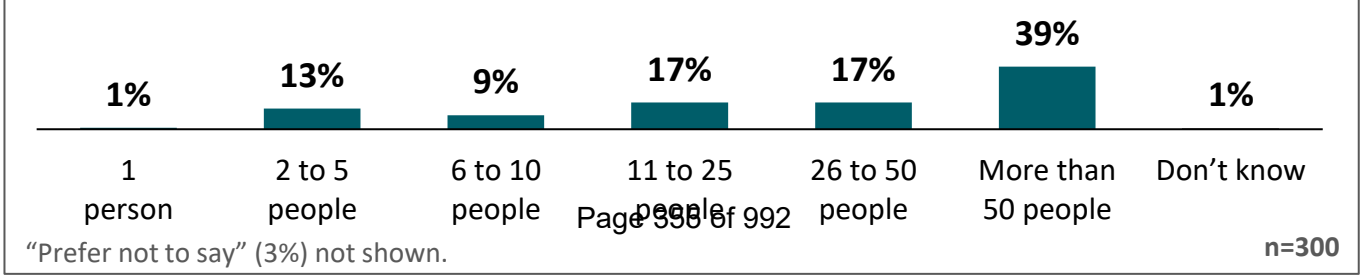
Q Business Sector



"Prefer not to say" (3%) not shown.

n=300

Q Business Size



"Prefer not to say" (3%) not shown.

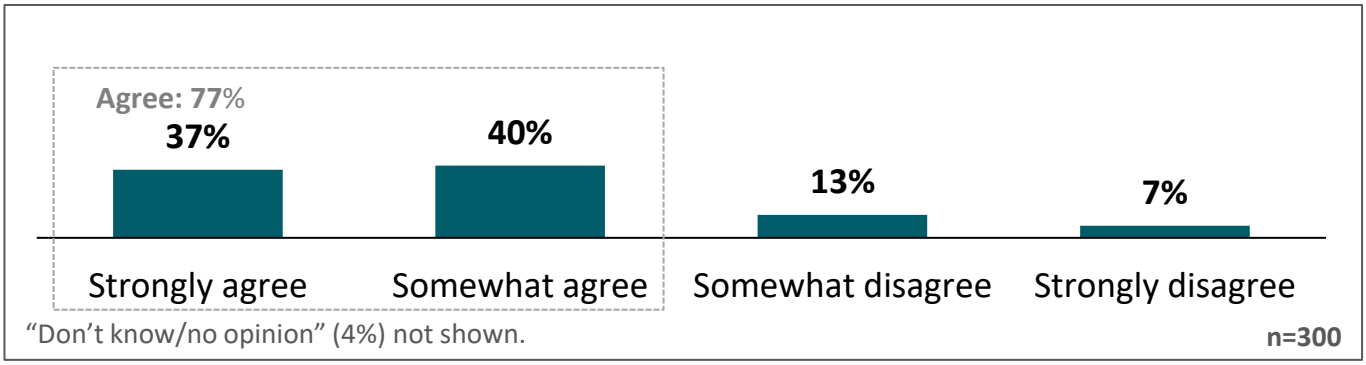
n=300

Environmental Controls

Commercial & Industrial

To what extent do you agree or disagree with the following statements?

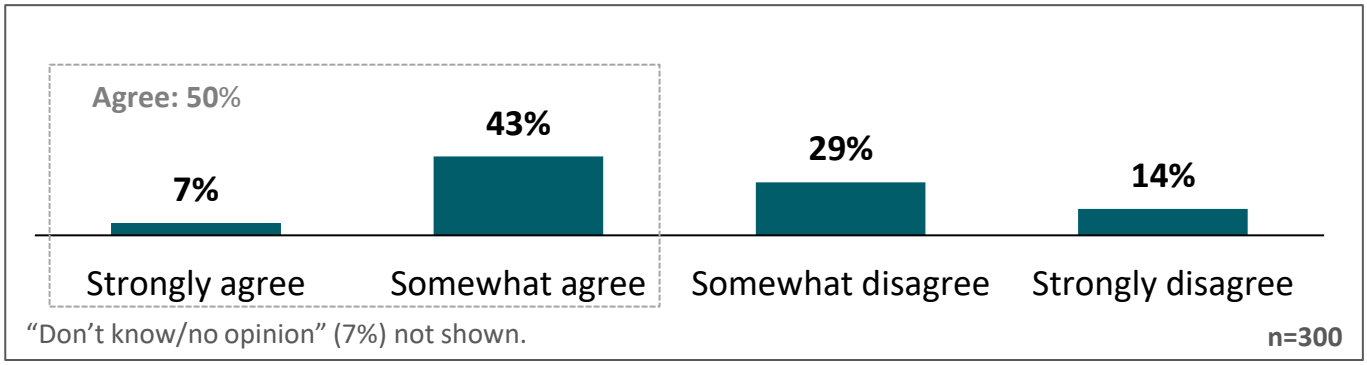
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (4%) not shown.

n=300

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (7%) not shown.

n=300

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Commercial & Industrial Customers

Familiarity & Experience



Familiarity & Experience
Preamble

Before we begin, this survey has **three key objectives**.

First, **Hydro One** wants to better understand your experiences as a customer.

Second, **Hydro One** wants your input on some of the investment areas they could focus on in the future.

Third, **Hydro One** wants to learn a little bit more about their customers. This will help them ensure that they are receiving feedback that represents a wide range of customers.

First, let's talk about your experience.

While you might have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a commercial & industrial customer.

***Note**: The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a customer with an average monthly demand of [demand] and average monthly consumption of [usage].

Estimate Legend

Customer Group	[demand]	[usage]
GSd	110 kW	34,334 kWh
ST-Low	500 kW	88,780 kWh
ST-Med	2,808 kW	1,373,443 kWh
ST-High	13,730 kW	2,641,420 kWh

Familiarity & Experience

Familiarity with Hydro One's Role in the System

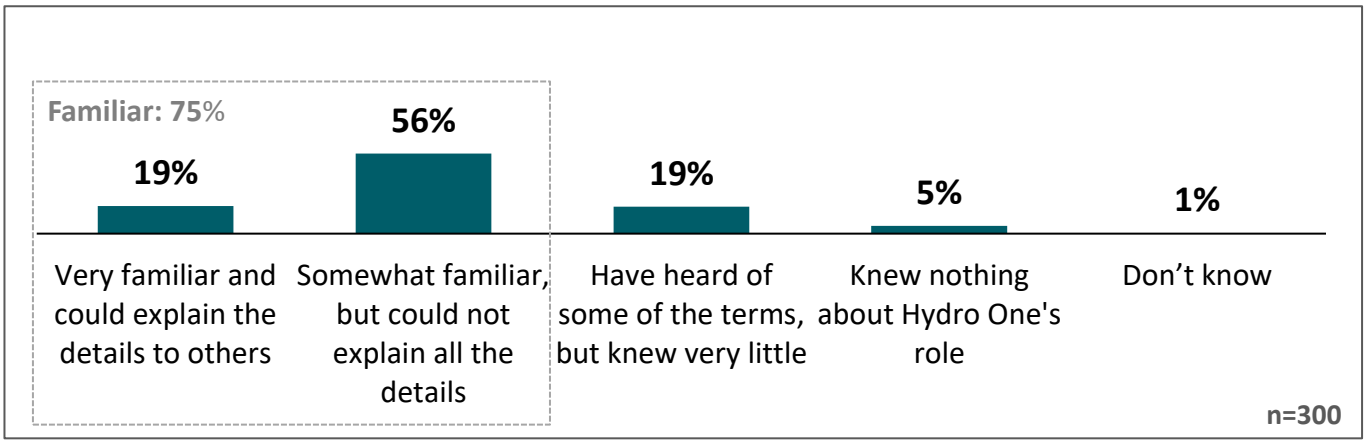
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	West	Central	Central East	East*	North
Very familiar	22%	21%	18%	22%	20%
Somewhat familiar	50%	58%	52%	61%	54%
Knew very little	22%	17%	22%	13%	17%
Knew nothing	7%	3%	8%	4%	9%
Don't know	--	2%	--	--	--
Familiar (Very + Somewhat)	**71%**	**79%**	**70%**	**83%**	**74%**

***Note: Small sample size (n=28); interpret results with caution**

Familiarity & Experience

Familiarity with Hydro One's Role in the System

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very familiar	19%	21%	15%	18%	23%	19%	21%
Somewhat familiar	56%	57%	54%	62%	51%	56%	55%
Knew very little	19%	17%	25%	15%	18%	20%	14%
Knew nothing	5%	6%	4%	4%	8%	5%	6%
Don't know	1%	--	1%	1%	--	--	3%
Familiar (Very + Somewhat)	**75%**	**77%**	**69%**	**80%**	**74%**	**75%**	**77%**

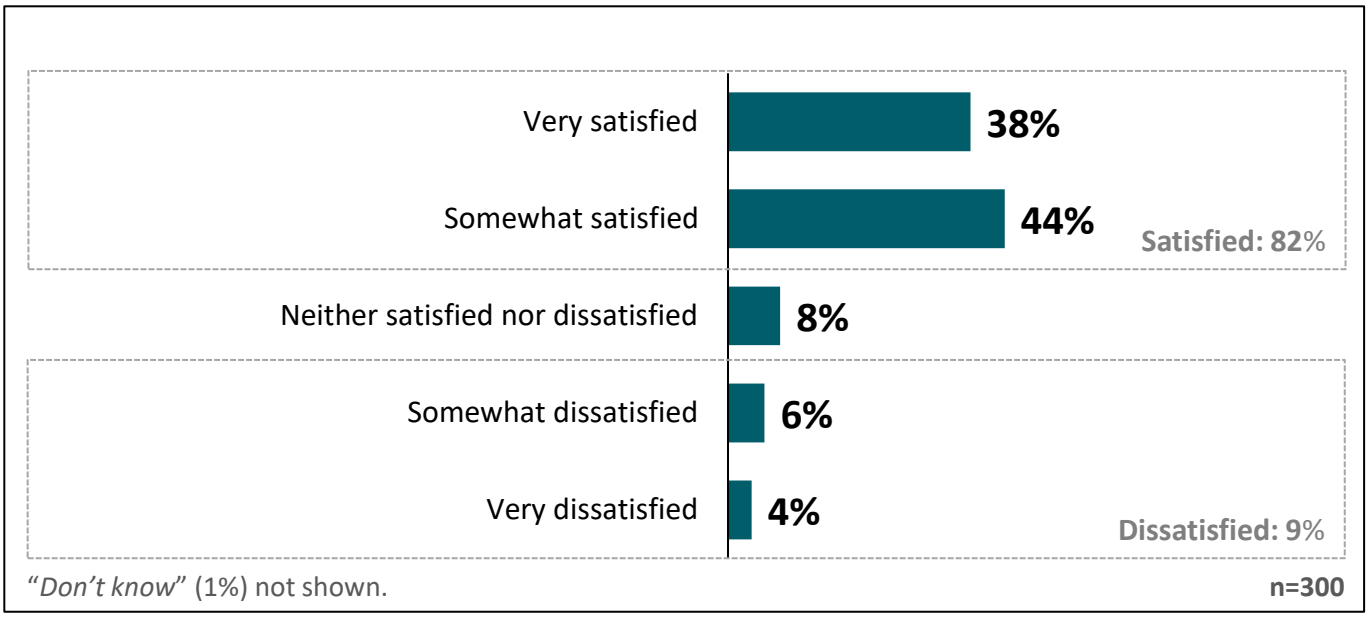
Familiarity & Experience

Overall Satisfaction with Hydro One

Commercial & Industrial

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from **Hydro One**?



"*Don't know*" (1%) not shown. **n=300**

Region

	West	Central	Central East	East*	North
Very satisfied	33%	45%	44%	45%	35%
Somewhat satisfied	48%	46%	35%	43%	44%
Neither	9%	5%	16%	--	7%
Somewhat dissatisfied	6%	2%	5%	--	10%
Very dissatisfied	3%	3%	--	8%	4%
Don't know	--	--	--	4%	--
Satisfied (Very + Somewhat)	**82%**	**91%**	**79%**	**88%**	**79%**
Dissatisfied (Very + Somewhat)	**9%**	**5%**	**5%**	**8%**	**14%**

***Note: Small sample size (n=28); interpret results with caution**

Familiarity & Experience

Overall Satisfaction with Hydro One

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from **Hydro One**?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very satisfied	38%	42%	38%	35%	38%	35%	47%
Somewhat satisfied	44%	38%	44%	41%	51%	44%	41%
Neither	8%	11%	7%	6%	9%	9%	7%
Somewhat dissatisfied	6%	6%	4%	10%	3%	7%	3%
Very dissatisfied	4%	4%	5%	6%	--	4%	1%
Don't know	1%	--	1%	1%	--	<1%	1%
Satisfied (Very + Somewhat)	**82%**	**80%**	**82%**	**77%**	**88%**	**80%**	**88%**
Dissatisfied (Very + Somewhat)	**9%**	**10%**	**9%**	**16%**	**3%**	**11%**	**4%**

Familiarity & Experience

How can Hydro One improve services?

Q Is there anything in particular you would like **Hydro One** to do to improve its services to your organization?

Response	%
Decrease outages/interruptions	9.1%
Improve customer service	4.0%
Satisfied with services/no issues	3.8%
Upgrade/better maintain infrastructure	3.2%
Lower rates/decrease bills	3.2%
Improve communication during outages	2.8%
Bury power lines/better line maintenance	2.8%
Improve general communication	2.0%
Billing improvements - timing/payments/bill format	1.9%
More information/visibility into usage	1.3%
Improve response time for outages	1.1%
More transparency around costs	0.9%
Find efficiencies/costs savings	0.8%
Provide incentives/rebates	0.7%
Improve website/app	0.6%
Address/proactive tree trimming	0.6%
Building capacity/addressing growth	0.4%
Other	2.2%
None/Don’t know	58.5%

Note: Only responses >0.1% shown

Familiarity & Experience

Bill Familiarity

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

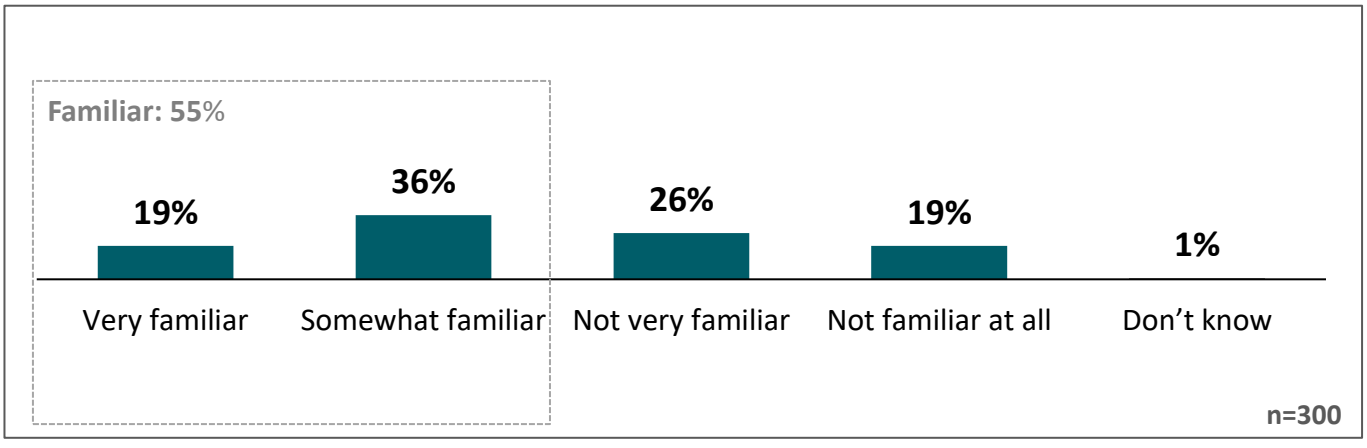
Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to **Hydro One**. As of October 1st, 2024, for a typical commercial & industrial customer, about **[bill percentage]** or **[bill amount]** goes to **Hydro One** per month. This amount is split into **[distribution amount]** for distribution and **[transmission amount]** for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Bill Legend

Customer Group	[bill percentage]	[bill amount]	[distribution amount]	[transmission amount]
GSd	38%	$2,945	$2,355	$590
ST-Low	36%	$6,640	$2,055	$4,585
ST-Med	16%	$31,550	$5,800	$25,750
ST-High	30%	$149,425	$23,525	$125,900

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Hydro One**?



Familiarity & Experience

Bill Familiarity

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Hydro One**?

		Region				
	Overall	**West**	**Central**	**Central East**	**East***	**North**
Very familiar	19%	21%	34%	18%	22%	7%
Somewhat familiar	36%	35%	29%	35%	26%	48%
Not very familiar	26%	21%	20%	24%	21%	45%
Not familiar at all	19%	22%	13%	23%	32%	--
Don't know	1%	--	4%	--	--	--
Familiar (Very + Somewhat)	**55%**	**56%**	**63%**	**53%**	**48%**	**55%**

	Consumption Quartiles				Bill Impact	
	Low	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very familiar	16%	15%	23%	20%	19%	16%
Somewhat familiar	44%	40%	27%	32%	36%	35%
Not very familiar	20%	28%	27%	28%	26%	26%
Not familiar at all	19%	17%	19%	19%	18%	21%
Don't know	--	--	3%	--	<1%	1%
Familiar (Very + Somewhat)	**60%**	**55%**	**51%**	**53%**	**56%**	**51%**

***Note: Small sample size (n=28); interpret results with caution**

Familiarity & Experience

Familiarity with Rate Applications

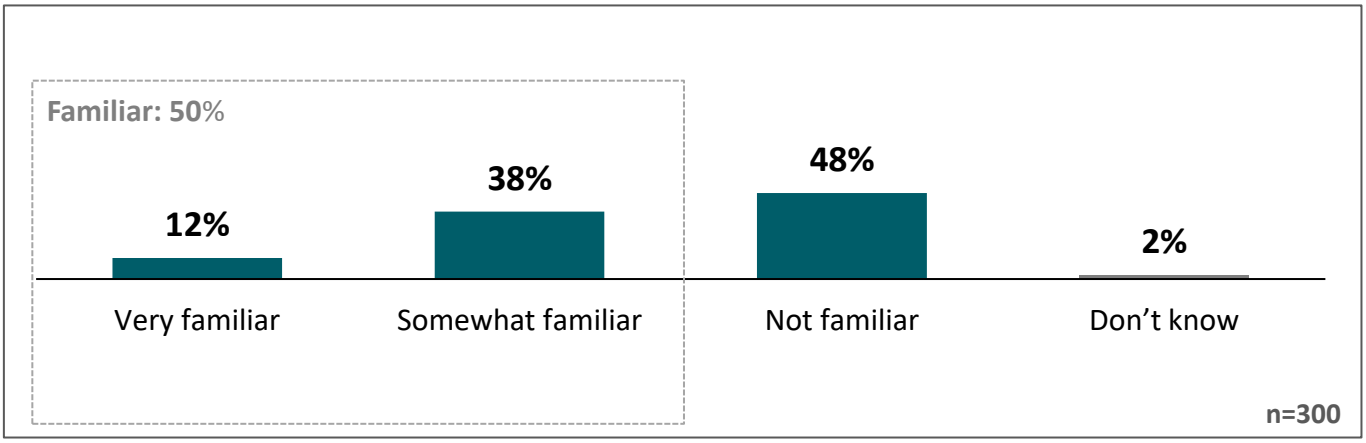
Hydro One is funded by the rates paid by its customers.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



Region

	West	Central	Central East	East*	North
Very familiar	13%	25%	8%	18%	12%
Somewhat familiar	40%	34%	38%	35%	43%
Not familiar	44%	37%	49%	42%	45%
Don't know	3%	5%	5%	4%	--
Familiar (Very + Somewhat)	**53%**	**59%**	**46%**	**53%**	**55%**

***Note: Small sample size (n=28); interpret results with caution**

Familiarity & Experience

Familiarity with Rate Applications

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?

		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Very familiar	12%	8%	16%	10%	13%	12%	11%
Somewhat familiar	38%	47%	33%	33%	37%	39%	32%
Not familiar	48%	43%	47%	54%	49%	46%	54%
Don't know	2%	2%	5%	3%	--	2%	3%
Familiar (Very + Somewhat)	**50%**	**56%**	**49%**	**43%**	**51%**	**51%**	**43%**

INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Customer Priorities



Customer Priorities

Response Labels Legend

Commercial & Industrial

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 8 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity	Providing reliable electricity to my organization
Enhancing Hydro One's customer service	Enhancing Hydro One's customer service
Offering programs to help manage usage	Offering programs that can help customers better manage their electricity usage
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Enhancing the grid for new technologies	Enhancing the grid so that customers can connect new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

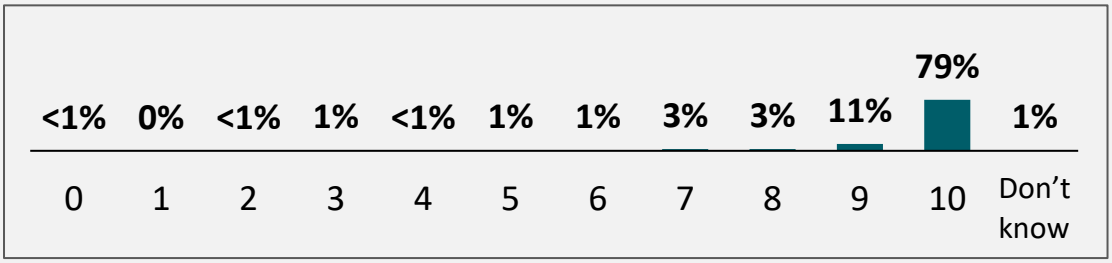
Customer Priorities

Importance of Customer Priorities

Commercial & Industrial

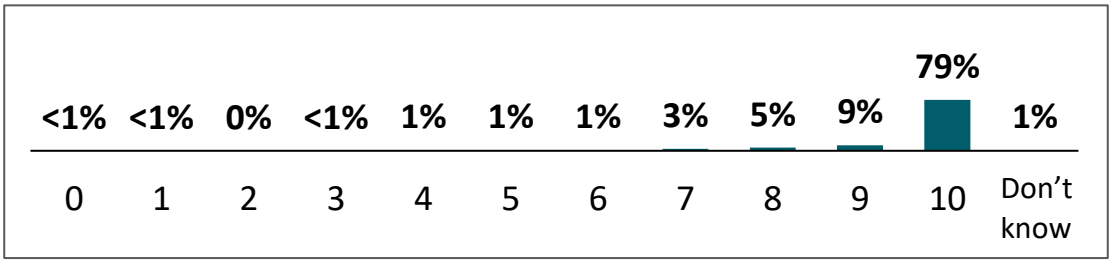
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

Delivering electricity at reasonable rates [average = **9.5**]



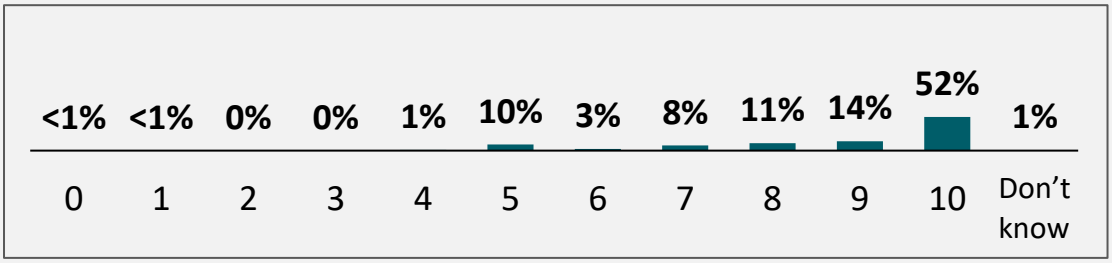
Not at all important — Extremely important

Providing reliable electricity [average = **9.5**]



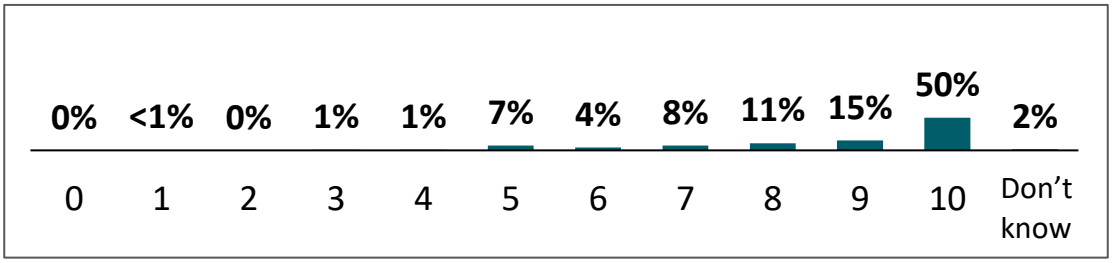
Not at all important — Extremely important

Ensuring the safety of electricity infrastructure [average = **8.7**]



Not at all important — Extremely important

Meeting the growing electricity need [average = **8.7**]



Not at all important — Extremely important

Note: Priority labels have been shortened for brevity. See slide 212 for full label text.
"Don't know" not included in calculation of means.

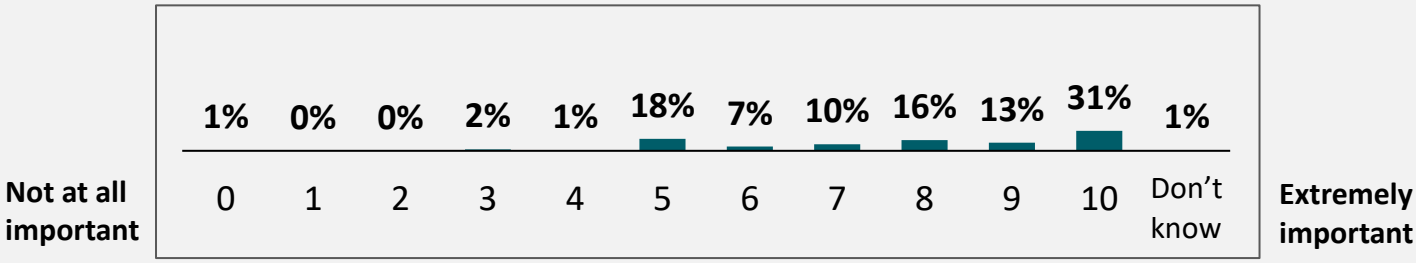
Customer Priorities

Importance of Customer Priorities (Cont'd)

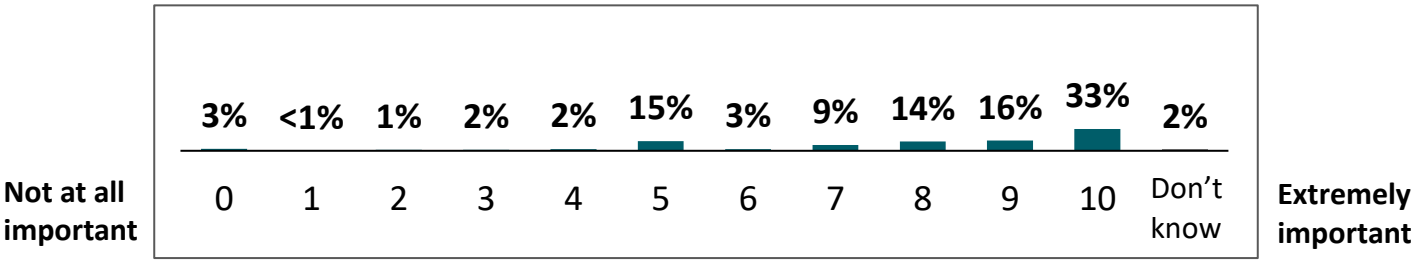
Commercial & Industrial

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

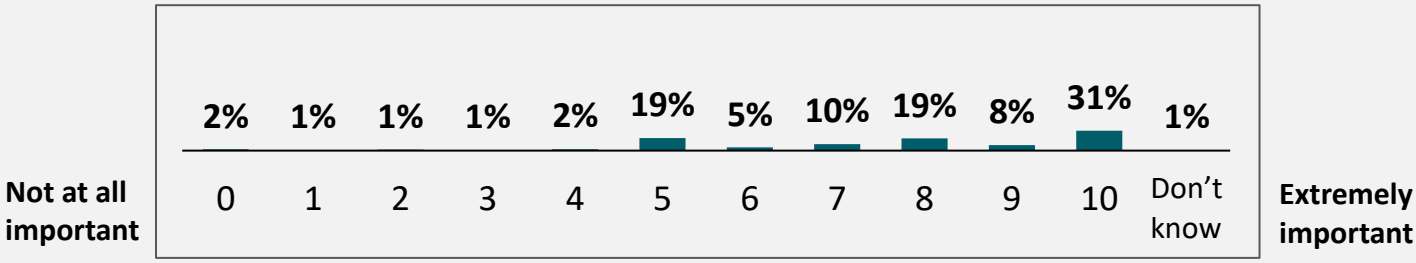
Enhancing Hydro One's customer service [average = **7.8**]



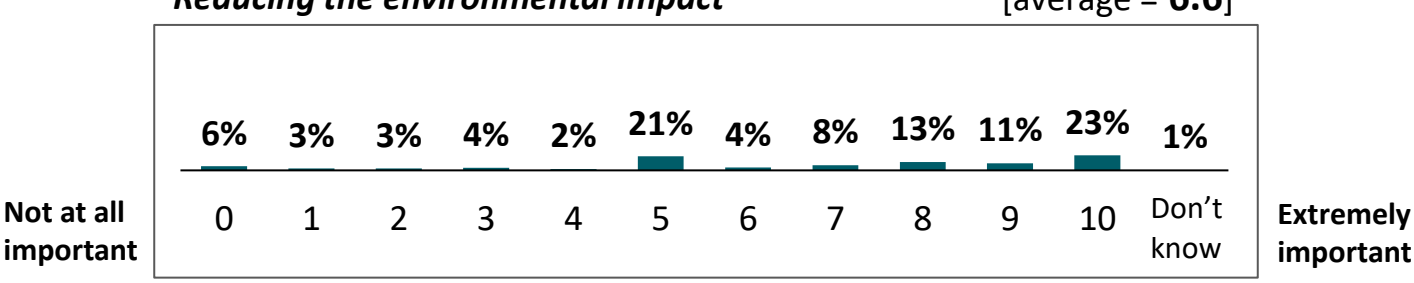
Enhancing the grid for new technologies [average = **7.7**]



Offering programs to help manage usage [average = **7.5**]



Reducing the environmental impact [average = **6.6**]



Note: Priority labels have been shortened for brevity. See slide 212 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Importance of Customer Priorities – Average Scores

Commercial & Industrial

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		Region				
Average Score	**Overall**	**West**	**Central**	**Central East**	**East***	**North**
Delivering electricity at reasonable rates	9.5	9.6	9.3	9.1	9.6	9.4
Providing reliable electricity	9.5	9.5	9.3	9.4	9.6	9.8
Ensuring the safety of electricity infrastructure	8.7	8.5	8.1	9.0	9.0	9.2
Meeting the growing electricity need	8.7	8.7	8.1	9.1	9.0	8.9
Enhancing Hydro One's customer service	7.8	7.9	6.9	7.9	8.0	8.2
Enhancing the grid for new technologies	7.7	7.4	7.6	8.1	8.3	8.1
Offering programs to help manage usage	7.5	7.2	7.7	8.1	7.8	7.7
Reducing the environmental impact	6.6	6.0	5.8	7.8	6.6	7.2

***Note: Small sample size (n=28); interpret results with caution.**
Priority labels have been shortened for brevity. See slide 212 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Importance of Customer Priorities – Average Scores

Commercial & Industrial

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		Consumption Quartiles				Bill Impact	
Average Score	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	9.5	9.6	9.6	9.3	9.5	9.6	9.3
Providing reliable electricity	9.5	9.4	9.6	9.3	9.6	9.5	9.5
Ensuring the safety of electricity infrastructure	8.7	8.8	8.5	8.4	9.0	8.7	8.6
Meeting the growing electricity need	8.7	8.9	8.5	8.7	8.5	8.6	8.9
Enhancing Hydro One's customer service	7.8	7.7	7.8	7.5	8.0	7.7	7.8
Enhancing the grid for new technologies	7.7	7.5	7.6	7.6	8.2	7.8	7.6
Offering programs to help manage usage	7.5	7.3	7.4	7.4	7.8	7.5	7.5
Reducing the environmental impact	6.6	6.6	6.4	6.4	6.9	6.4	6.9

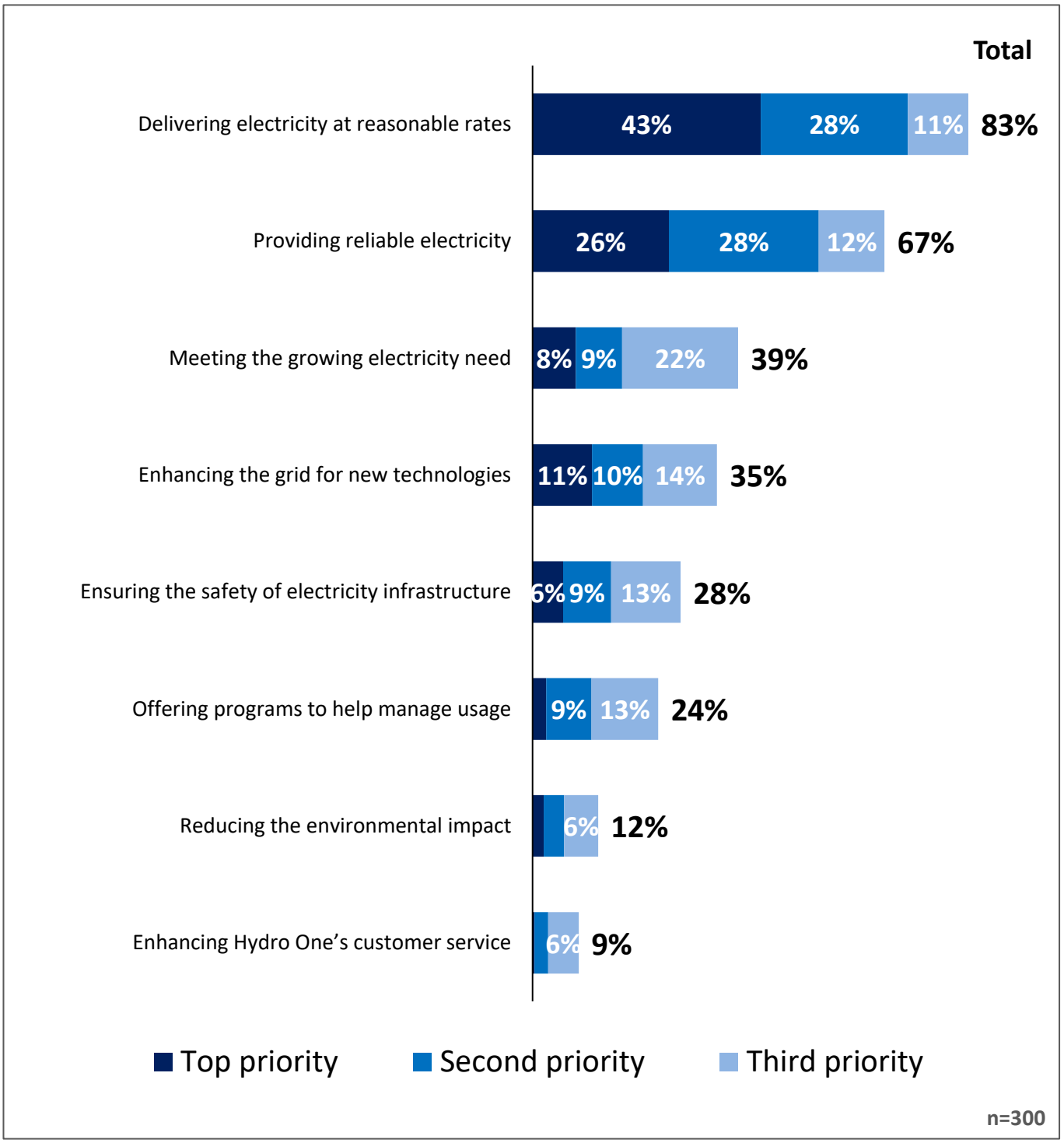
Note: Priority labels have been shortened for brevity. See slide 212 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Commercial & Industrial

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 212 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Commercial & Industrial

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Overall	Region: West	Region: Central	Region: Central East	Region: East*	Region: North
Delivering electricity at reasonable rates	83%	89%	83%	73%	82%	77%
Providing reliable electricity	67%	76%	71%	69%	69%	69%
Meeting the growing electricity need	39%	52%	31%	54%	23%	27%
Enhancing the grid for new technologies	35%	34%	30%	36%	38%	38%
Ensuring the safety of electricity infrastructure	28%	12%	33%	27%	33%	29%
Offering programs to help manage usage	24%	20%	17%	19%	17%	41%
Reducing the environmental impact	12%	2%	11%	20%	21%	15%
Enhancing Hydro One's customer service	9%	14%	10%	--	17%	5%

***Note: Small sample size (n=28); interpret results with caution**

Priority labels have been shortened for brevity. See slide 212 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Commercial & Industrial

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

		Consumption Quartiles				Bill Impact	
% who select as top 3 priority	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	83%	76%	86%	84%	84%	86%	72%
Providing reliable electricity	67%	72%	65%	67%	62%	65%	72%
Meeting the growing electricity need	39%	49%	35%	31%	41%	39%	39%
Enhancing the grid for new technologies	35%	32%	32%	35%	41%	34%	37%
Ensuring the safety of electricity infrastructure	28%	18%	38%	28%	28%	28%	27%
Offering programs to help manage usage	24%	20%	19%	33%	23%	24%	24%
Reducing the environmental impact	12%	15%	13%	11%	10%	14%	6%
Enhancing Hydro One's customer service	9%	8%	11%	7%	9%	8%	11%

Note: Priority labels have been shortened for brevity. See slide 212 for full label text. "Don't know" not shown.

Customer Priorities

Other Priorities

Commercial & Industrial

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Reasonable/affordable rates	5.9%
Enhancing the grid/infrastructure	4.9%
Improving reliability/less outages	3.7%
Having alternative energy/sustainable sources/green technology	2.0%
Electric vehicle (EV) infrastructure investment	1.5%
Burying lines underground/removing hydro poles	1.1%
Information/programs to manage electricity usage	0.9%
Affordable renewable energy	0.8%
Improving customer service/communication	0.8%
Meeting growing needs for electricity	0.7%
Support/incentives for new technologies or energy efficiency efforts	0.5%
Tree trimming/removal	0.4%
Focus on nuclear energy/power	0.4%
Reducing length of outages	0.4%
Reducing environmental impacts	0.3%
Other	1.9%
None/Don't know	73.8%

Note: Only responses >0.1% shown

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Commercial & Industrial Customers

Reliability Experience

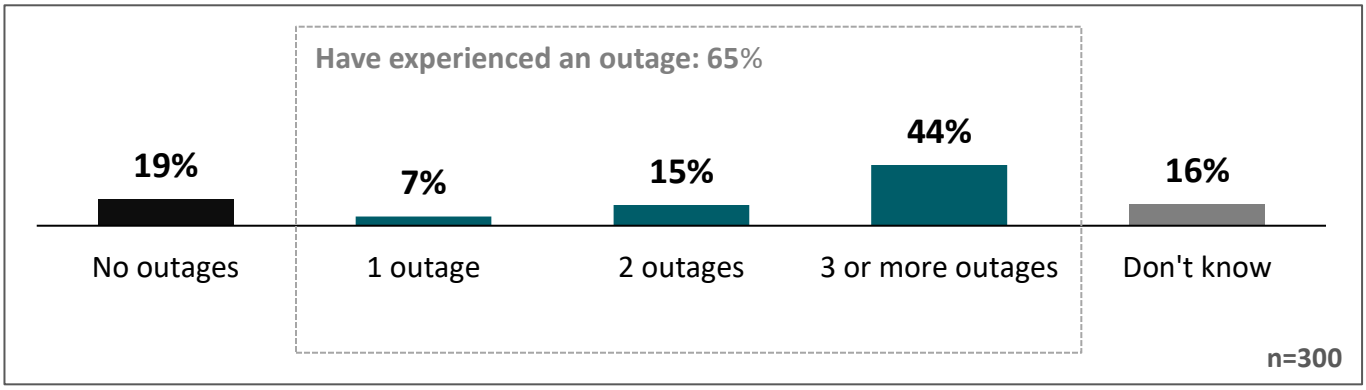


Reliability Experience
Number of Outages Experienced

Commercial & Industrial

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at your organization **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



Region

	West	Central	Central East	East*	North
No outages	15%	15%	30%	21%	5%
1 outage	7%	3%	11%	13%	6%
2 outages	9%	11%	16%	20%	28%
3 or more outages	50%	48%	28%	38%	51%
Don't know	20%	23%	14%	8%	10%
Have experienced at least 1 outage	**66%**	**62%**	**56%**	**71%**	**85%**

***Note: Small sample size (n=28); interpret results with caution**

Reliability Experience
Number of Outages Experienced

Commercial & Industrial

Q Have you experienced any power outages at your organization **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

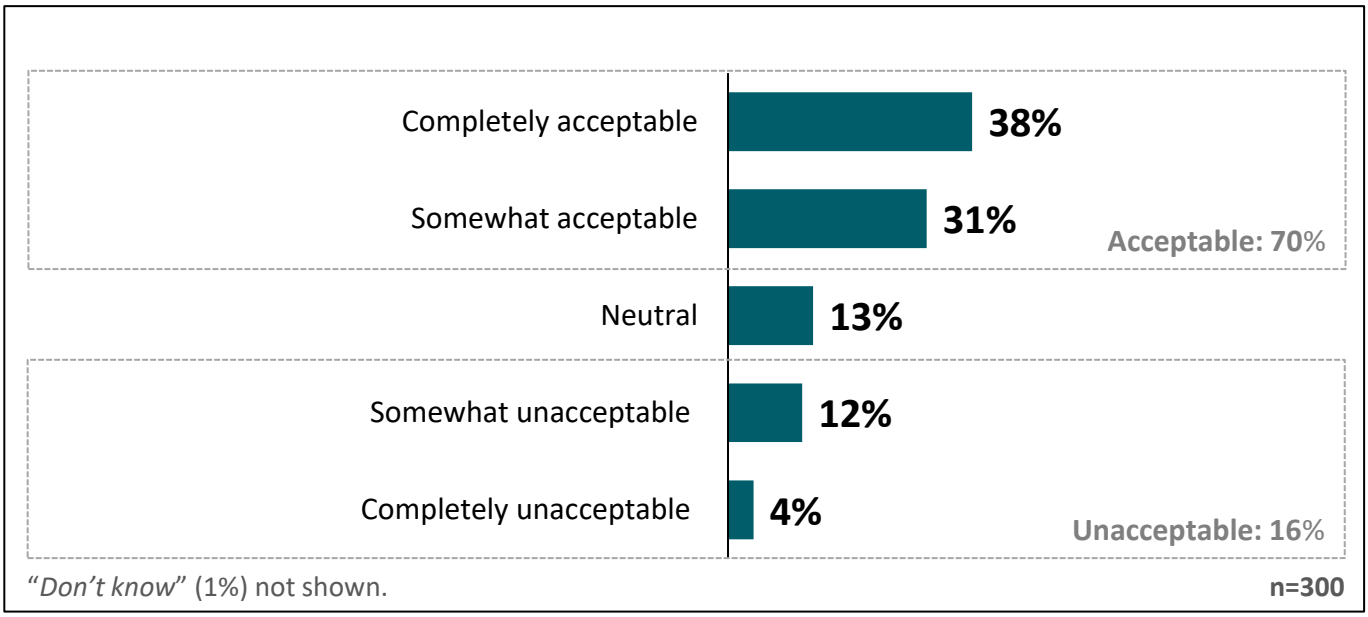
		Consumption Quartiles				Bill Impact	
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
No outages	19%	24%	16%	18%	19%	20%	17%
1 outage	7%	3%	11%	3%	10%	6%	10%
2 outages	15%	17%	16%	16%	10%	14%	19%
3 or more outages	44%	46%	39%	44%	46%	46%	37%
Don't know	16%	11%	18%	18%	15%	15%	17%
Have experienced at least 1 outage	**65%**	**66%**	**66%**	**64%**	**66%**	**65%**	**66%**

Reliability Experience

Current Reliability of Electricity Service

Commercial & Industrial

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (1%) not shown. n=300

Region

	West	Central	Central East	East*	North
Completely acceptable	31%	36%	42%	63%	36%
Somewhat acceptable	43%	29%	27%	29%	35%
Neutral	11%	16%	15%	8%	7%
Somewhat unacceptable	10%	17%	10%	--	18%
Completely unacceptable	4%	--	3%	--	4%
Don't know	1%	2%	3%	--	--
Acceptable (Completely + Somewhat)	**74%**	**65%**	**70%**	**92%**	**71%**
Unacceptable (Completely + Somewhat)	**14%**	**17%**	**13%**	**--**	**22%**

***Note: Small sample size (n=28); interpret results with caution**

Reliability Experience

Current Reliability of Electricity Service

Commercial & Industrial

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?

		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Completely acceptable	38%	27%	39%	40%	48%	35%	49%
Somewhat acceptable	31%	36%	34%	28%	28%	33%	27%
Neutral	13%	18%	11%	15%	9%	15%	8%
Somewhat unacceptable	12%	12%	11%	11%	13%	12%	11%
Completely unacceptable	4%	7%	3%	4%	1%	5%	2%
Don't know	1%	--	1%	3%	1%	1%	3%
Acceptable (Completely + Somewhat)	**70%**	**63%**	**73%**	**67%**	**75%**	**68%**	**76%**
Unacceptable (Completely + Somewhat)	**16%**	**19%**	**14%**	**15%**	**14%**	**16%**	**13%**

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Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights
Improving communications during outages	Improving communications during outages, including estimated restoration times

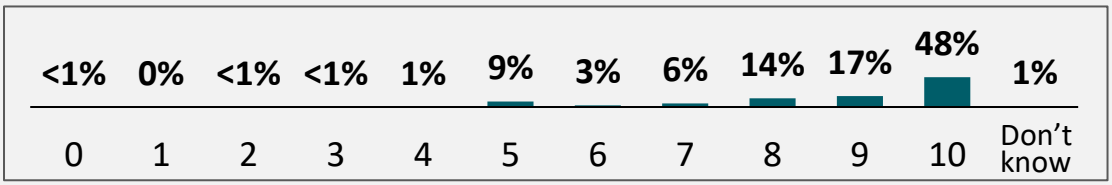
Reliability Experience

Importance of Reliability Priorities

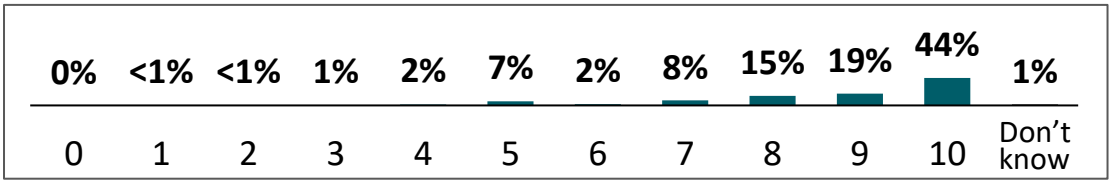
Commercial & Industrial

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

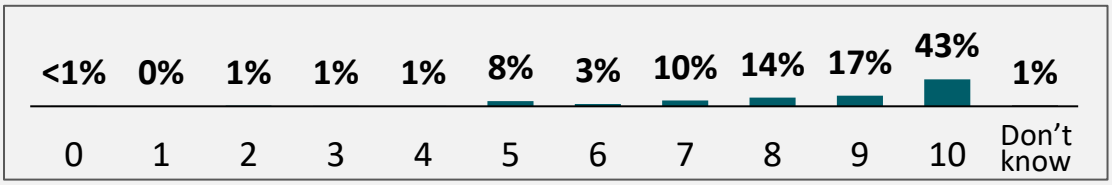
Reducing length of non-weather outages [average = **8.7**]



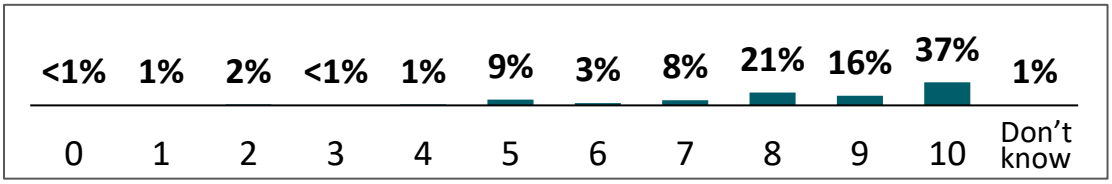
Reducing number of non-weather outages [average = **8.6**]



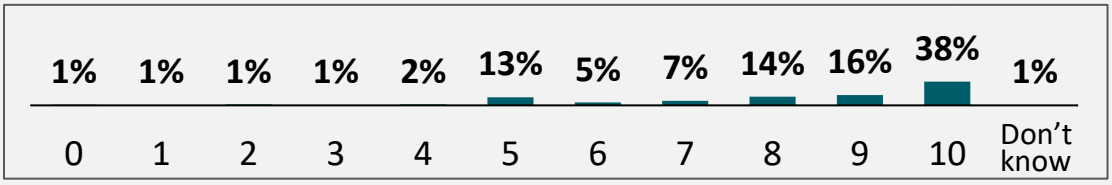
Reducing length of weather-caused outages [average = **8.5**]



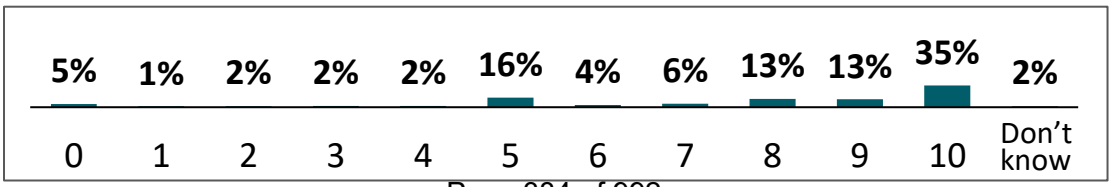
Reducing number of weather-caused outages [average = **8.2**]



Improving communications during outages [average = **8.1**]



Reducing momentary interruptions in power [average = **7.4**]



Note: Priority labels have been shortened for brevity. See slide 226 for full label text.
"Don't know" not included in calculation of means.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Commercial & Industrial

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Region				
Average Score	**Overall**	**West**	**Central**	**Central East**	**East***	**North**
Reducing length of non-weather outages	8.7	8.5	8.8	8.5	9.0	8.8
Reducing number of non-weather outages	8.6	8.6	8.5	8.4	8.8	8.7
Reducing length of weather-caused outages	8.5	7.9	8.4	8.6	8.6	9.2
Reducing number of weather-caused outages	8.2	7.6	8.2	8.3	8.4	8.5
Improving communications during outages	8.1	7.7	7.7	8.5	8.4	8.7
Reducing momentary interruptions in power	7.4	7.7	7.9	7.0	6.3	7.5

***Note: Small sample size (n=28); interpret results with caution**
Priority labels have been shortened for brevity. See slide 226 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Commercial & Industrial

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Consumption Quartiles				Bill Impact	
Average Score	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Reducing length of non-weather outages	8.7	8.9	8.8	8.4	8.7	8.7	8.7
Reducing number of non-weather outages	8.6	8.7	8.7	8.2	8.9	8.7	8.5
Reducing length of weather-caused outages	8.5	8.3	8.4	8.4	8.7	8.6	8.0
Reducing number of weather-caused outages	8.2	8.0	8.1	8.2	8.7	8.3	7.9
Improving communications during outages	8.1	8.0	7.9	7.8	8.5	8.2	7.6
Reducing momentary interruptions in power	7.4	7.4	7.8	7.1	7.5	7.7	6.5

Note: Priority labels have been shortened for brevity. See slide 226 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

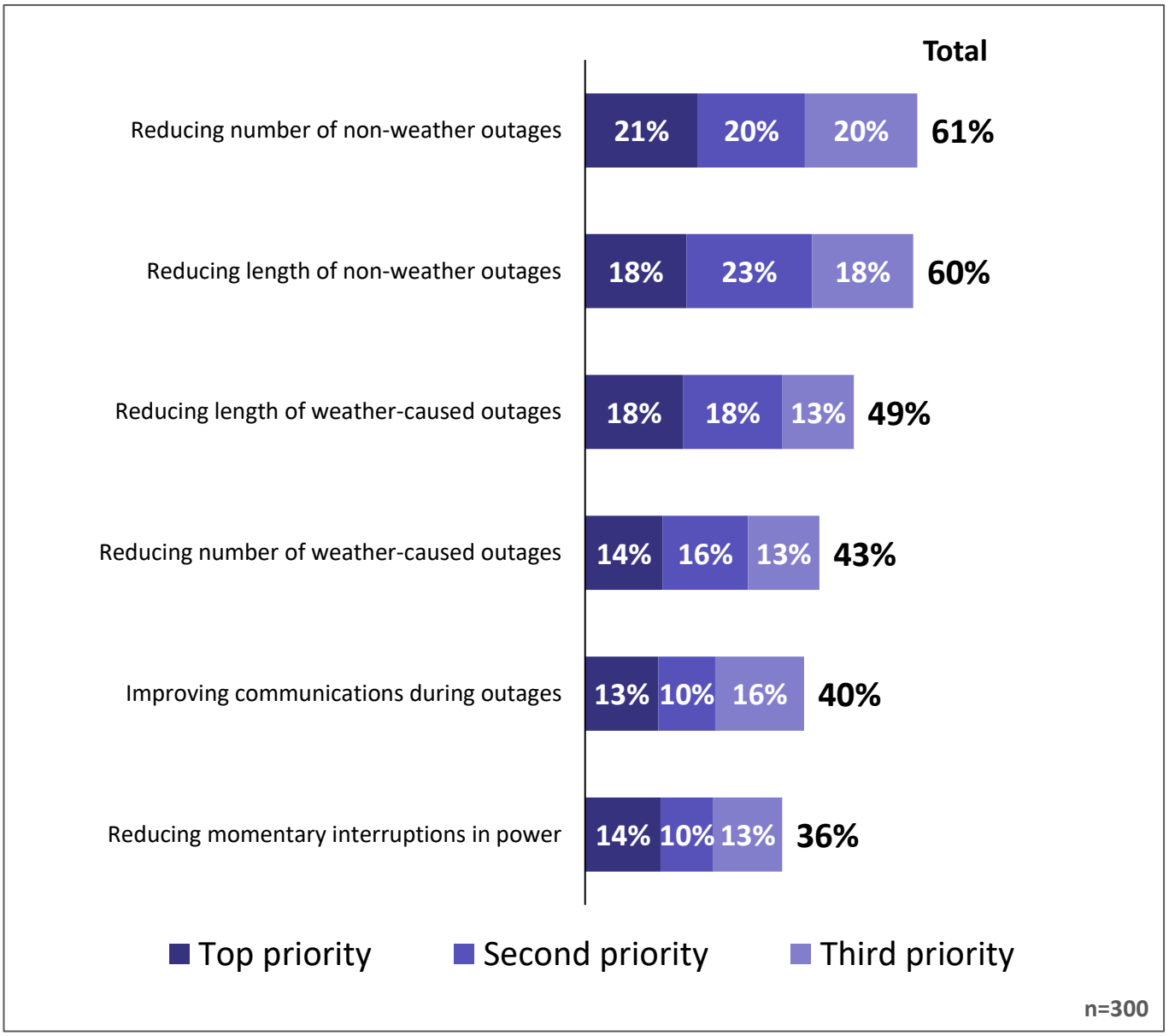
Reliability Experience

Ranking Reliability Priorities

Commercial & Industrial

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?



Note: Priority labels have been shortened for brevity. See slide 226 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Commercial & Industrial

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Region				
% who select as top 3 priority	**Overall**	**West**	**Central**	**Central East**	**East***	**North**
Reducing number of non-weather outages	61%	56%	62%	59%	61%	80%
Reducing length of non-weather outages	60%	68%	61%	46%	55%	52%
Reducing length of weather-caused outages	49%	45%	48%	62%	46%	42%
Reducing number of weather-caused outages	43%	31%	42%	48%	57%	40%
Improving communications during outages	40%	35%	42%	40%	35%	49%
Reducing momentary interruptions in power	36%	49%	38%	26%	32%	27%

***Note: Small sample size (n=28); interpret results with caution**

Priority labels have been shortened for brevity. See slide 226 for full label text. "Don't know" not shown.226

Reliability Experience
Ranking Reliability Priorities

Commercial & Industrial

Q Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

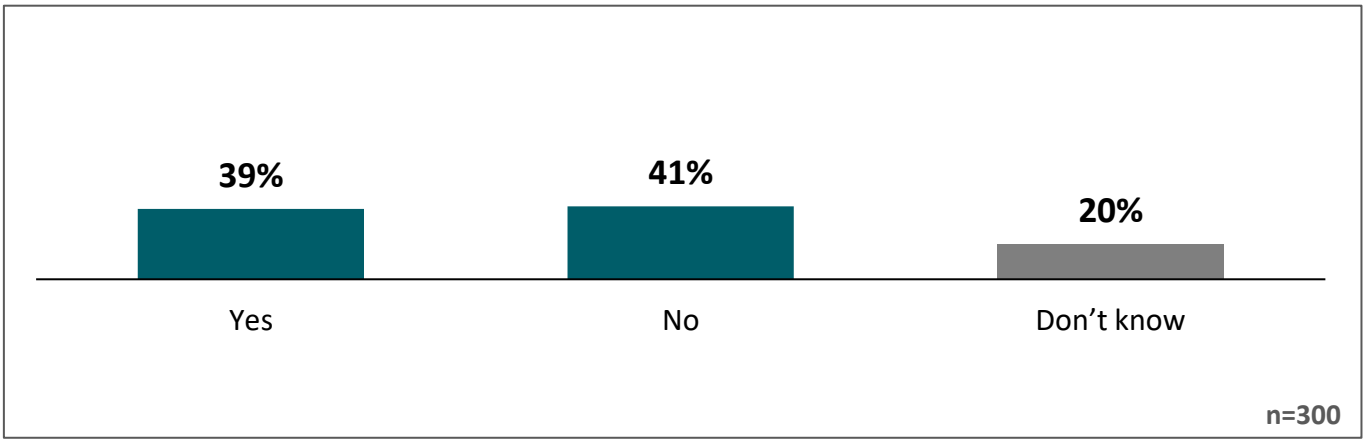
		Consumption Quartiles				Bill Impact	
% who select as top 3 priority	**Overall**	**Low**	**Medium-Low**	**Medium-High**	**High**	**Major Impact**	**No Major Impact**
Reducing number of non-weather outages	61%	61%	68%	51%	63%	62%	57%
Reducing length of non-weather outages	60%	59%	61%	60%	60%	62%	53%
Reducing length of weather-caused outages	49%	50%	48%	46%	53%	50%	45%
Reducing number of weather-caused outages	43%	45%	39%	43%	43%	43%	43%
Improving communications during outages	40%	43%	36%	44%	36%	38%	48%
Reducing momentary interruptions in power	36%	38%	41%	35%	30%	36%	36%

Note: Priority labels have been shortened for brevity. See slide 226 for full label text. "Don't know" not shown.

Reliability Experience
Planned Power Outages

Commercial & Industrial

Q In the past year, has your organization experienced any **planned power outages** (or loss of supply) with **Hydro One**?



Region

	West	Central	Central East	East*	North
Yes	40%	30%	36%	56%	35%
No	44%	36%	32%	30%	47%
Don't know	16%	34%	32%	14%	18%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Yes	44%	33%	46%	36%	38%	44%
No	42%	43%	37%	42%	44%	31%
Don't know	15%	25%	17%	22%	18%	26%

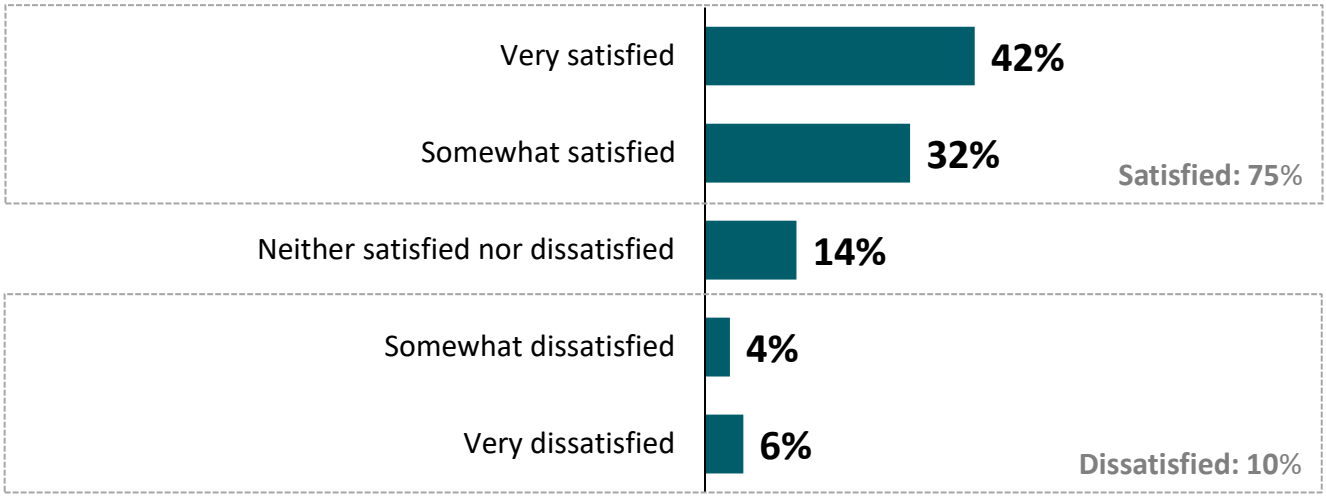
***Note: Small sample size (n=28); interpret results with caution**

Reliability Experience

Satisfaction with Planned Outage Management

Commercial & Industrial

Q Generally, how satisfied or dissatisfied were you with the way your organization's **planned power outages** were managed by **Hydro One**? *[Asked of those who have experienced a planned outage in the past year]*



"*Don't know*" (1%) not shown.

n=118

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Commercial & Industrial Customers

Investment Priorities



Investment Priorities

High-Level Reliability

Now let's turn to next topic – investment trade-offs. There are **6** investment areas that **Hydro One** would like your input on.

You do not need to be a system planner or engineer to answer these questions. The trade-offs will focus on what outcomes matter most to you as a customer – balancing investment outcomes and cost to you.

First, we would like to talk about the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

The first category is related to the reliability you experience.

On average, between 2019 and 2023, the typical **Hydro One** customer has experienced about 3.8 outages per year, resulting in a total of 16.6 hours without power.

It's important to keep in mind that these are system averages, and that your actual experience may be different.

Hydro One has historically identified investments in maintaining or improving reliability by taking into consideration the overall age, health, and likelihood of failure of equipment.

Investment Priorities

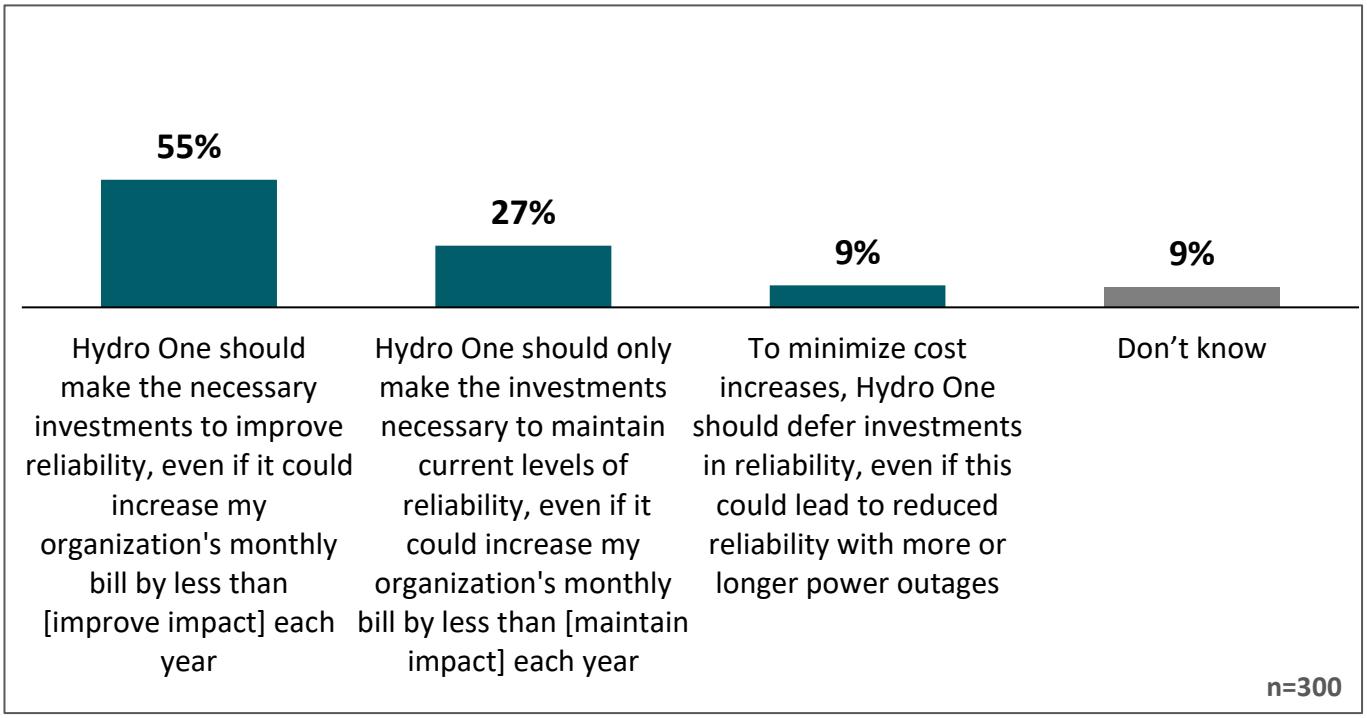
High-Level Reliability

Commercial & Industrial

Q Based on your own reliability experience, which of the following is closest to your point of view?

High-Level Reliability Legend

Customer Group	[improve impact]	[maintain impact]
GSd	$75	$40
ST-Low	$35	$20
ST-Med	$185	$105
ST-High	$920	$520



Investment Priorities
High-Level Reliability

Commercial & Industrial

Q Based on your own reliability experience, which of the following is closest to your point of view?

	Overall	Region: West	Region: Central	Region: Central East	Region: East*	Region: North
Necessary investments to improve reliability	55%	60%	51%	54%	54%	56%
Necessary investments to maintain reliability	27%	22%	34%	28%	29%	38%
Defer investments	9%	10%	10%	7%	4%	6%
Don't know	9%	8%	5%	12%	13%	--

	Consumption Quartiles: Low	Consumption Quartiles: Medium-Low	Consumption Quartiles: Medium-High	Consumption Quartiles: High	Bill Impact: Major Impact	Bill Impact: No Major Impact
Necessary investments to improve reliability	50%	54%	63%	54%	55%	56%
Necessary investments to maintain reliability	34%	27%	21%	24%	26%	30%
Defer investments	7%	7%	8%	16%	11%	3%
Don't know	9%	12%	8%	6%	8%	11%

***Note: Small sample size (n=28); interpret results with caution**

Response labels have been shortened for brevity. See slide 237 for full label text.

Investment Priorities

Targeted Reliability

The second category is related to more targeted improvements to reliability.

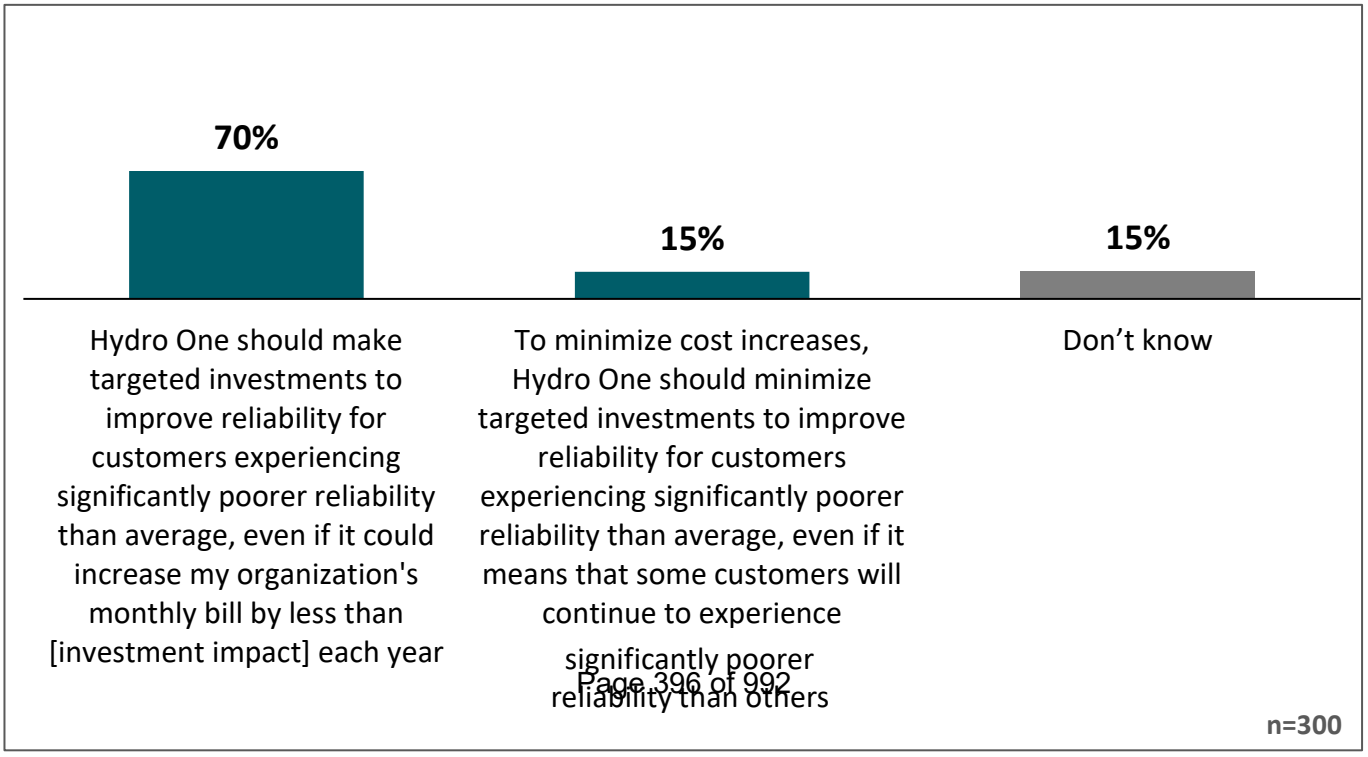
Hydro One customers experience different levels of reliability, depending on where they live, the design of the system and the condition of the equipment supplying them.

While some **Hydro One** customers didn't experience any outages in 2022 or 2023, others were without power more than 10 times per year. Similarly, the total length of time that customers were without power ranges from less than one hour to more than 50 hours per year.

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?

Targeted Reliability Legend

Customer Group	[investment impact]
GSd	$20
ST-Low	$10
ST-Med	$55
ST-High	$260



Investment Priorities
Targeted Reliability

Commercial & Industrial

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?

		Region				
	Overall	West	Central	Central East	East*	North
Targeted investments to improve reliability	70%	69%	71%	70%	51%	78%
Minimize targeted investments	15%	15%	15%	13%	21%	6%
Don't know	15%	17%	14%	17%	28%	16%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Targeted investments to improve reliability	70%	71%	65%	73%	70%	69%
Minimize targeted investments	14%	15%	19%	12%	17%	9%
Don't know	16%	14%	15%	15%	13%	22%

***Note: Small sample size (n=28); interpret results with caution**
Response labels have been shortened for brevity. See slide 239 for full label text.

Investment Priorities

Responding to Severe Weather

Commercial & Industrial

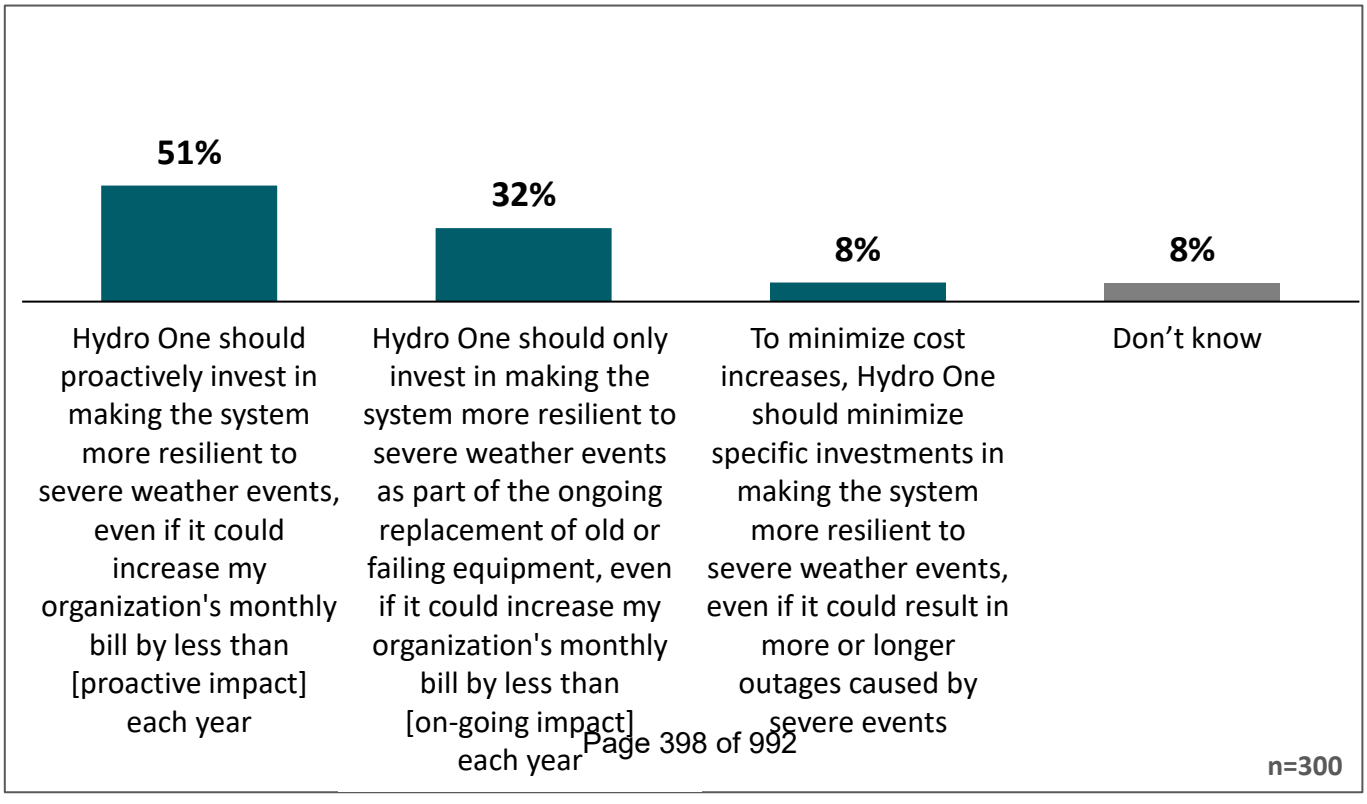
On average, between 2019 and 2023, **severe weather events**, such as ice storms, windstorms or thunderstorms, have contributed to 51% of all hours that the typical customer has been without power per year.

While some of these outages may be inevitable, **Hydro One** could make additional investments to make the system more resilient to these types of events. These investments could help either reduce the number of outages caused by severe weather events or improve restoration times when these outages do occur.

Q Based on this, which of the following is closest to your point of view?

Responding to Severe Weather Legend

Customer Group	[proactive impact]	[on-going impact]
GSd	$13	$10
ST-Low	$6	$5
ST-Med	$30	$25
ST-High	$155	$130



Investment Priorities

Responding to Severe Weather

Commercial & Industrial

Q Based on this, which of the following is closest to your point of view?

	Overall	Region: West	Region: Central	Region: Central East	Region: East*	Region: North
Proactively invest in resiliency	51%	49%	39%	57%	54%	53%
Invest as part of ongoing replacement	32%	27%	44%	29%	25%	32%
Minimize specific investments	8%	14%	7%	4%	4%	11%
Don't know	8%	10%	10%	10%	18%	4%

	Consumption Quartiles: Low	Consumption Quartiles: Medium-Low	Consumption Quartiles: Medium-High	Consumption Quartiles: High	Bill Impact: Major Impact	Bill Impact: No Major Impact
Proactively invest in resiliency	51%	50%	50%	54%	49%	57%
Invest as part of ongoing replacement	30%	31%	36%	31%	34%	27%
Minimize specific investments	7%	11%	7%	9%	9%	5%
Don't know	12%	7%	7%	6%	7%	11%

***Note: Small sample size (n=28); interpret results with caution**

Response labels have been shortened for brevity. See slide 241 for full label text.

Investment Priorities

Growth

Commercial & Industrial

Electricity demand is on the rise across Ontario. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Hydro One** to make significant investments in the grid.

Increased growth can result in longer wait times to connect new homes or businesses to the system or facilitate upgrades for existing customers if insufficient capacity is available.

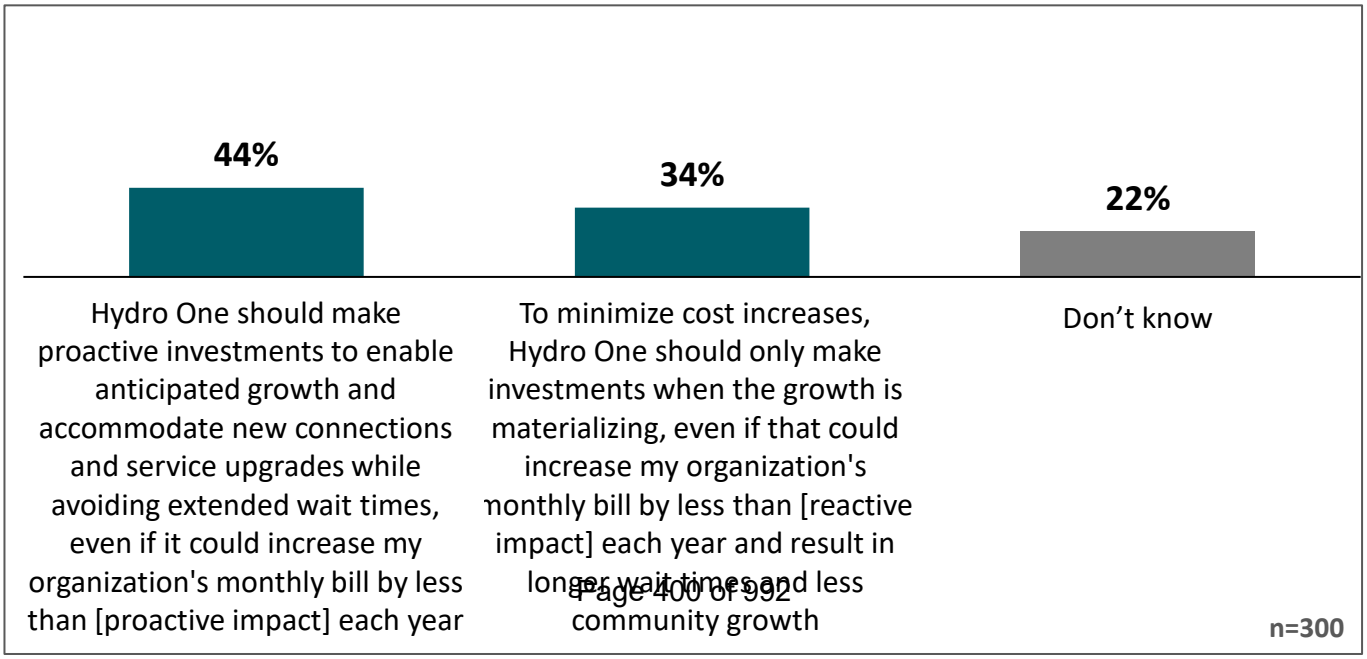
For instance, as increasing growth occurs, some new businesses may be asked to wait up to 2 years or longer for their facility to be connected to the **Hydro One** grid.

However, **Hydro One** could make proactive investments to enable anticipated growth and allow new homes or businesses to connect to the system in a timely manner, and to not delay service upgrades for existing customers.

Q Based on this, which is closest to your point of view?

Growth Legend

Customer Group	[proactive impact]	[reactive impact]
GSd	$50	$30
ST-Low	$25	$15
ST-Med	$135	$80
ST-High	$650	$390



Investment Priorities
Growth

Commercial & Industrial

Q Based on this, which is closest to your point of view?

	Overall	Region: West	Region: Central	Region: Central East	Region: East*	Region: North
Proactive investments to enable growth	44%	40%	44%	48%	30%	61%
Only make investments as growth materializes	34%	34%	32%	32%	48%	20%
Don't know	22%	26%	24%	20%	22%	19%

	Consumption Quartiles: Low	Consumption Quartiles: Medium-Low	Consumption Quartiles: Medium-High	Consumption Quartiles: High	Bill Impact: Major Impact	Bill Impact: No Major Impact
Proactive investments to enable growth	35%	56%	40%	45%	43%	45%
Only make investments as growth materializes	34%	29%	35%	38%	35%	32%
Don't know	32%	15%	25%	17%	22%	23%

***Note: Small sample size (n=28); interpret results with caution**
Response labels have been shortened for brevity. See slide 243 for full label text.

Investment Priorities

Evolving Customer Requests & System Visibility

Beyond residential and industrial growth, customers are increasingly requesting information and upgrades related to new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers.

Whether or not you are actively considering these types of technologies for yourself, **Hydro One** needs to be prepared to accommodate these types of customer requests, not just today, but over the next 5 to 10 years.

While **Hydro One** has an obligation to make certain investments to accommodate customer requests, planners have identified incremental investments that can help:

- Ensure that **Hydro One's** grid is ready to accommodate if and when customers request to connect new technologies.

- Give the **Hydro One** control room more "visibility" into exactly where and how much electricity is being used in real-time, helping make more informed decisions on managing electricity demand and equipment maintenance or upgrades.

As the pace of change and customer needs are rapidly evolving, delaying or limiting these investments means that **Hydro One** could struggle to keep up with customer demand for connecting new technology and lack the precision to monitor the grid as new technology adoption increases.

Investment Priorities

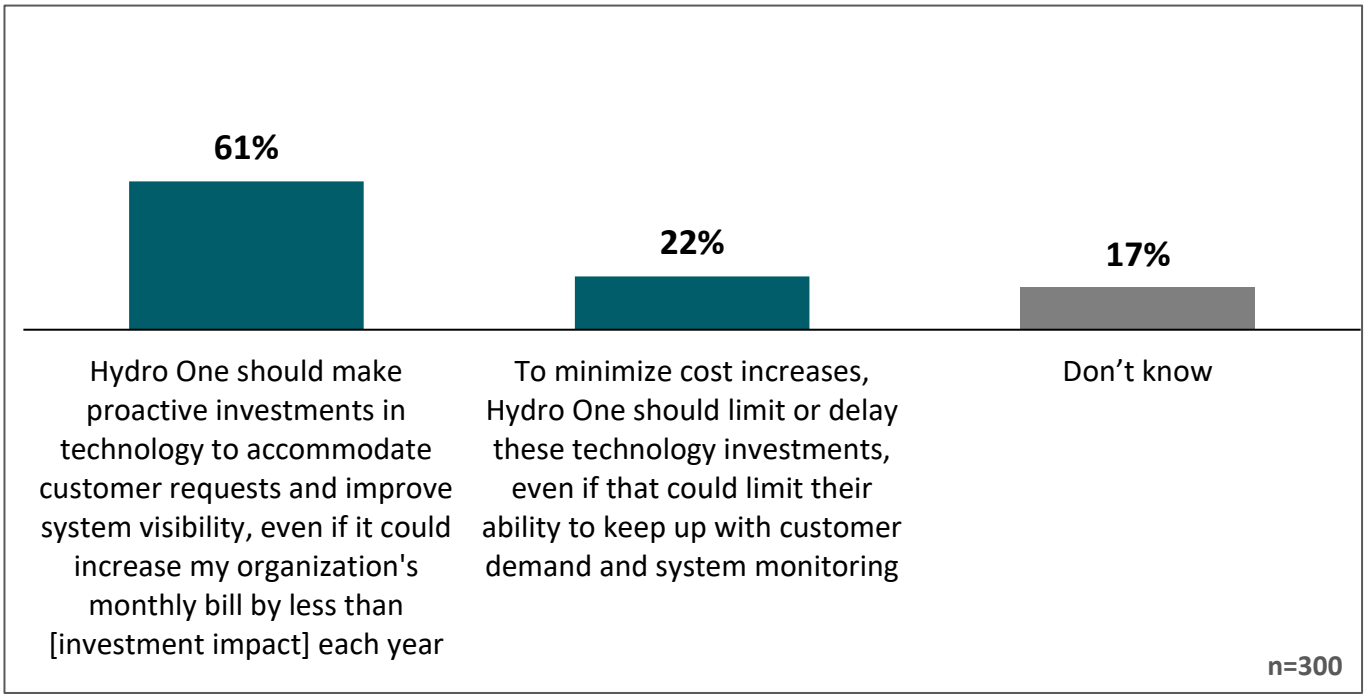
Evolving Customer Requests & System Visibility

Commercial & Industrial

Q With regards to these investments, which of the following is closest to your point of view?

Evolving Customer Requests & System Visibility Legend

Customer Group	[investment impact]
GSd	$20
ST-Low	$10
ST-Med	$55
ST-High	$260



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Investment Priorities

Evolving Customer Requests & System Visibility

Commercial & Industrial

Q With regards to these investments, which of the following is closest to your point of view?

	Overall	Region: West	Region: Central	Region: Central East	Region: East*	Region: North
Proactive investments in technology	61%	54%	64%	67%	63%	60%
Limit or delay technology investments	22%	25%	17%	19%	20%	26%
Don't know	17%	21%	19%	14%	18%	14%

	Consumption Quartiles: Low	Consumption Quartiles: Medium-Low	Consumption Quartiles: Medium-High	Consumption Quartiles: High	Bill Impact: Major Impact	Bill Impact: No Major Impact
Proactive investments in technology	58%	65%	57%	63%	60%	64%
Limit or delay technology investments	19%	22%	26%	21%	24%	15%
Don't know	23%	13%	17%	16%	16%	20%

***Note: Small sample size (n=28); interpret results with caution**

Response labels have been shortened for brevity. See slide 246 for full label text.

Investment Priorities

Transmission Renewal

Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

Investment Priorities

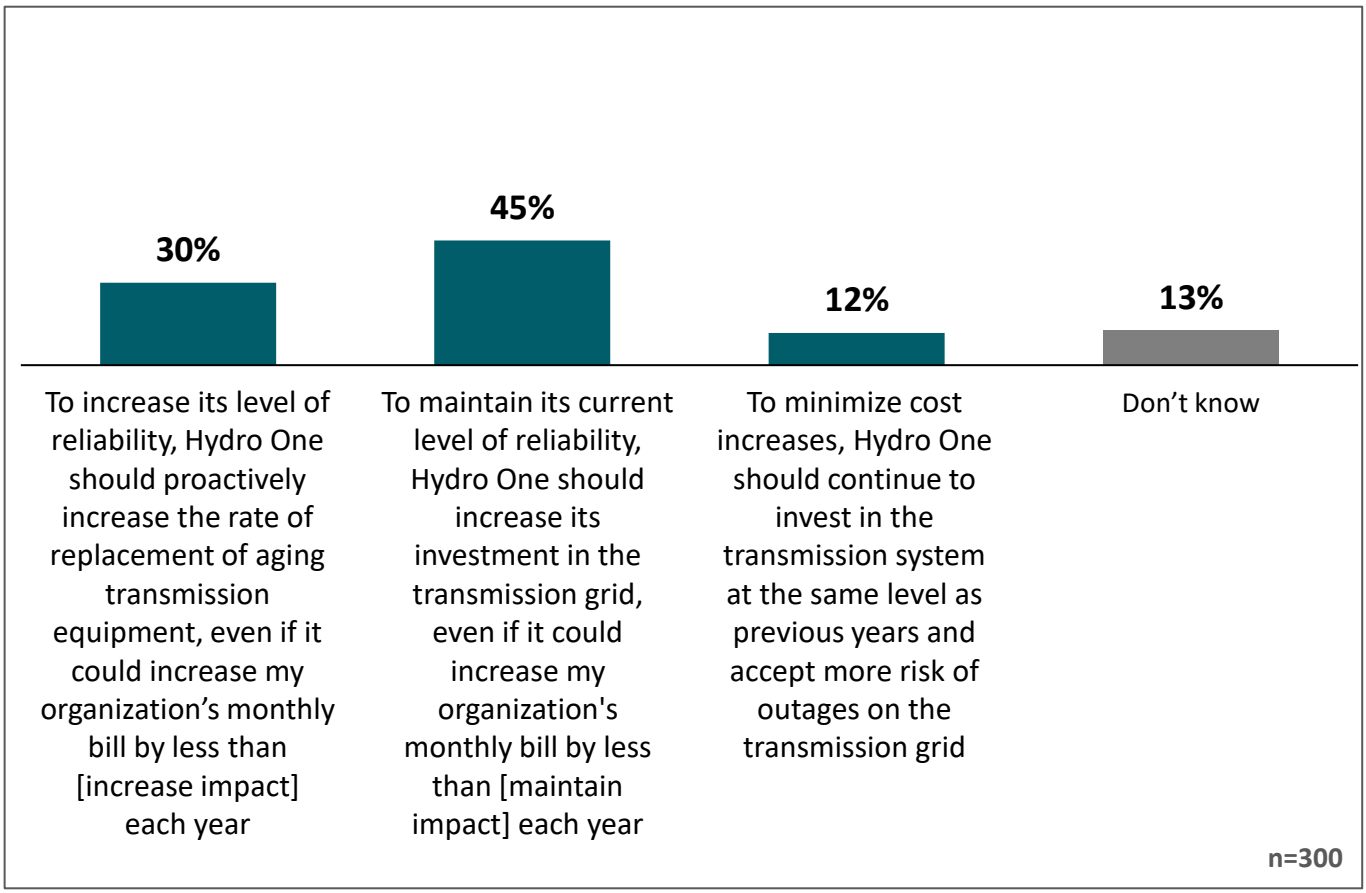
Transmission Renewal

Commercial & Industrial

Q With this in mind, what is closest to your point of view?

Transmission Renewal Legend

Customer Group	[increase impact]	[maintain impact]
GSd	$40	$15
ST-Low	$300	$105
ST-Med	$1,670	$590
ST-High	$8,180	$2,890



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Investment Priorities
Transmission Renewal

Commercial & Industrial

Q With this in mind, what is closest to your point of view?

	Region				
	Overall	West	Central	Central East	East*	North
Proactively increase investment to increase reliability	30%	29%	22%	31%	14%	44%
Increase investment to maintain current reliability	45%	46%	52%	47%	52%	39%
Continue to invest at the same level	12%	10%	10%	12%	12%	6%
Don't know	13%	15%	16%	10%	22%	11%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Proactively increase investment to increase reliability	27%	29%	28%	36%	30%	30%
Increase investment to maintain current reliability	43%	52%	46%	40%	45%	46%
Continue to invest at the same level	14%	8%	14%	11%	13%	8%
Don't know	16%	11%	12%	12%	12%	16%

***Note: Small sample size (n=28); interpret results with caution**
Response labels have been shortened for brevity. See slide 249 for full label text.

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Large Distribution Account Customers

Online Survey Results

Section 6



Field Dates

The **Large Distribution Account Customers Online Survey** was sent to all Hydro One large distribution account customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **November 13th and December 12th, 2024**.

Each customer received a unique URL that could be linked back to their average monthly demand, region and rate class. Customers were sent a survey that reflects their rate class (Sub Transmission low, medium, high, or General Service Demand).

In total, the large distribution account customers survey was sent to **276** customers from *customerexperience@hydroone.com*. Reminder emails were sent on November 20th, November 27th, December 4th, and December 10th 2024 to those who had not yet completed the survey.

Large Distribution Accounts Online Survey Completes

A total of **61** (unweighted) Hydro One large distribution account customers completed the online survey.

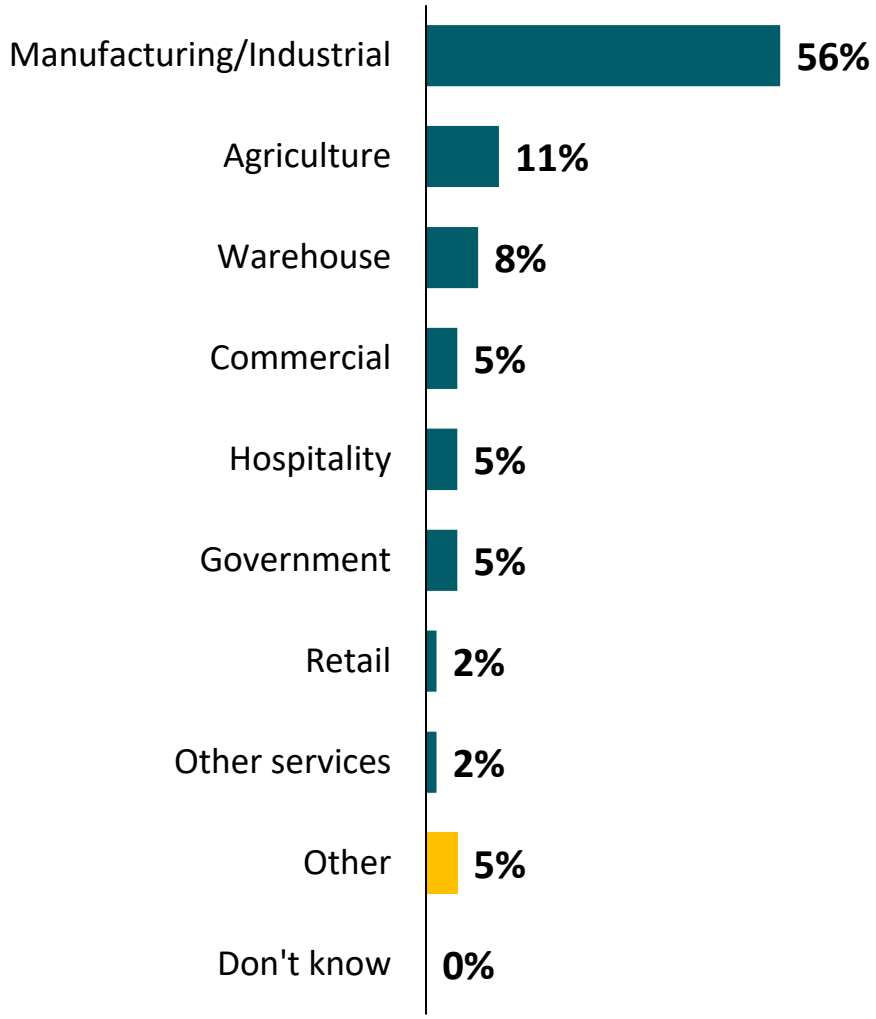
Sample Weighting

The large distribution account online survey sample was not weighted due to the small number of completes.

Firmographic Breakdown

Large Distribution

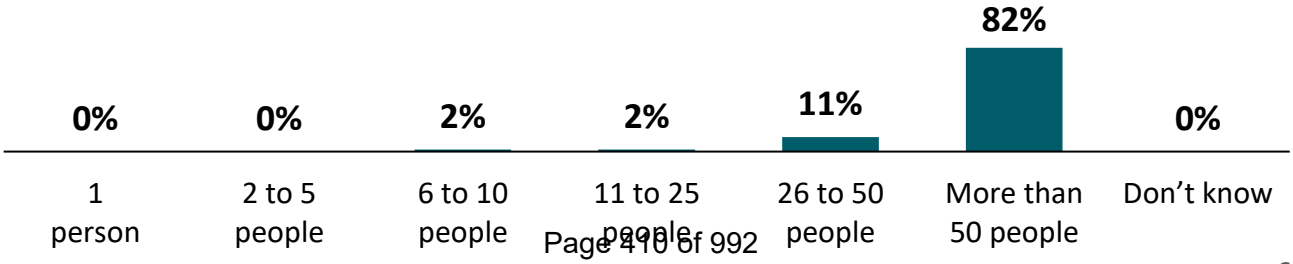
Q Business Sector



"Prefer not to say" (2%) not shown.

n=61

Q Business Size



"Prefer not to say" (3%) not shown.

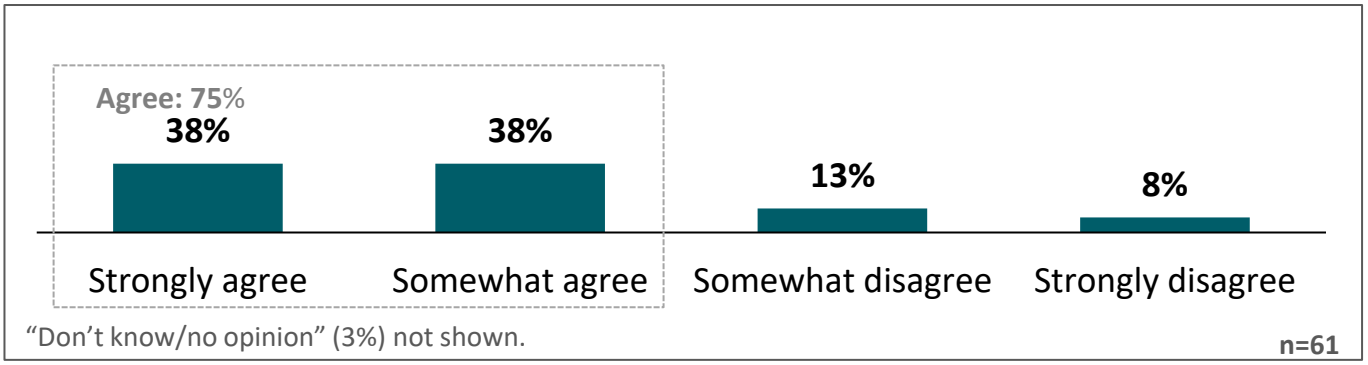
n=61

Environmental Controls

Large Distribution

To what extent do you agree or disagree with the following statements?

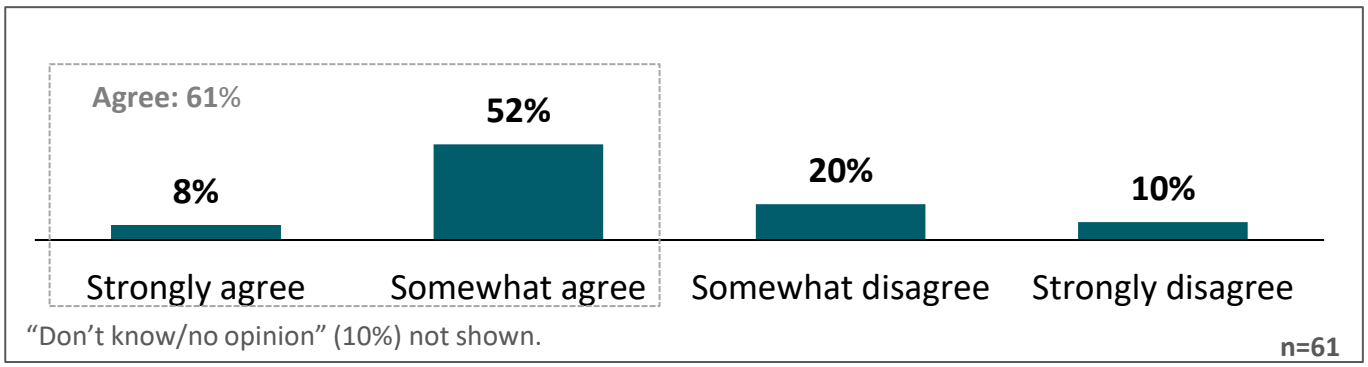
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (3%) not shown.

n=61

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (10%) not shown.

n=61

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Large Distribution Account Customers

Familiarity & Experience



Familiarity & Experience
Preamble

Before we begin, this survey has **three key objectives**.

First, **Hydro One** wants to better understand your experiences as a customer.

Second, **Hydro One** wants your input on some of the investment areas they could focus on in the future.

Third, **Hydro One** wants to learn a little bit more about their customers. This will help them ensure that they are receiving feedback that represents a wide range of customers.

First, let's talk about your experience.

While you might have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large distribution customer.

***Note**: The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a customer with an average monthly demand of [demand assumption] and average monthly consumption of [usage assumption].

Estimate Assumptions Legend

Customer Group	[demand]	[usage]
GSd	110 kW	34,334 kWh
ST-Low	500 kW	88,780 kWh
ST-Med	2,808 kW	1,373,443 kWh
ST-High	13,730 kW	2,641,420 kWh

Familiarity & Experience

Familiarity with Hydro One's Role in the System

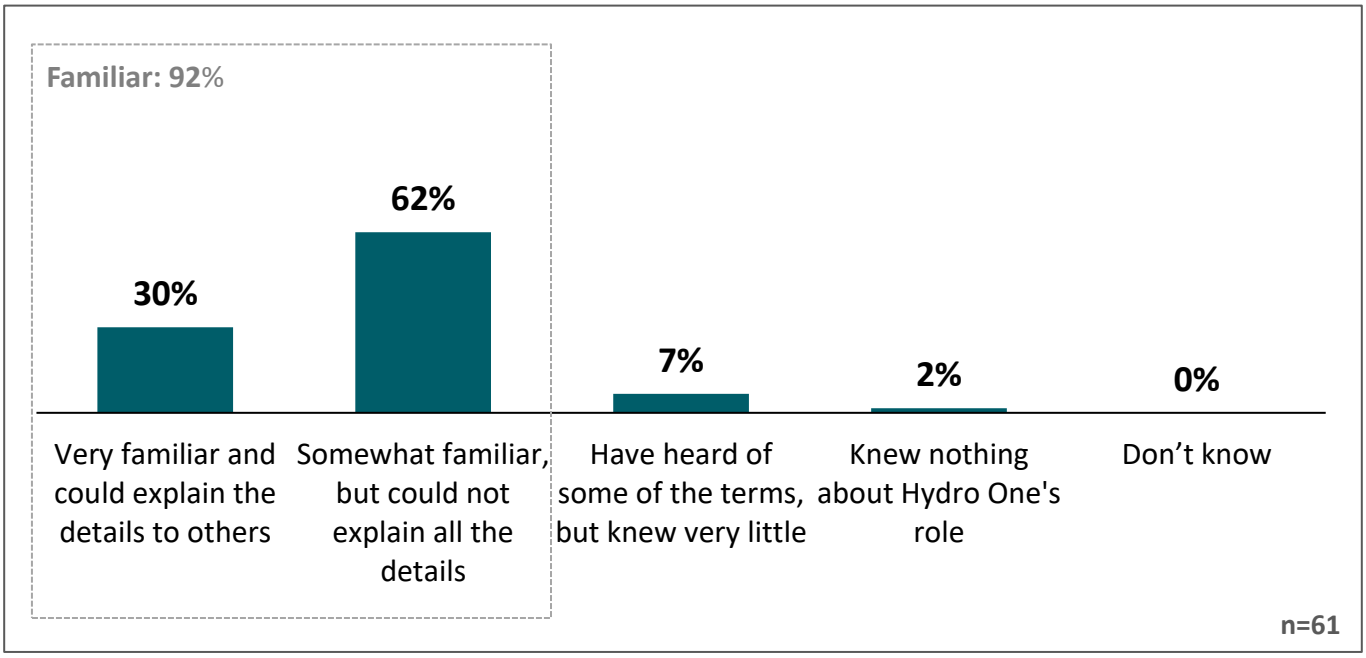
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



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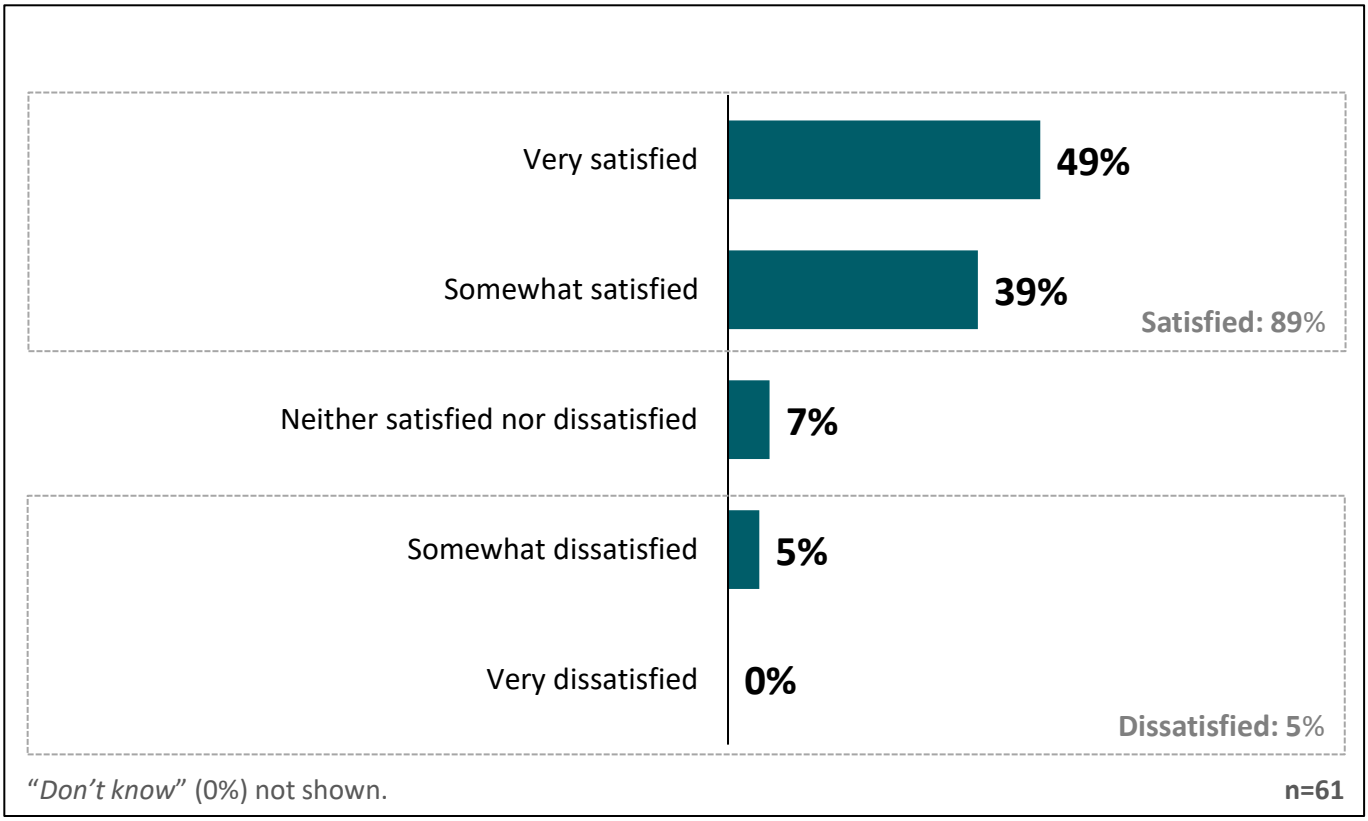
Familiarity & Experience

Overall Satisfaction with Hydro One

Large Distribution

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from **Hydro One**?



"*Don't know*" (0%) not shown.

n=61

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Familiarity & Experience

How can Hydro One improve services?

Large Distribution

Q Is there anything in particular you would like **Hydro One** to do to improve its services to your organization?

Response	%
Decrease outages/interruptions	14.8%
Improve communication during outages	9.8%
Satisfied with services/no issues	8.2%
Building capacity/addressing growth	6.6%
Improve customer service	3.3%
Upgrade/better maintain infrastructure	1.6%
Billing improvements - timing/payments/bill format	1.6%
Other	1.6%
None/Don't know	52.5%

Note: Only responses >0.1% shown

Familiarity & Experience

Bill Familiarity

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

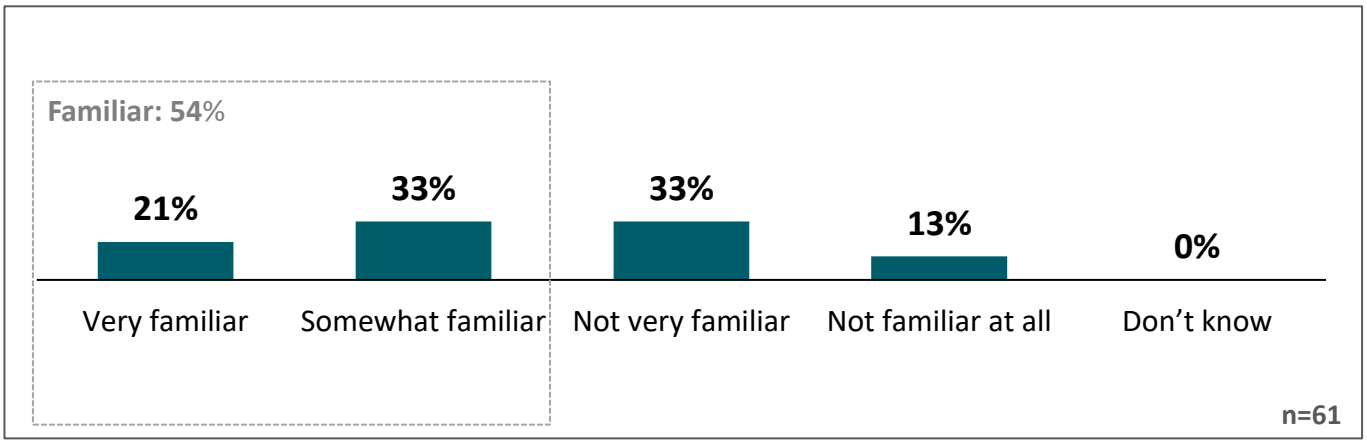
Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to **Hydro One**. As of October 1st, 2024, for a typical large distribution customer, about **[bill percentage]** or **[bill amount]** goes to **Hydro One** per month. This amount is split into **[distribution amount]** for distribution and **[transmission amount]** for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Bill Legend

Customer Group	[bill percentage]	[bill amount]	[distribution amount]	[transmission amount]
GSd	38%	$2,945	$2,355	$590
ST-Low	36%	$6,640	$2,055	$4,585
ST-Med	16%	$31,550	$5,800	$25,750
ST-High	30%	$149,425	$23,525	$125,900

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Hydro One**?



Familiarity & Experience

Familiarity with Rate Applications

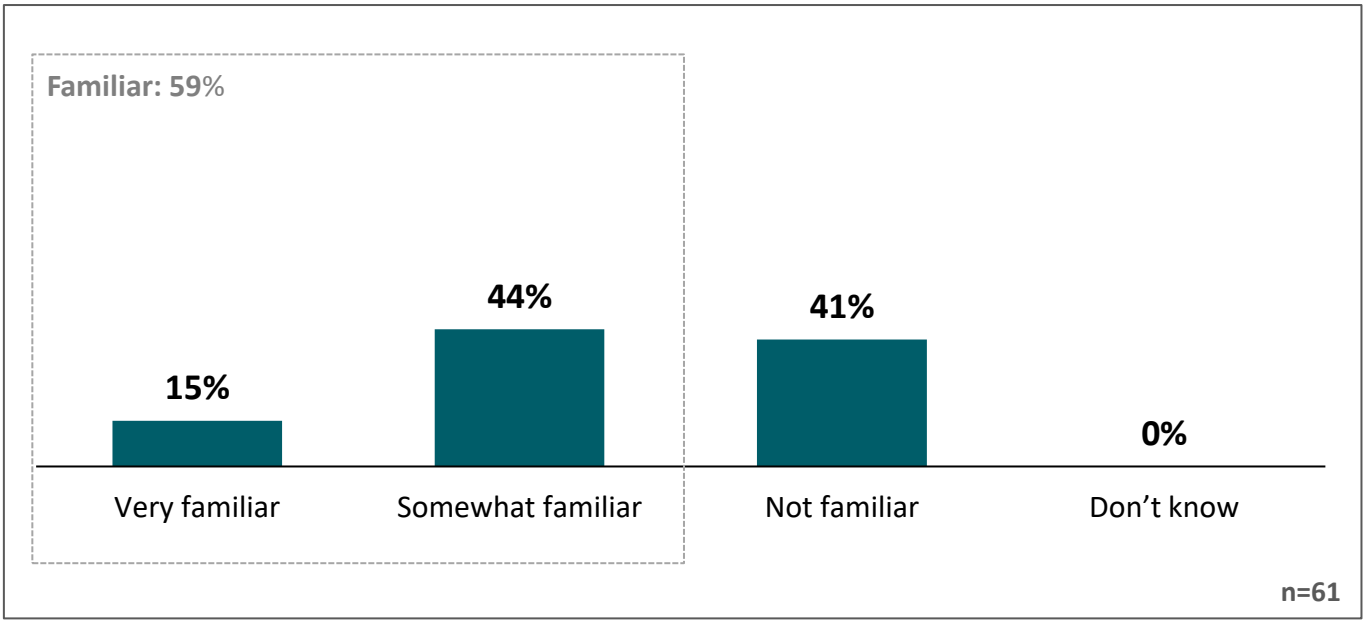
Hydro One is funded by the rates paid by its customers.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



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Large Distribution Account Customers

Customer Priorities



Customer Priorities

Response Labels Legend

Large Distribution

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 8 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity	Providing reliable electricity to my organization
Enhancing Hydro One's customer service	Enhancing Hydro One's customer service
Offering programs to help manage usage	Offering programs that can help customers better manage their electricity usage
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Enhancing the grid for new technologies	Enhancing the grid so that customers can connect new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

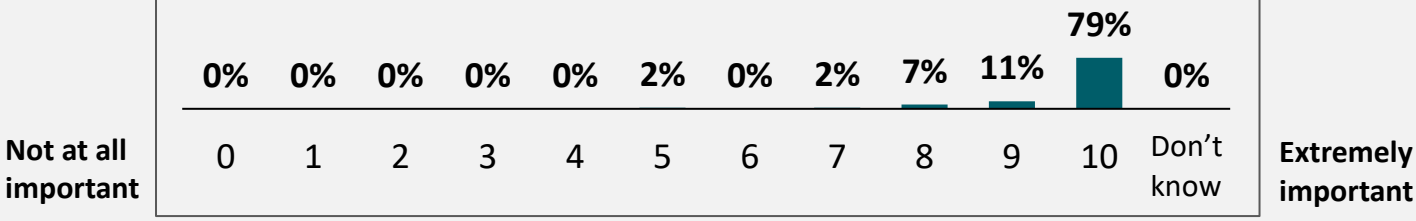
Customer Priorities

Importance of Customer Priorities

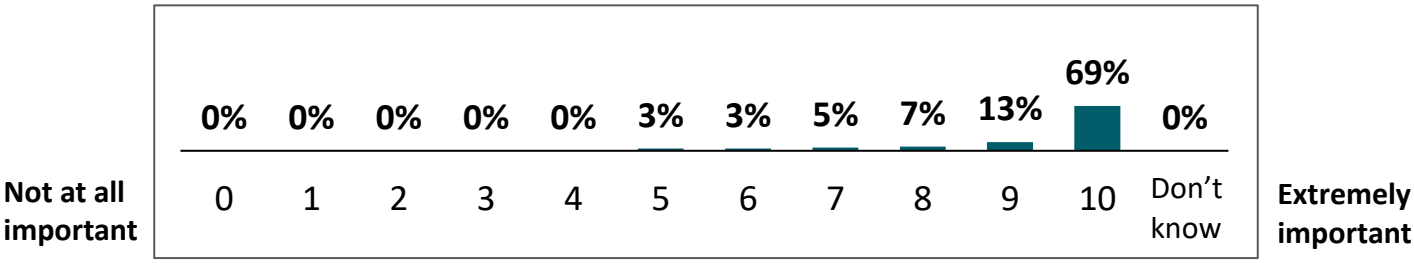
Large Distribution

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

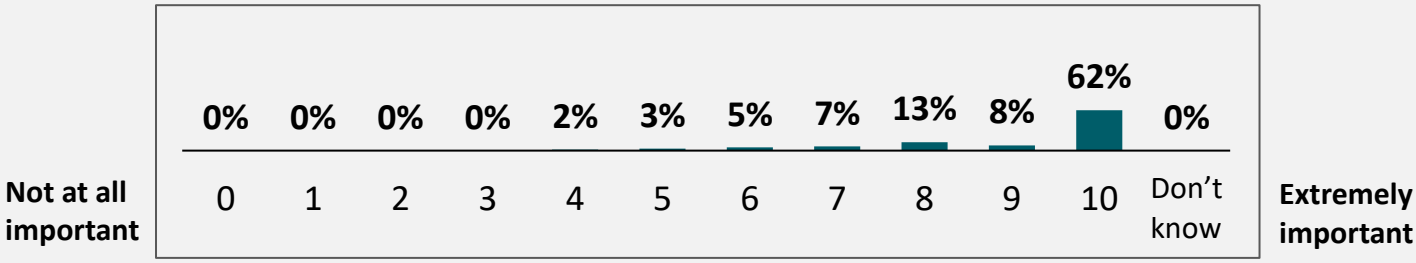
Providing reliable electricity [average = **9.6**]



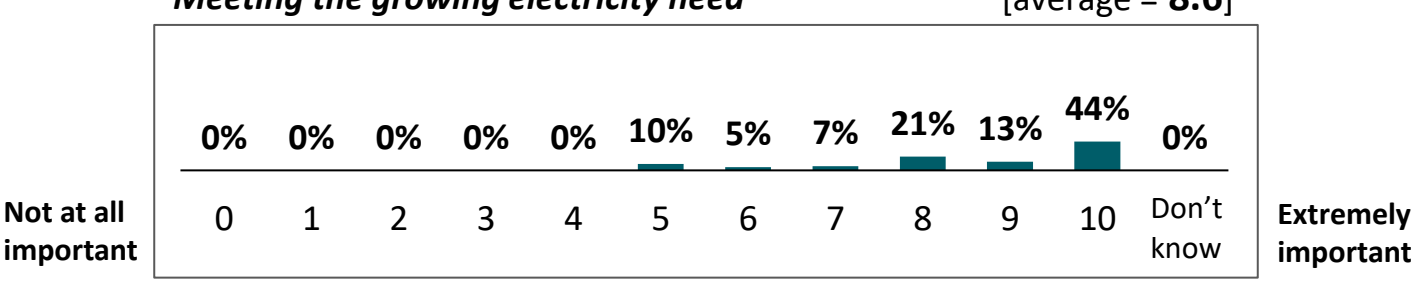
Delivering electricity at reasonable rates [average = **9.3**]



Ensuring the safety of electricity infrastructure [average = **9.0**]



Meeting the growing electricity need [average = **8.6**]



Note: Priority labels have been shortened for brevity. See slide 263 for full label text.
"Don't know" not included in calculation of means.

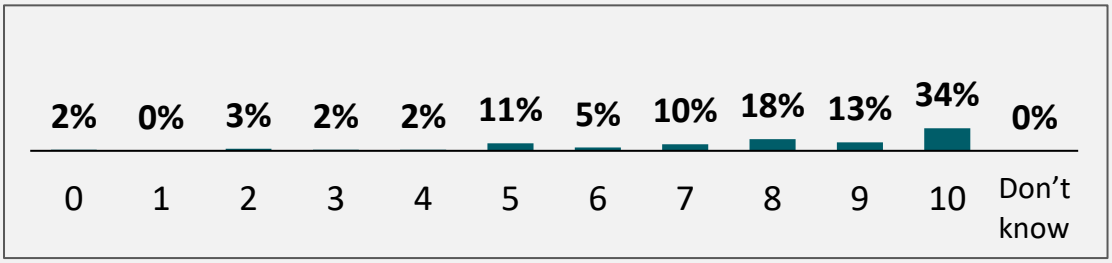
Customer Priorities

Importance of Customer Priorities (Cont'd)

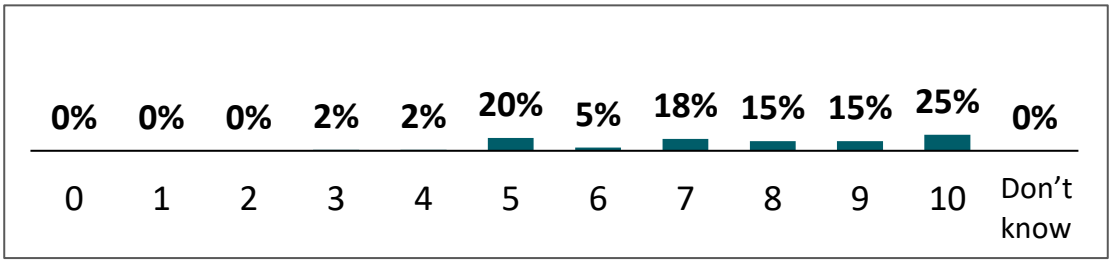
Large Distribution

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

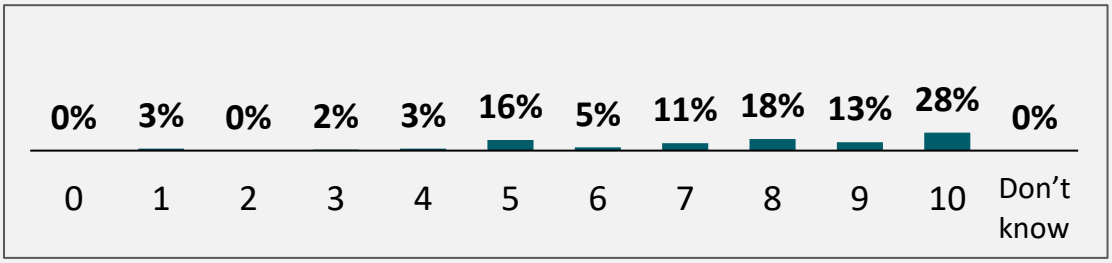
Offering programs to help manage usage [average = **7.8**]



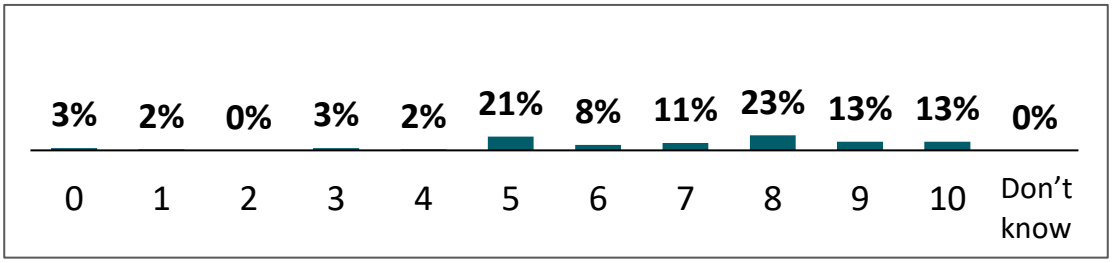
Enhancing Hydro One's customer service [average = **7.6**]



Enhancing the grid for new technologies [average = **7.5**]



Reducing the environmental impact [average = **6.9**]



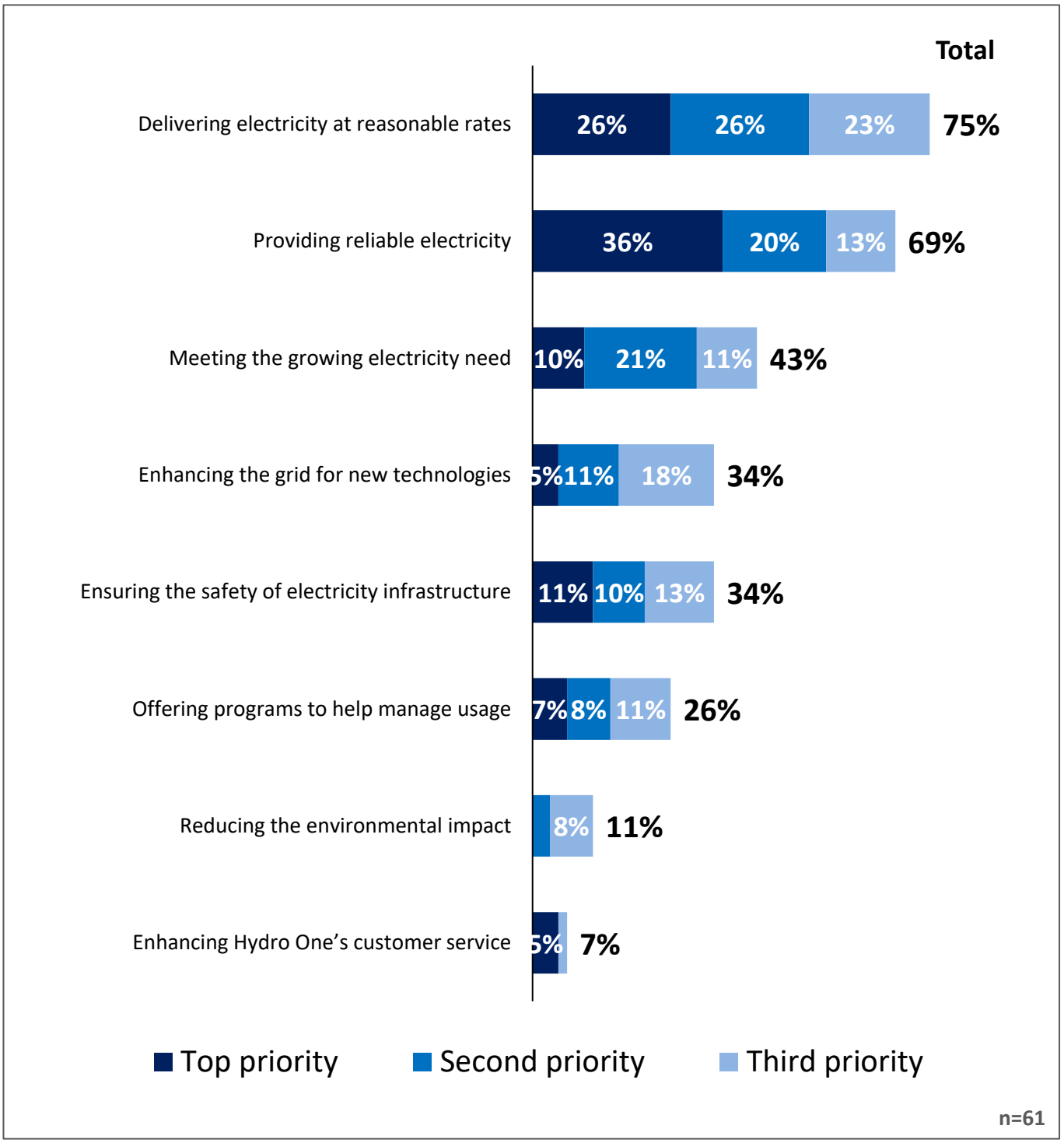
Note: Priority labels have been shortened for brevity. See slide 263 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Ranking Customer Priorities

Large Distribution

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 263 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Other Priorities

Large Distribution

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Enhancing the grid/infrastructure	9.8%
Having alternative energy/sustainable sources/green technology	8.2%
Meeting growing needs for electricity	3.3%
Reasonable/affordable rates	1.6%
Incentives for seniors/subsidy programs	1.6%
Affordable renewable energy	1.6%
Reducing environmental impacts	1.6%
Tree trimming/removal	1.6%
Improving reliability/less outages	1.6%
Information/programs to manage electricity usage	1.6%
Other	3.3%
None/Don’t know	63.9%

Note: Only responses >0.1% shown

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Large Distribution Account Customers

Reliability Experience

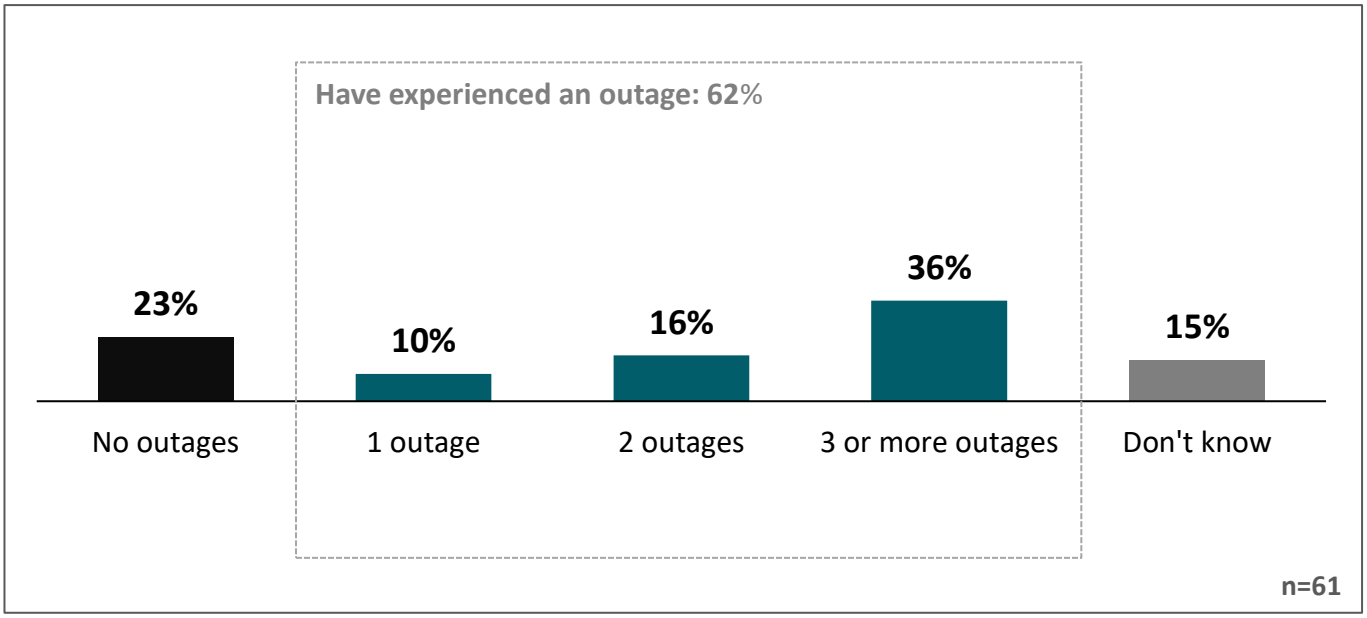


Reliability Experience

Number of Outages Experienced

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at your organization **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

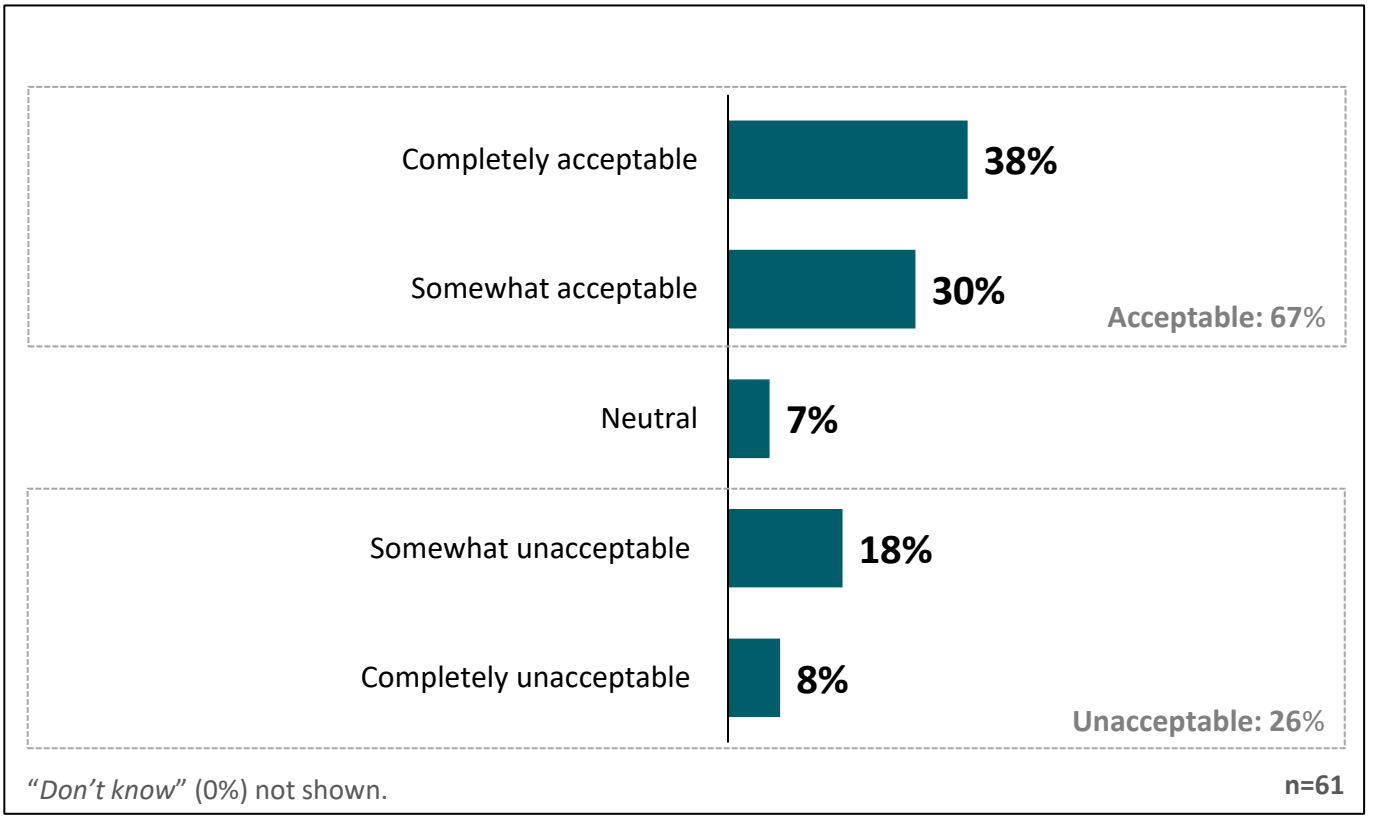


Reliability Experience

Current Reliability of Electricity Service

Large Distribution

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (0%) not shown.

n=61

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Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights
Improving communications during outages	Improving communications during outages, including estimated restoration times

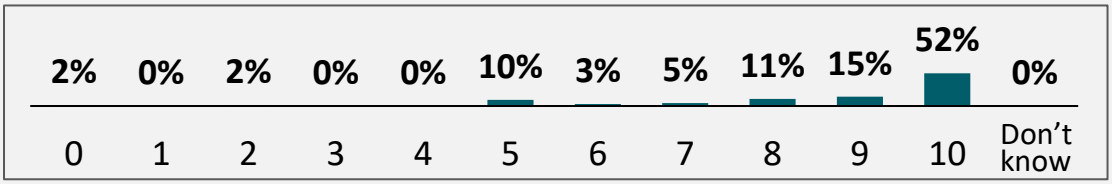
Reliability Experience

Importance of Reliability Priorities

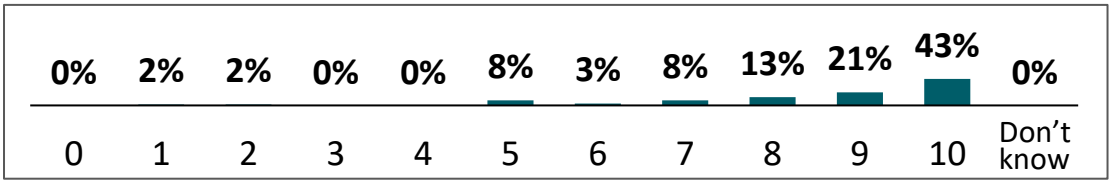
Large Distribution

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

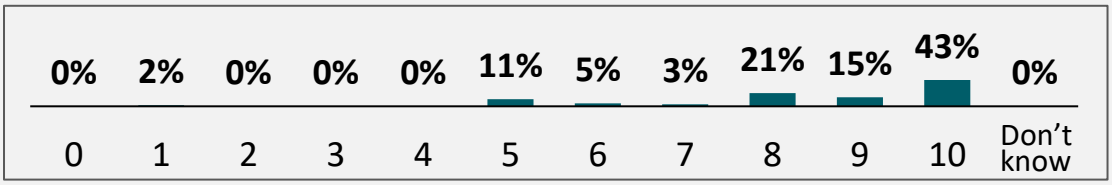
Reducing number of non-weather outages [average = **8.6**]



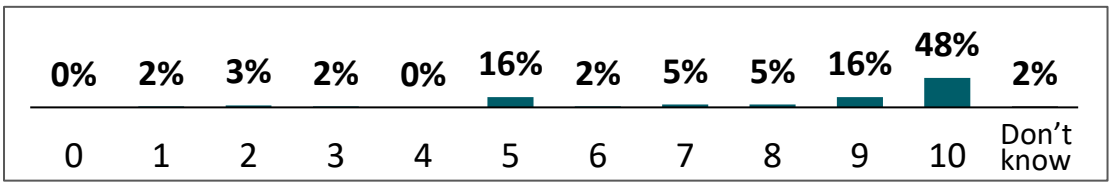
Reducing length of non-weather outages [average = **8.5**]



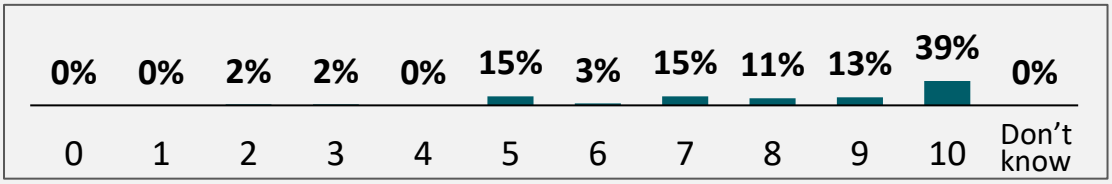
Reducing length of weather-caused outages [average = **8.4**]



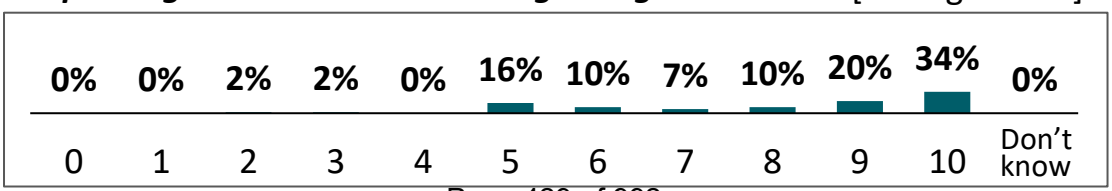
Reducing momentary interruptions in power [average = **8.2**]



Reducing number of weather-caused outages [average = **8.1**]



Improving communications during outages [average = **8.0**]



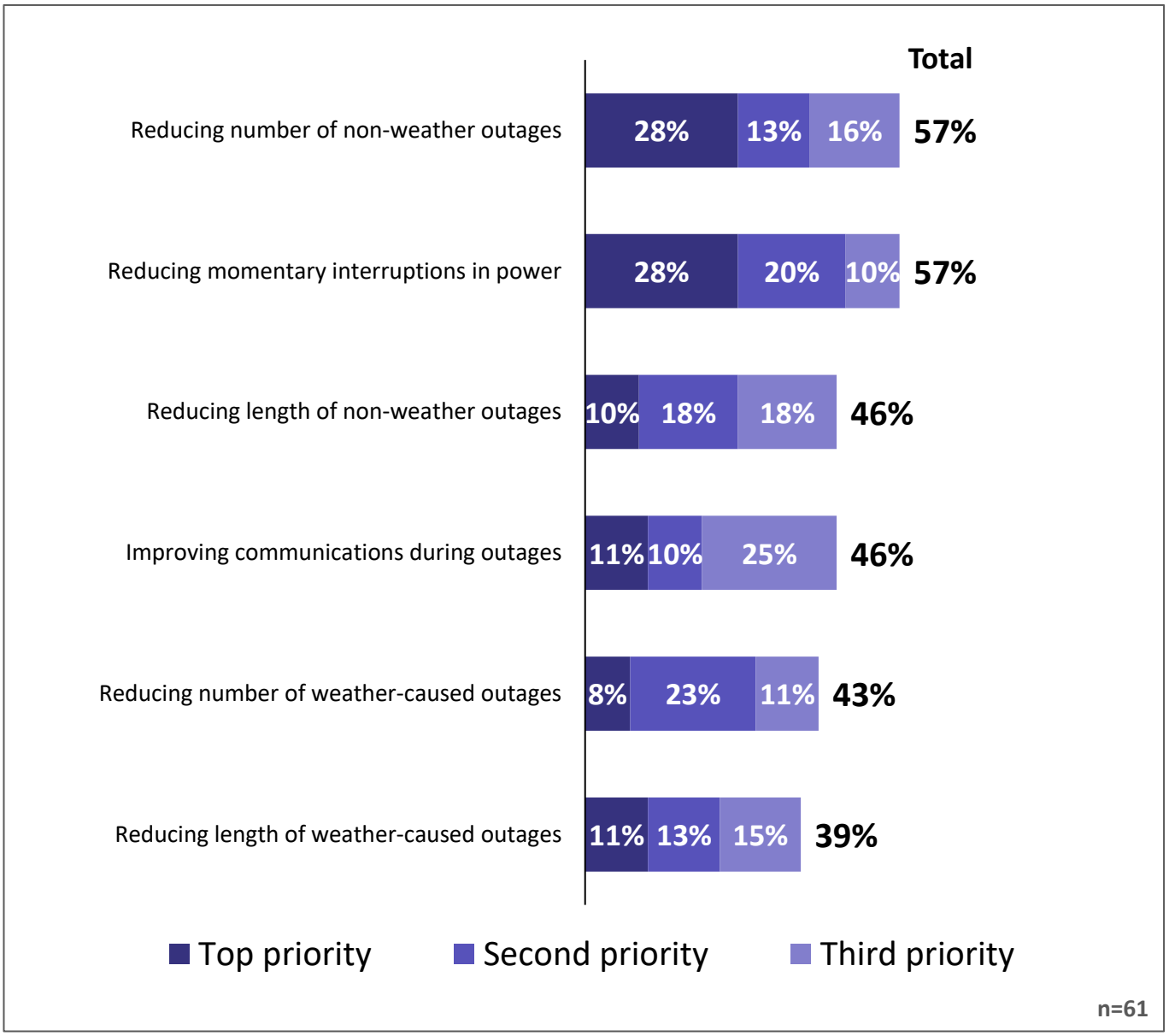
Note: Priority labels have been shortened for brevity. See slide 271 for full label text.
"Don't know" not included in calculation of means.

Reliability Experience
Ranking Reliability Priorities

Large Distribution

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

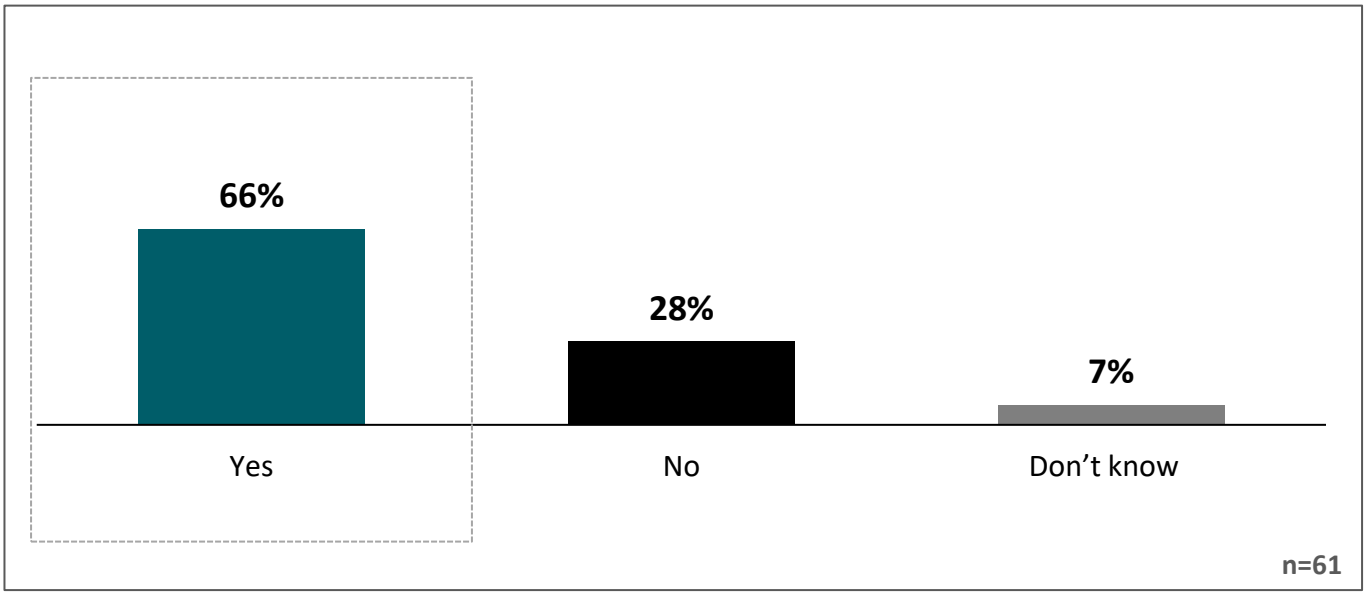


Note: Priority labels have been shortened for brevity. See slide 271 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

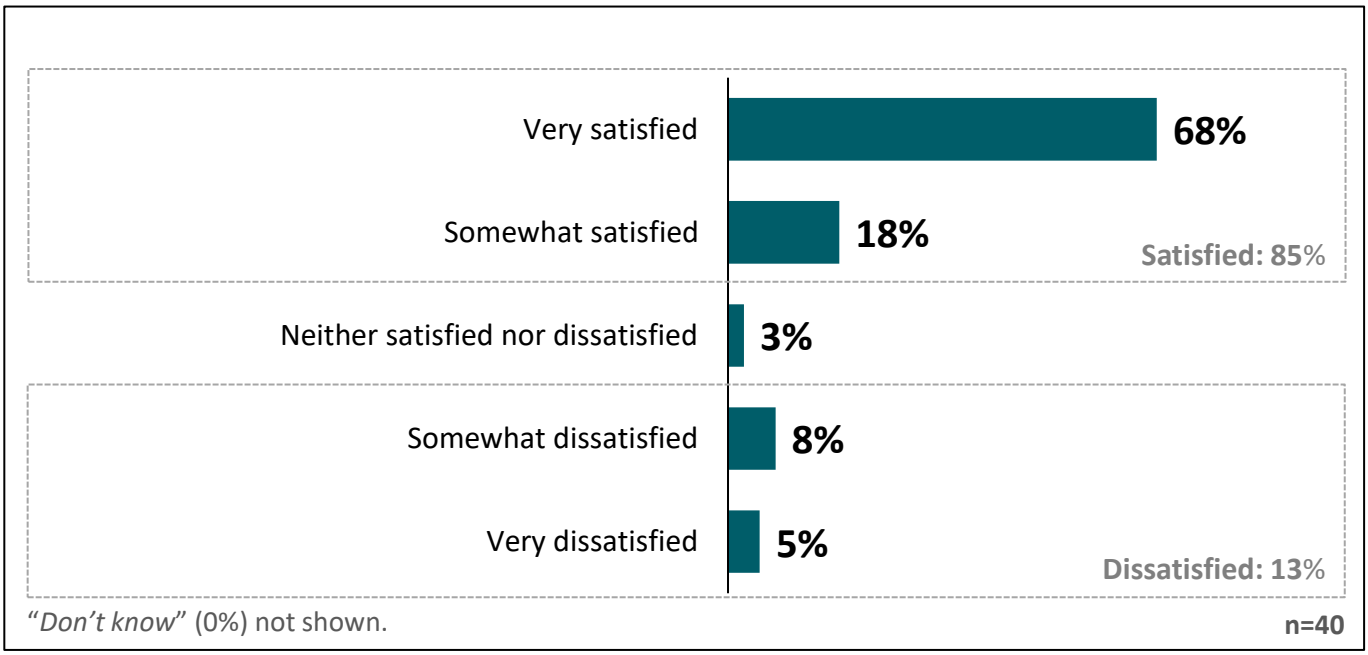
Reliability Experience
Planned Power Outages

Large Distribution

Q In the past year, has your organization experienced any **planned power outages** (or loss of supply) with **Hydro One**?



Q Generally, how satisfied or dissatisfied were you with the way your organization's **planned power outages** were managed by **Hydro One**? *[Asked of those who have experienced a planned outage in the past year]*



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Large Distribution Account Customers

Investment Priorities



Investment Priorities

High-Level Reliability

Now let's turn to next topic – investment trade-offs. There are **6** investment areas that **Hydro One** would like your input on.

You do not need to be a system planner or engineer to answer these questions. The trade-offs will focus on what outcomes matter most to you as a customer – balancing investment outcomes and cost to you.

First, we would like to talk about the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

The first category is related to the reliability you experience.

On average, between 2019 and 2023, the typical **Hydro One** customer has experienced about 3.8 outages per year, resulting in a total of 16.6 hours without power.

It's important to keep in mind that these are system averages, and that your actual experience may be different.

Hydro One has historically identified investments in maintaining or improving reliability by taking into consideration the overall age, health, and likelihood of failure of equipment.

Investment Priorities

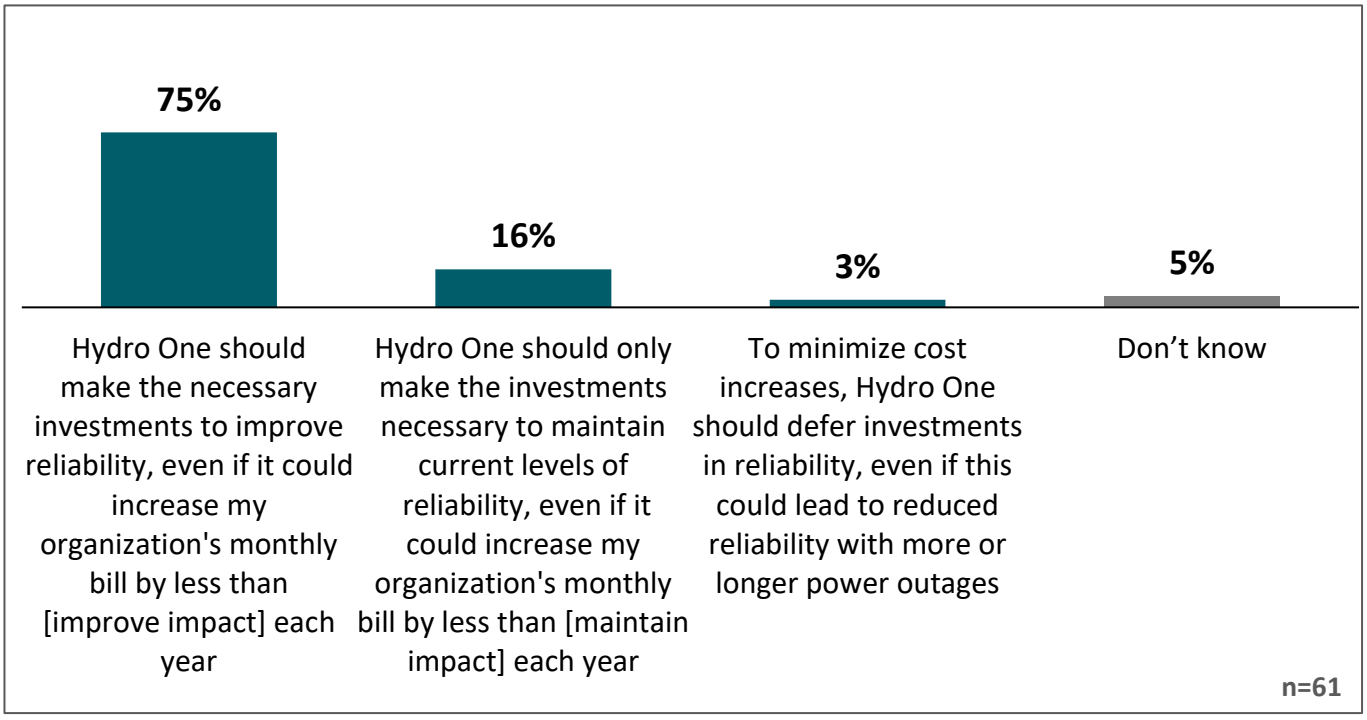
High-Level Reliability

Large Distribution

Q Based on your own reliability experience, which of the following is closest to your point of view?

High-Level Reliability Legend

Customer Group	[improve impact]	[maintain impact]
GSd	$75	$40
ST-Low	$35	$20
ST-Med	$185	$105
ST-High	$920	$520



INNOVATIVE RESEARCH GROUP

Investment Priorities

Targeted Reliability

The second category is related to more targeted improvements to reliability.

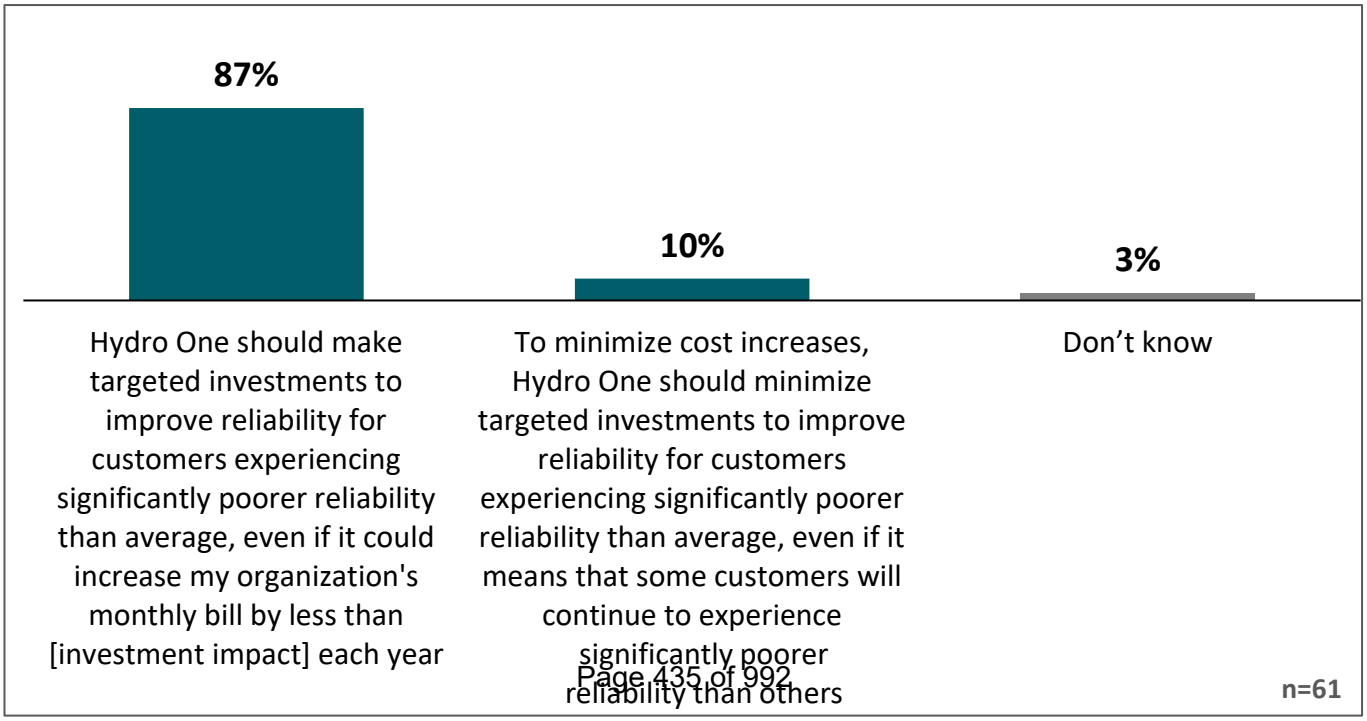
Hydro One customers experience different levels of reliability, depending on where they live, the design of the system and the condition of the equipment supplying them.

While some **Hydro One** customers didn't experience any outages in 2022 or 2023, others were without power more than 10 times per year. Similarly, the total length of time that customers were without power ranges from less than one hour to more than 50 hours per year.

Q When it comes to more targeted investments to improve reliability for those customers that experience significantly poorer reliability than average, which of the following is closest to your point of view?

Targeted Reliability Legend

Customer Group	[investment impact]
GSd	$20
ST-Low	$10
ST-Med	$55
ST-High	$260



Investment Priorities

Responding to Severe Weather

Large Distribution

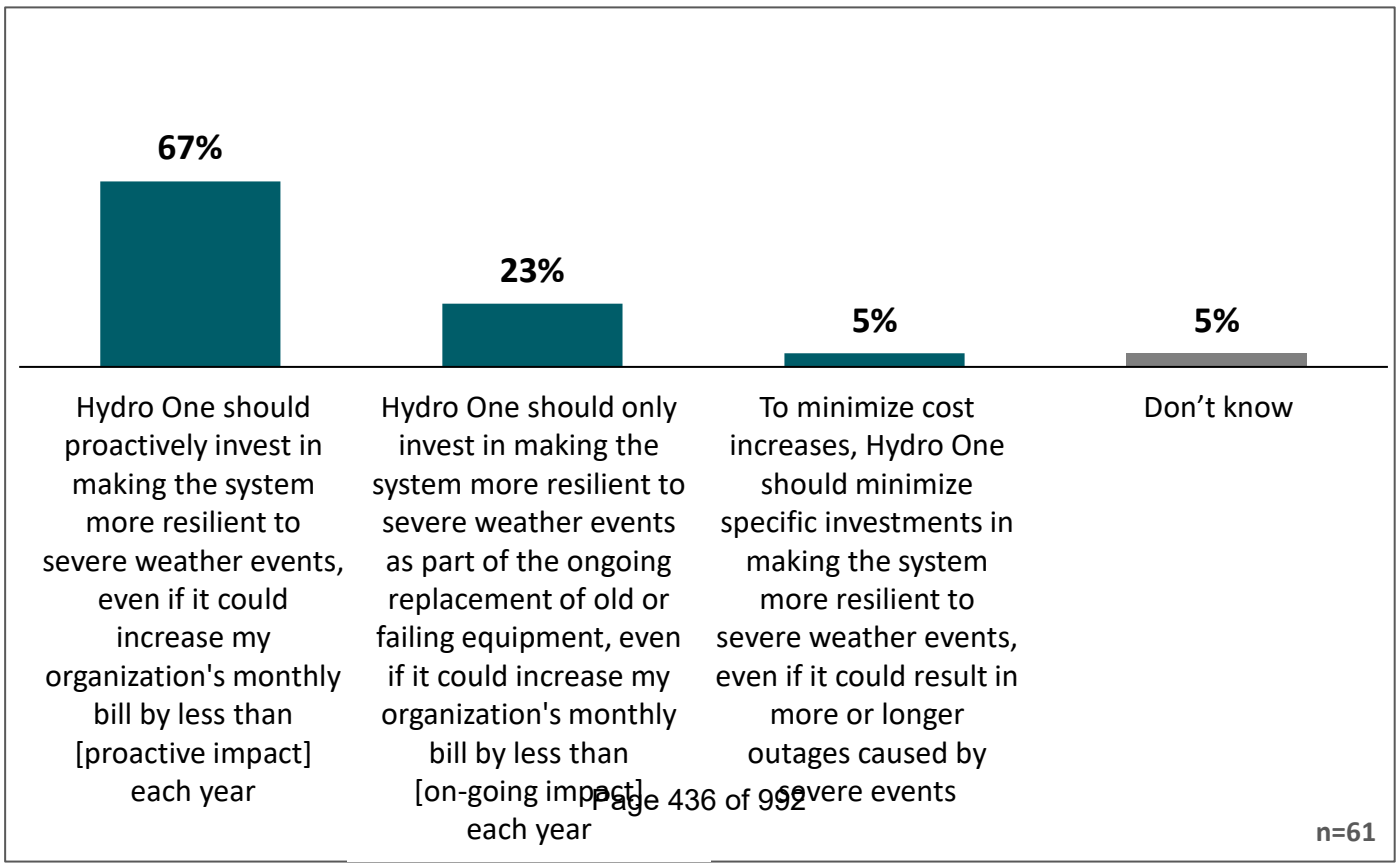
On average, between 2019 and 2023, **severe weather events**, such as ice storms, windstorms or thunderstorms, have contributed to 51% of all hours that the typical customer has been without power per year.

While some of these outages may be inevitable, **Hydro One** could make additional investments to make the system more resilient to these types of events. These investments could help either reduce the number of outages caused by severe weather events or improve restoration times when these outages do occur.

Q Based on this, which of the following is closest to your point of view?

Responding to Severe Weather Legend

Customer Group	[proactive impact]	[on-going impact]
GSd	$13	$10
ST-Low	$6	$5
ST-Med	$30	$25
ST-High	$155	$130



Investment Priorities

Growth

Large Distribution

Electricity demand is on the rise across Ontario. This increasing demand, resulting from industrial and residential growth, as well as the changing ways we use electricity, will require electricity companies like **Hydro One** to make significant investments in the grid.

Increased growth can result in longer wait times to connect new homes or businesses to the system or facilitate upgrades for existing customers if insufficient capacity is available.

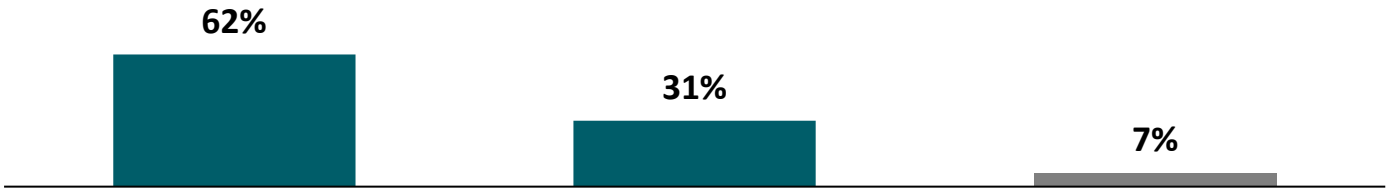
For instance, as increasing growth occurs, some new businesses may be asked to wait up to 2 years or longer for their facility to be connected to the **Hydro One** grid.

However, **Hydro One** could make proactive investments to enable anticipated growth and allow new homes or businesses to connect to the system in a timely manner, and to not delay service upgrades for existing customers.

Q Based on this, which is closest to your point of view?

Growth Legend

Customer Group	[proactive impact]	[reactive impact]
GSd	$50	$30
ST-Low	$25	$15
ST-Med	$135	$80
ST-High	$650	$390



Hydro One should make proactive investments to enable anticipated growth and accommodate new connections and service upgrades while avoiding extended wait times, even if it could increase my organization's monthly bill by less than [proactive impact] each year

To minimize cost increases, Hydro One should only make investments when the growth is materializing, even if that could increase my organization's monthly bill by less than [reactive impact] each year and result in longer wait times and less community growth

Don't know

n=61

Investment Priorities

Evolving Customer Requests & System Visibility

Beyond residential and industrial growth, customers are increasingly requesting information and upgrades related to new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers.

Whether or not you are actively considering these types of technologies for yourself, **Hydro One** needs to be prepared to accommodate these types of customer requests, not just today, but over the next 5 to 10 years.

While **Hydro One** has an obligation to make certain investments to accommodate customer requests, planners have identified incremental investments that can help:

- Ensure that **Hydro One's** grid is ready to accommodate if and when customers request to connect new technologies.

- Give the **Hydro One** control room more "visibility" into exactly where and how much electricity is being used in real-time, helping make more informed decisions on managing electricity demand and equipment maintenance or upgrades.

As the pace of change and customer needs are rapidly evolving, delaying or limiting these investments means that **Hydro One** could struggle to keep up with customer demand for connecting new technology and lack the precision to monitor the grid as new technology adoption increases.

Investment Priorities

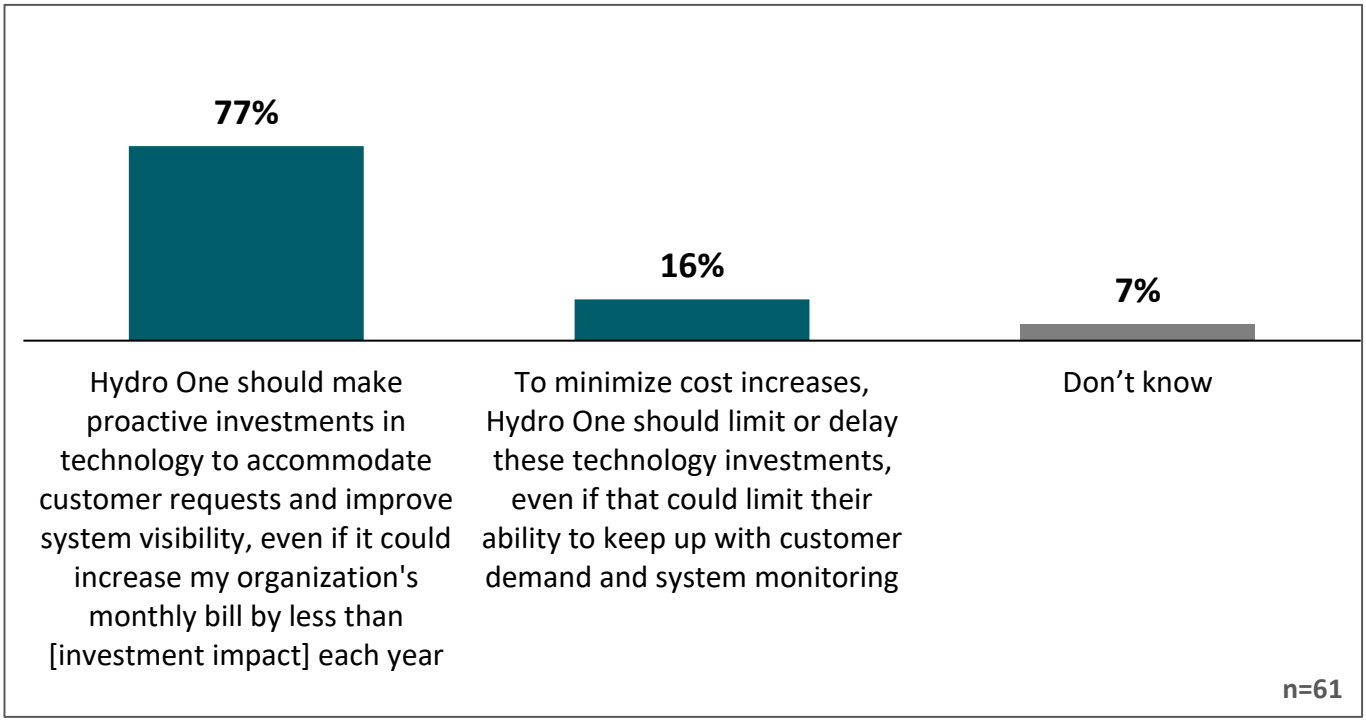
Evolving Customer Requests & System Visibility

Large Distribution

Q With regards to these investments, which of the following is closest to your point of view?

Evolving Customer Requests & System Visibility Legend

Customer Group	[investment impact]
GSd	$20
ST-Low	$10
ST-Med	$55
ST-High	$260



INNOVATIVE RESEARCH GROUP

Investment Priorities

Transmission Renewal

Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

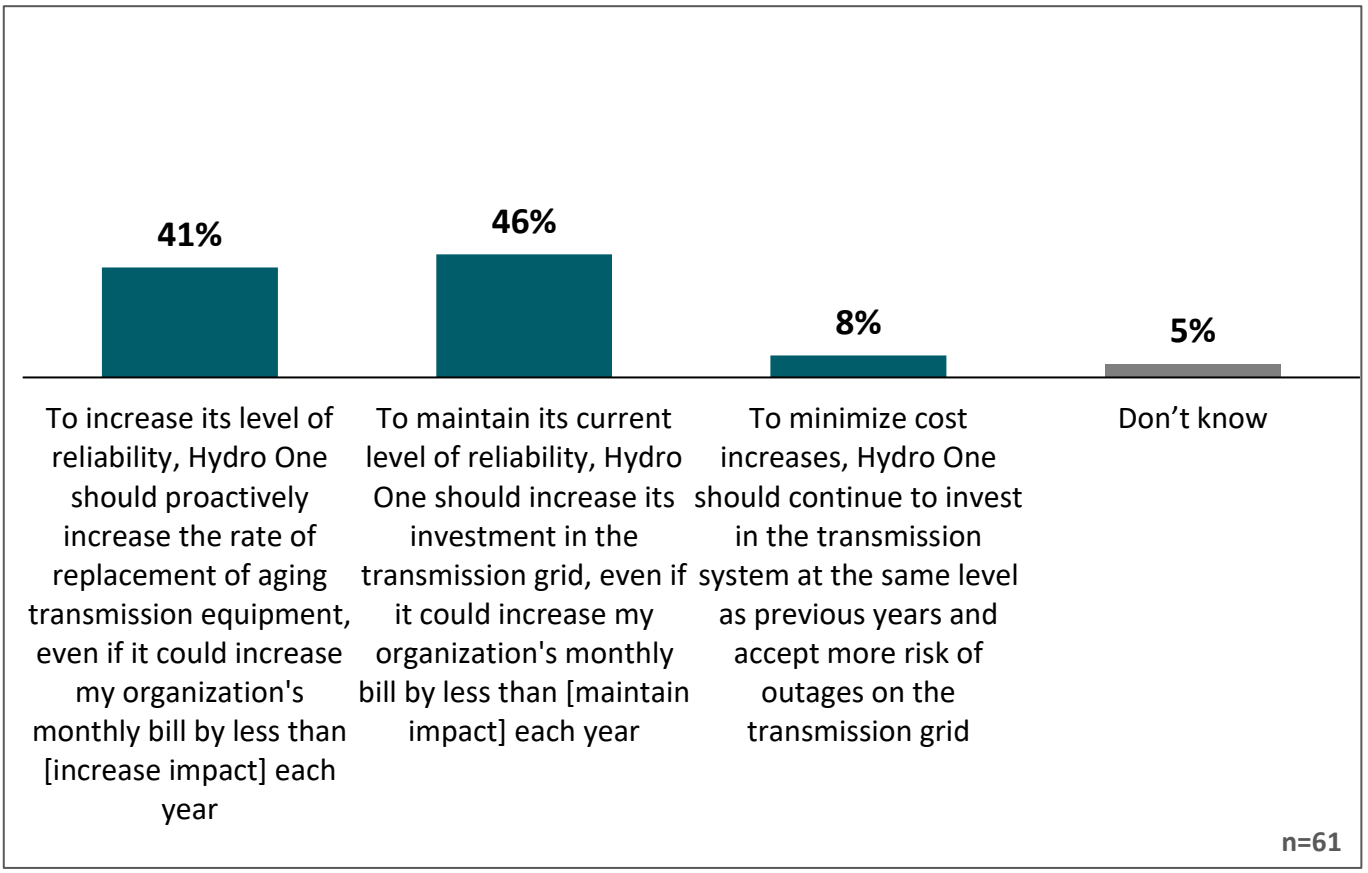
Investment Priorities

Transmission Renewal

Q With this in mind, what is closest to your point of view?

Transmission Renewal Legend

Customer Group	[increase impact]	[maintain impact]
GSd	$40	$15
ST-Low	$300	$105
ST-Med	$1,670	$590
ST-High	$8,180	$2,890



INNOVATIVE RESEARCH GROUP

Other LDC Residential

Online Survey Results

Section 7



Online Survey
Survey Design & Methodology

Field Dates

To obtain feedback from **Other LDC Residential customers**, a random sample of online panelists were invited to complete the survey from a set of partner panels based on the Lucid exchange platform.

In order to qualify to complete the survey, respondents must be Ontarians 18+ who at least share responsibility for paying the electricity bill in their household, excluding Hydro One distribution customers.

Survey responses were collected between **December 2nd and December 4th, 2024**.

Other LDC Residential Online Survey Completes

A total of **1,019** (unweighted) Ontarians completed the online survey.

Sample Weighting

The Other LDC Residential online survey sample was weighted down to n=1,000 proportionately by age, gender, region and education in order to be representative of the broader Ontario population based on Census data.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

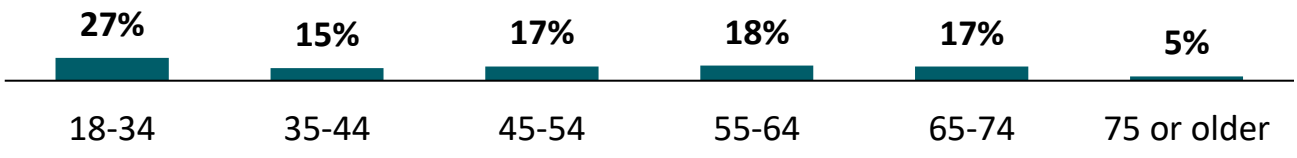
The table below summarizes the unweighted and weighted (in brackets) sample breakdown by age, gender, and region. Totals may not correspond with cell values as some respondents prefer to self-describe their gender. Weights are calculated based off of all available information for a given respondent.

Region	Age-Gender						Total
	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+	
Toronto	32 (33)	40 (31)	34 (33)	34 (33)	42 (35)	46 (40)	229 (205)
Rest of GTA	38 (38)	53 (44)	52 (47)	34 (37)	61 (49)	65 (51)	303 (265)
South/West	25 (37)	49 (40)	61 (54)	24 (35)	36 (40)	68 (61)	263 (267)
North/East	31 (36)	36 (41)	47 (54)	22 (27)	36 (41)	52 (64)	224 (263)
Total	126 (142)	178 (156)	194 (188)	114 (131)	175 (165)	231 (217)	1,019 (1,000)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Demographic Breakdown

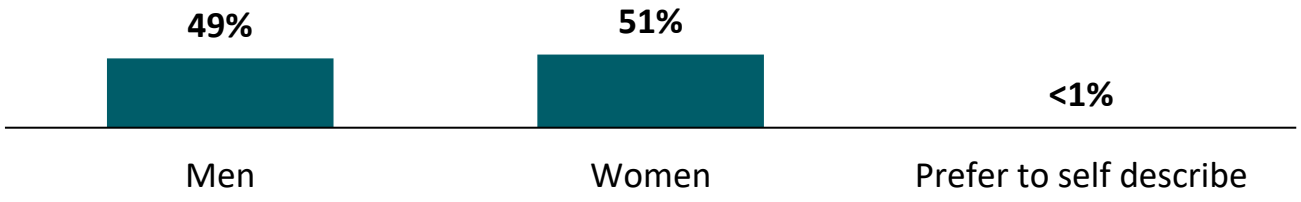
Q Age



"Prefer not to say" (0%) not shown.

n=1,000

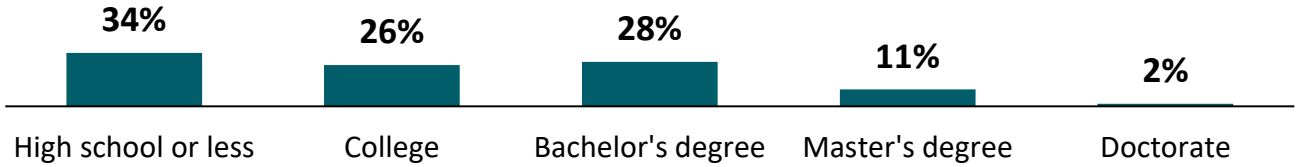
Q Gender



"Prefer not to say" (0%) not shown.

n=1,000

Q Education



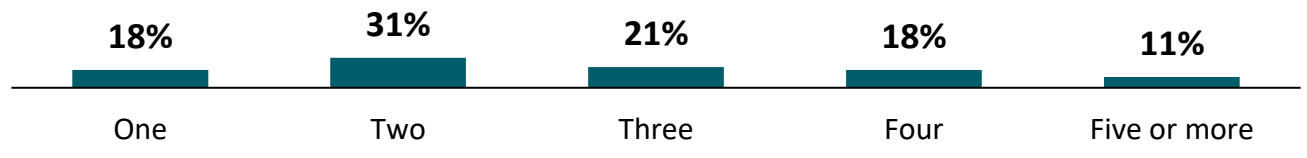
"Other" (<1%) and "Prefer not to say" (0%) not shown.

n=1,000

Demographic Breakdown
Continued

Other LDC Residential

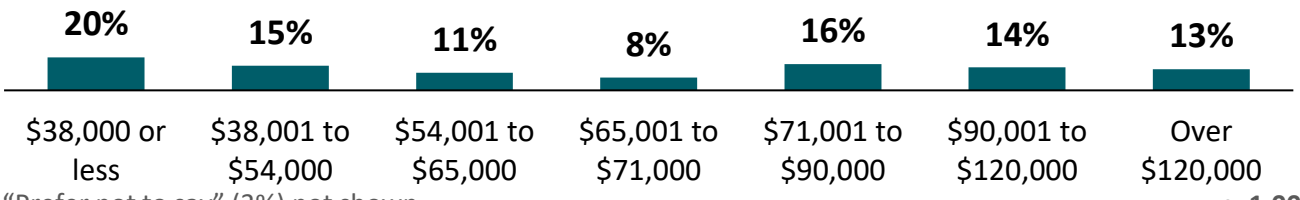
Q Household Size



"Prefer not to say" (0%) not shown.

n=1,000

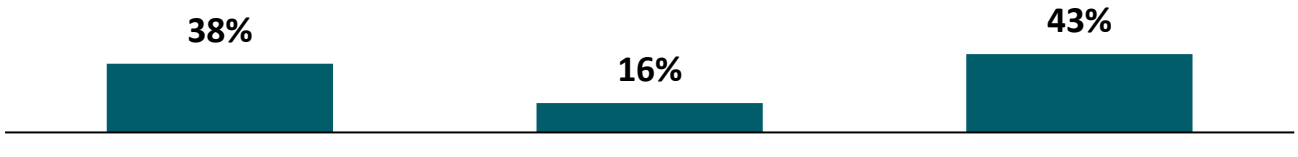
Q After Tax Household Income



"Prefer not to say" (3%) not shown.

n=1,000

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (3%) not shown.

n=1,000

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Demographic Breakdown
Continued

Other LDC Residential

Are you:

Q First Nations



"Prefer not to say" (1%) not shown.

n=1,000

Q Métis



"Prefer not to say" (1%) not shown.

n=1,000

Q Inuk



"Prefer not to say" (2%) not shown.

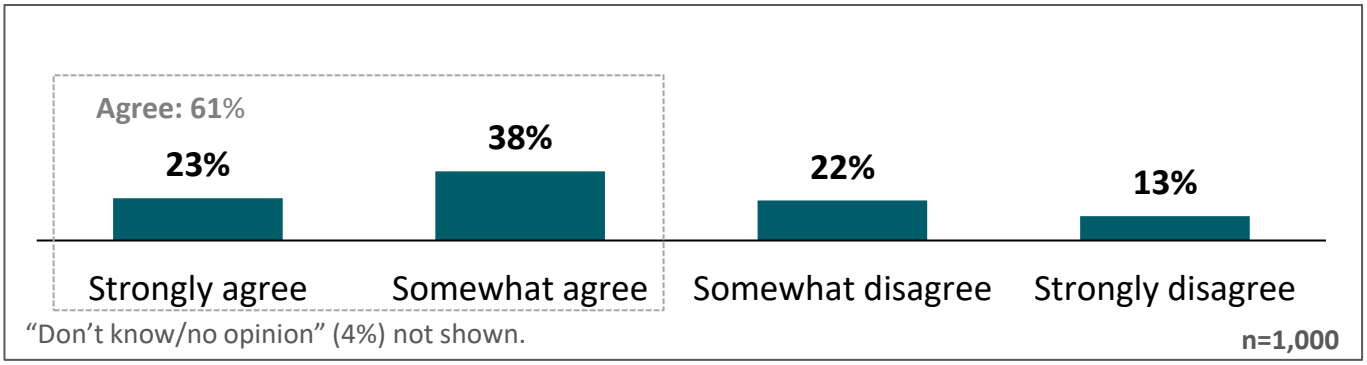
n=1,000

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Environmental Controls

To what extent do you agree or disagree with the following statements?

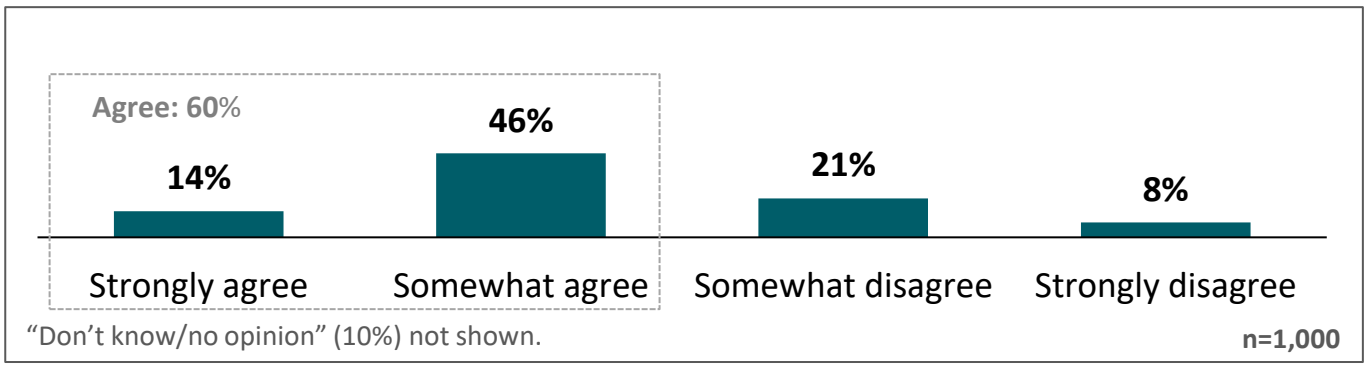
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=1,000

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (10%) not shown.

n=1,000

Other LDC Residential

Familiarity & Experience

Preamble:

This survey is part of **Hydro One's** on-going customer engagement.

Hydro One, Ontario's largest electricity transmission and distribution service provider, is looking for input into choices that will affect the rates Ontarians pay for electricity.

This engagement is about the choices **Hydro One** can make for its transmission system, which serves most electricity customers in Ontario.

The goal is to understand your point of view as a residential ratepayer.

Familiarity & Experience

Familiarity with Hydro One's Role in the System

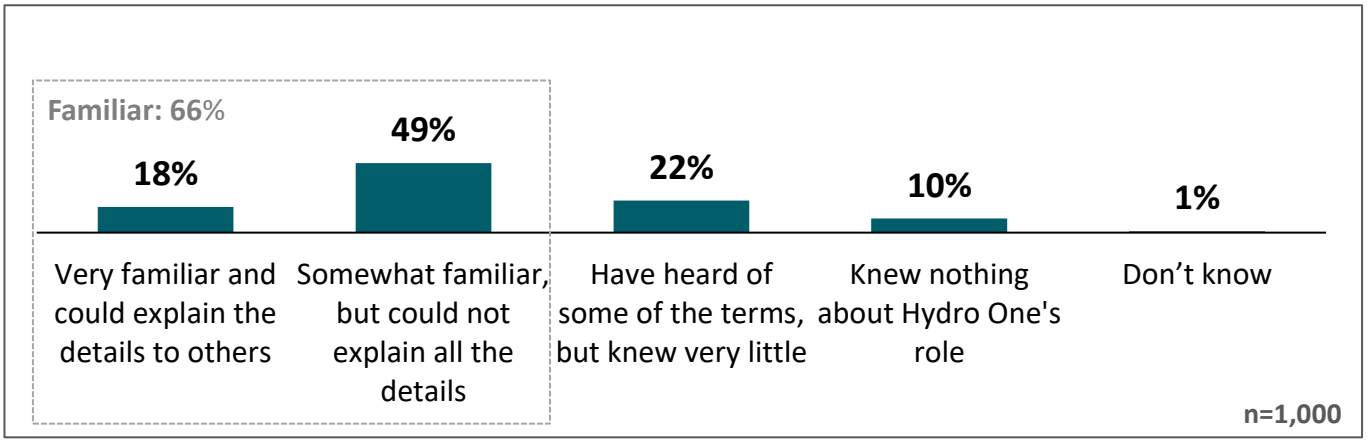
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, your local distribution company is responsible for the local distribution system, which takes electricity from transmission lines and brings it to your home through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	Toronto	Rest of GTA	South/West	North/East
Very familiar	22%	21%	14%	15%
Somewhat familiar	45%	48%	48%	52%
Knew very little	20%	23%	23%	23%
Knew nothing	9%	8%	12%	9%
Don't know	3%	<1%	2%	<1%
Familiar (Very + Somewhat)	**67%**	**69%**	**63%**	**67%**

Familiarity & Experience

Familiarity with Hydro One's Role in the System

Other LDC Residential

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	18%	16%	13%	22%	21%	13%
Somewhat familiar	49%	47%	44%	52%	50%	46%
Knew very little	22%	24%	28%	18%	21%	25%
Knew nothing	10%	11%	14%	7%	8%	13%
Don't know	1%	2%	1%	1%	1%	2%
Familiar (Very + Somewhat)	**66%**	**63%**	**56%**	**74%**	**71%**	**59%**

Familiarity & Experience

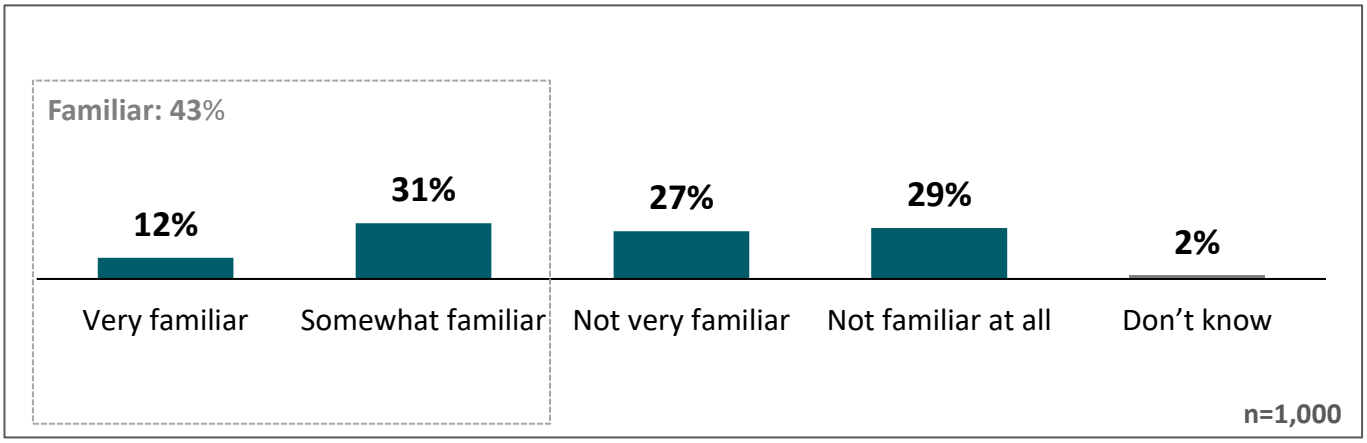
Bill Familiarity

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

About **8% ($10)** of the typical residential customer's monthly electricity bill goes to Hydro One to pay for transmitting electricity from generation stations to your local electricity provider.

The rest of your bill payment goes to your local electricity distribution companies, power generation companies, taxes, and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Hydro One** for the transmission of electricity?



Region

	Toronto	Rest of GTA	South/West	North/East
Very familiar	14%	12%	11%	11%
Somewhat familiar	32%	36%	31%	26%
Not very familiar	26%	24%	24%	32%
Not familiar at all	27%	27%	32%	28%
Don't know	2%	1%	2%	3%
Familiar (Very + Somewhat)	**45%**	**48%**	**42%**	**36%**

Familiarity & Experience

Bill Familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Hydro One** for the transmission of electricity?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	12%	11%	10%	14%	14%	8%
Somewhat familiar	31%	28%	25%	37%	36%	23%
Not very familiar	27%	26%	28%	26%	25%	29%
Not familiar at all	29%	33%	35%	22%	24%	36%
Don't know	2%	2%	2%	1%	1%	3%
Familiar (Very + Somewhat)	**43%**	**39%**	**34%**	**51%**	**51%**	**31%**

Familiarity & Experience

Familiarity with Rate Applications

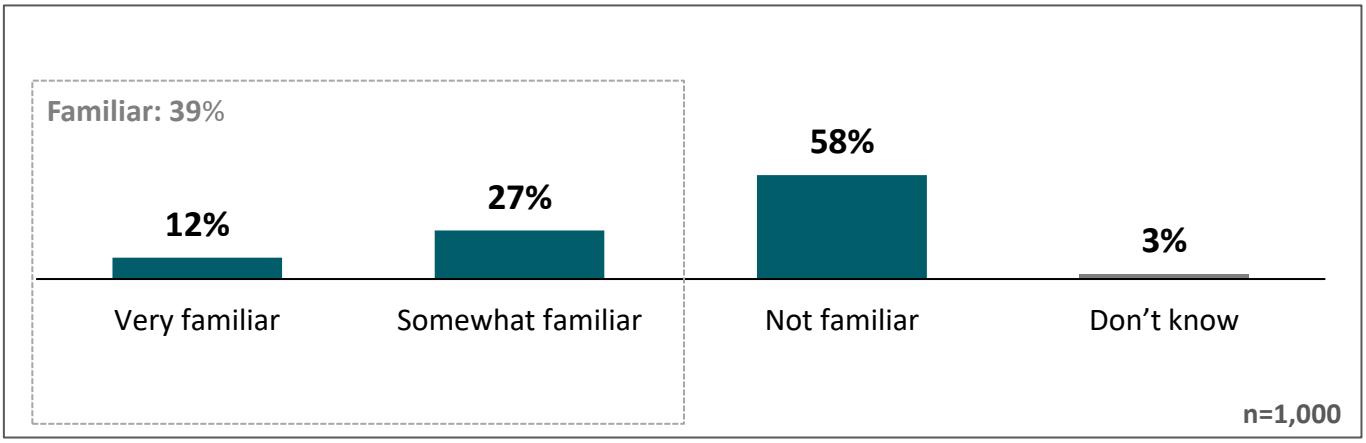
Hydro One's transmission system is funded by the rates paid by Ontario electricity customers, like you.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



Region

	Toronto	Rest of GTA	South/West	North/East
Very familiar	16%	11%	14%	8%
Somewhat familiar	26%	32%	24%	26%
Not familiar	55%	55%	59%	62%
Don't know	3%	1%	3%	4%
Familiar (Very + Somewhat)	**42%**	**44%**	**38%**	**34%**

Familiarity & Experience

Familiarity with Rate Applications

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	12%	10%	9%	15%	15%	7%
Somewhat familiar	27%	24%	24%	31%	32%	19%
Not familiar	58%	63%	65%	51%	51%	70%
Don't know	3%	2%	2%	2%	2%	4%
Familiar (Very + Somewhat)	**39%**	**34%**	**33%**	**47%**	**47%**	**26%**

INNOVATIVE RESEARCH GROUP

Other LDC Residential

Customer Priorities



Customer Priorities

Response Labels Legend

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments in its transmission system that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 5 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity to my LDC	Reliably providing electricity to my local electricity distribution company
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

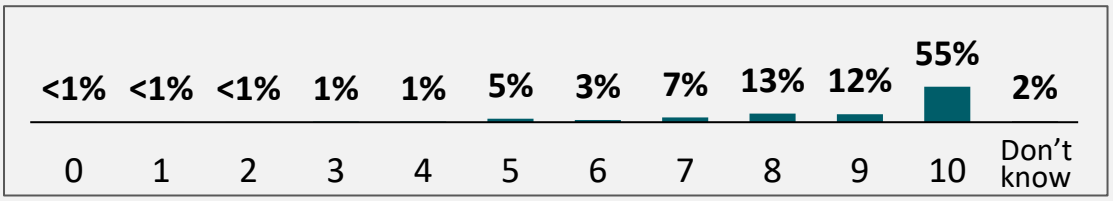
Customer Priorities

Importance of Customer Priorities

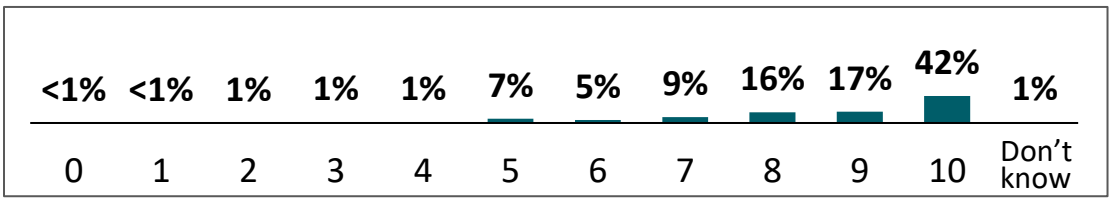
Other LDC Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

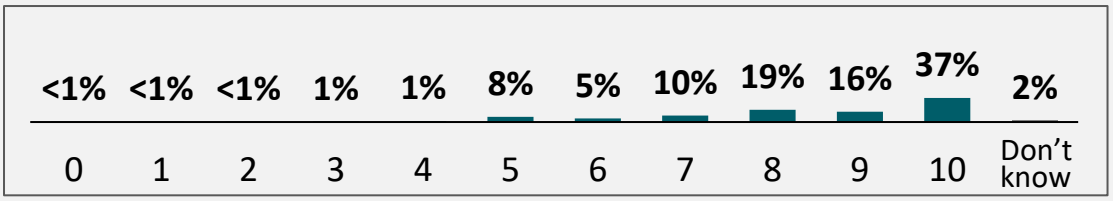
Delivering electricity at reasonable rates [average = **8.8**]



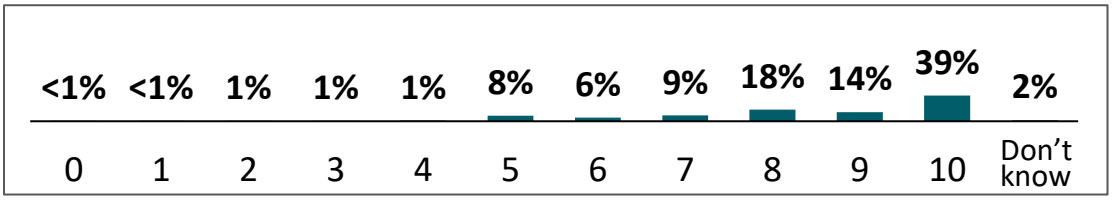
Providing reliable electricity to my LDC [average = **8.5**]



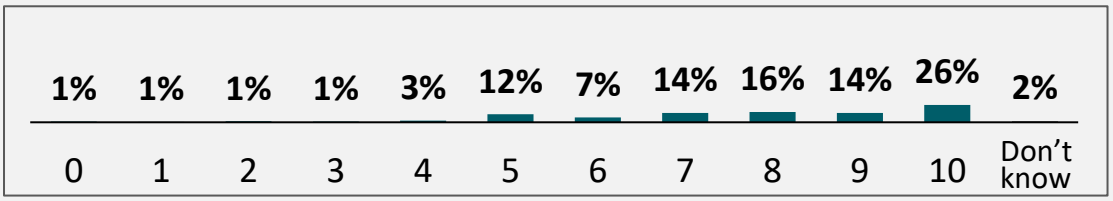
Meeting the growing electricity need [average = **8.3**]



Ensuring the safety of electricity infrastructure [average = **8.3**]



Reducing the environmental impact [average = **7.6**]



Note: Priority labels have been shortened for brevity. See slide 299 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Importance of Customer Priorities – Average Scores

Other LDC Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

	Region				
Average Score	**Overall**	**Toronto**	**Rest of GTA**	**South/West**	**North/East**
Delivering electricity at reasonable rates	8.8	8.8	8.7	8.9	8.9
Providing reliable electricity to my LDC	8.5	8.5	8.4	8.7	8.3
Meeting the growing electricity need	8.3	8.2	8.3	8.4	8.2
Ensuring the safety of electricity infrastructure	8.3	8.3	8.2	8.3	8.4
Reducing the environmental impact	7.6	7.8	7.6	7.7	7.4

Note: Priority labels have been shortened for brevity. See slide 299 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Importance of Customer Priorities – Average Scores

Other LDC Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

		LEAP/OESP Qualification			Bill Impact	
Average Score	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	8.8	8.8	9.0	8.8	8.9	8.8
Providing reliable electricity to my LDC	8.5	8.4	8.6	8.5	8.4	8.6
Meeting the growing electricity need	8.3	8.3	8.3	8.3	8.3	8.3
Ensuring the safety of electricity infrastructure	8.3	8.3	8.1	8.4	8.2	8.3
Reducing the environmental impact	7.6	7.7	7.6	7.6	7.6	7.6

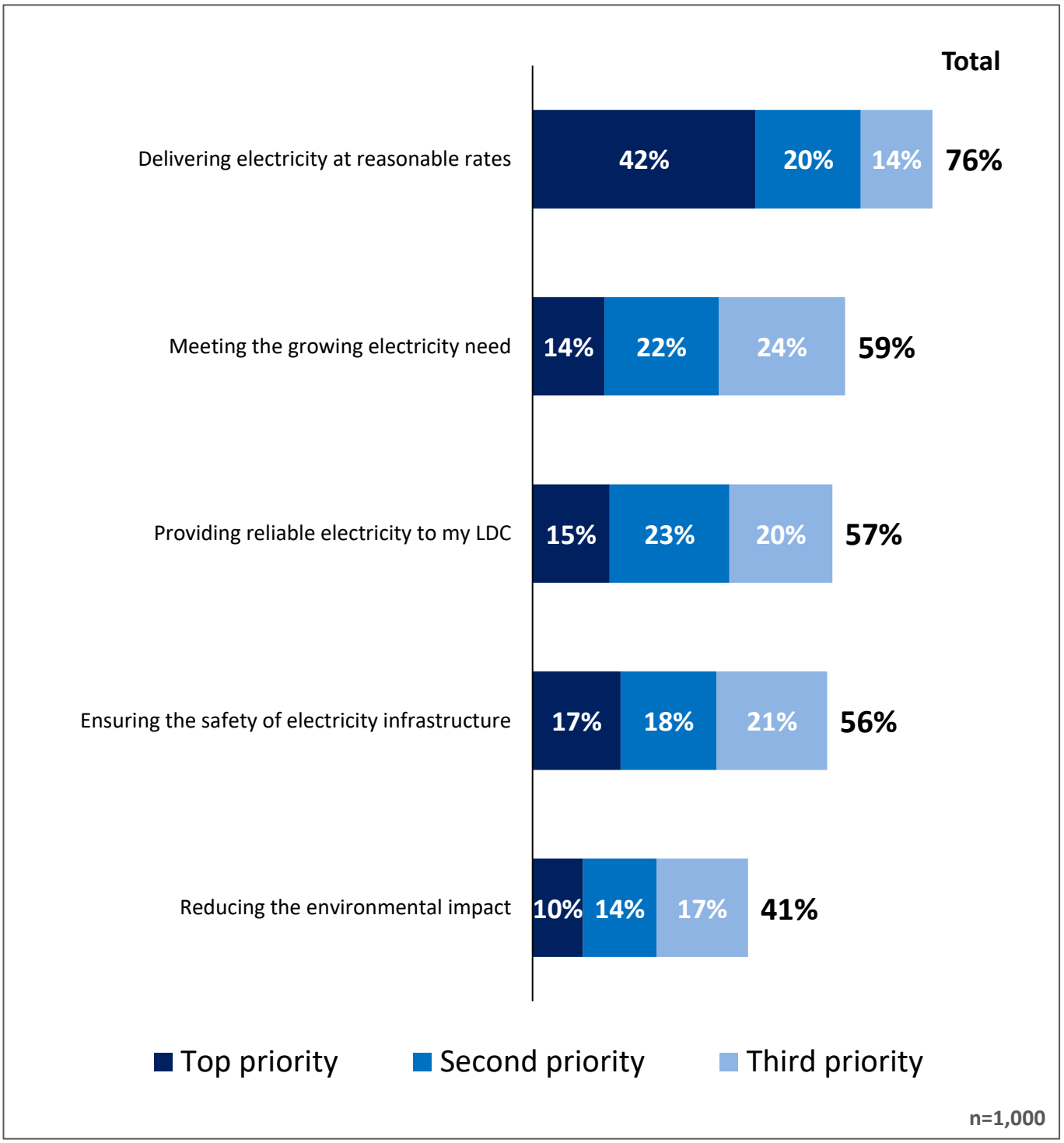
Note: Priority labels have been shortened for brevity. See slide 299 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Other LDC Residential

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 299 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

% who select as top 3 priority	Overall	Region: Toronto	Region: Rest of GTA	Region: South/West	Region: North/East
Delivering electricity at reasonable rates	76%	74%	77%	78%	74%
Meeting the growing electricity need	59%	58%	62%	58%	59%
Providing reliable electricity to my LDC	57%	64%	55%	57%	53%
Ensuring the safety of electricity infrastructure	56%	54%	55%	55%	59%
Reducing the environmental impact	41%	42%	38%	39%	45%

Note: Priority labels have been shortened for brevity. See slide 299 for full label text. "Don't know" not shown.

Customer Priorities

Ranking Customer Priorities

Other LDC Residential

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?

		LEAP/OESP Qualification			Bill Impact	
% who select as top 3 priority	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Delivering electricity at reasonable rates	76%	74%	80%	75%	78%	73%
Meeting the growing electricity need	59%	56%	55%	64%	57%	63%
Providing reliable electricity to my LDC	57%	53%	58%	60%	57%	56%
Ensuring the safety of electricity infrastructure	56%	57%	54%	57%	58%	53%
Reducing the environmental impact	41%	44%	44%	39%	42%	38%

Note: Priority labels have been shortened for brevity. See slide 299 for full label text. “Don’t know” not shown.

Customer Priorities

Other Priorities

Other LDC Residential

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Reasonable/affordable rates	13.7%
Having alternative energy/sustainable sources/green technology	3.7%
Reducing environmental impacts	2.1%
Affordable renewable energy	1.8%
Improving reliability/less outages	1.3%
Enhancing the grid/infrastructure	1.3%
Meeting growing needs for electricity	1.2%
Incentives for seniors/subsidy programs	0.8%
Tree trimming/removal	0.4%
Electric vehicle (EV) infrastructure investment	0.3%
Support/incentives for new technologies or energy efficiency efforts	0.3%
Prioritizing safety	0.2%
Burying lines underground/removing hydro poles	0.2%
Reducing length of outages	0.2%
Information/programs to manage electricity usage	0.2%
Focus on nuclear energy/power	0.2%
Other	3.7%
None/Don't know	68.5%

Note: Only responses >0.1% shown

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Other LDC Residential

Reliability Experience

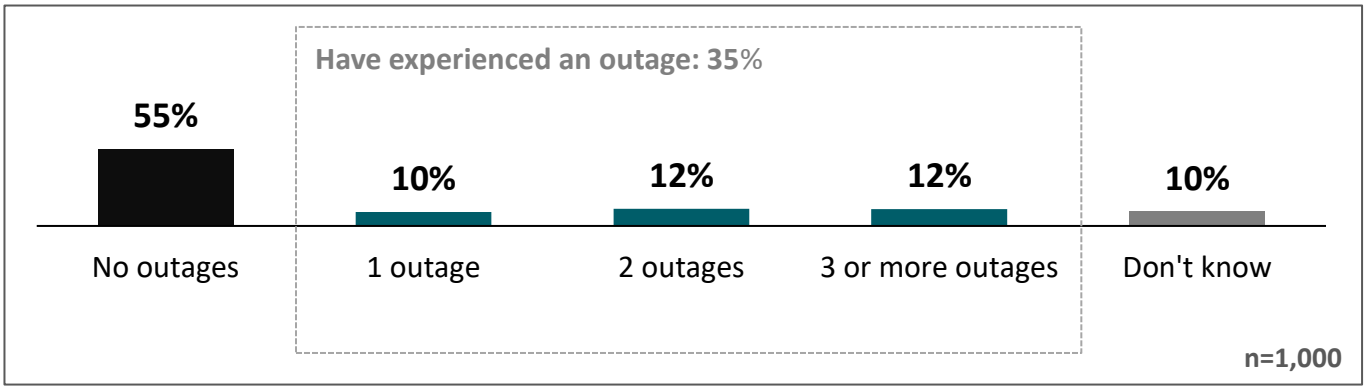


Reliability Experience
Number of Outages Experienced

Other LDC Residential

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at home **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



Region

	Toronto	Rest of GTA	South/West	North/East
No outages	50%	67%	54%	48%
1 outage	12%	7%	12%	11%
2 outages	11%	11%	14%	14%
3 or more outages	16%	7%	9%	17%
Don't know	12%	9%	11%	10%
Have experienced at least 1 outage	**38%**	**24%**	**35%**	**42%**

LEAP/OESP Qualification / Bill Impact

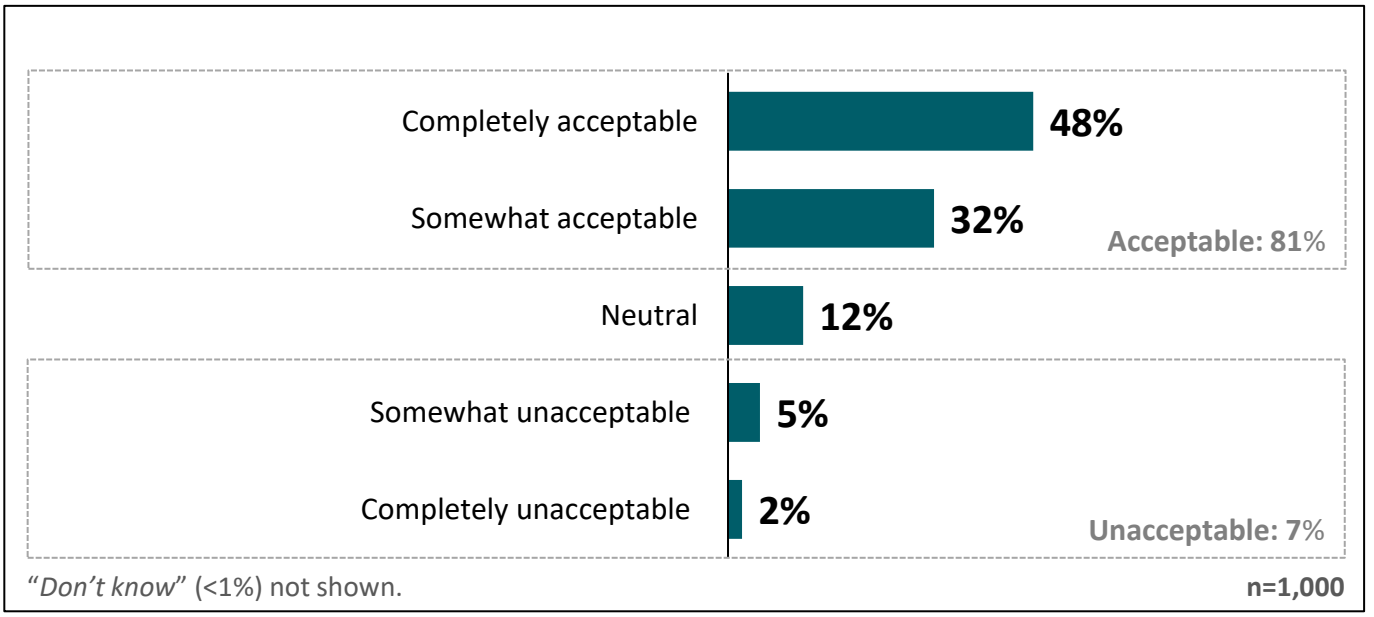
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
No outages	52%	59%	56%	57%	52%
1 outage	9%	11%	11%	9%	12%
2 outages	12%	12%	13%	12%	13%
3 or more outages	13%	11%	12%	12%	12%
Don't know	14%	7%	7%	10%	10%
Have experienced at least 1 outage	**33%**	**33%**	**36%**	**32%**	**38%**

Reliability Experience

Current Reliability of Electricity Service

Other LDC Residential

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (<1%) not shown. n=1,000

Region

	Toronto	Rest of GTA	South/West	North/East
Completely acceptable	39%	50%	54%	47%
Somewhat acceptable	37%	36%	24%	34%
Neutral	16%	11%	12%	10%
Somewhat unacceptable	5%	3%	7%	5%
Completely unacceptable	3%	1%	1%	4%
Don't know	<1%	<1%	1%	<1%
Acceptable (Completely + Somewhat)	**76%**	**85%**	**79%**	**81%**
Unacceptable (Completely + Somewhat)	**8%**	**4%**	**9%**	**9%**

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Reliability Experience

Current Reliability of Electricity Service

Other LDC Residential

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Completely acceptable	48%	51%	49%	45%	45%	53%
Somewhat acceptable	32%	28%	34%	36%	35%	28%
Neutral	12%	13%	11%	11%	11%	13%
Somewhat unacceptable	5%	4%	3%	6%	7%	3%
Completely unacceptable	2%	4%	2%	1%	2%	2%
Don't know	<1%	<1%	--	1%	<1%	1%
Acceptable (Completely + Somewhat)	**81%**	**79%**	**83%**	**81%**	**80%**	**81%**
Unacceptable (Completely + Somewhat)	**7%**	**8%**	**5%**	**8%**	**9%**	**5%**

Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights

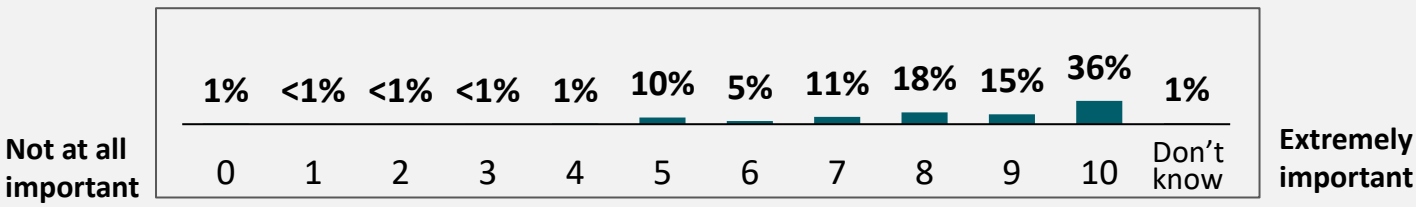
Reliability Experience

Importance of Reliability Priorities

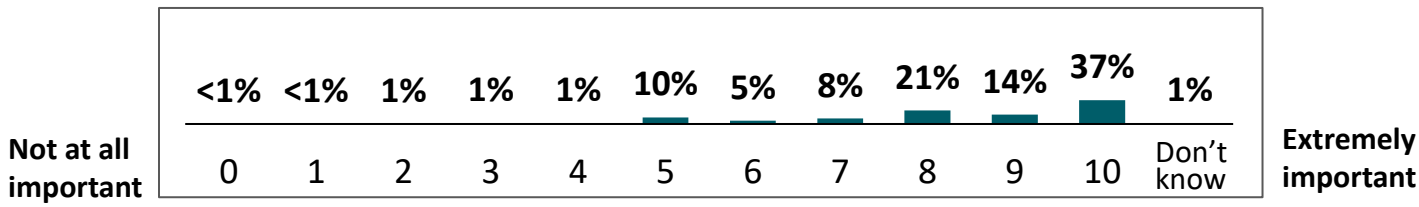
Other LDC Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

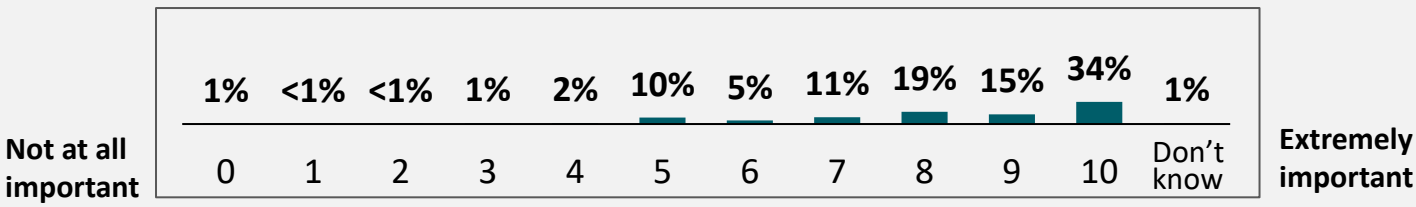
Reducing length of non-weather outages [average = **8.2**]



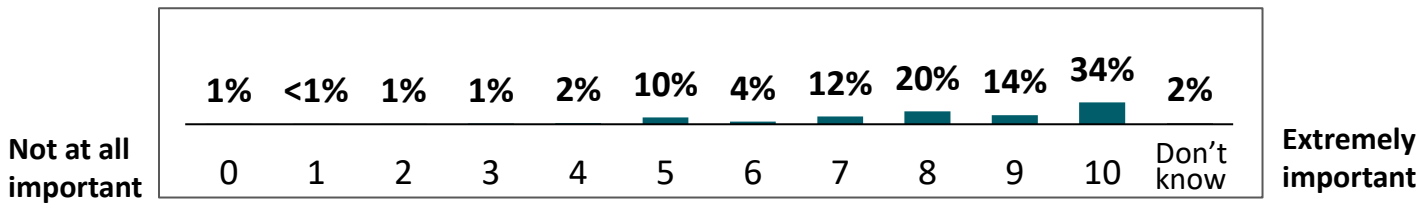
Reducing length of weather-caused outages [average = **8.2**]



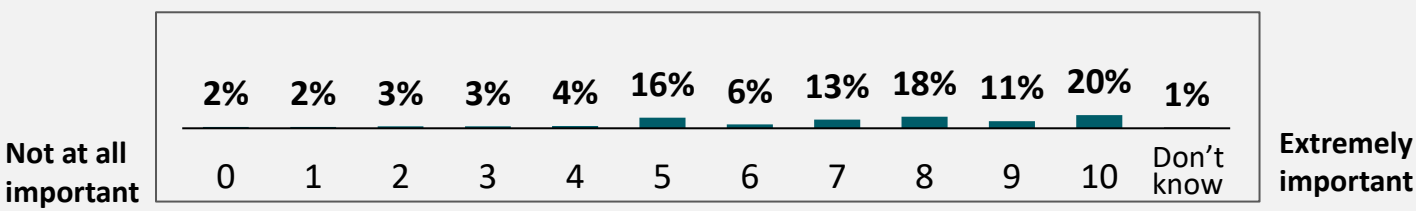
Reducing number of non-weather outages [average = **8.1**]



Reducing number of weather-caused outages [average = **8.1**]



Reducing momentary interruptions in power [average = **7.0**]



Note: Priority labels have been shortened for brevity. See slide 311 for full label text.
"Don't know" not included in calculation of means.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Other LDC Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		Region			
Average Score	**Overall**	**Toronto**	**Rest of GTA**	**South/West**	**North/East**
Reducing length of non-weather outages	8.2	8.2	8.2	8.2	8.1
Reducing length of weather-caused outages	8.2	8.4	8.3	8.2	7.9
Reducing number of non-weather outages	8.1	8.2	8.2	8.1	7.8
Reducing number of weather-caused outages	8.1	8.2	8.1	8.1	7.8
Reducing momentary interruptions in power	7.0	7.4	7.1	6.9	6.5

Note: Priority labels have been shortened for brevity. See slide 311 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

Reliability Experience

Importance of Reliability Priorities – Average Scores

Other LDC Residential

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

		LEAP/OESP Qualification			Bill Impact	
Average Score	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Reducing length of non-weather outages	8.2	8.2	8.0	8.3	8.2	8.2
Reducing length of weather-caused outages	8.2	8.1	8.1	8.2	8.2	8.1
Reducing number of non-weather outages	8.1	8.1	8.0	8.1	8.1	8.0
Reducing number of weather-caused outages	8.1	8.0	7.9	8.1	8.2	7.9
Reducing momentary interruptions in power	7.0	6.8	6.8	7.1	7.2	6.5

Note: Priority labels have been shortened for brevity. See slide 311 for full label text.
"Don't know" not included in calculation of means. "Don't know" not shown.

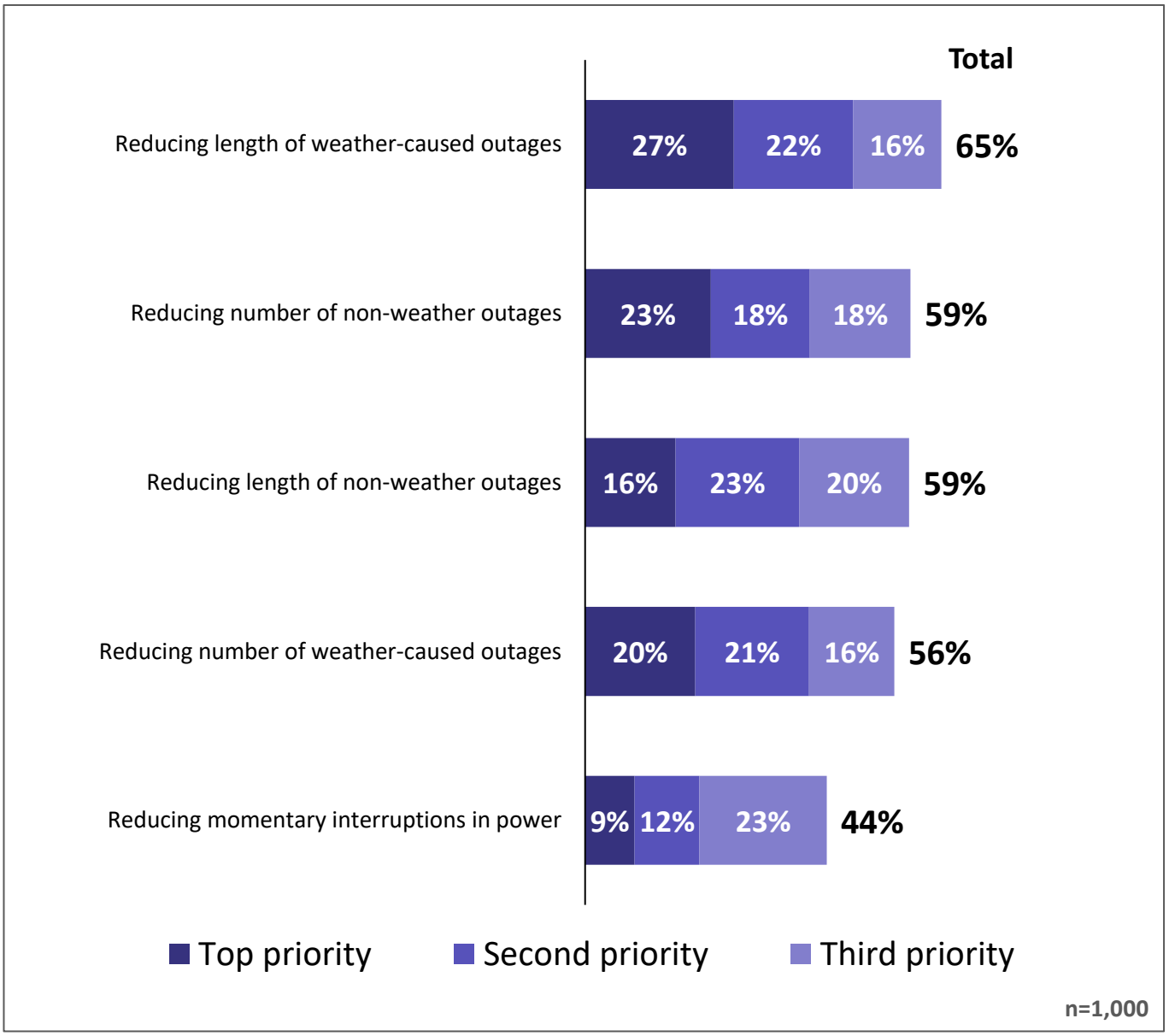
Reliability Experience

Ranking Reliability Priorities

Other LDC Residential

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?



Note: Priority labels have been shortened for brevity. See slide 311 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Other LDC Residential

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		Region			
% who select as top 3 priority	**Overall**	**Toronto**	**Rest of GTA**	**South/West**	**North/East**
Reducing length of weather-caused outages	65%	65%	62%	69%	65%
Reducing number of non-weather outages	59%	61%	62%	54%	62%
Reducing length of non-weather outages	59%	64%	54%	56%	64%
Reducing number of weather-caused outages	56%	56%	58%	55%	56%
Reducing momentary interruptions in power	44%	42%	50%	43%	41%

Note: Priority labels have been shortened for brevity. See slide 311 for full label text. "Don't know" not shown.

Reliability Experience

Ranking Reliability Priorities

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

		LEAP/OESP Qualification			Bill Impact	
% who select as top 3 priority	**Overall**	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Reducing length of weather-caused outages	65%	63%	67%	67%	65%	64%
Reducing number of non-weather outages	59%	58%	60%	60%	60%	59%
Reducing length of non-weather outages	59%	59%	58%	60%	58%	62%
Reducing number of weather-caused outages	56%	55%	55%	58%	58%	54%
Reducing momentary interruptions in power	44%	46%	40%	45%	48%	38%

Note: Priority labels have been shortened for brevity. See slide 311 for full label text. "Don't know" not shown.

INNOVATIVE RESEARCH GROUP

Other LDC Residential

Investment Priority



Investment Priorities

Transmission Renewal

Other LDC Residential

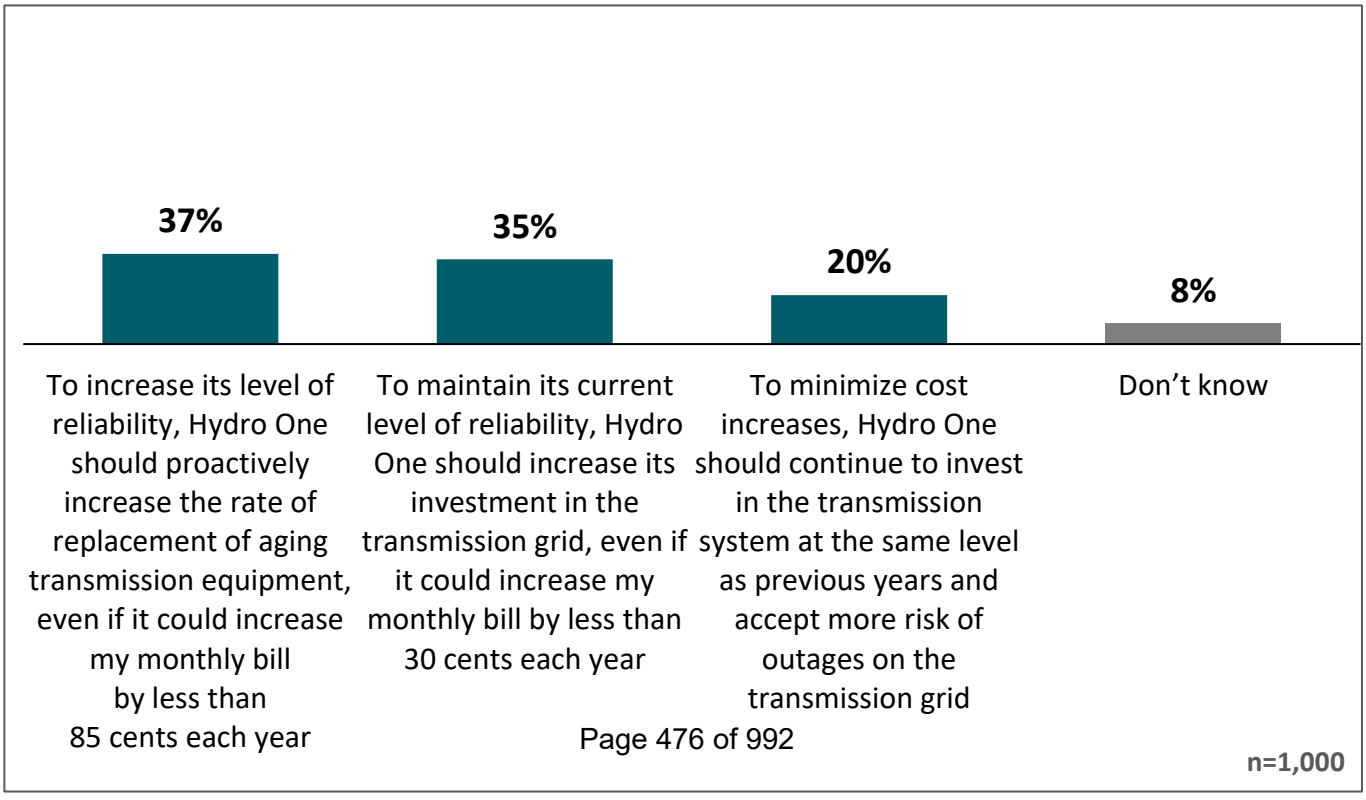
Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

Q With this in mind, what is closest to your point of view?



Investment Priorities
Transmission Renewal

Other LDC Residential

Q With this in mind, what is closest to your point of view?

	Region				
	Overall	Toronto	Rest of GTA	South/West	North/East
Proactively increase investment to increase reliability	37%	39%	34%	34%	41%
Increase investment to maintain current reliability	35%	32%	40%	37%	30%
Continue to invest at the same level	20%	21%	19%	20%	21%
Don't know	8%	8%	7%	10%	8%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Proactively increase investment to increase reliability	37%	41%	35%	32%	45%
Increase investment to maintain current reliability	33%	33%	38%	36%	33%
Continue to invest at the same level	20%	19%	21%	26%	10%
Don't know	11%	7%	6%	6%	12%

Note: Response labels have been shortened for brevity. See slide 319 for full label text.

INNOVATIVE RESEARCH GROUP

Large Transmission Account Customers

Online Survey Results

Section 8



Field Dates

The **Large Transmission Customers Online Survey** was sent to all Hydro One large transmission account customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **November 13th and December 12th, 2024**.

Each customer received a unique URL that could be linked back to their region and customer type (End-User, Generator, or LDC).

In total, the large transmission customers survey was sent to **195** customers from *customerexperience@hydroone.com*. Reminder emails were sent on November 20th, November 27th, December 4th, and December 10th, 2024, to those who had not yet completed the survey.

Large Transmission Accounts Online Survey Completes

A total of **72** (unweighted) Hydro One large transmission account customers completed the online survey.

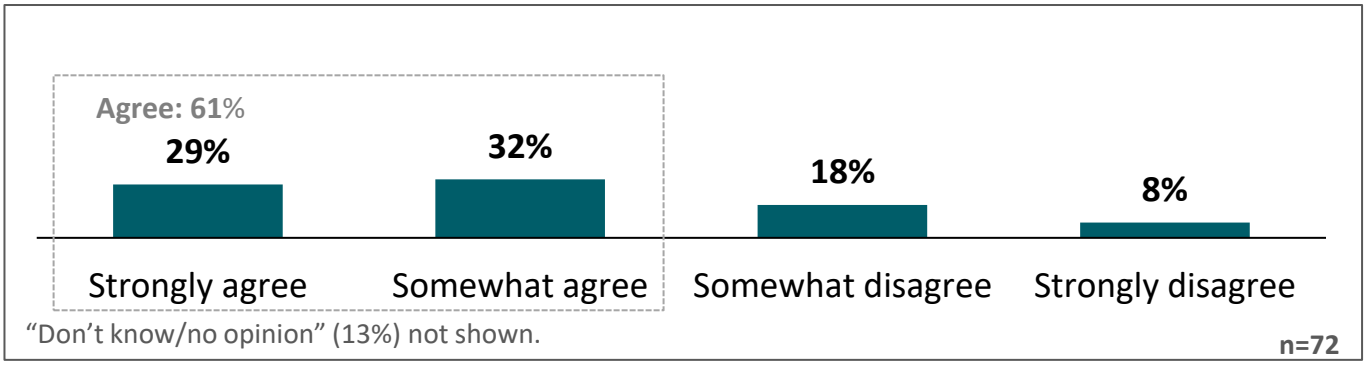
Sample Weighting

The large transmission account online survey sample was not weighted due to the small number of completes.

Environmental Controls

To what extent do you agree or disagree with the following statements?

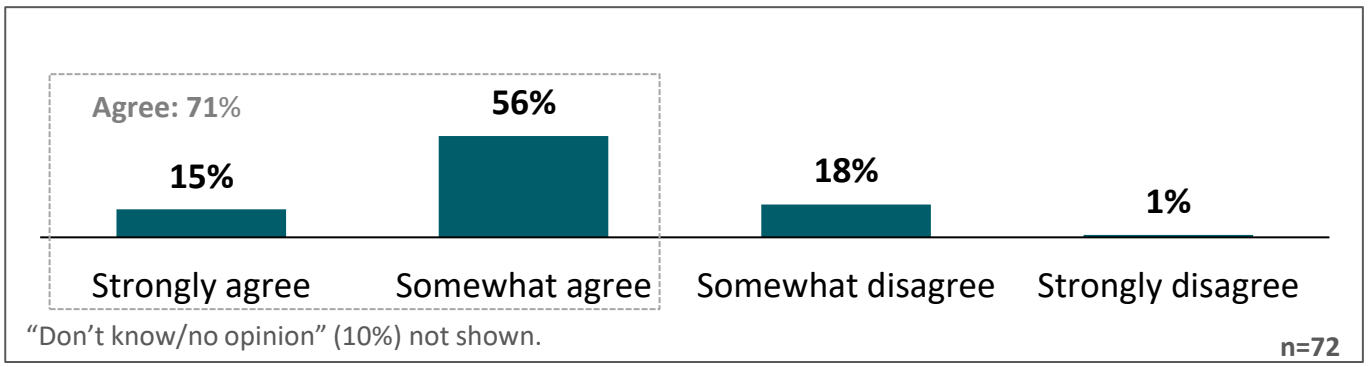
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (13%) not shown.

n=72

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (10%) not shown.

n=72

Large Transmission Account Customers

Familiarity & Experience

Preamble:

Before we begin, this survey has **two key objectives**.

First, **Hydro One** wants to better understand your experiences as a customer.

Second, **Hydro One** wants your input on some of the investment areas they could focus on in the future.

First, let's talk about your experience.

While you might have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a transmission-connected customer.

***Note**: The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

Familiarity & Experience

Familiarity with Hydro One's Role in the System

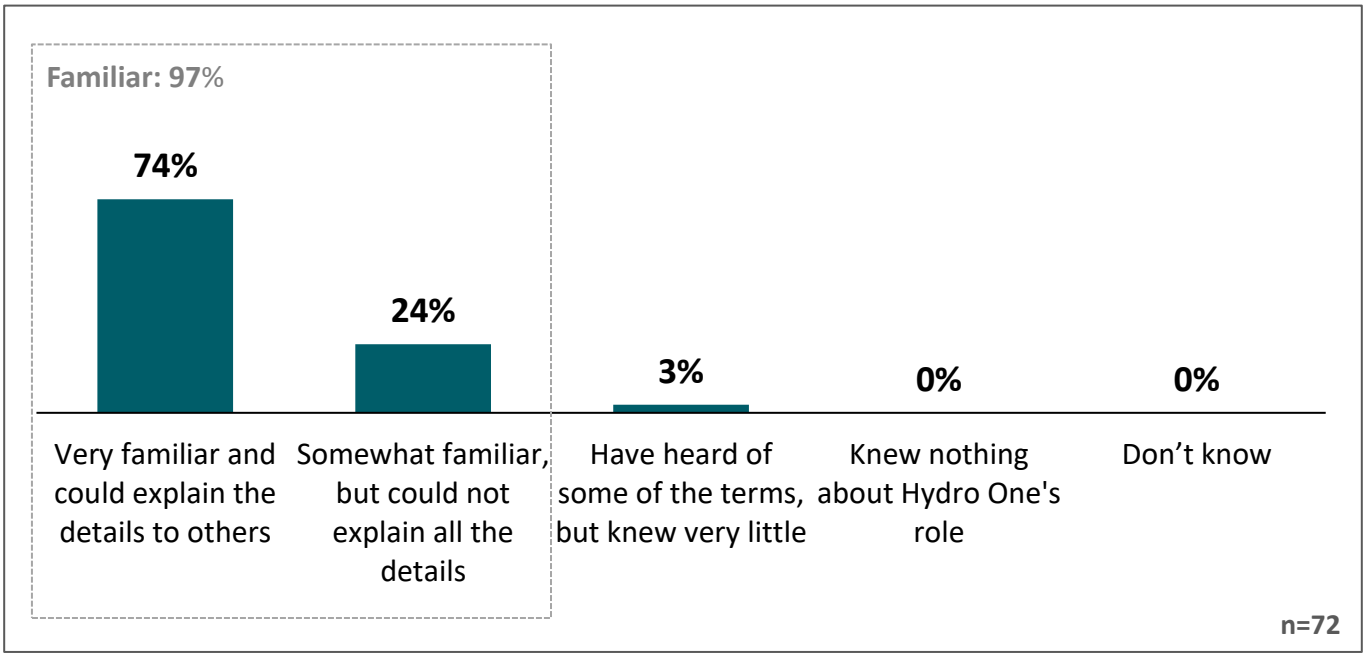
Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which takes electricity from transmission lines and brings it to your organization through a network of wires, poles and other equipment.

Hydro One does not generate electricity or set electricity prices.

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

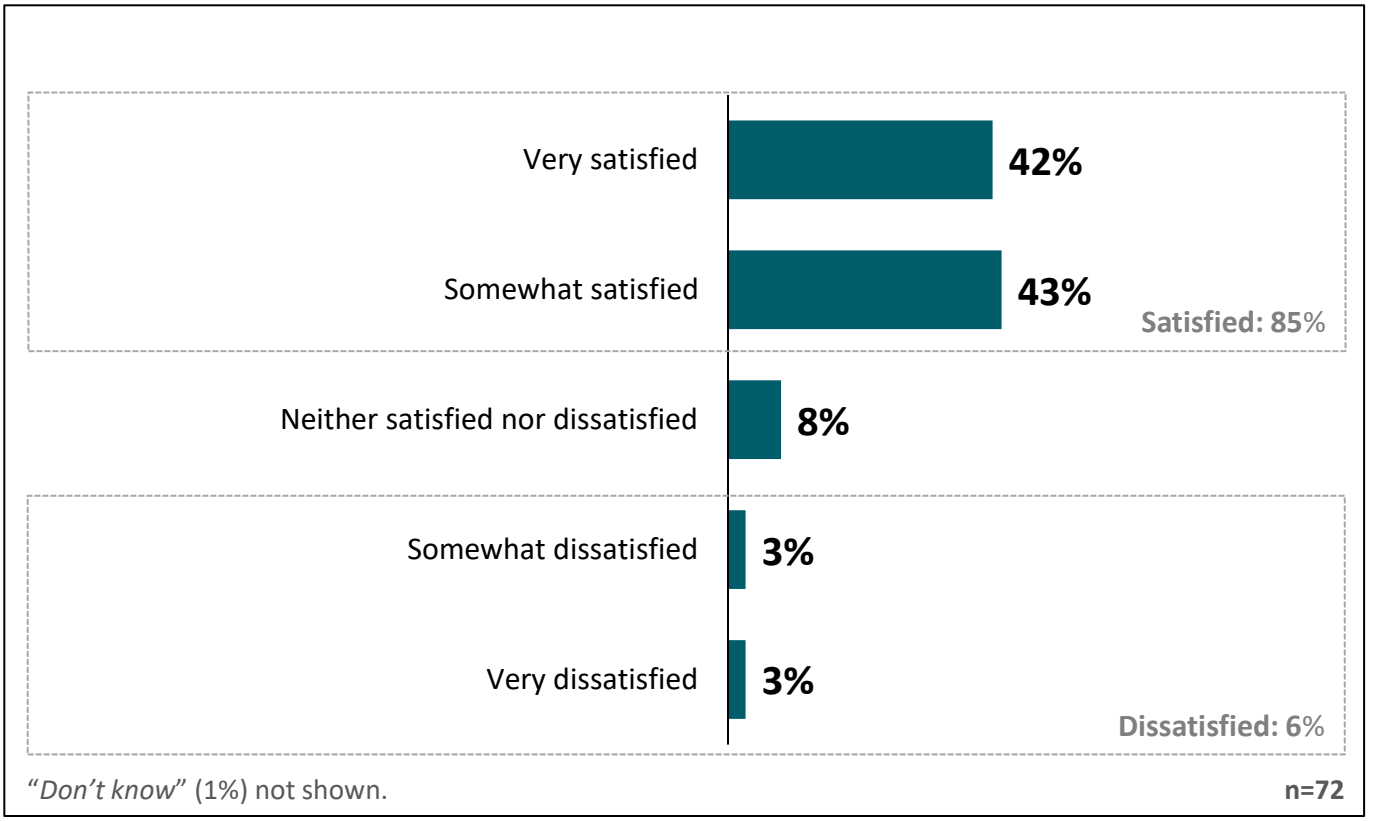


Familiarity & Experience

Overall Satisfaction with Hydro One

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from **Hydro One**?



"*Don't know*" (1%) not shown.

n=72

Familiarity & Experience

How can Hydro One improve services?

Large Transmission

Q Is there anything in particular you would like **Hydro One** to do to improve its services to your organization?

Response	%
Improve customer service	19.4%
Decrease outages/interruptions	12.5%
Improve information sharing	6.9%
Improve communication during outages	5.6%
Building capacity/addressing growth	5.6%
Lower rates/decrease bills	2.8%
Upgrade/better maintain infrastructure	2.8%
Satisfied with services/no issues	2.8%
Improve response time for outages	1.4%
Other	5.6%
None/Don't know	34.7%

Note: Only responses >0.1% shown

Familiarity & Experience

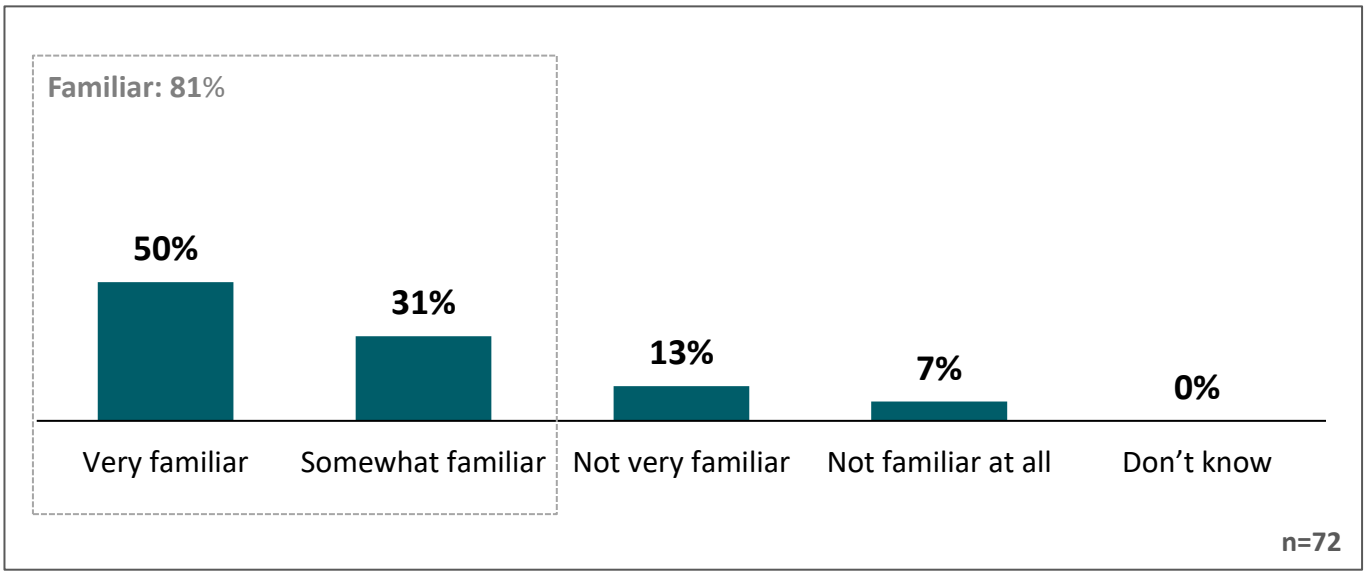
Bill Familiarity

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board, the provincial energy regulator.

Hydro One is responsible for most of the transmission charges on your organization's monthly bill. For the average transmission-connected customer, transmission charges represent about 12% of the total bill. This share may vary for your organization, depending on your organization's load profile.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Hydro One**?



Familiarity & Experience

Familiarity with Rate Applications

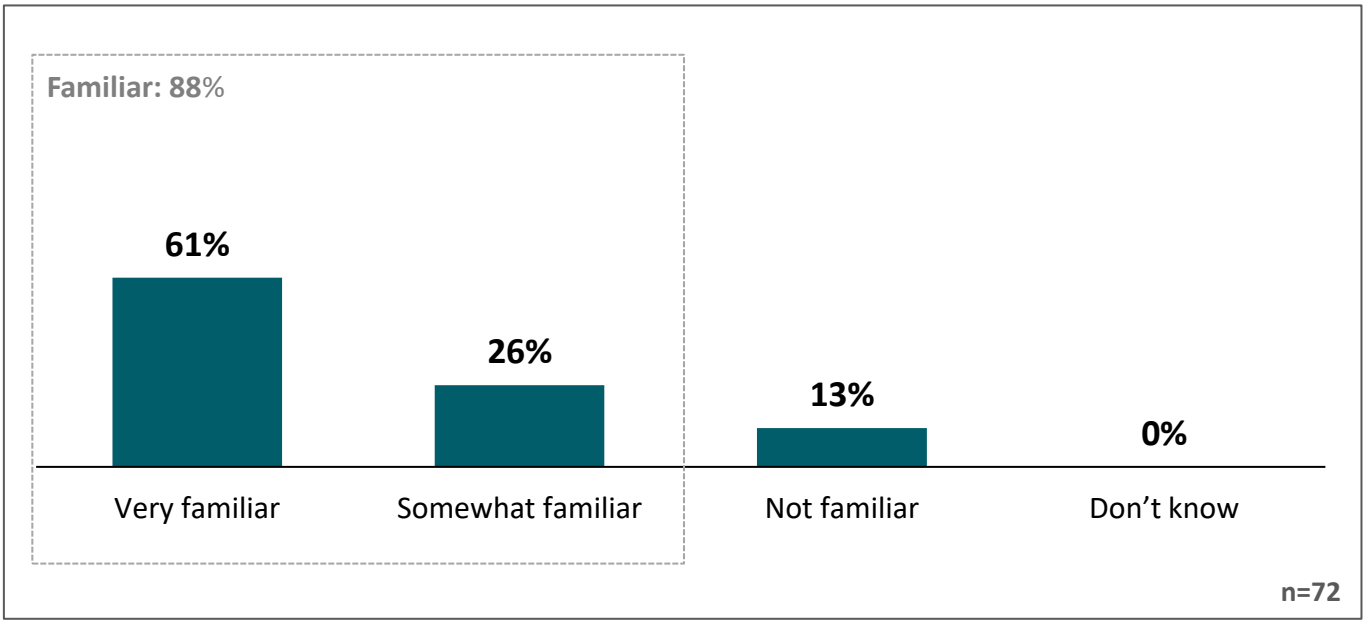
Hydro One is funded by the rates paid by its customers.

Roughly every five years, **Hydro One** is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. **Hydro One's** next rate application will cover the years 2028-2032.

In this process, **Hydro One's** rate application will be examined in detail and **Hydro One** must demonstrate that customer needs and priorities were factored into its investment planning process.

If approved by the OEB, the investments areas that are discussed throughout the remainder of this survey would be directly funded by customers.

Q Before this survey, were you aware that **Hydro One** must file a rate application with the OEB every 5 years?



INNOVATIVE RESEARCH GROUP

Large Transmission Account Customers

Customer Priorities



Customer Priorities

Response Labels Legend

Now, let's talk about the priorities that matter most to you.

Hydro One is considering investments that can help address a range of issues. The list below is not exhaustive of all **Hydro One** priorities but includes 8 different themes that may be important to customers like you.

Shortened Customer Priorities Response Labels	Full Customer Priorities Response Labels
Delivering electricity at reasonable rates	Delivering electricity at reasonable rates
Providing reliable electricity	Providing reliable electricity to my organization
Enhancing Hydro One's customer service	Enhancing Hydro One's customer service
Offering programs to help manage usage	Offering programs that can help customers better manage their electricity usage
Meeting the growing electricity need	Meeting the growing need for electricity in my community
Ensuring the safety of electricity infrastructure	Ensuring the safety of electricity infrastructure for Hydro One employees and the public
Enhancing the grid for new technologies	Enhancing the grid so that customers can connect new technologies like rooftop solar panels, heat pumps, and electric vehicle chargers
Reducing the environmental impact	Reducing the environmental impact of Hydro One's operations

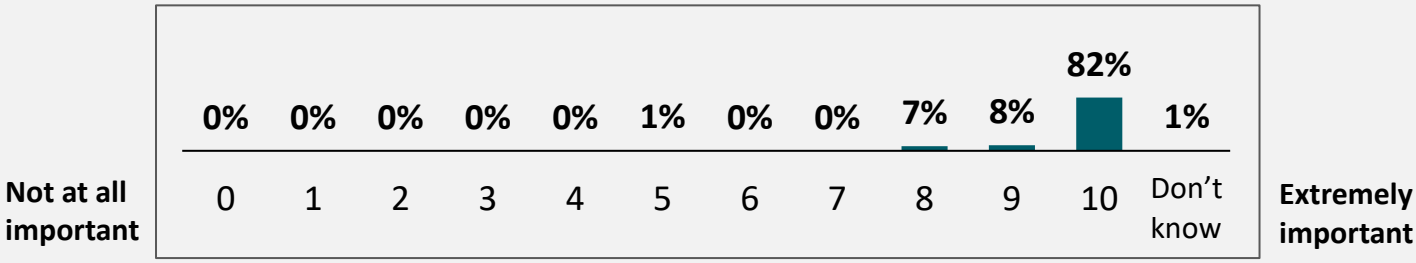
Customer Priorities

Importance of Customer Priorities

Large Transmission

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

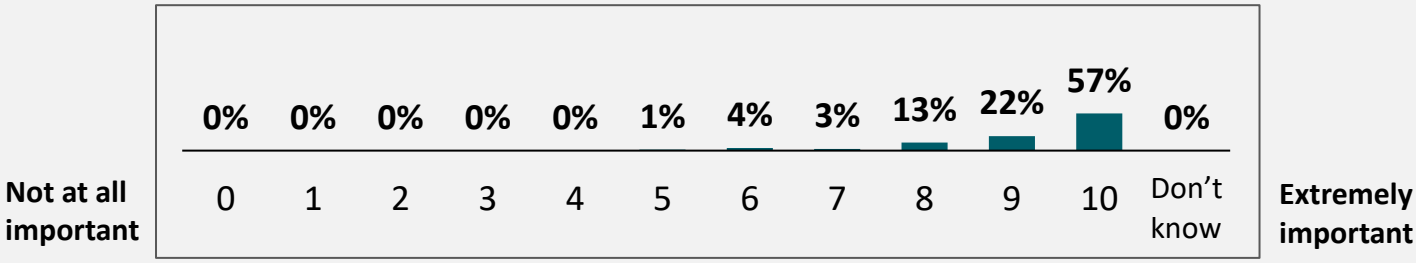
Providing reliable electricity [average = **9.7**]



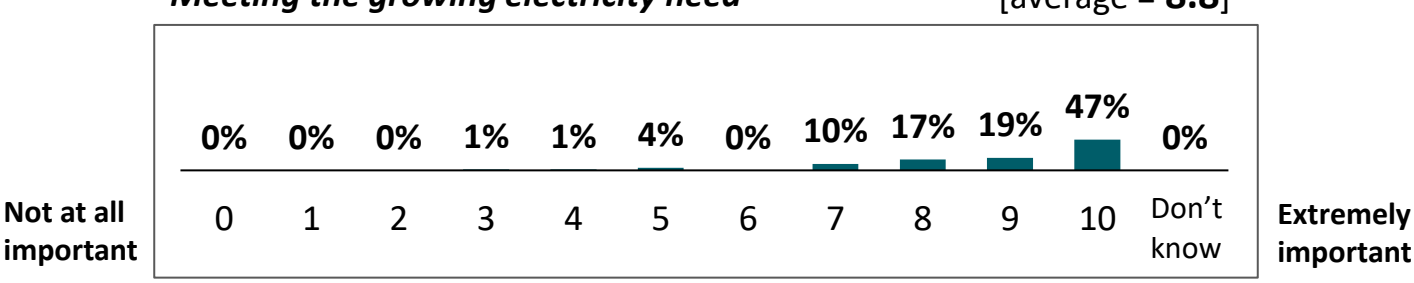
Ensuring the safety of electricity infrastructure [average = **9.4**]



Delivering electricity at reasonable rates [average = **9.2**]



Meeting the growing electricity need [average = **8.8**]



Note: Priority labels have been shortened for brevity. See slide 331 for full label text.
"Don't know" not included in calculation of means.

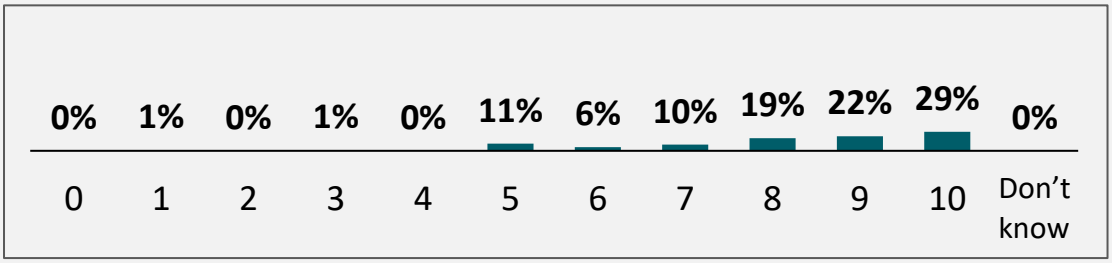
Customer Priorities

Importance of Customer Priorities (Cont'd)

Large Transmission

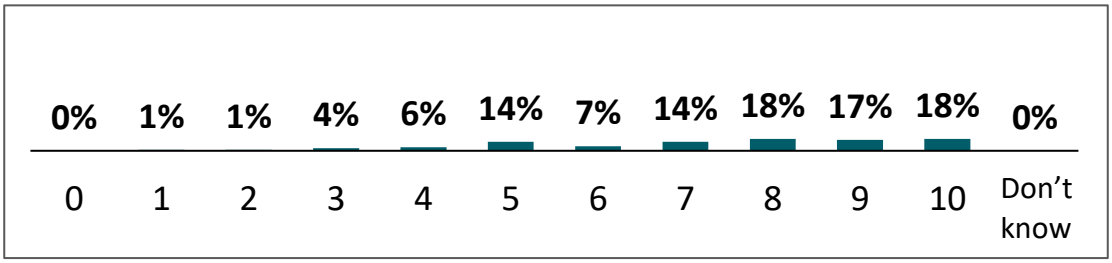
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following priorities to you as a customer?

Enhancing Hydro One's customer service [average = **8.1**]



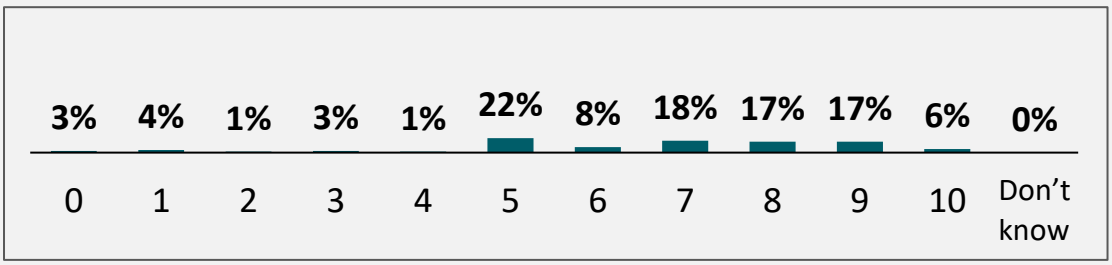
Not at all important — Extremely important

Enhancing the grid for new technologies [average = **7.2**]



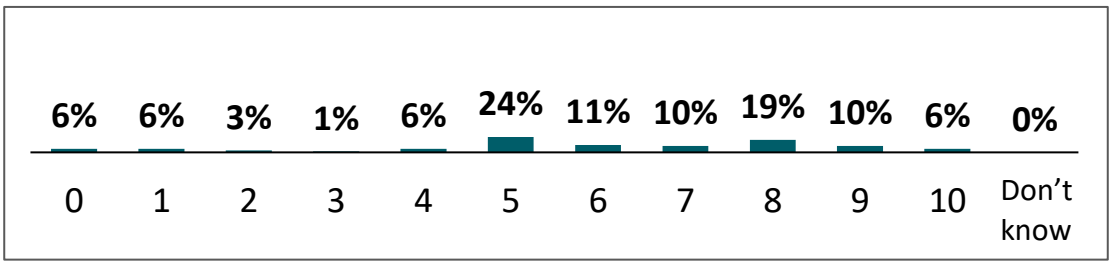
Not at all important — Extremely important

Reducing the environmental impact [average = **6.5**]



Not at all important — Extremely important

Offering programs to help manage usage [average = **5.9**]



Not at all important — Extremely important

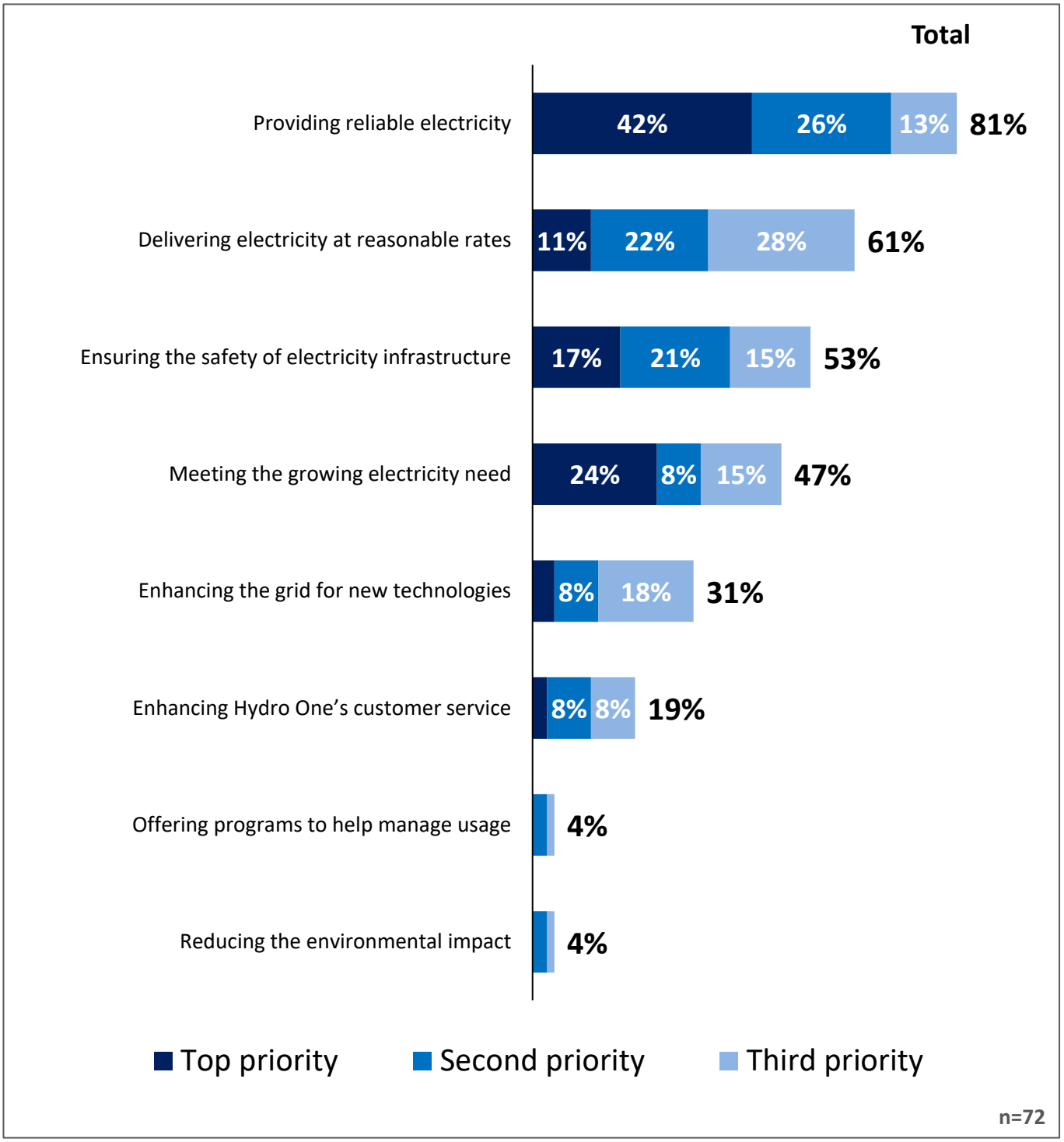
Note: Priority labels have been shortened for brevity. See slide 331 for full label text.
"Don't know" not included in calculation of means.

Customer Priorities

Ranking Customer Priorities

Large Transmission

Q Thinking of the investment priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important investment priority? And which would you say is the third most important investment priority?



Note: Priority labels have been shortened for brevity. See slide 331 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

Customer Priorities

Other Priorities

Large Transmission

Q Over the next 5 to 10 years, are there any additional priorities that you would like to see **Hydro One** focus on?

Response	%
Enhancing the grid/infrastructure	12.5%
Improving reliability/less outages	11.1%
Meeting growing needs for electricity	11.1%
Improving customer service/communication	4.2%
Reasonable/affordable rates	2.8%
Burying lines underground/removing hydro poles	2.8%
Having alternative energy/sustainable sources/green technology	1.4%
Electric vehicle (EV) infrastructure investment	1.4%
Other	1.4%
None/Don't know	51.4%

Note: Only responses >0.1% shown

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Large Transmission Account Customers

Reliability Experience

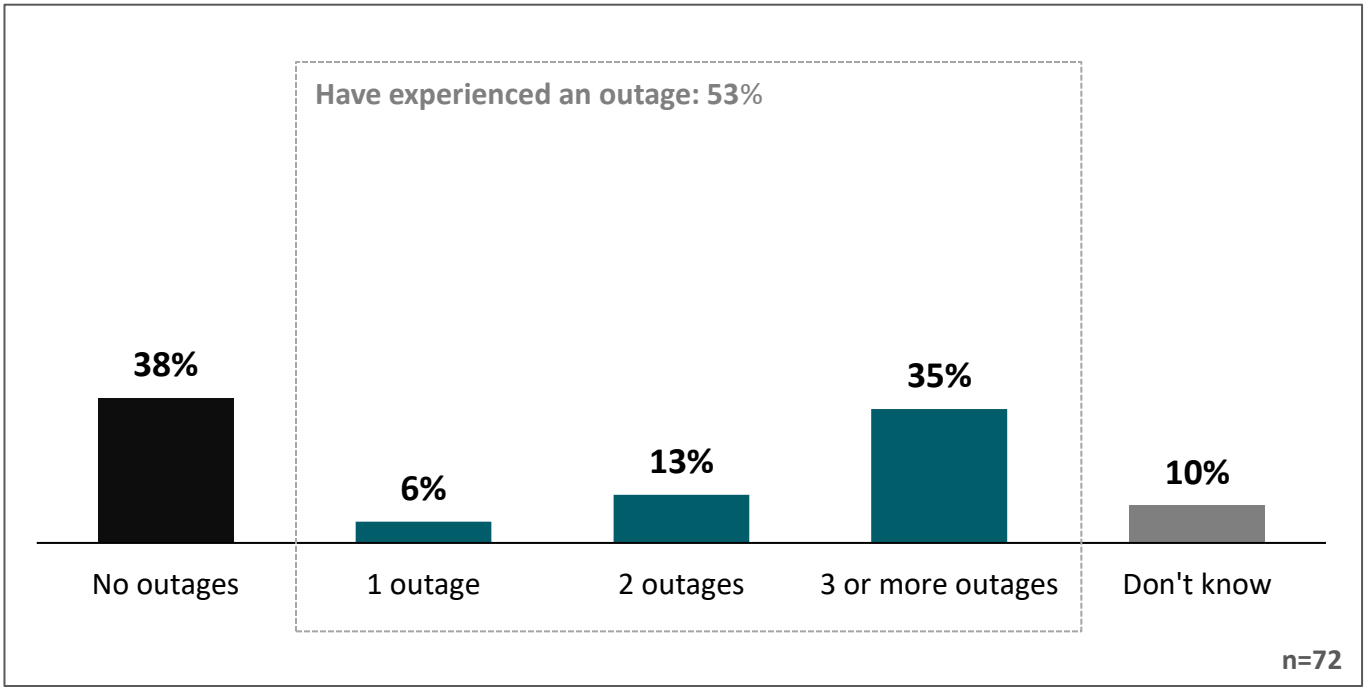


Reliability Experience

Number of Outages Experienced

Now, let's talk about the reliability of electricity service you receive.

Q Have you experienced any power outages at your organization **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

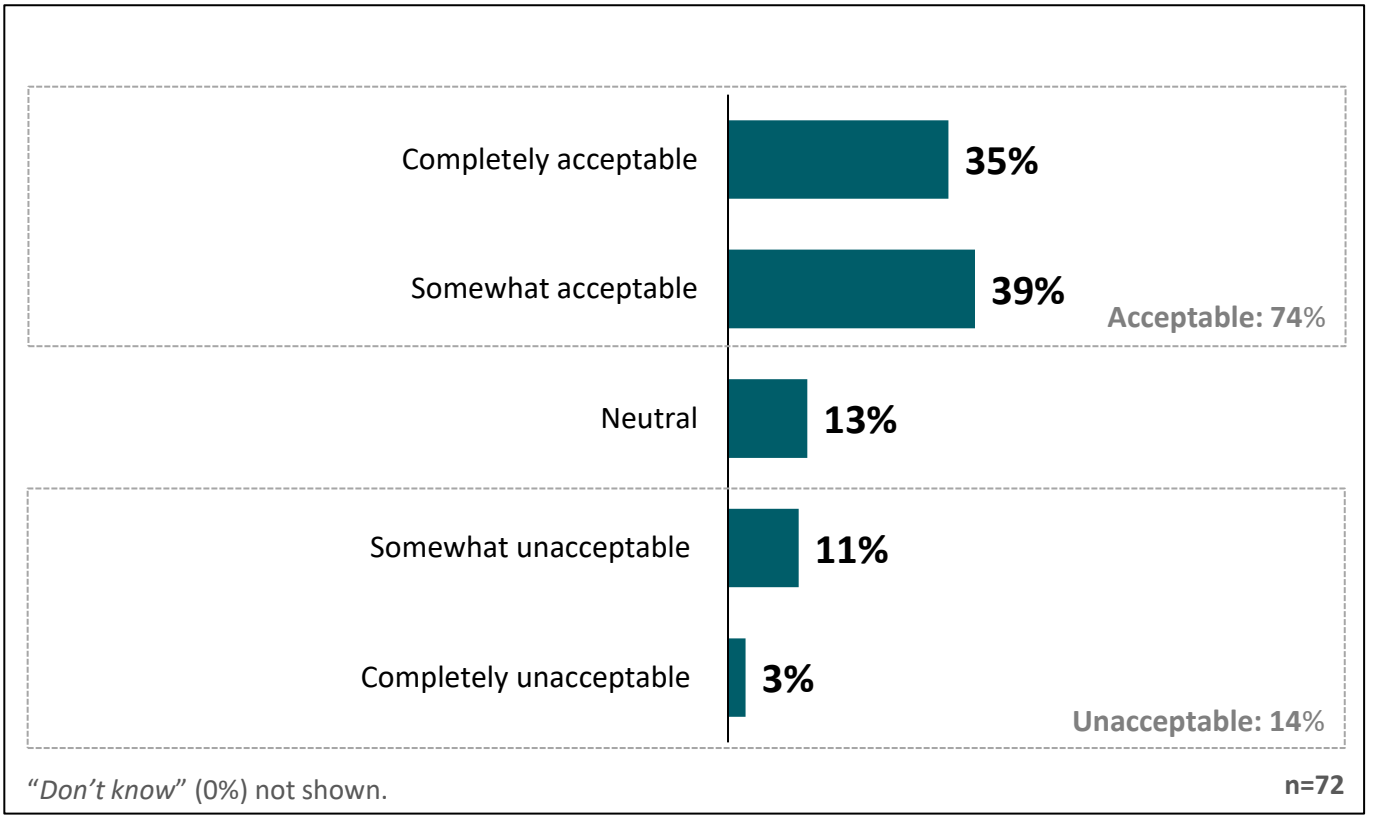


Reliability Experience

Current Reliability of Electricity Service

Large Transmission

Q And would you say that the current reliability of electricity service you receive today is acceptable or unacceptable?



"*Don't know*" (0%) not shown.

n=72

INNOVATIVE RESEARCH GROUP

Reliability Experience

Importance of Reliability Priorities

When it comes to reliability, there are several areas that **Hydro One** can focus their investments on.

Some of these areas are **related to severe weather**, such as ice storms, windstorms and thunderstorms.

Others are **not related to severe weather** and include issues such as aging or defective equipment, animal interference, and vehicle collisions.

Shortened Reliability Priorities Response Labels	Full Reliability Priorities Response Labels
Reducing number of non-weather outages	Reducing the number of outages not caused by severe weather
Reducing length of non-weather outages	Reducing the length of outages not caused by severe weather
Reducing number of weather-caused outages	Reducing the number of outages caused by severe weather
Reducing length of weather-caused outages	Reducing the length of outages caused by severe weather
Reducing momentary interruptions in power	Reducing momentary interruptions (less than one minute) in power that can result in the flickering or dimming of lights
Improving communications during outages	Improving communications during outages, including estimated restoration times

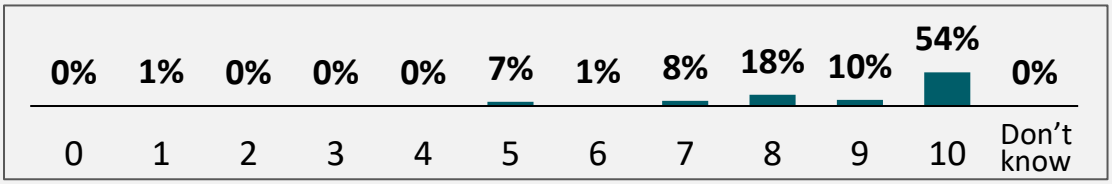
Reliability Experience

Importance of Reliability Priorities

Large Transmission

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **reliability** priorities to you as a customer?

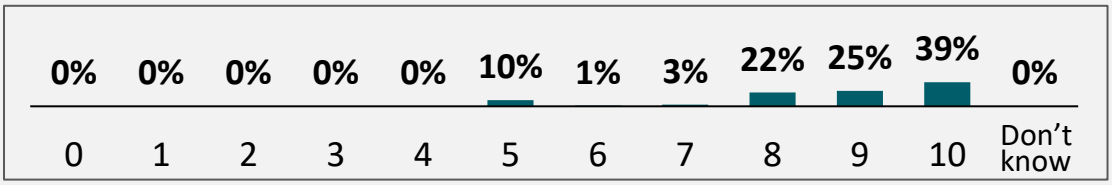
Reducing length of non-weather outages [average = **8.8**]



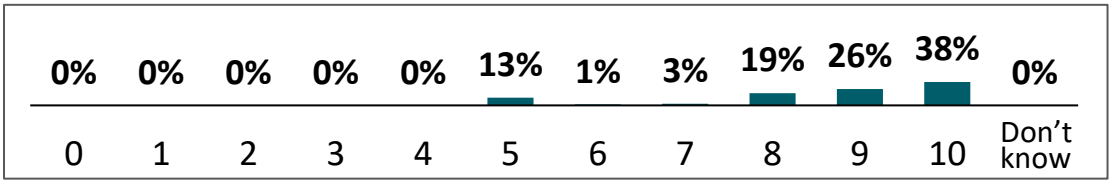
Reducing number of non-weather outages [average = **8.7**]



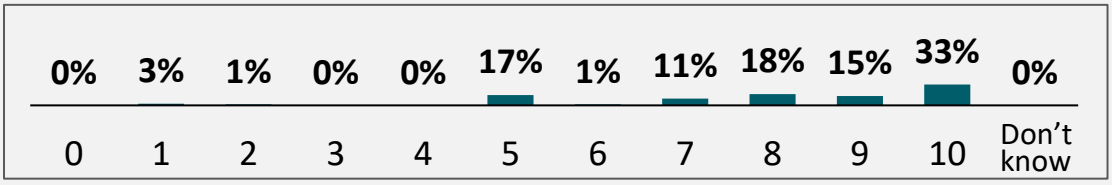
Reducing length of weather-caused outages [average = **8.7**]



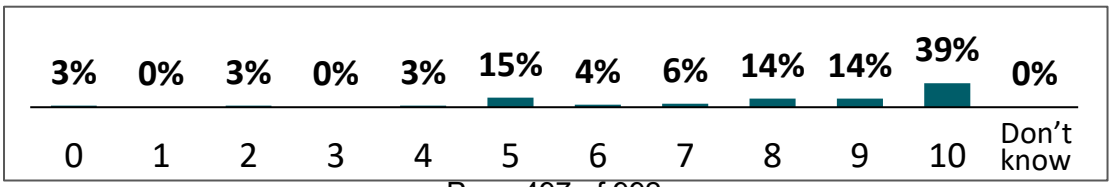
Reducing number of weather-caused outages [average = **8.6**]



Improving communications during outages [average = **7.9**]



Reducing momentary interruptions in power [average = **7.8**]



Note: Priority labels have been shortened for brevity. See slide 339 for full label text.
"Don't know" not included in calculation of means.

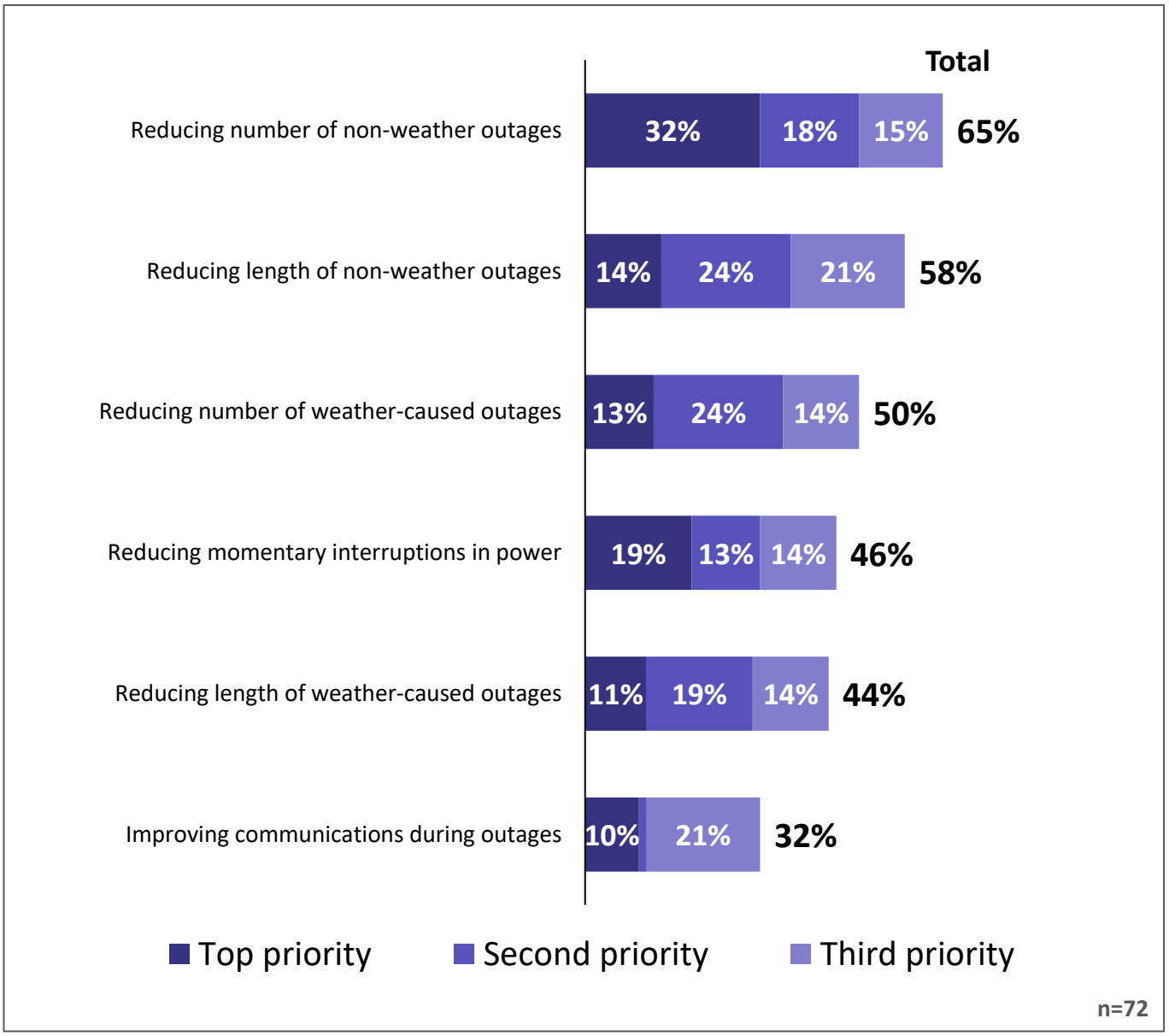
Reliability Experience

Ranking Reliability Priorities

Large Transmission

Q

Thinking of the **reliability** priorities on the previous page, which would you say is the **most** important? And which would you say is the second most important **reliability** priority you think **Hydro One** should focus on? And which would you say is the third most important **reliability** priority you think **Hydro One** should focus on?

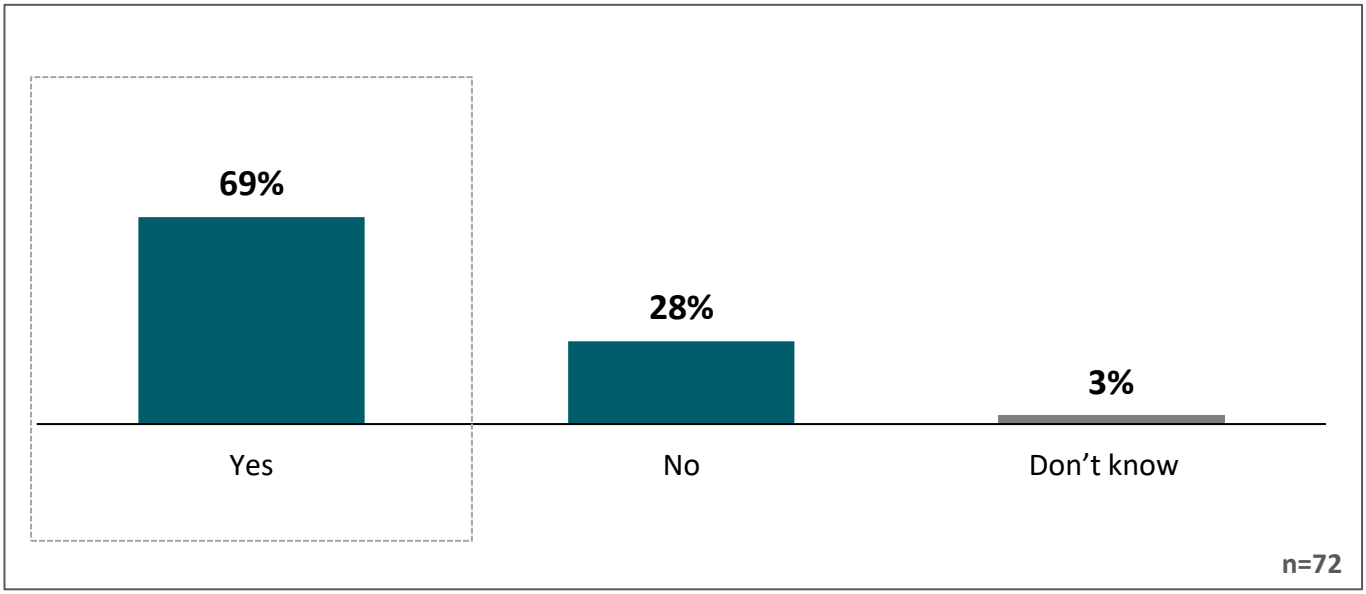


Note: Priority labels have been shortened for brevity. See slide 339 for full label text.
Data labels are removed where 4% or less. "Don't know" not shown.

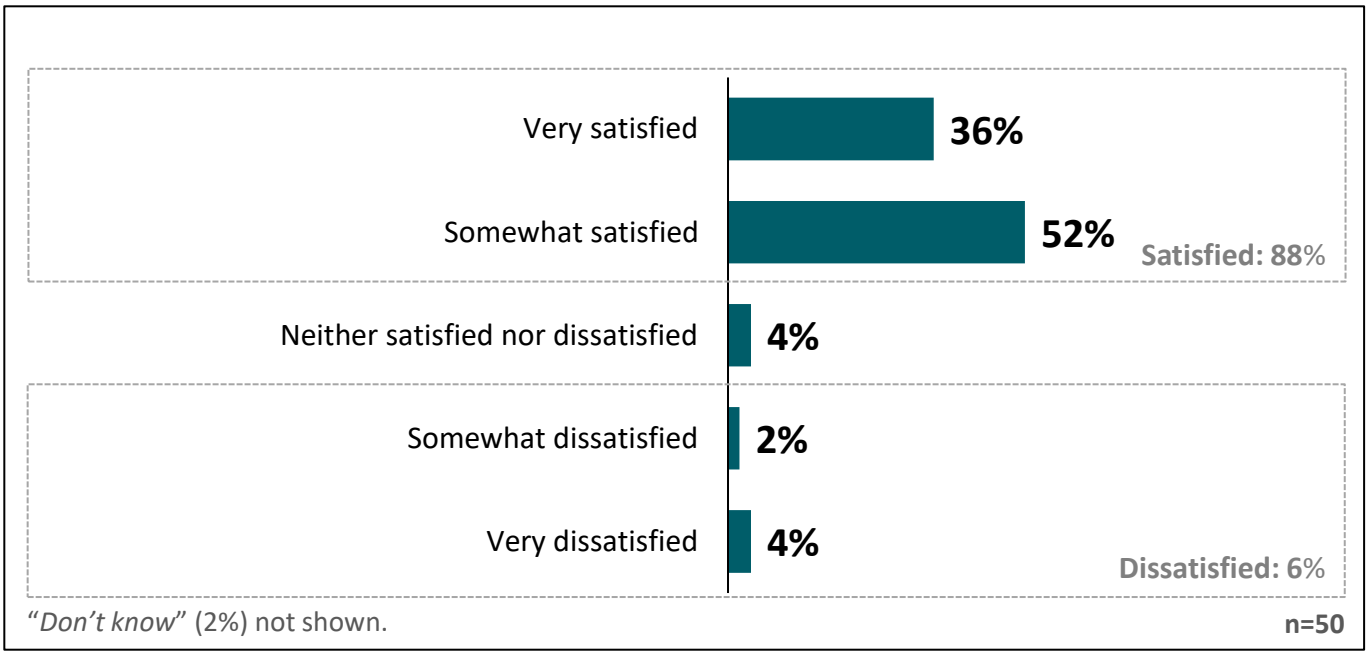
Reliability Experience
Planned Power Outages

Large Transmission

Q In the past year, has your organization experienced any **planned power outages** (or loss of supply) with **Hydro One**?



Q Generally, how satisfied or dissatisfied were you with the way your organization's **planned power outages** were managed by **Hydro One**? *[Asked of those who have experienced a planned outage in the past year]*



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Large Transmission Account Customers

Investment Priorities



Investment Priorities

Transmission Renewal

Large Transmission

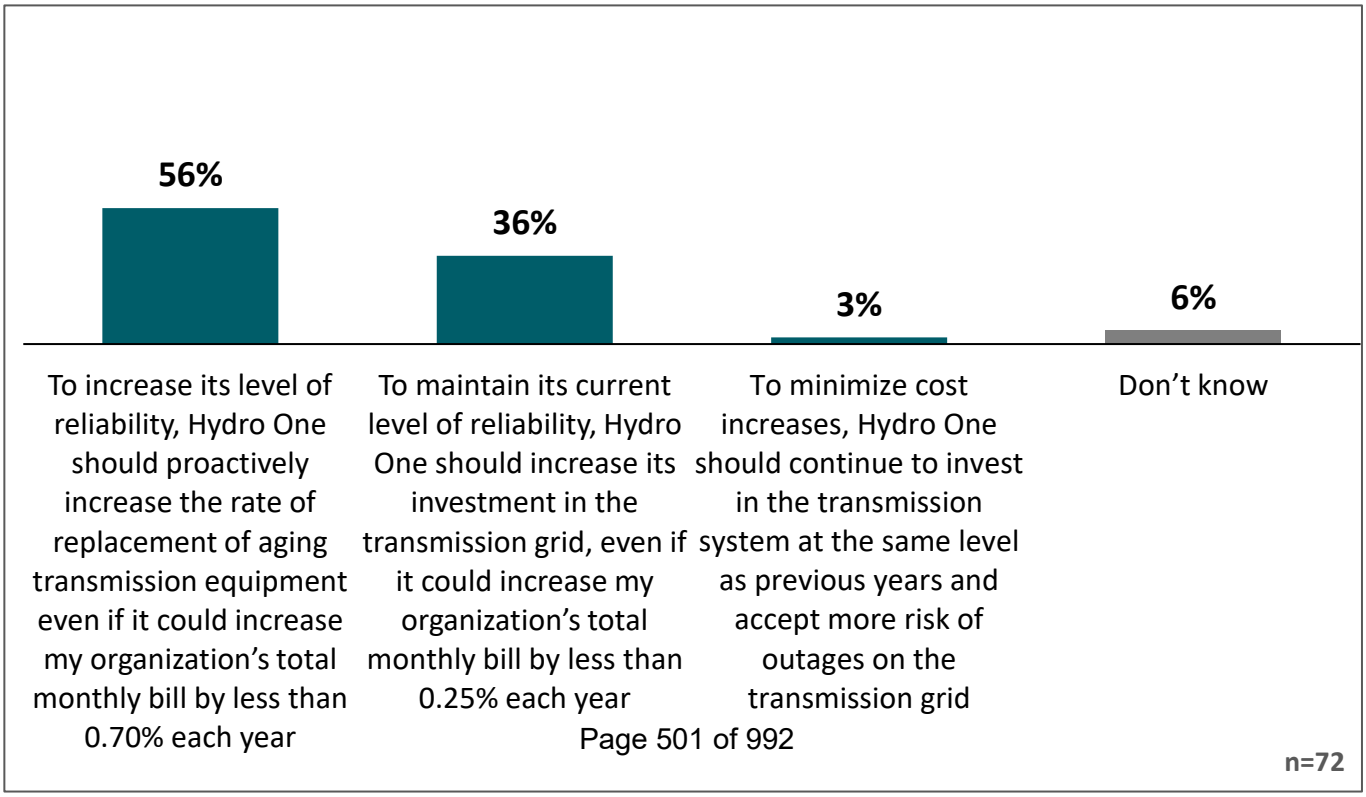
Now, we would like to talk about the provincial transmission system. That is the part of the system that uses high voltage transmission lines that serve as highways for electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including local distribution companies across the province. In fact, many large industrial customers like mines and auto manufacturers, as well as electricity generators like nuclear plants and hydro dams are directly connected to the transmission grid.

When an outage occurs on **Hydro One's** transmission system, the impacts are significant, both to communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages. For example, most of Ontario's population centres are served by multiple transmission lines, so that if one fails, there is always a backup to keep power flowing.

Portions of **Hydro One's** transmission system were built in the 1930s, 40s, and 50s. Even at historical levels of investment, portions of the transmission system continue to age and degrade, increasing the risk of failure. To minimize the risk of potential outages and support the growing electricity demands of communities, industries, and businesses across the province, **Hydro One** will need to continue to make significant investments to renew and upgrade older and degrading equipment.

Q With this in mind, what is closest to your point of view?



Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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Appendix 8

INNOVATIVE RESEARCH GROUP

2028-2032 Joint Rate Application
Phase II: Planning Placemat

hydro one



Hydro One Phase II Customer Engagement Planning Placemat

Between November and December 2025, INNOVATIVE engaged with over 100,000 customers to gather feedback on Hydro One's draft 2028-2032 investment plans, including key investment decisions. These investment choices covered both the distribution and transmission systems, as well as shared services. This placemat summarizes feedback collected through a series of online surveys. The online survey was customized for different customer types and rate classes with estimated bill impacts provided.

Customer Type Unweighted n (weighted in brackets)	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small Business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Distribution Investment Trade-Offs								
Across all customer types, a majority or near majority of customers selected Hydro One's draft plan level of spending as it relates to distribution investments in overall system reliability, managing severe weather, and targeted reliability improvements.								
Overall System Reliability								
Spend More	28%	27%	23%	16%	23%			
Draft Plan	49%	47%	49%	59%	58%			
Spend Less	23%	26%	28%	25%	19%			
Managing the Impacts of Severe Weather								
Spend More	28%	27%	23%	19%	21%			
Draft Plan	50%	50%	49%	52%	60%			
Spend Less	22%	23%	28%	29%	19%			
Targeted Reliability Improvements								
Spend More	23%	25%	18%	16%	13%			
Draft Plan	50%	51%	48%	50%	51%			
Spend Less	27%	23%	34%	33%	36%			
Transmission Investment Trade-Offs								
Across all customer types, a majority or near majority of customers selected Hydro One's draft plan level of spending as it relates to transmission investments in keeping pace with transmission renewal, and stewardship of the transmission system.								
Keeping Pace with Transmission Renewal								
Spend More	32%	32%	27%	24%	25%	33%	29%	36%
Draft Plan	50%	50%	50%	54%	60%	50%	53%	58%
Spend Less	18%	18%	23%	22%	15%	17%	18%	7%
Stewardship of the Transmission System								
Spend More	30%	28%	25%	20%	21%	33%	33%	37%
Draft Plan	51%	52%	51%	54%	66%	48%	47%	58%
Spend Less	19%	20%	24%	25%	13%	19%	20%	5%

*Local distribution company | Note: Tables may not total 100% due to rounding.

Customer Type Unweighted n (weighted in brackets)	Hydro One Distribution & Transmission Customers					Hydro One Transmission-Only Customers		
	Residential n=94,611 (90,000)	First Nations On-Reserve Residential n=793 (775)	Small Business n=2,791 (2,790)	Commercial & Industrial n=368 (350)	Large Dx Accounts n=53	Other LDC* Residential n=2,071 (2,000)	Other LDC* Small Business n=305 (300)	Large Tx Accounts n=73
Shared Investment Trade-Offs Across all customer types, a majority or near majority of customers selected the draft plan level of spending as it relates to shared investments in maintaining buildings and facilities, and information technology.								
Maintaining Buildings and Facilities								
Spend More	25%	24%	21%	16%	19%	34%	32%	29%
Draft Plan	51%	55%	50%	55%	60%	46%	45%	48%
Spend Less	24%	21%	29%	29%	21%	20%	23%	23%
Information Technology								
Draft Plan	73%	72%	67%	68%	68%	70%	69%	77%
Spend Less	27%	28%	33%	32%	32%	30%	31%	23%
Evaluating Hydro One's 2028-2032 Draft Plans** Across all customer types, most customers support Hydro One spending at or above the level of investment included in the 2028-2032 draft plan(s).								
Spend More	25%	28%	21%	16%	23%	37%	35%	33%
Draft Plan	50%	49%	49%	52%	47%	45%	44%	55%
Spend Less	16%	11%	21%	22%	26%	12%	15%	8%
Other	3%	2%	4%	5%	2%	1%	1%	3%

*Local distribution company | ** "don't know" not shown | Note: Tables may not total 100% due to rounding.

Survey Methodology

Residential, First Nations On-Reserve Residential, Small Business, and Commercial & Industrial results are weighted by Hydro One region and consumption or demand quartile to ensure the results are representative of Hydro One's broader customer base. Other LDC Residential results are weighted by age, gender, region, and education to ensure that the overall sample's composition reflects that of the actual population according to Census data. Other LDC Small Business results are weighted by region, employee count, and sector, again, according to Census data. Large Dx Accounts and Large Tx Account results are not weighted due to sample size.

Appendix 9

INNOVATIVE RESEARCH GROUP

2028-2032 Joint Rate Application
Phase II: Customer Engagement Report

hydro one



Report Navigation

2028-2032 Joint Rate Application

Phase II Customer Engagement Report

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Hydro One 2028-2032 Joint Rate Application Customer Engagement (Phase 2)

Innovative Research Group Inc. (INNOVATIVE) was engaged by Torys LLP on behalf of its client, Hydro One Networks Inc. (Hydro One), to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of online surveys conducted as part of Phase 2 of this customer engagement for the 2028-2032 joint rate application.

Both distribution and transmission connected customers were invited to participate. Hydro One distribution customers – those who receive an electricity bill from Hydro One – had the opportunity to comment on both distribution and transmission related questions. Those who do not receive an electricity bill from Hydro One were only presented with transmission related questions.

Report Overview

Between November and December 2025, INNOVATIVE engaged with over 100,000 customers to gather feedback on Hydro One's draft 2028-2032 investment plans, including key investment decisions. These investment choices covered both the distribution and transmission systems, as well as shared services.

The online workbook was customized for different customer types, and this report contains separate sections for each: **Residential & Seasonal**, **First Nations On-Reserve Residential**, **Small Business (GS<50)**, **Commercial & Industrial**, **Large Distribution Accounts**, **Large Transmission Accounts**, **Other LDC Residential,** and **Other LDC Small Business**.

Ways Distribution and Transmission-Only Customers Could Participate

Hydro One Distribution Customers

All Hydro One distribution customers with an available email address on file were invited to participate in the customer engagement via direct email outreach.

For those without an email address on file, an open-access survey link was made available. Customers who accessed the survey through the open link could verify themselves as customers by entering their account number and the first three characters of a postal code associated with one of their accounts. Verified customers were routed into the "representative" stream, where their account information such as customer type, consumption level, and region were appended to their survey results for segmentation and weighting purposes.

Customers who chose not to verify their account information or were unable to do so could still participate by self-selecting the appropriate survey version (residential including seasonal, First Nations On-Reserve residential, or small business) and were included in the "voluntary", unverified stream. Feedback provided through the voluntary stream is shown separately in this report.

Transmission-Only Customers

Transmission-only representative results were collected through a separate sampling approach. A representative sample of residential and small business customers from other local distribution companies (LDCs) were recruited through online research panels.

Other-LDC customers could also participate through the open-access survey link. Those entering through this route self-selected the residential or small business survey version and were included in the voluntary stream rather than the representative sample. Feedback provided through the voluntary stream is shown separately in this report.

Promotion of the Open-Access Survey

The open-access survey was promoted by Hydro One through multiple communication channels, including social media, bill inserts, and the Hydro One website in an effort to encourage participation across both representative and voluntary streams.

Introduction
Segmenting Customers

Customer Segmentation

In addition to segmenting customers based on where they reside or operate in Hydro One's service territory, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within, and what is outside of Hydro One's influence or control.

Segmentation, where possible, is used throughout this report to look beyond the topline numbers and to analyze the results for key segments:

1. **Region:** Using customer data provided by Hydro One, we split customers into regions for analysis based on Hydro One's service zones.

2. **Consumption Quartiles**: For residential, First Nations On-Reserve, small business (GS<50), and commercial & industrial customers, results are also shown by consumption quartiles. For low-volume customers, this is based on how much electricity the customer consumes in an average month (in kWh). For commercial & industrial customers, this is based on customer demand in an average month (in kW). This is used to ensure that no one customer consumption/demand profile is over or underrepresented in the survey results.

3. **Bill Impact on Finances**: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement(s):

    a) Residential/First Nations On-Reserve: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

    b) Small Business/Commercial & Industrial*: The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

4. **Vulnerable Consumers**: For residential and First Nations On-Reserve customers, using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Ontario Electricity Support Program (OESP)* criteria.

Understanding Segmentation

Segmentation is an effective way to look past the topline numbers and dig deeper into the needs and preferences of the customer segments outlined above. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel based on perceptions that may be outside of the utility's influence or control.

INNOVATIVE RESEARCH GROUP

Sample Validation

Overview and Methodology

Section 1



Overview of Approach

In Phase 1, INNOVATIVE undertook a rigorous "sample validation" process to understand whether and where differences existed between customers who have provided their email to Hydro One and the full population of customers. Telephone reference surveys were conducted for all low-volume customer types, namely residential (both primary and seasonal), First Nations On-Reserve, and small business (GS>50kW).

Since email addresses were available for all Large Distribution Accounts (LDA) and nearly all Commercial and Industrial (C&I) and Large Transmission Accounts (LTX), telephone reference surveys were not conducted among those customer groups.

In Phase 2, we focus on **using complete customer lists to compare known sample variables between those with an email address and the full population of customers**.

This allows us to identify systematic differences between those with an email on file and the full population of customers regarding known characteristics (rate class, region, and consumption). All samples except Large Distribution Accounts (LDA) and Large Transmission Accounts (LTX) are weighted by region and consumption quartile to ensure representativeness.

After collecting survey responses, sample differences based on known sample variables (region, consumption quartile) are corrected for with weighting.

Comparing Known Sample Variables

Overall Customer Email Coverage

Overall Customer Email Coverage

The table below summarizes the email coverage of each of Hydro One's customer types.

Rate Class	Total Records (Meters)	Unique customers*	Customers with an email	Email coverage (out of unique customers)
Residential	1,209,388	1,090,008	831,248	**76.3%**
Seasonal	137,981	102,107	73,261	**71.7%**
First Nations On-Reserve	21,671	17,916	12,747	**71.1%**
Small Business	114,721	63,193	50,003	**79.1%**
Commercial & Industrial	7,554	5,371	5,105	**95.0%**
Large Distribution	357	313	313	**100%**
Large Transmission	249	197	197	**100%**

*Unique *customers* from the complete list of Hydro One's records (individual meters) are identified by cross-referencing available contact information to identify customers with multiple meters. Customers are assigned to their highest-order rate class in the following order: Large Transmission Account, Large Distribution Account, Commercial & Industrial, Small Business (GS<50kW), First Nations On-Reserve, Residential, Seasonal. For customers with multiple records within the same rate class, the record with the highest average monthly consumption or demand is used for the purpose of assigning sample variables.

Comparing Known Sample Variables

Overall Customer Email Coverage (Con't)

Comparing Known Sample Variables

The information below compares the sample of each customer type with email addresses to the total customer accounts of that customer type across regions.

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

(1) Regional Distribution by Customer Type

Using service zones, areas are grouped into five distinct regions within Hydro One's service territory.

Distributions of region are similar (+/- 4%) across residential, seasonal, and First Nations On-Reserve customer types. Any differences are accounted for by making weighting adjustments based on region.

Customer Type	Region	Share of full population	Share of email sample	Difference
Residential	Central	26%	26%	**0%**
	Central East	31%	31%	**0%**
	East	16%	17%	**+1%**
	North	11%	10%	**-1%**
	West	16%	15%	**-1%**
Seasonal	Central	39%	40%	**+1%**
	Central East	32%	32%	**0%**
	East	6%	6%	**0%**
	North	16%	15%	**0%**
	West	7%	6%	**0%**
First Nations On-Reserve	Central	26%	24%	**-1%**
	Central East	15%	15%	**+1%**
	East	1%	1%	**0%**
	North	48%	50%	**+2%**
	West	11%	10%	**-2%**

Comparing Known Sample Variables

Regional Distribution by Customer Type

(1) Regional Distribution by Customer Type

Using service zones, areas are grouped into five distinct regions within Hydro One's service territory.

Distributions of region are similar (+-/ 4%) for small business (GS<50) customers. Any differences are accounted for by making weighting adjustments based on region.

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Customer Type*	Region	Share of full population	Share of email sample	Difference
Small Business (GS<50)	Central	24%	25%	**+1%**
	Central East	26%	27%	**0%**
	East	14%	15%	**0%**
	North	14%	14%	**0%**
	West	21%	20%	**-1%**

Note: LTX, LDA, and C&I customers are not shown as all, or nearly all customers have an email on file.

Comparing Known Sample Variables

Distribution of Consumption Quartile by Customer Type

Comparing Known Sample Variables

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

The information below compares the sample of each customer type with email addresses to the total customer accounts across average monthly consumption (low-volume) or demand (commercial & industrial).

(2) Distribution of Consumption Quartile by Customer Type

Within each customer type, customers are grouped into four equal quartiles based on average monthly consumption (measured in kWh).

Distributions of consumption quartile are similar (+/- 4%) for residential and First Nations On-Reserve customers. Seasonal customers with an email on file skew towards higher consumption. Any differences are accounted for by making weighting adjustments based on consumption quartile.

Customer Type	Region	Share of full population	Share of email sample	Difference
Residential	First	25%	23%	**-2%**
	Second	25%	24%	**0%**
	Third	25%	25%	**0%**
	Fourth	25%	26%	**+1%**
	Average Monthly Consumption (kWh)	987.8	1,011.3	**+2%**
Seasonal	First	25%	21%	**-4%**
	Second	25%	24%	**-1%**
	Third	25%	26%	**+1%**
	Fourth	25%	28%	**+3%**
	Average Monthly Consumption (kWh)	465.4	517.6	**+11%**
First Nations On-Reserve	First	25%	23%	**-2%**
	Second	25%	24%	**0%**
	Third	25%	25%	**0%**
	Fourth	25%	26%	**+2%**
	Average Monthly Consumption (kWh)	1,271.4	1,312.5	**+3%**

Comparing Known Sample Variables

Distribution of Consumption Quartile by Customer Type

(2) Distribution of Consumption Quartile by Customer Type

Within each customer type, customers are grouped into four equal quartiles based on average monthly consumption (measured in kWh).

Small business (GS<50) customers with an email on file skew towards higher consumption. Any differences are accounted for by making weighting adjustments based on consumption quartile.

Legend: Difference
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Customer Type	Region	Share of full population	Share of email sample	Difference
Small Business (GS<50)	First	25%	22%	**-3%**
	Second	25%	24%	**-1%**
	Third	25%	25%	**0%**
	Fourth	25%	27%	**+3%**
	Average Monthly Consumption (kWh)	2,522.1	2,777.5	**+10%**

Note: LTX, LDA, and C&I customers are not shown as all, or nearly all customers have an email on file.

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Hydro One Distribution Customer Results



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Residential and Seasonal Customers

Online Survey Results

Section 2



Field Dates

The **Residential and Seasonal Online Survey** was sent to all Hydro One residential and seasonal customers with an available email address. Customers had an opportunity to complete the survey between **November 12th and December 22nd, 2025**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class. Survey pages that differed by customer type are identified as residential or seasonal versions throughout this report.

In total, the residential survey was sent to **831,248** customers and the seasonal survey was sent to **73,261** customers from *customerexperience@hydroone.com*. A total of three reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Residential & Seasonal Online Survey Completes

A total of **94,611** (unweighted) Hydro One residential and seasonal customers completed the online survey.

Sample Weighting

The residential and seasonal online survey sample was weighted to n=90,000 proportionately by consumption quartile, region, and customer type (primary residential vs. seasonal) in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

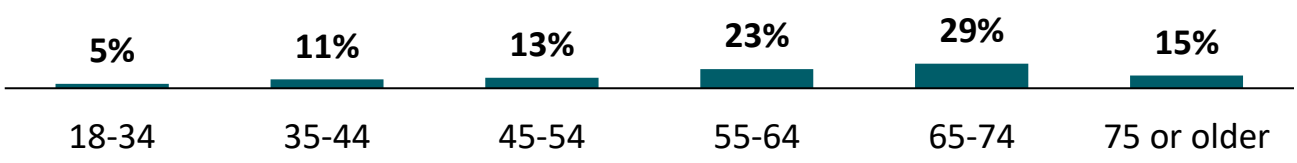
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	3,039 (3,138)	3,331 (3,329)	3,445 (3,494)	3,010 (3,335)	12,980 (13,445)
Central	5,980 (6,061)	6,232 (5,957)	6,406 (6,011)	6,319 (6,359)	25,236 (24,670)
Central East	6,787 (6,773)	7,446 (6,591)	7,477 (6,868)	7,094 (6,685)	29,165 (27,621)
East	3,757 (3,387)	4,138 (3,482)	4,130 (3,511)	3,972 (3,444)	16,231 (14,048)
North	2,821 (2,853)	2,721 (2,495)	2,668 (2,329)	2,629 (2,389)	10,998 (10,215)
Total	22,384 (22,213)	23,868 (22,213)	24,126 (22,213)	23,024 (22,213)	94,611 (90,000)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Demographic Breakdown

Residential & Seasonal

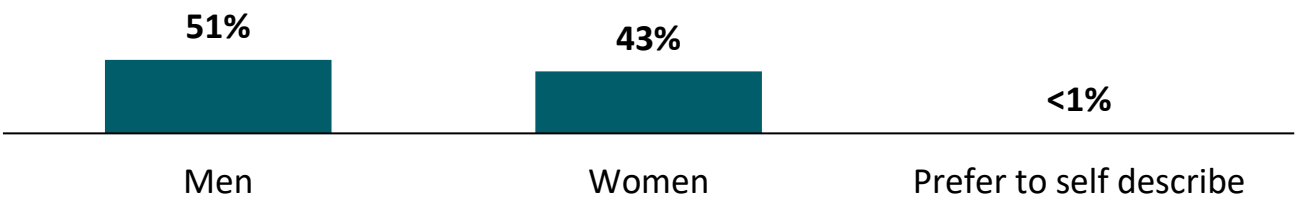
Q Age



"Prefer not to say" (4%) not shown.

n=90,000

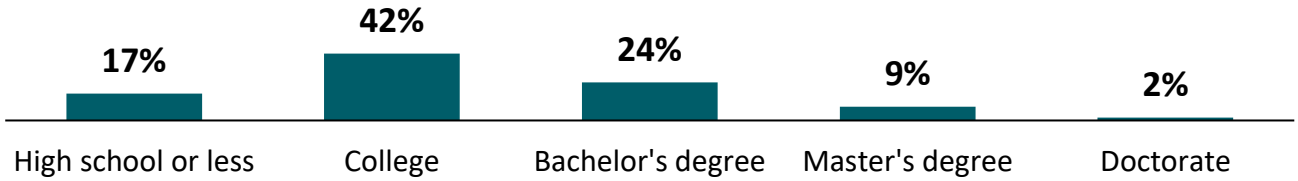
Q Gender



"Prefer not to say" (5%) not shown.

n=90,000

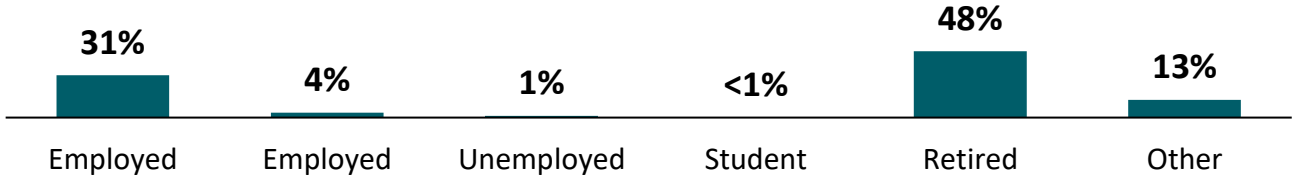
Q Education



"Other" (2%) and "Prefer not to say" (5%) not shown.

n=90,000

Q Employment Status



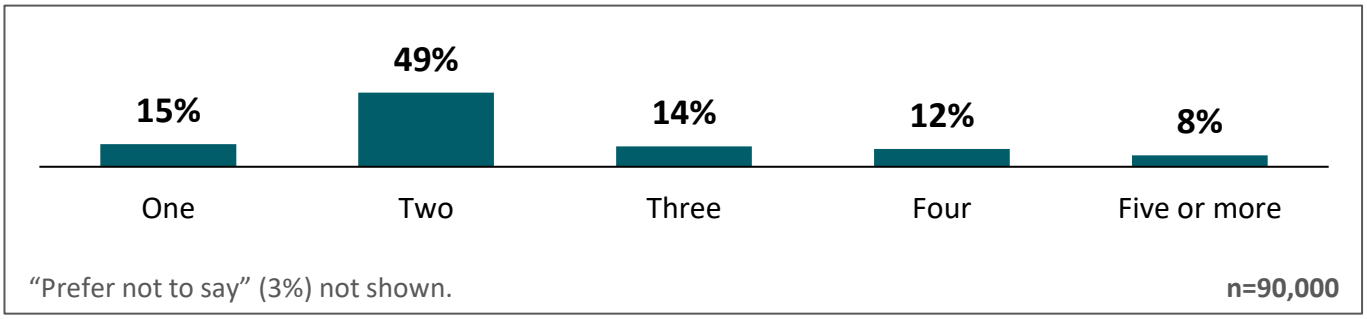
"Prefer not to say" (3%) not shown.

n=90,000

Demographic Breakdown
Continued

Residential & Seasonal

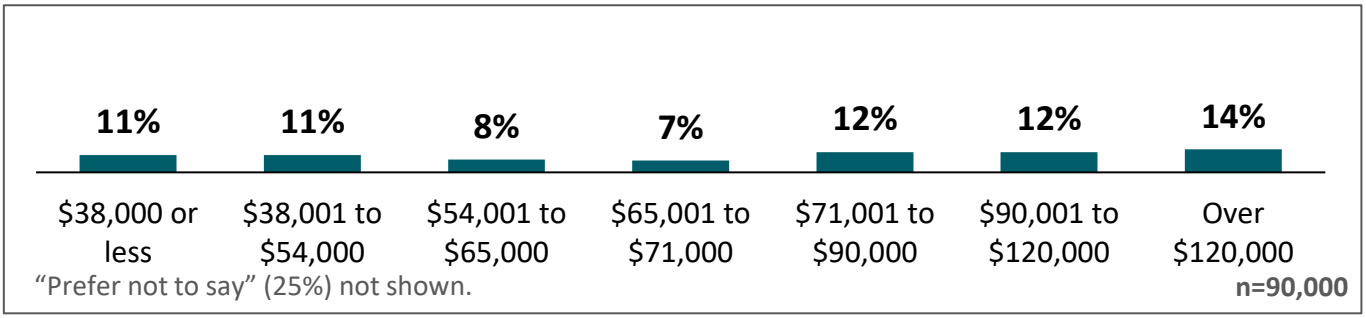
Q Household Size



"Prefer not to say" (3%) not shown.

n=90,000

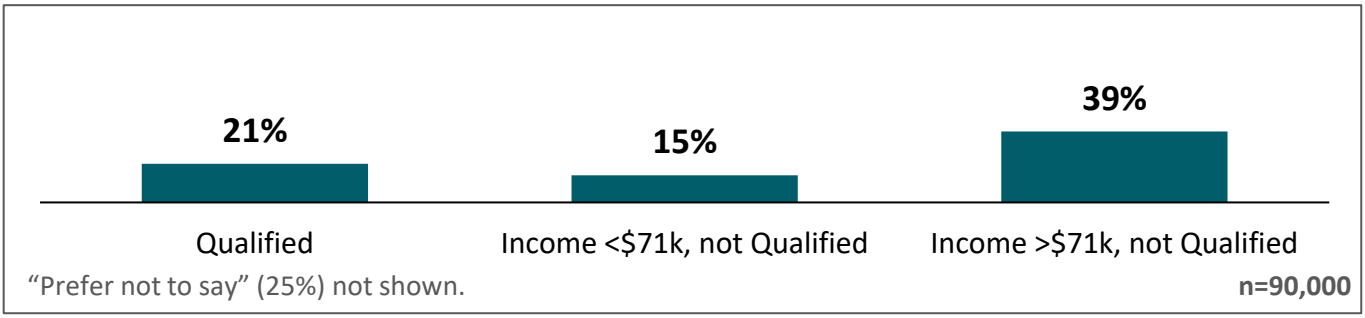
Q After Tax Household Income



"Prefer not to say" (25%) not shown.

n=90,000

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (25%) not shown.

n=90,000

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Demographic Breakdown
Continued

Residential & Seasonal

Are you:

Q First Nations



"Prefer not to say" (6%) not shown.

n=90,000

Q Métis



"Prefer not to say" (7%) not shown.

n=90,000

Q Inuk



"Prefer not to say" (6%) not shown.

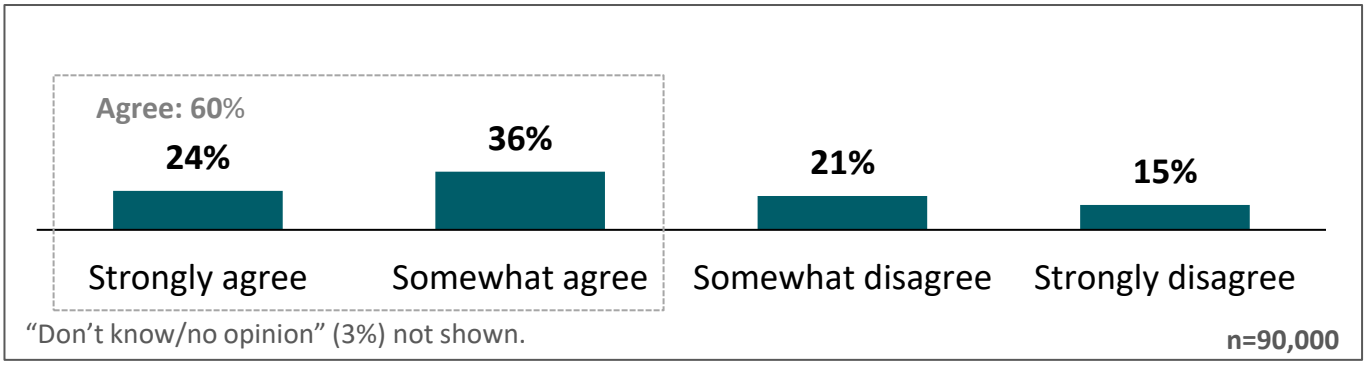
n=90,000

INNOVATIVE RESEARCH GROUP

Environmental Controls

To what extent do you agree or disagree with the following statements?

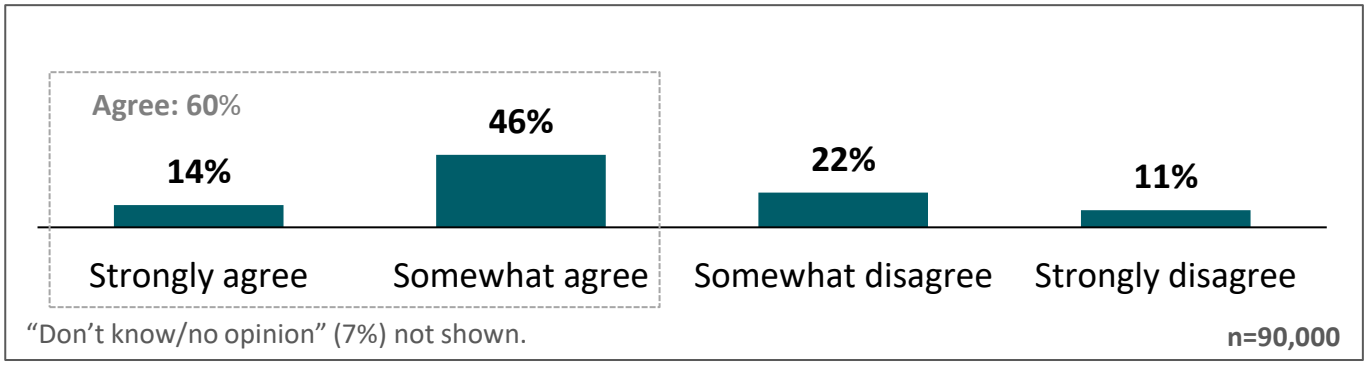
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (3%) not shown.

n=90,000

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (7%) not shown.

n=90,000

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



Those who complete the survey will be invited to enter a draw to win one (1) of five (5) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

INNOVATIVE RESEARCH GROUP

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by their customers. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plans, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plans.

Next year, Hydro One will present their proposed plans and input provided by customers to the OEB.

SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Residential & Seasonal

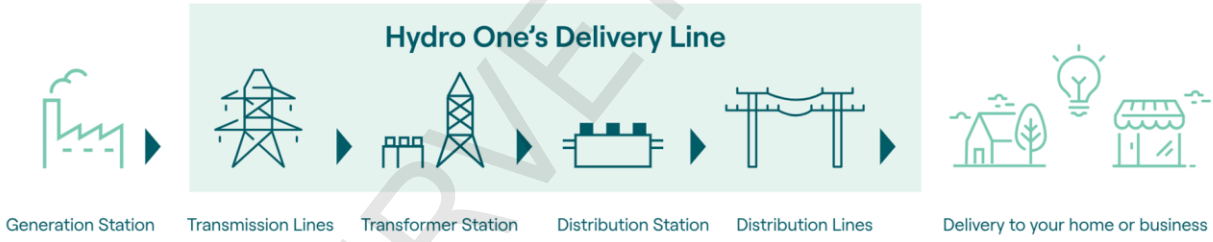
Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which delivers electricity to your home, seasonal property, or organization through a network of wires, poles and other equipment.



Hydro One does not generate electricity or set electricity prices.

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

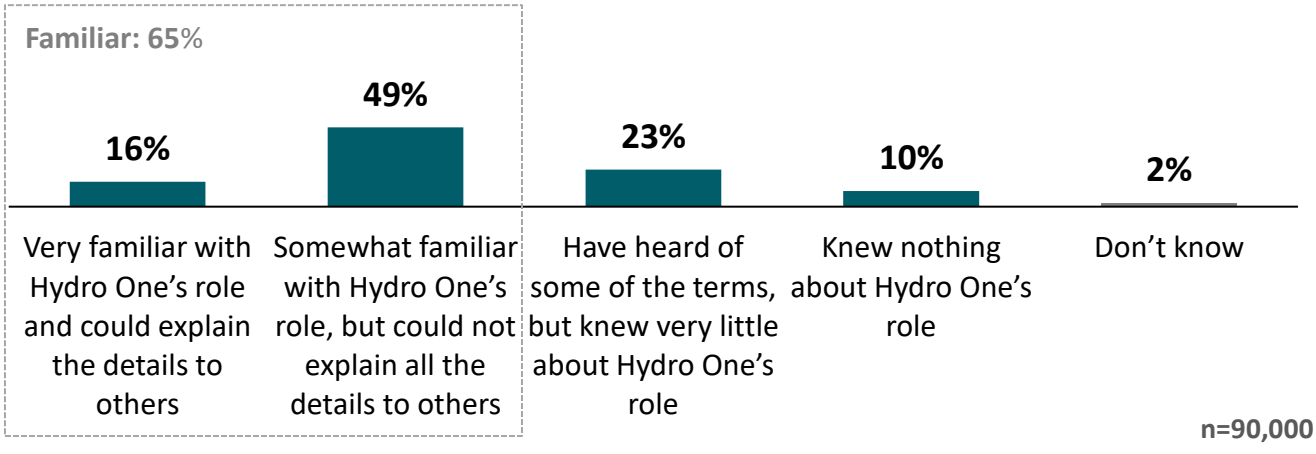
SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Residential & Seasonal

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Customer Type **Region**

	Residential	Seasonal	West	Central	Central East	East	North
Very familiar	15%	18%	15%	16%	17%	14%	15%
Somewhat familiar	49%	54%	49%	50%	50%	50%	48%
Knew very little	24%	19%	23%	23%	23%	24%	24%
Knew nothing	10%	8%	10%	10%	9%	10%	11%
Don't know	2%	1%	2%	2%	2%	2%	2%
Familiar (Very + Somewhat)	**64%**	**71%**	**64%**	**66%**	**66%**	**64%**	**63%**

LEAP/OESP Qualification **Bill Impact**

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	13%	14%	18%	15%	16%
Somewhat familiar	46%	50%	51%	48%	52%
Knew very little	25%	24%	22%	24%	22%
Knew nothing	12%	9%	8%	11%	8%
Don't know	3%	2%	1%	2%	2%
Familiar (Very + Somewhat)	**59%**	**64%**	**69%**	**63%**	**68%**

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

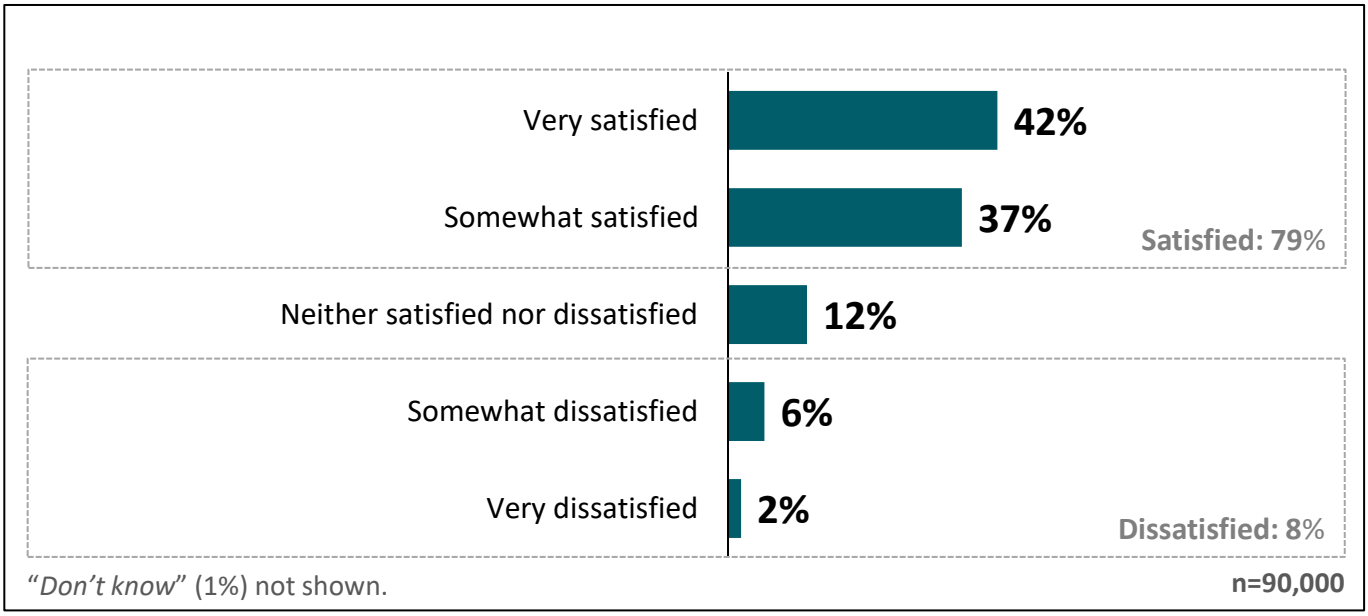
		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Very familiar	16%	14%	15%	16%	18%
Somewhat familiar	49%	48%	50%	50%	51%
Knew very little	23%	25%	24%	23%	21%
Knew nothing	10%	11%	10%	9%	9%
Don't know	2%	2%	2%	2%	2%
Familiar (Very + Somewhat)	**65%**	**62%**	**64%**	**66%**	**68%**

Familiarity & Experience

Overall satisfaction with Hydro One's service

Residential & Seasonal

Q Overall, how satisfied or dissatisfied are you with the service you receive from Hydro One?



"*Don't know*" (1%) not shown.

n=90,000

	Customer Type		Region				
	Residential	**Seasonal**	**West**	**Central**	**Central East**	**East**	**North**
Very satisfied	43%	33%	44%	41%	43%	46%	39%
Somewhat satisfied	37%	40%	36%	38%	37%	35%	37%
Neither	12%	13%	13%	12%	12%	12%	14%
Somewhat dissatisfied	5%	10%	5%	7%	6%	5%	6%
Very dissatisfied	2%	3%	2%	2%	2%	2%	2%
Don't know	1%	1%	1%	1%	1%	1%	1%
Satisfied (Very + Somewhat)	**80%**	**73%**	**79%**	**79%**	**80%**	**81%**	**77%**
Dissatisfied (Very + Somewhat)	**7%**	**14%**	**7%**	**9%**	**7%**	**6%**	**9%**

INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Overall satisfaction with Hydro One's service

Residential & Seasonal

Q Overall, how satisfied or dissatisfied are you with the service you receive from Hydro One?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very satisfied	42%	46%	47%	42%	37%	51%
Somewhat satisfied	37%	34%	35%	38%	39%	34%
Neither	12%	12%	11%	12%	15%	9%
Somewhat dissatisfied	6%	5%	5%	6%	7%	4%
Very dissatisfied	2%	2%	2%	2%	3%	1%
Don't know	1%	1%	<1%	<1%	1%	1%
Satisfied (Very + Somewhat)	**79%**	**80%**	**83%**	**80%**	**75%**	**85%**
Dissatisfied (Very + Somewhat)	**8%**	**7%**	**6%**	**7%**	**9%**	**5%**

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Very satisfied	47%	44%	41%	39%
Somewhat satisfied	34%	36%	38%	39%
Neither	12%	12%	13%	13%
Somewhat dissatisfied	5%	5%	6%	7%
Very dissatisfied	2%	2%	2%	3%
Don't know	1%	1%	1%	1%
Satisfied (Very + Somewhat)	**81%**	**80%**	**79%**	**77%**
Dissatisfied (Very + Somewhat)	**7%**	**7%**	**8%**	**9%**

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Residential & Seasonal

Residential Version

SURVEY PAGE

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical residential customer, about 41% of the bill, or $60.63, goes to Hydro One per month. This amount is split into $42.88 for distribution and $17.75 for transmission.

Approximately 60% of Hydro One's residential customers are classified as rural and receive **distribution rate protection**, a government program designed to bring rural customer bills more in line with what urban customers pay. For these customers, distribution charges are currently capped at $42.88.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Sample Residential Monthly Bill
(based on consumption of 750 kWh as of July 1, 2025)

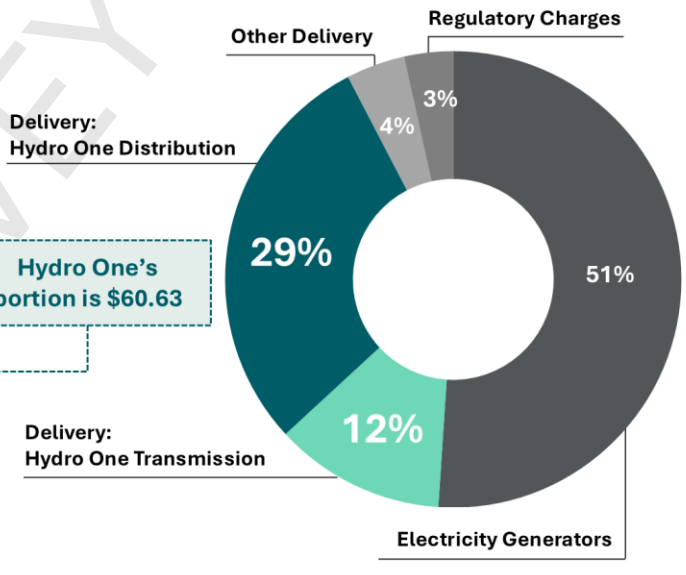
Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges

Electricity	
On-Peak (highest price) @ 18.2 c/kWh	22.52
Mid-Peak (mid price) @ 12.2 c/kWh	16.47
Off-Peak (lowest price) @ 8.7 c/kWh	35.91
Delivery	66.74
Regulatory Charges	5.09
Total Electricity Charges	$146.73
HST	19.07
Ontario Electricity Rebate	(-$19.22)
Total Amount	$146.58

Hydro One's portion is $60.63



The pie chart above is based on a total bill of $146.73 including distribution rate protection and excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 750kWh per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Residential & Seasonal

Seasonal Version

SURVEY PAGE

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical seasonal customer, about 66% of the bill, or $79.34, goes to Hydro One per month. This amount is split into $71.05 for distribution and $8.29 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Sample Seasonal Monthly Bill
(based on consumption of 350 kWh as of July 1, 2025)

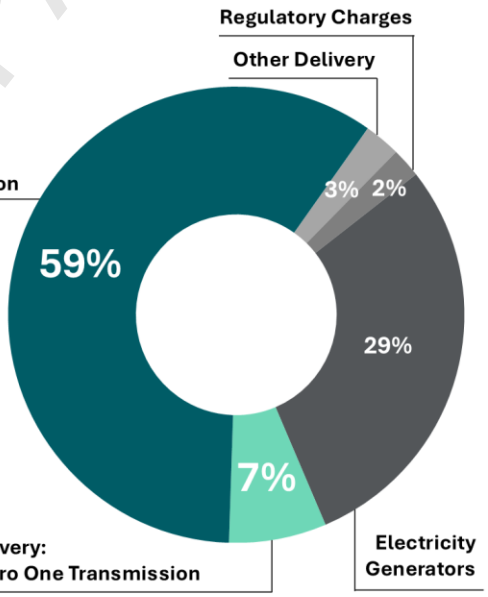
Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges

Electricity	
On-Peak (highest price) @ 18.2 c/kWh	10.51
Mid-Peak (mid price) @ 12.2 c/kWh	7.69
Off-Peak (lowest price) @ 8.7 c/kWh	16.76
Delivery	82.42
Regulatory Charges	2.51
Total Electricity Charges	$119.88
HST	15.58
Ontario Electricity Rebate	(-$15.70)
Total Amount	$119.76

Hydro One's portion is $79.34



The pie chart above is based on a total bill of $119.88 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

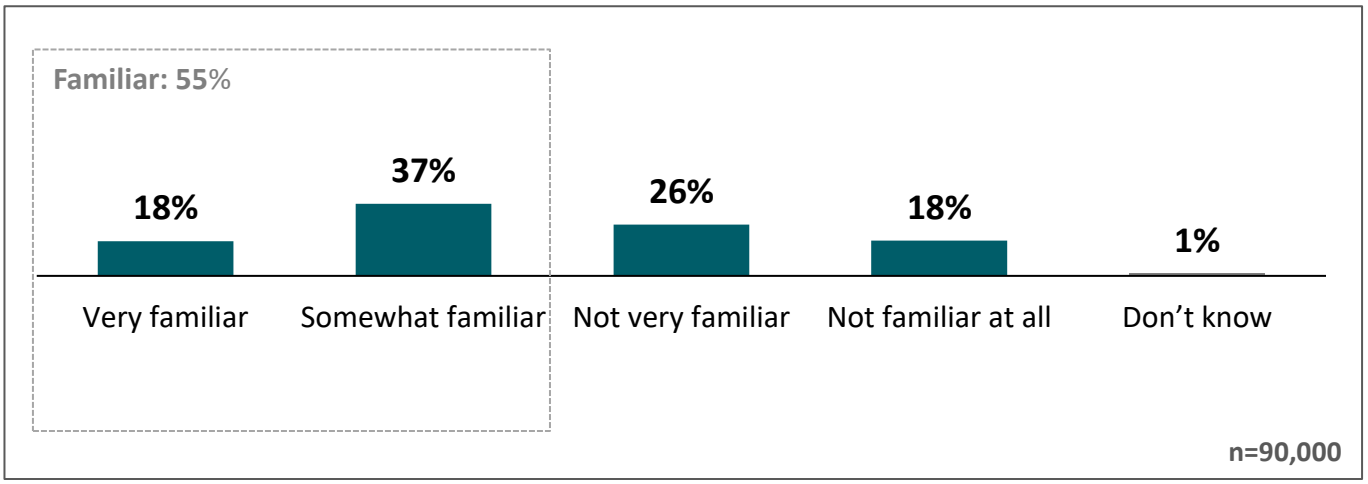
The sample bill above uses an average consumption level of 350kWh per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Familiarity & Experience

Bill familiarity

Residential & Seasonal

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Very familiar	18%	19%	17%	18%	18%	17%	19%
Somewhat familiar	37%	37%	37%	37%	37%	37%	36%
Not very familiar	26%	25%	27%	26%	26%	26%	26%
Not familiar at all	18%	18%	18%	18%	18%	19%	18%
Don't know	1%	1%	1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**54%**	**57%**	**54%**	**55%**	**55%**	**54%**	**55%**

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	17%	15%	19%	19%	15%
Somewhat familiar	35%	37%	37%	38%	35%
Not very familiar	26%	27%	26%	25%	28%
Not familiar at all	19%	19%	17%	17%	20%
Don't know	2%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**53%**	**53%**	**56%**	**57%**	**51%**

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Very familiar	18%	16%	17%	18%	19%
Somewhat familiar	37%	36%	37%	37%	38%
Not very familiar	26%	26%	27%	26%	26%
Not familiar at all	18%	20%	18%	17%	16%
Don't know	1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**55%**	**52%**	**54%**	**55%**	**57%**

Summary of Investment Plan

How Hydro One plans

Residential & Seasonal

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity distribution and transmission services. This feedback was used to inform planners in developing the draft investment plans.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.
3. Make **targeted investments to improve reliability** for customers experiencing significantly poorer reliability than average.
4. Make investments to make the system **more resilient to severe weather**.
5. Make investments in technology to **accommodate customer requests and improve visibility into the system** (e.g., where and how much electricity is being used).

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

Residential & Seasonal

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations, and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

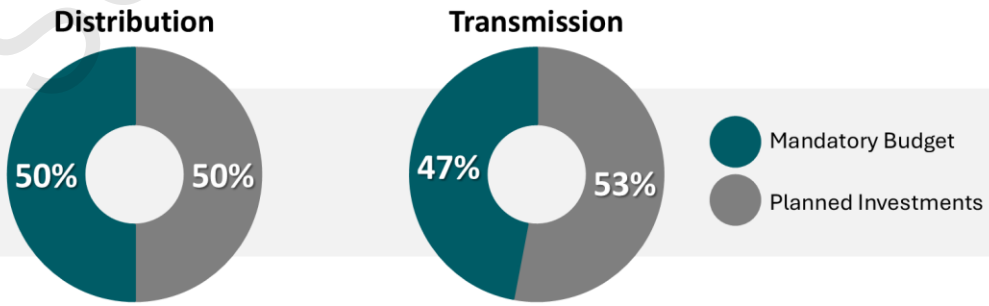
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Residential & Seasonal

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

While Hydro One's draft plans cover both the **distribution system** serving approximately 1.5 million customers, as well as the **transmission system** serving most Ontarians, each system has different needs and objectives.

Some of the highlights of Hydro One's draft plans include:

Distribution Objectives



1. Improving the **day-to-day reliability** of the system by addressing equipment that is at a higher risk of failure.
2. Preparing for the **impacts of severe weather** by investing in vulnerable lines, clearing more overgrown vegetation, and using technology to restore power more quickly.
3. Improving reliability for thousands of customers experiencing below average reliability by investing in **new battery storage technology**.
4. Ensuring the grid is prepared to **keep pace with evolving customer needs** and accommodate higher levels of growth.

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest distributor and transmitter of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plan include:

Shared Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Residential & Seasonal

Residential Version

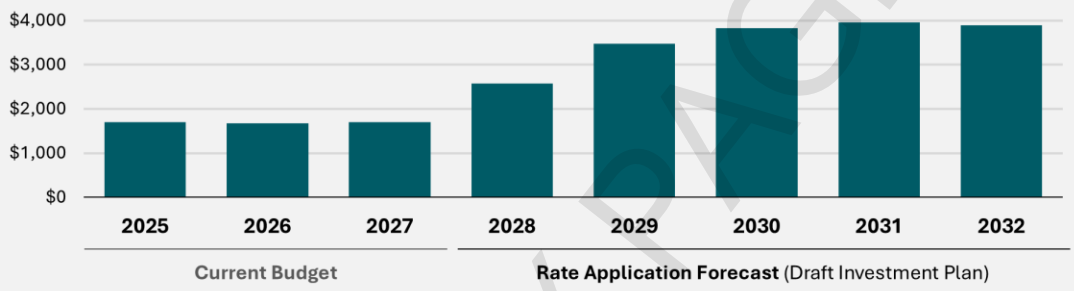
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)



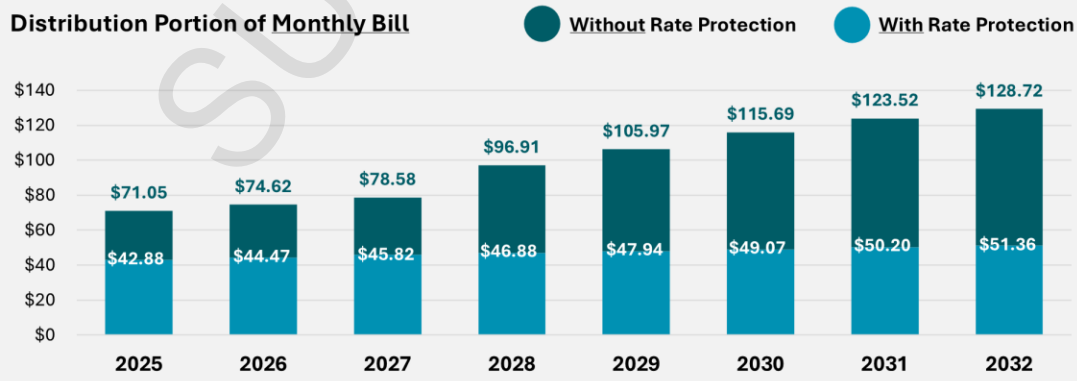
The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For the approximately 60% of Hydro One customers who receive **distribution rate protection**, in 2025, the distribution portion of their monthly bill is capped at $42.88. These customers won't pay more in distribution charges than the maximum set out by this program.

For a typical residential customer who does not receive rate protection, the **distribution** portion of their **monthly bill** is estimated to increase from $78.58 in 2027 to $128.72 by the end of 2032 – an increase of **$50.14** on the monthly bill. This represents an average increase of **$10.03** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:

- The Hydro One Distribution Portion of the monthly bill for customers receiving distribution rate protection beyond 2026 has been estimated based on Hydro One's forecast.
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Residential & Seasonal

Seasonal Version

SURVEY PAGE

Hydro One Customer Engagement Survey

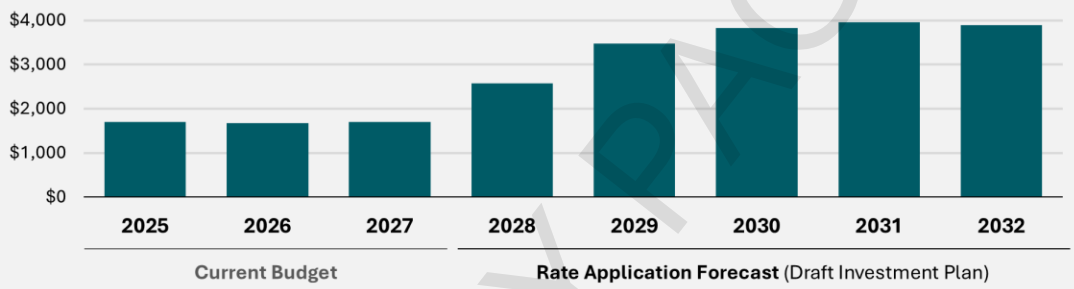
How much will Hydro One's draft distribution plan cost?

hydro one

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)

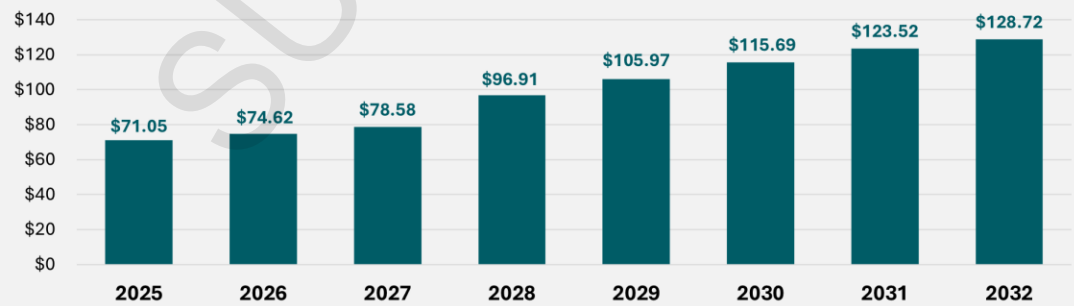


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **seasonal customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $78.58 in 2027 to $128.72 by the end of 2032 – an increase of **$50.14** on the monthly bill. This represents an average increase of **$10.03** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Residential & Seasonal

Residential Version

SURVEY PAGE

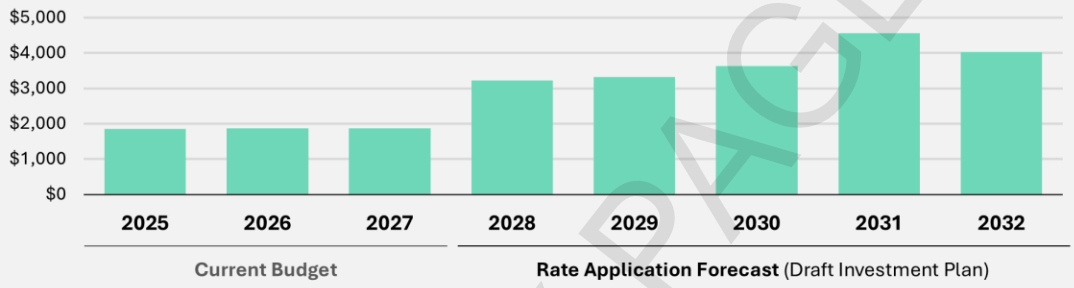
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

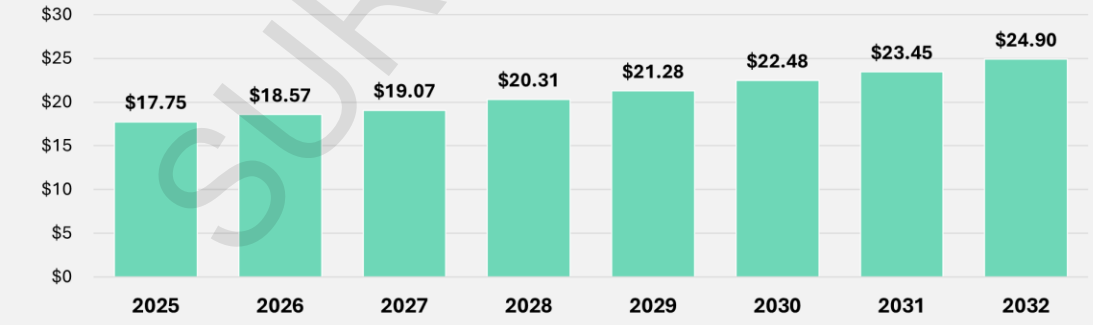


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **residential customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $19.07 in 2027 to $24.90 by the end of 2032 – an increase of **$5.83** on the monthly bill. This represents an average increase of **$1.17** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Residential & Seasonal

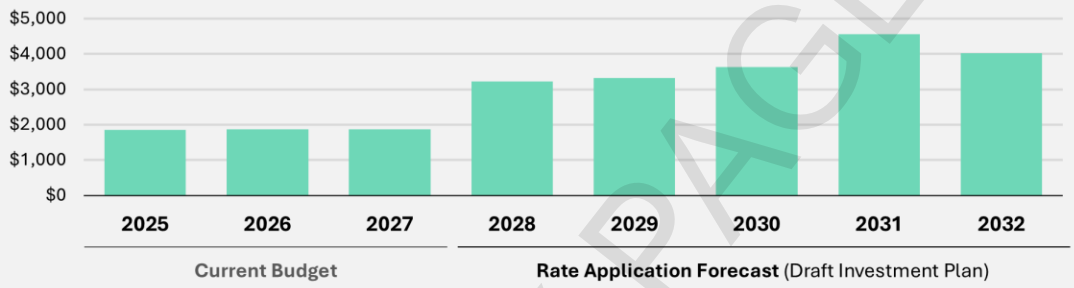
Seasonal Version

Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

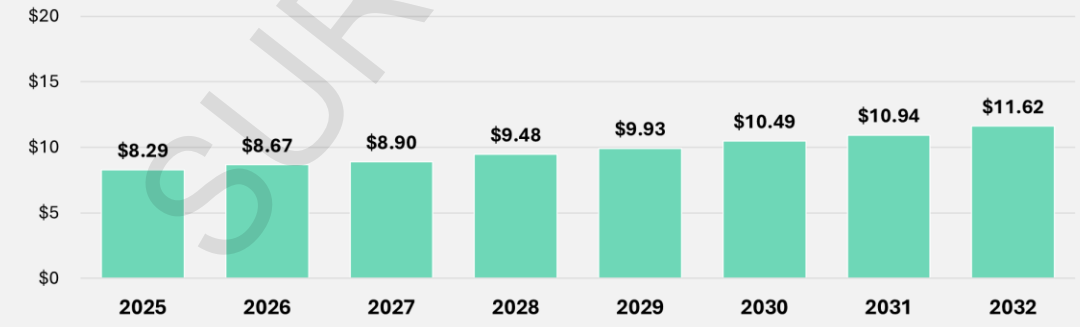


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **seasonal customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $8.90 in 2027 to $11.62 by the end of 2032 – an increase of **$2.72** on the monthly bill. This represents an average increase of **$0.54** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

How to make choices

Residential & Seasonal

Residential Version

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft investment plans, plus **7 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- These impacts **will not be paid by the approximately 60% of residential customers who receive distribution rate protection** but still represent the true cost of the choices.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost for you.



SURVEY PAGE

Summary of Investment Plan

How to make choices

Residential & Seasonal

Seasonal Version

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

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SURVEY PAGE

Summary of Investment Plan

How Hydro One's distribution grid performs

Residential & Seasonal

Hydro One Customer Engagement Survey

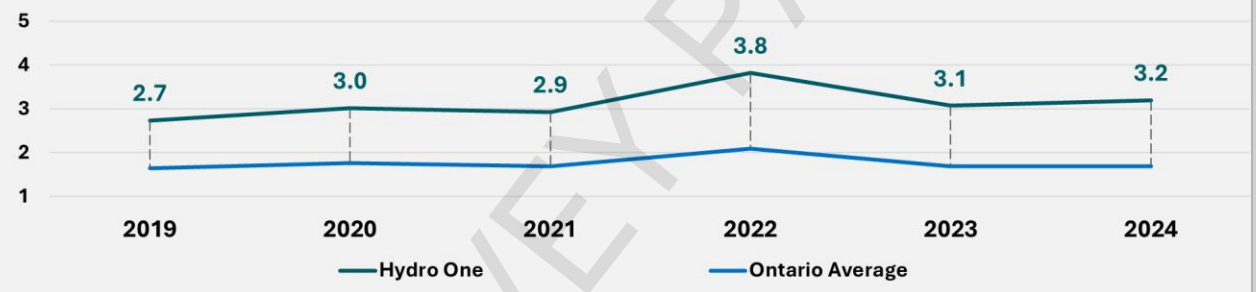
How does Hydro One's distribution grid perform?

Since most Hydro One customers live in rural areas, their distribution system looks different from other Ontario utilities. Serving more sparsely populated communities separated by significant distances means more equipment is needed, outages can take longer to locate, and power can take longer to restore.



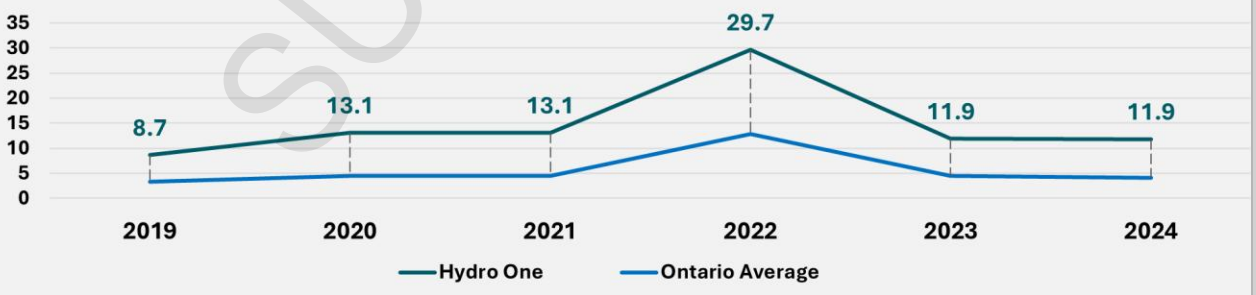
On average, between 2019 and 2024, the typical Hydro One customer has experienced 1.4 more outages per year compared to the Ontario average.

Number of Outages (Average Outages Per Customer)



When it comes to the total time spent without electricity per year, the typical Hydro One customer has been without power for 14.7 hours each year on average, which is 9.1 hours more than the Ontario average.

Duration of Outages (Average Hours Per Customer)



Severe weather, **tree contacts**, and **equipment failure** account for most of these outages. Notably, the distribution system experienced widespread outages due to severe weather in both 2022 and again in April 2025.

SURVEY P

Investment Trade-Offs

Overall system reliability

Residential & Seasonal

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

Hydro One typically identifies investments in equipment by taking into consideration the overall age, health, and likelihood of equipment failure.

In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

Hydro One generally tries to replace poor condition equipment before it fails. However, when equipment does fail, it can result in significant interruptions for customers.

In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$2.20 less by 2032 (average of $0.44 less each year)	Included in Draft Plan	$2.18 more by 2032 (average of $0.44 more each year)

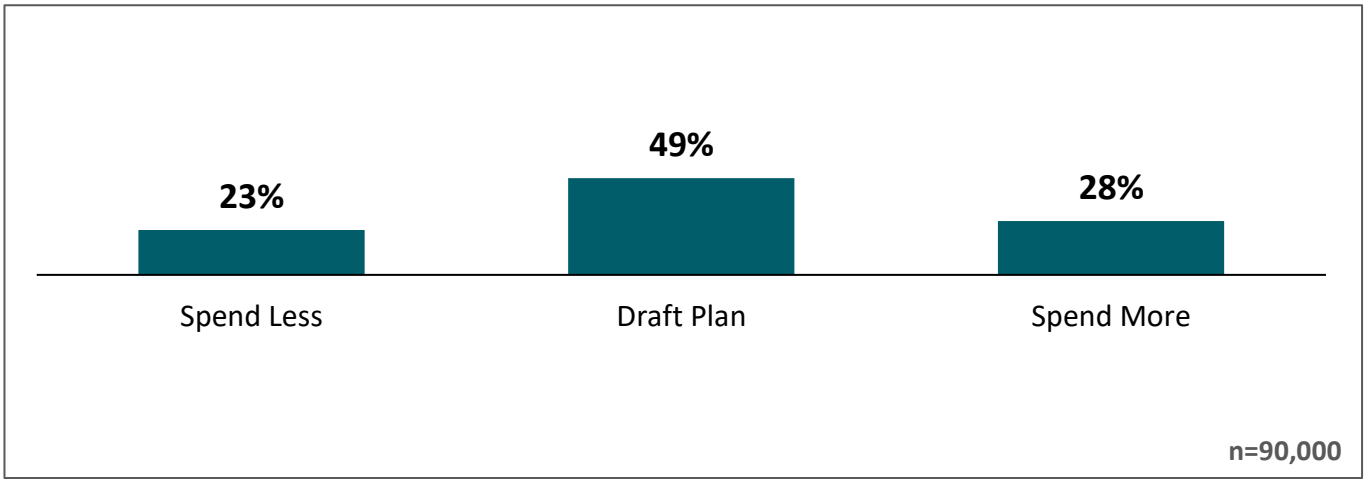
SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	23%	24%	24%	23%	22%	22%	25%
Draft Plan	50%	49%	52%	49%	48%	50%	50%
Spend More	28%	27%	25%	28%	29%	28%	25%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	28%	19%	20%	30%	12%
Draft Plan	49%	52%	48%	50%	49%
Spend More	23%	29%	32%	20%	39%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Overall system reliability

Residential & Seasonal

Q Which of the following options do you prefer?

	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Spend Less	23%	23%	22%	23%	23%
Draft Plan	49%	50%	50%	49%	48%
Spend More	28%	27%	27%	28%	29%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Overall system reliability

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Improve reliability/reduce outages	1.2%
Invest now to prepare for future/prevent future increases	1.1%
Against increases/costs are too expensive	1.1%
Find efficiencies/alternative funding/customers shouldn't pay	0.9%
Improve line maintenance/vegetation management	0.9%
Willing to pay more for improved reliability	0.8%
Infrastructure needs to be upgraded	0.7%
Maintain current service levels/prioritize areas of higher need	0.5%
Distrust in the engagement/rate increases are inevitable	0.5%
Need more information	0.4%
Concerns around cost of living/inflation	0.4%
Bury the lines	0.4%
Financial strain on vulnerable customers (seniors, fixed income)	0.3%
Support the draft plan/increase is reasonable	0.3%
Feel the investment is necessary, but try to minimize costs	0.3%
Customers affected should pay/more equal distribution of rates	0.2%
Focus on renewable, nuclear and energy storage solutions	0.2%
Concern with severe weather	0.2%
Hydro One is profit-driven	0.1%
Other	0.2%
No comment/None/Don't know	89.4%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Investment Trade-Offs

Managing the impacts of severe weather

Residential & Seasonal

Hydro One Customer Engagement Survey

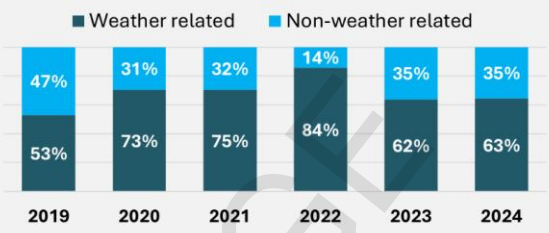
Managing the impacts of severe weather

hydro one

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.



Share of Customer Hours Without Power by Cause



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$1.44 less by 2032 (average of $0.29 less each year)	Included in Draft Plan	$1.43 more by 2032 (average of $0.29 more each year)

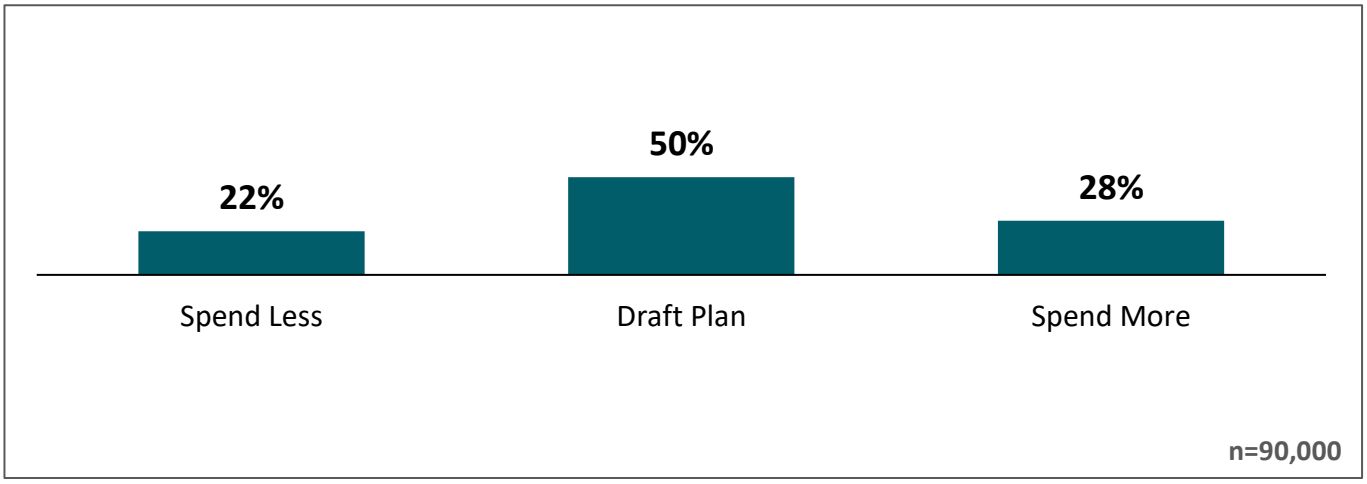
SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	22%	24%	24%	23%	21%	22%	24%
Draft Plan	50%	47%	52%	49%	49%	51%	51%
Spend More	28%	29%	24%	28%	30%	27%	25%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	26%	19%	20%	29%	12%
Draft Plan	51%	52%	48%	51%	49%
Spend More	23%	29%	32%	20%	39%

Investment Trade-Offs

Managing the impacts of severe weather

Residential & Seasonal

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	22%	23%	22%	22%	23%
Draft Plan	50%	51%	51%	50%	48%
Spend More	28%	27%	27%	28%	29%

Investment Trade-Offs

Managing the impacts of severe weather

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Improve line maintenance/vegetation management	1.3%
Improve reliability/reduce outages	0.6%
Find efficiencies/alternative funding/customers shouldn't pay	0.6%
Invest now to prepare for future/prevent future increases	0.5%
Against increases/costs are too expensive	0.4%
Support the draft plan/increase is reasonable	0.4%
Maintain current service levels/prioritize areas of higher need	0.4%
Willing to pay more for improved reliability	0.3%
Bury the lines	0.3%
Need more information	0.3%
Distrust in the engagement/rate increases are inevitable	0.2%
Infrastructure needs to be upgraded	0.1%
Customers affected should pay/more equal distribution of rates	0.1%
Concern with increased frequency of severe weather	0.1%
Support automated switches/strategic use	0.1%
Concerns around cost of living/inflation	0.1%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Focus on renewable, nuclear and energy storage solutions	0.1%
Concerns with automated switches/limitations	0.1%
Other	0.3%
No comment/None/Don’t know	93.8%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Investment Trade-Offs

Targeted reliability improvements

Residential & Seasonal

Hydro One Customer Engagement Survey

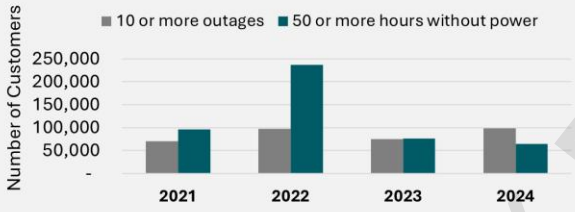
Targeted reliability improvements

Hydro One customers experience different levels of reliability depending on where they live, the design of the system, the condition of the equipment supplying them, and weather patterns.

While some Hydro One customers might not have experienced any outages in the last four years, in any given year more than **70,000 customers were without power more than 10 times**, and more than **60,000 customers were in the dark for 50 hours or more**.

Today, rural and remote communities are more likely to experience poorer reliability, and the increased frequency of severe weather events create and will continue to create further challenges.

Number of Customers Experiencing Significantly Poorer Reliability than Average





Community-scale battery storage facility outside of Thunder Bay

In a 2024 survey, a majority of customers said that they want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.

In their **current draft plan**, Hydro One has developed a program that includes a combination of larger **community-scale** batteries and smaller **individual customer** batteries, which store electricity and provide backup power if an outage does occur.

Batteries are an effective way to target reliability improvements for individual customers and communities that experience the poorest reliability.

At the rate of investment being proposed in the draft plan, Hydro One anticipates reliability improvements for around **10,000** customers. However, based on customer feedback, Hydro One could install more or fewer batteries.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$1.49 less by 2032 (average of $0.30 less each year)	**Included in Draft Plan**	$1.49 more by 2032 (average of $0.30 more each year)

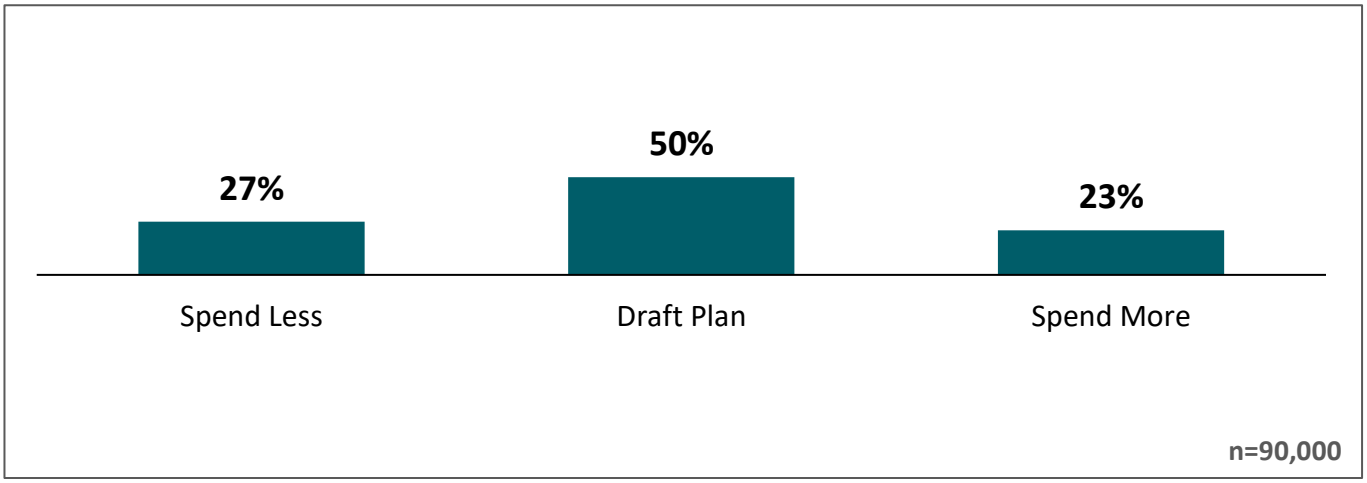
SURVEY ONLY

Investment Trade-Offs

Targeted reliability improvements

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	27%	30%	29%	27%	26%	27%	30%
Draft Plan	50%	48%	51%	50%	50%	50%	49%
Spend More	23%	22%	21%	23%	24%	23%	21%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	29%	23%	26%	33%	18%
Draft Plan	50%	53%	49%	49%	51%
Spend More	21%	24%	25%	17%	31%

Investment Trade-Offs

Targeted reliability improvements

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	27%	26%	26%	28%	28%
Draft Plan	50%	51%	51%	50%	48%
Spend More	23%	22%	23%	23%	23%

Investment Trade-Offs

Targeted reliability improvements

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Concerns over community-scale battery storage facilities/limitations	0.8%
Need more information	0.7%
Improve reliability/reduce outages	0.5%
Support the draft plan/increase is reasonable	0.5%
Against increases/costs are too expensive	0.4%
Focus on home back-up sources/incentive to install	0.4%
Customers affected should pay/more equal distribution of rates	0.3%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Focus on renewable, nuclear and energy storage solutions	0.2%
Willing to pay more for improved reliability	0.2%
Infrastructure needs to be upgraded	0.1%
Focus on rural customers/communities	0.1%
Maintain current service levels/prioritize areas of higher need	0.1%
Improve line maintenance/vegetation management	0.1%
Rural customers are prepared/should accept their choice	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Other	1.1%
No comment/None/Don’t know	93.9%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Summary of Investment Plan

Hydro One's transmission system

Residential & Seasonal

Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

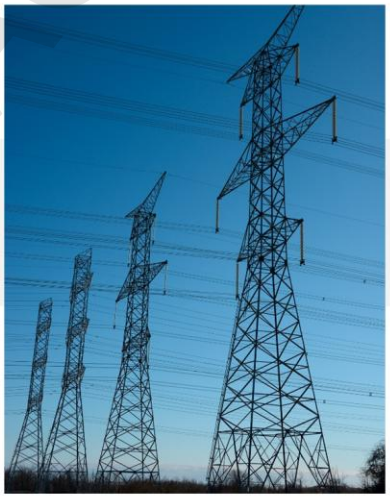
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

Residential & Seasonal

Residential Version

SURVEY BRIEF

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$0.59 less by 2032 (average of $0.12 less each year)	**Included in Draft Plan**	$0.59 more by 2032 (average of $0.12 more each year)

Investment Trade-Offs

Keeping pace with transmission renewal

Residential & Seasonal

Seasonal Version

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

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- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$0.28 less by 2032 (average of $0.06 less each year)	**Included in Draft Plan**	$0.28 more by 2032 (average of $0.06 more each year)

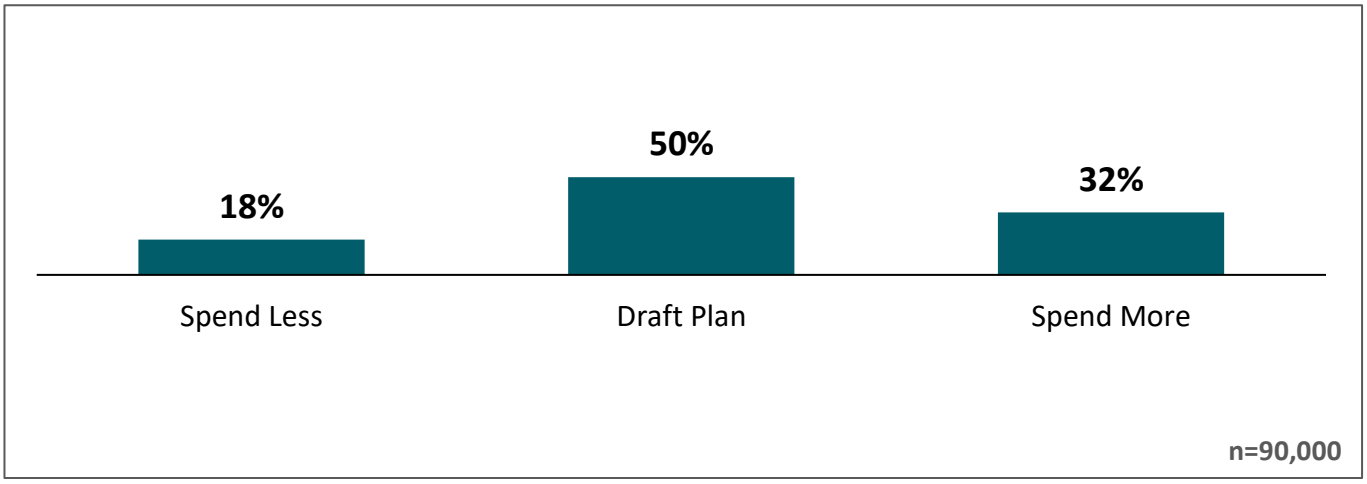
SURVEY PROOF

Investment Trade-Offs

Keeping pace with transmission renewal

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	18%	19%	19%	18%	17%	18%	20%
Draft Plan	50%	50%	52%	49%	49%	50%	51%
Spend More	32%	31%	30%	32%	34%	32%	29%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	21%	15%	16%	24%	9%
Draft Plan	51%	52%	49%	51%	48%
Spend More	28%	33%	35%	25%	43%

Investment Trade-Offs

Keeping pace with transmission renewal

Residential & Seasonal

Q Which of the following options do you prefer?

	Overall	Consumption Quartiles: Low	Medium-Low	Medium-High	High
Spend Less	18%	18%	18%	18%	19%
Draft Plan	50%	50%	50%	51%	49%
Spend More	32%	32%	32%	31%	33%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Keeping pace with transmission renewal

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Need more information	0.5%
Find efficiencies/alternative funding/customers shouldn't pay	0.4%
Infrastructure needs to be upgraded	0.4%
Invest now to prepare for future/prevent future increases	0.4%
Against increases/costs are too expensive	0.3%
Willing to pay more for improved reliability	0.3%
Improve reliability/reduce outages	0.3%
Support the draft plan/increase is reasonable	0.3%
Focus on preventative maintenance	0.3%
Bury the lines	0.2%
Maintain current service levels/prioritize areas of higher need	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Concerns around cost of living/inflation	0.1%
Focus on renewable, nuclear and energy storage solution	0.1%
Other	0.4%
No comment/None/Don't know	95.9%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Investment Trade-Offs

Stewardship of the transmission system

Residential & Seasonal

Residential Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$0.48 less by 2032 (average of $0.10 less each year)	Included in Draft Plan	$0.48 more by 2032 (average of $0.10 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Residential & Seasonal

Seasonal Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

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These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$0.22 less by 2032 (average of $0.04 less each year)	Included in Draft Plan	$0.22 more by 2032 (average of $0.04 more each year)

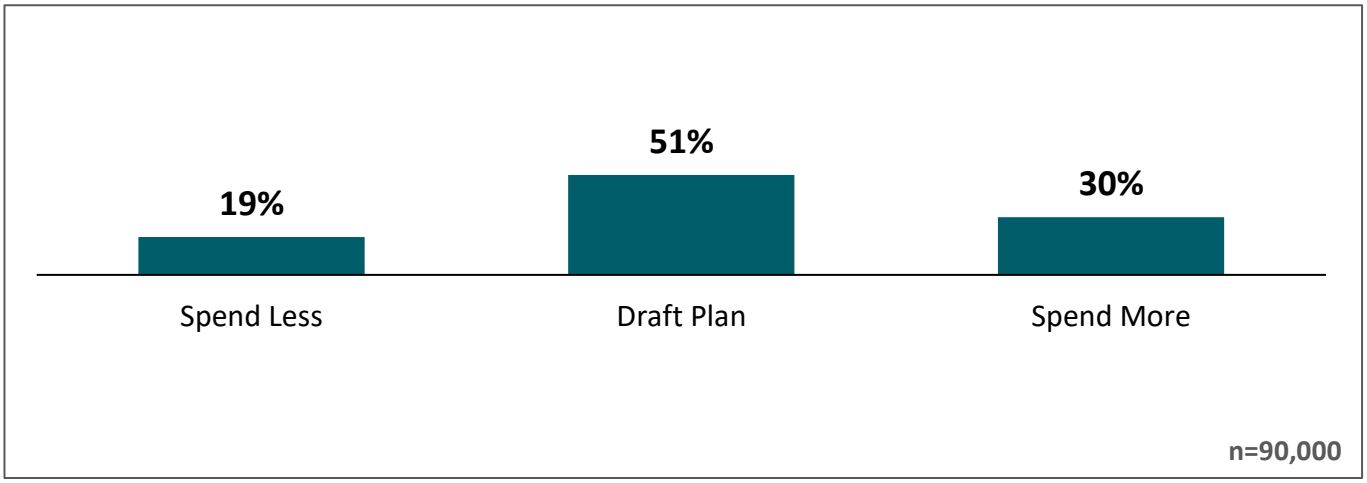
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	19%	20%	20%	20%	18%	19%	21%
Draft Plan	51%	49%	54%	50%	50%	51%	51%
Spend More	29%	31%	26%	30%	31%	30%	28%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	22%	16%	17%	26%	10%
Draft Plan	52%	54%	49%	52%	50%
Spend More	26%	30%	34%	22%	41%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Stewardship of the transmission system

Residential & Seasonal

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	19%	19%	19%	19%	20%
Draft Plan	51%	52%	52%	51%	50%
Spend More	30%	29%	29%	30%	31%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Stewardship of the transmission system

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Improve line maintenance/vegetation management	0.8%
Find efficiencies/alternative funding/customers shouldn't pay	0.5%
Against increases/costs are too expensive	0.4%
Willing to pay more for improved reliability	0.3%
Replace wood poles with stronger/more durable materials	0.2%
Support the draft plan/increase is reasonable	0.2%
Infrastructure needs to be upgraded	0.2%
Distrust in the engagement/rate increases are inevitable	0.2%
Bury the lines	0.2%
Improve reliability/reduce outages	0.2%
Need more information	0.1%
Concerns with severe weather	0.1%
Need climate-resilient infrastructure	0.1%
Maintain current service levels/prioritize areas of higher need	0.1%
Other	0.3%
No comment/None/Don't know	96.2%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Investment Trade-Offs

Maintaining buildings and facilities

Residential & Seasonal

Residential Version

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$0.34 less by 2032 (average of $0.07 less each year)	Included in Draft Plan	$0.31 more by 2032 (average of $0.06 more each year)
Average Monthly Transmission Bill Impact	$0.02 less by 2032 (average of $0.005 less each year)		$0.07 more by 2032 (average of $0.01 more each year)

SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Residential & Seasonal

Seasonal Version

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
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Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$0.34 less by 2032 (average of $0.07 less each year)	Included in Draft Plan	$0.31 more by 2032 (average of $0.06 more each year)
Average Monthly Transmission Bill Impact	$0.01 less by 2032 (average of $0.002 less each year)		$0.03 more by 2032 (average of $0.01 more each year)

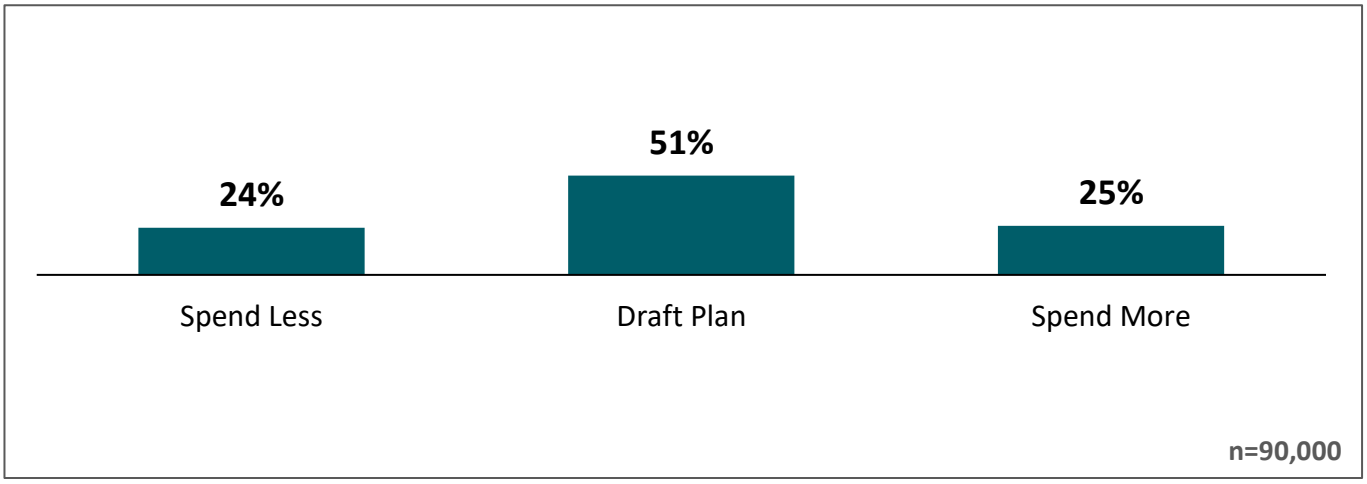
SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	24%	26%	25%	24%	23%	24%	26%
Draft Plan	51%	50%	52%	51%	50%	51%	51%
Spend More	25%	24%	23%	25%	26%	25%	23%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	26%	20%	22%	31%	14%
Draft Plan	51%	54%	50%	50%	52%
Spend More	23%	27%	28%	19%	35%

Investment Trade-Offs

Maintaining buildings and facilities

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	24%	23%	24%	24%	25%
Draft Plan	51%	51%	52%	51%	50%
Spend More	25%	25%	25%	25%	25%

Investment Trade-Offs

Maintaining buildings and facilities

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	0.7%
Against increases/costs are too expensive	0.5%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Seems Hydro One didn't plan well in the past	0.2%
Support meeting modern accessibility standards	0.1%
Improve reliability/reduce outages	0.1%
Infrastructure needs to be upgraded	0.1%
Prioritize safety	0.1%
Other	0.6%
No comment/None/Don't know	97.3%

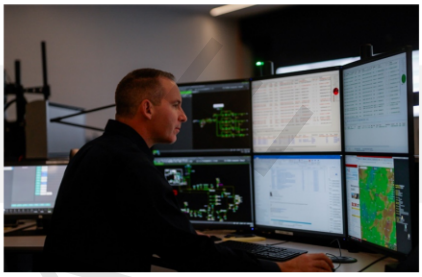
Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Investment Trade-Offs
Information technology

Residential Version

Hydro One Customer Engagement Survey
Information technology

Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.



When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$0.45 less by 2032 (average of $0.09 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$0.16 less by 2032 (average of $0.03 less each year)	

SURVEY PAPER

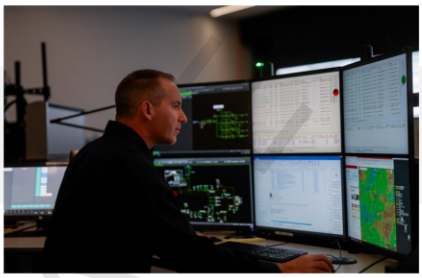
Investment Trade-Offs
Information technology

Residential & Seasonal

Seasonal Version

Hydro One Customer Engagement Survey
Information technology

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Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$0.45 less by 2032 (average of $0.09 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$0.07 less by 2032 (average of $0.01 less each year)	

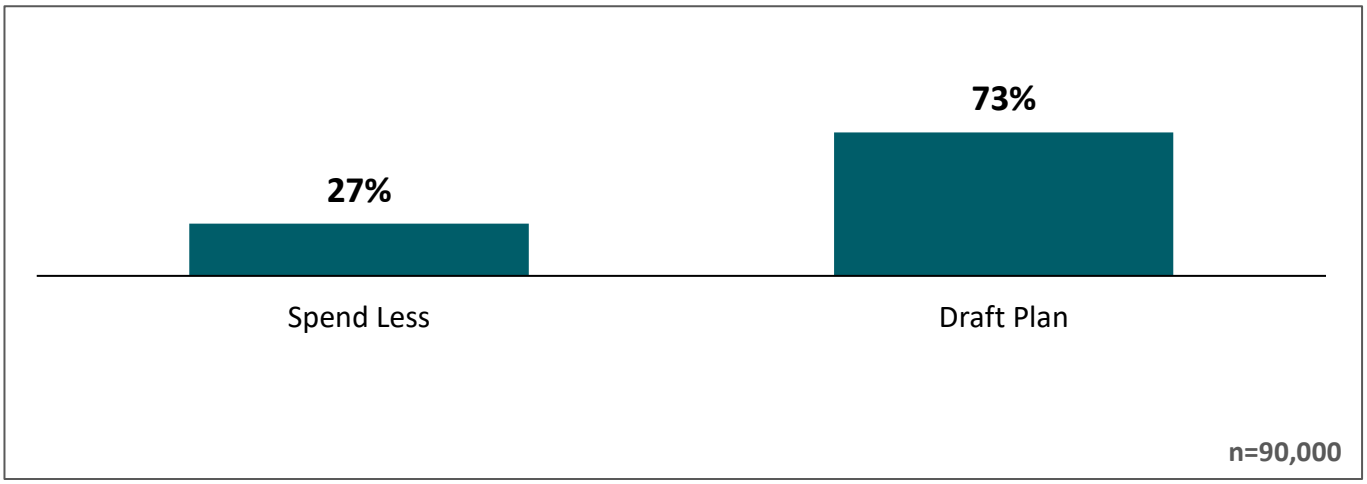
SURVEY PLAN

Investment Trade-Offs

Information technology

Residential & Seasonal

Q Which of the following options do you prefer?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend Less	27%	27%	27%	27%	26%	26%	29%
Draft Plan	73%	73%	73%	73%	74%	74%	71%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	30%	22%	24%	34%	16%
Draft Plan	70%	78%	76%	66%	84%

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Spend Less	26%	26%	27%	27%
Draft Plan	74%	74%	73%	73%

Investment Trade-Offs

Information technology

Residential & Seasonal

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	0.8%
Concerns with cyber attacks/prioritize cyber security	0.4%
Find efficiencies/alternative funding/customers shouldn't pay	0.4%
Against increases/costs are too expensive	0.3%
Satisfied with current customer service levels	0.3%
Infrastructure needs to be upgraded	0.2%
Concerns with AI/limitations	0.2%
Distrust in the engagement/rate increases are inevitable	0.1%
Need more information	0.1%
Supportive of AI	0.1%
IT investments should reduce other administrative and operational costs	0.1%
Other	0.3%
No comment/None/Don't know	96.7%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Investment Trade-Offs

Finalizing Choices

Residential & Seasonal

SURVEY PAGE

Hydro One Customer Engagement Survey

What is the impact of my choices?

hydro one

Throughout this survey, you have been asked about 7 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on your bill will be recalculated.

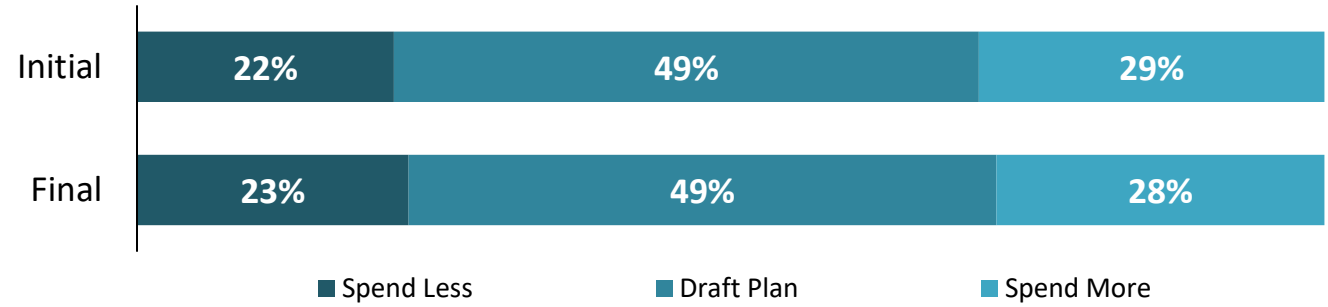
The bill impacts associated with each choice represent the average increase on your monthly bill from 2027 to 2032, followed by the average increase on your monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

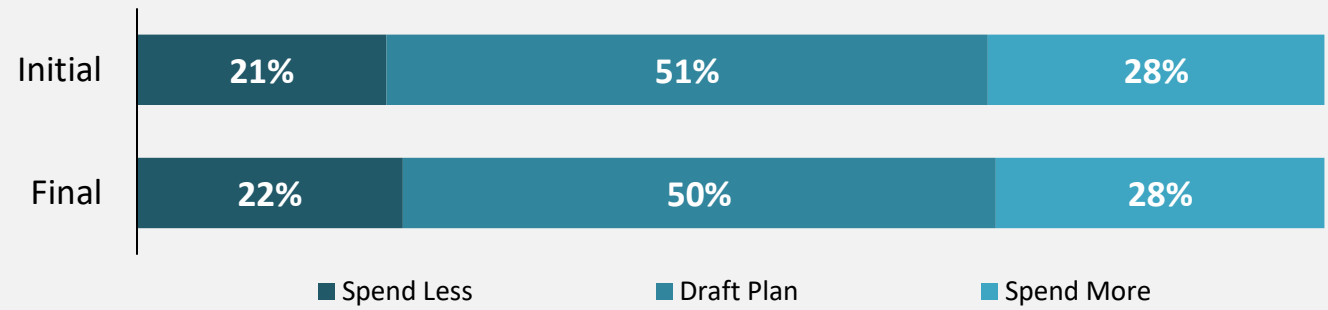
Finalizing Choices

Residential & Seasonal

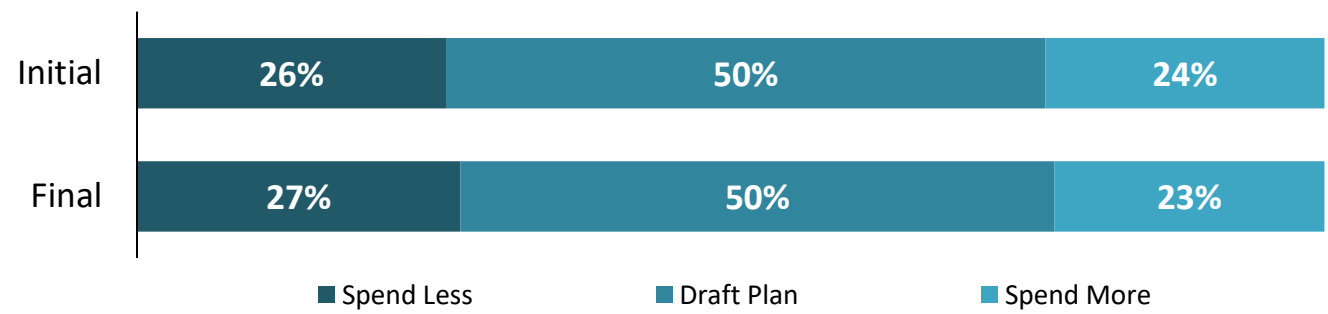
Overall system reliability



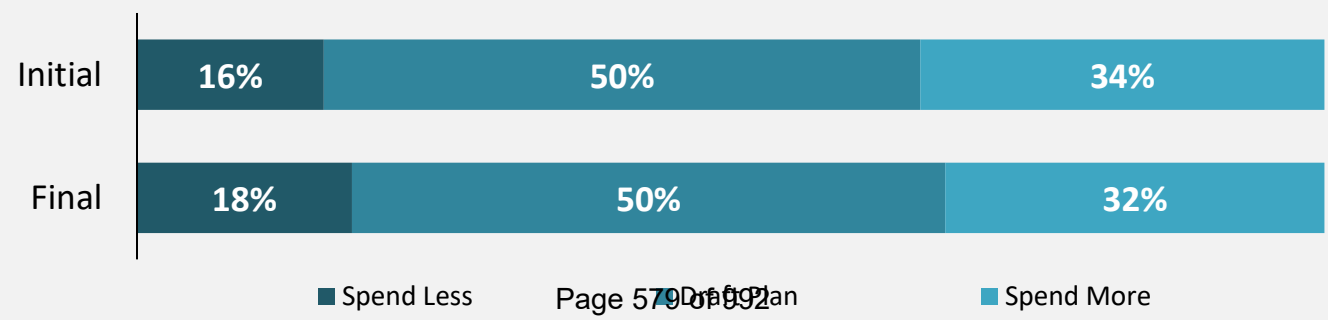
Managing the impacts of severe weather



Targeted reliability improvements



Keeping pace with transmission renewal

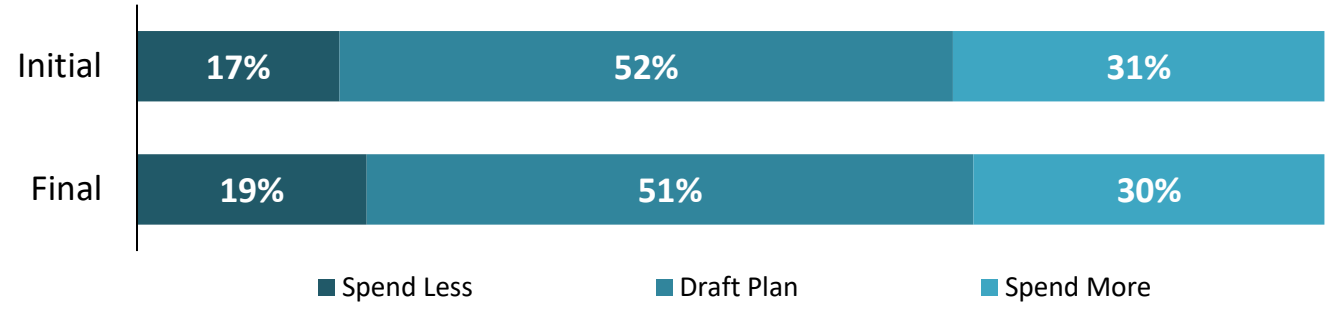


Investment Trade-Offs

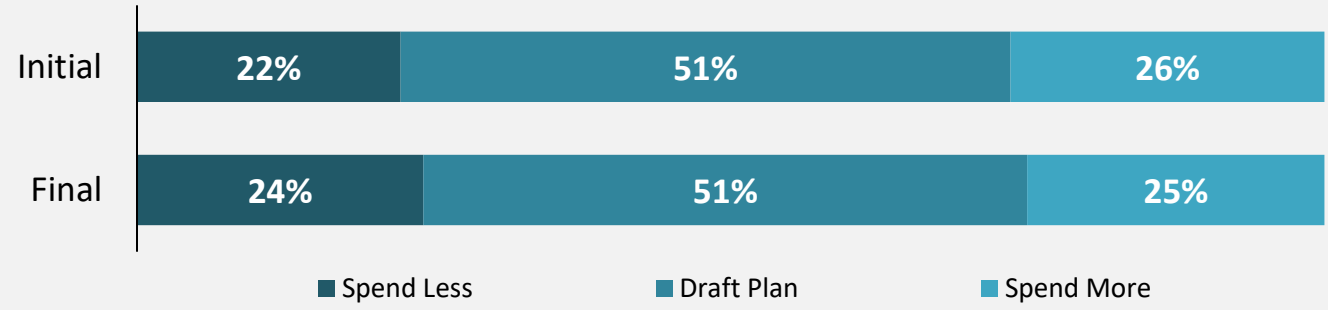
Finalizing Choices

Residential & Seasonal

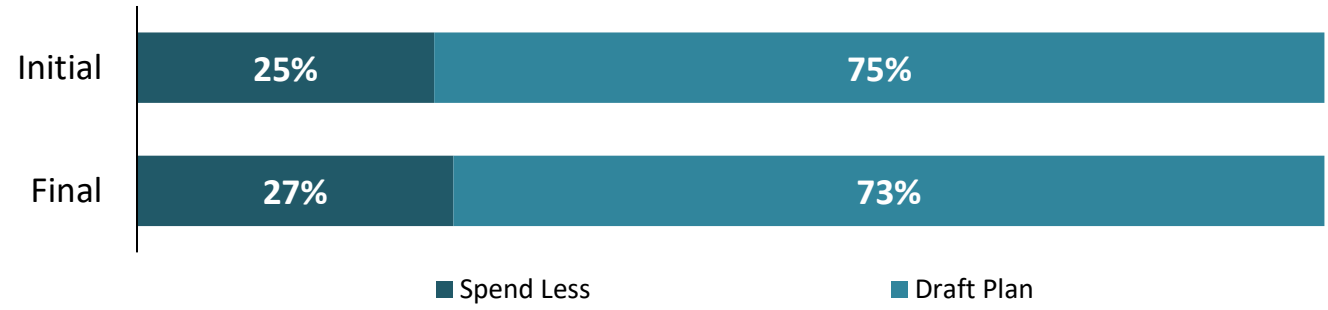
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Overall evaluation of the draft plans

Residential Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **residential customer** who does not receive distribution rate protection would see:

- The **distribution** portion of their **monthly bill** increase from $78.58 in 2027 to $128.72 by the end of 2032 – an increase of **$50.14** on the monthly bill. This represents an average increase of **$10.03** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $19.07 in 2027 to $24.90 by the end of 2032 – an increase of **$5.83** on the monthly bill. This represents an average increase of **$1.17** on the monthly bill each year.

SURVEY PAGE

Seasonal Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **seasonal customer** would see:

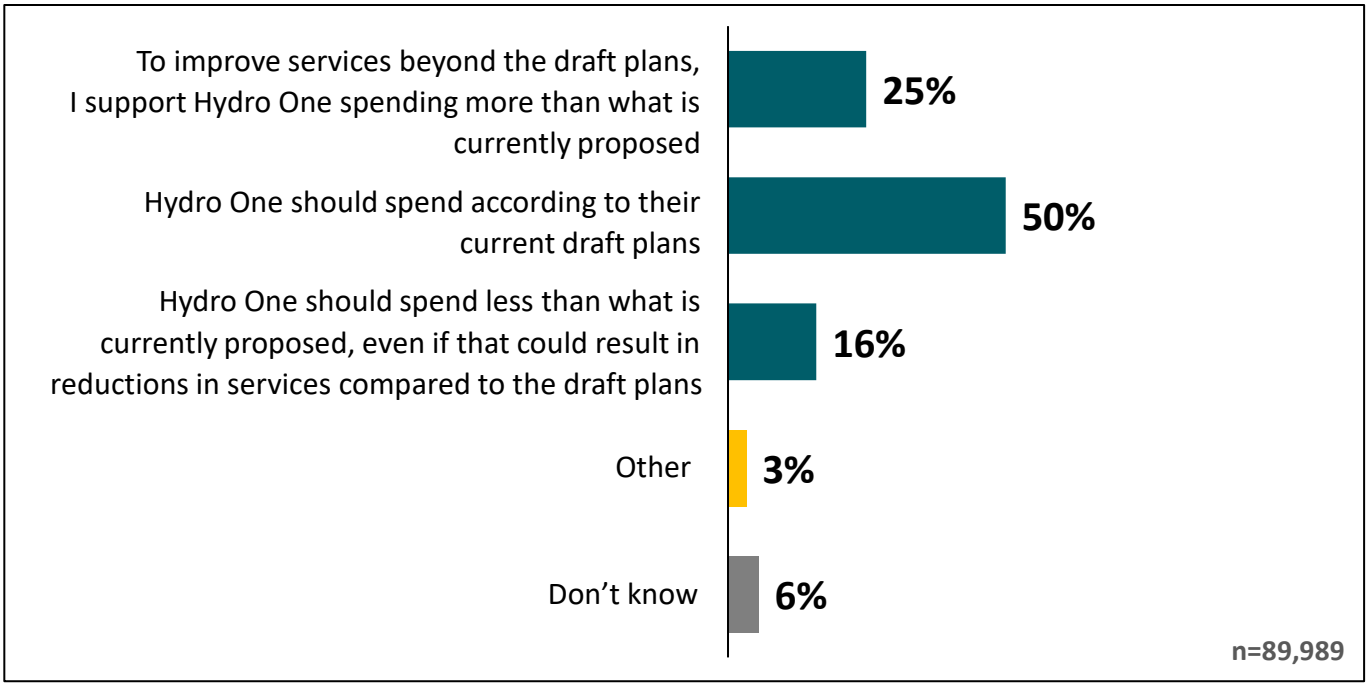
- The **distribution** portion of their **monthly bill** increase from $78.58 in 2027 to $128.72 by the end of 2032 – an increase of **$50.14** on the monthly bill. This represents an average increase of **$10.03** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $8.90 in 2027 to $11.62 by the end of 2032 – an increase of **$2.72** on the monthly bill. This represents an average increase of **$0.54** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plans

Residential & Seasonal

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?



	Customer Type		Region				
	Residential	Seasonal	West	Central	Central East	East	North
Spend More	25%	26%	22%	25%	27%	25%	22%
Draft Plans	51%	46%	52%	50%	49%	51%	51%
Spend Less	16%	20%	17%	16%	15%	15%	17%
Other	3%	4%	3%	3%	3%	4%	3%
Don't know	6%	4%	6%	5%	6%	5%	7%

Investment Trade-Offs

Overall evaluation of the draft plans

Residential & Seasonal

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	25%	21%	26%	30%	17%	37%
Draft Plans	50%	52%	54%	49%	51%	49%
Spend Less	16%	16%	13%	15%	21%	8%
Other	3%	3%	2%	3%	4%	2%
Don't know	6%	8%	5%	3%	6%	4%

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Spend More	24%	24%	25%	26%
Draft Plans	51%	51%	50%	48%
Spend Less	16%	16%	16%	16%
Other	3%	3%	3%	4%
Don't know	6%	6%	5%	5%

Investment Trade-Offs

Final comments on the draft plans

Residential & Seasonal

Q Do you have any final comments regarding Hydro One's draft plans for 2028–2032 and the proposed rate increase? (Optional)

Responses	%
Lower rates/rates are too high	2.5%
Find efficiencies/alternative funding/customers shouldn't pay	1.7%
Support the increase/investments are necessary	1.5%
Improve reliability/reduce outages	1.4%
Invest now to prepare for future/prevent future increases	1.2%
Transparency on internal operations	1.2%
Fair cost allocation/user-pays for system impacts/upgrades	0.8%
Environmental concerns/green initiatives	0.8%
Distrust in the engagement/rate increases are inevitable	0.6%
Need more information/educate customers	0.6%
Financial strain on vulnerable customers (seniors, fixed income)	0.6%
Positive comment about Hydro One/service	0.6%
Concerns around cost of living/inflation	0.5%
Improve line maintenance/vegetation management	0.4%
Rate protection questions/eligibility	0.3%
Be transparent/communicate about rate increases/investments	0.2%
Stop selling power to the US/increase price to the US	0.2%
Maintain current service levels/prioritize areas of higher need	0.1%
Hydro One is profit-driven	0.1%
Other	0.6%
No comment/None/Don't know	84.0%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

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Residential and Seasonal Customers

Survey Diagnostics



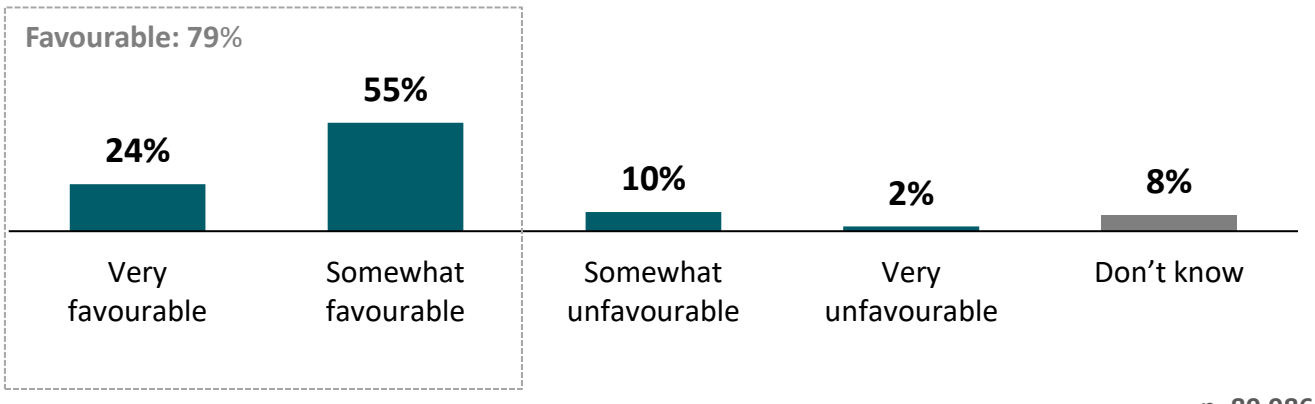
Survey Diagnostics

Favourability and amount of information

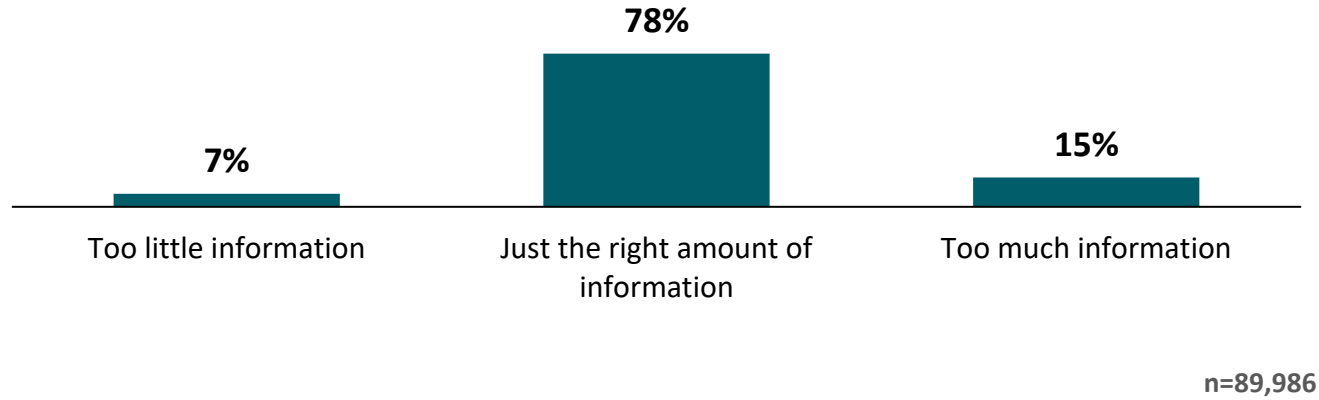
Residential & Seasonal

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



INNOVATIVE RESEARCH GROUP

Survey Diagnostics

Other information not included

Residential & Seasonal

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
Transparency on internal operations	2.5%
Reducing customer costs/affordability measures	1.2%
More information on renewable energy	1.0%
Survey/engagement experience feedback - negative	0.8%
More detailed information on the investments/infrastructure	0.8%
More information/communication about rate increases	0.7%
Distrust in the engagement/rate increases are inevitable	0.7%
Better outage communication/information	0.5%
Rate protection questions/eligibility	0.5%
Impact of EVs/AI/new technology	0.5%
Survey/engagement experience feedback – positive	0.5%
Focus on renewable, nuclear and energy storage solution	0.5%
Customer demographic comparison/region specific information	0.4%
Better explanation/transparency on bills	0.4%
Historical data (e.g. spending, impact, cost)	0.2%
Helping seniors/fixed-income individuals	0.2%
How Hydro One's costs compare to other companies/jurisdictions	0.2%
Impact on the environment/wildlife	0.2%
Information on energy sold to US/other countries/out of province	0.1%
Positive comment about Hydro One/service	0.1%
Government involvement/subsidization	0.1%
Other	0.8%
No comment/None/Don’t know	87.2%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

Survey Diagnostics
Outstanding questions

Residential & Seasonal

Q Is there anything that you would still like answered? (Optional)

Responses	%
Plans to reduce/lower customer costs	1.4%
Transparency on internal operations	1.3%
Focus on renewable, nuclear & energy storage solution	1.0%
More detailed information on the investments/infrastructure	0.7%
Improve reliability/reduce outages	0.5%
Rate protection questions/eligibility	0.5%
Be transparent/communicate about rate increases	0.4%
Better explanation/transparency on bills	0.4%
Different types of customers and their rates	0.3%
Improve line maintenance/vegetation management	0.3%
Survey/engagement experience feedback - negative	0.3%
Helping seniors/fixed-income individuals	0.3%
Improve customer service/communication (general/outage)	0.3%
Distrust in the engagement/rate increases are inevitable	0.3%
Stop selling power to the US/increase price to the US	0.2%
Government involvement/subsidies	0.2%
Positive comment about Hydro One/service	0.2%
Survey/engagement experience feedback - positive	0.2%
How Hydro One's costs compare to other companies/jurisdictions	0.2%
Other	0.6%
No comment/None/Don't know	90.5%

Note: Results for open-ended questions are based on coding of a random sample of 25% of all responses. Only responses >0.1% shown

First Nations On-Reserve Customers

Online Survey Results

Section 3



Online Survey
Methodology

Field Dates

The **First Nations On-Reserve Residential Customer Online Survey** was sent to all Hydro One on-reserve residential customers with an available email address. Customers had an opportunity to complete the survey between **November 13th and December 22nd, 2025**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the on-reserve residential survey was sent to **12,747** customers from *customerexperience@hydroone.com*. A total of 3 reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

First Nations On-Reserve Customer Online Survey Completes

A total of **793** (unweighted) Hydro One on-reserve residential customers completed the online survey.

Sample Weighting

The First Nations On-Reserve Customer online survey sample was weighted to n=775 proportionately by consumption quartiles and region in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

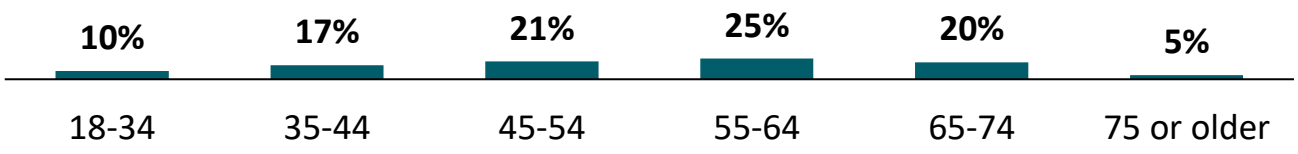
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	14 (19)	16 (21)	22 (25)	21 (18)	74 (85)
Central	66 (67)	56 (54)	39 (43)	39 (33)	203 (200)
East/Central East	49 (33)	53 (33)	41 (29)	35 (23)	182 (120)
North	62 (73)	77 (81)	92 (94)	96 (117)	334 (371)
Total	191 (191)	202 (189)	194 (191)	191 (191)	793 (775)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Demographic Breakdown

First Nations On-Reserve

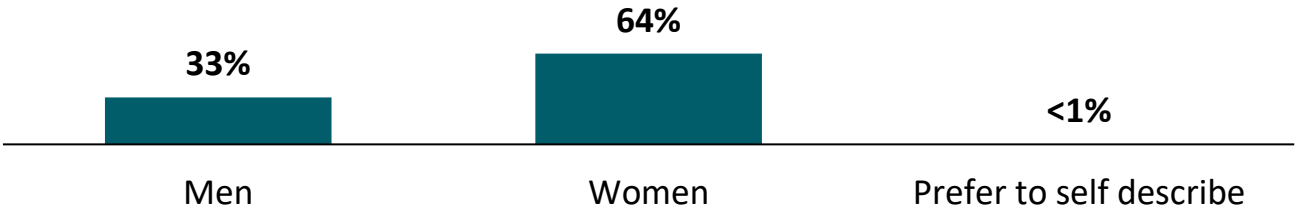
Q Age



"Prefer not to say" (2%) not shown.

n=775

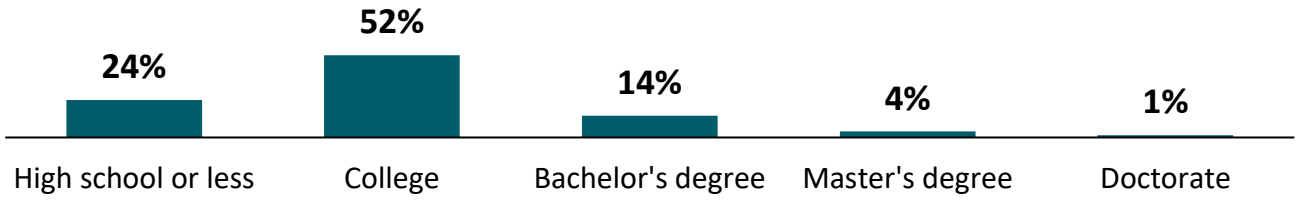
Q Gender



"Prefer not to say" (3%) not shown.

n=775

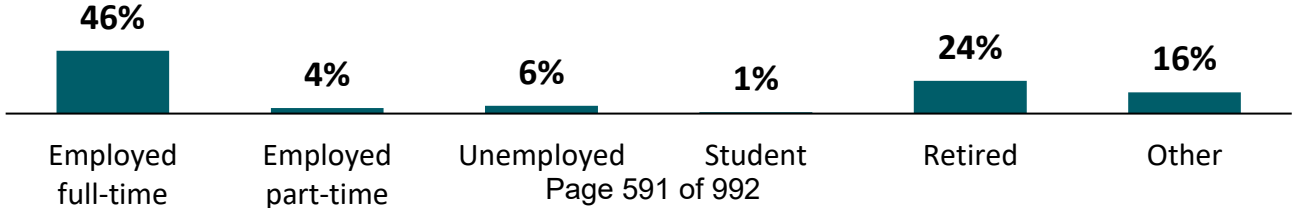
Q Education



"Other" (1%) and "Prefer not to say" (5%) not shown.

n=775

Q Employment Status



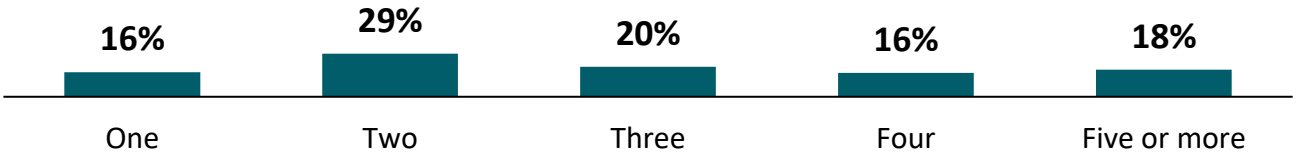
"Prefer not to say" (4%) not shown.

n=775

Demographic Breakdown
Continued

First Nations On-Reserve

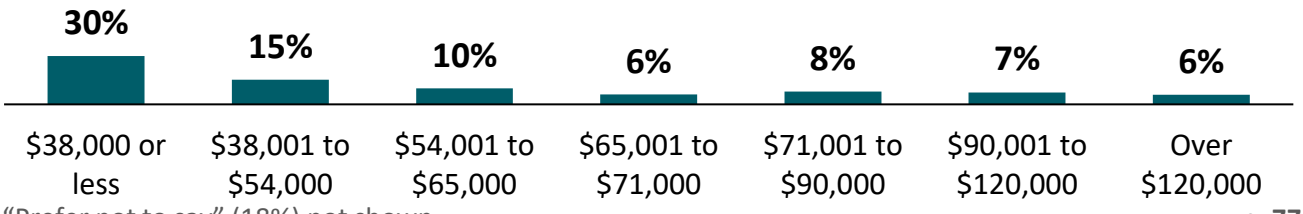
Q Household Size



"Prefer not to say" (1%) not shown.

n=775

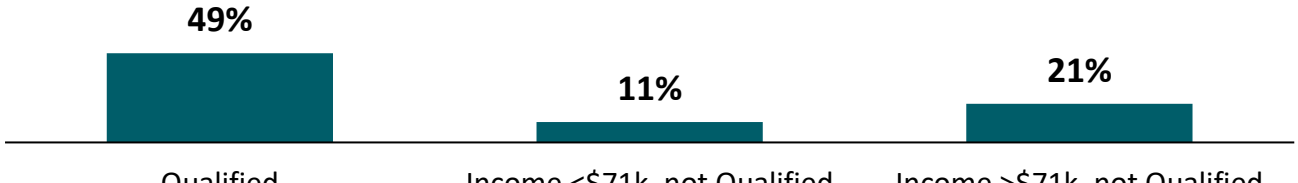
Q After Tax Household Income



"Prefer not to say" (18%) not shown.

n=775

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (18%) not shown.

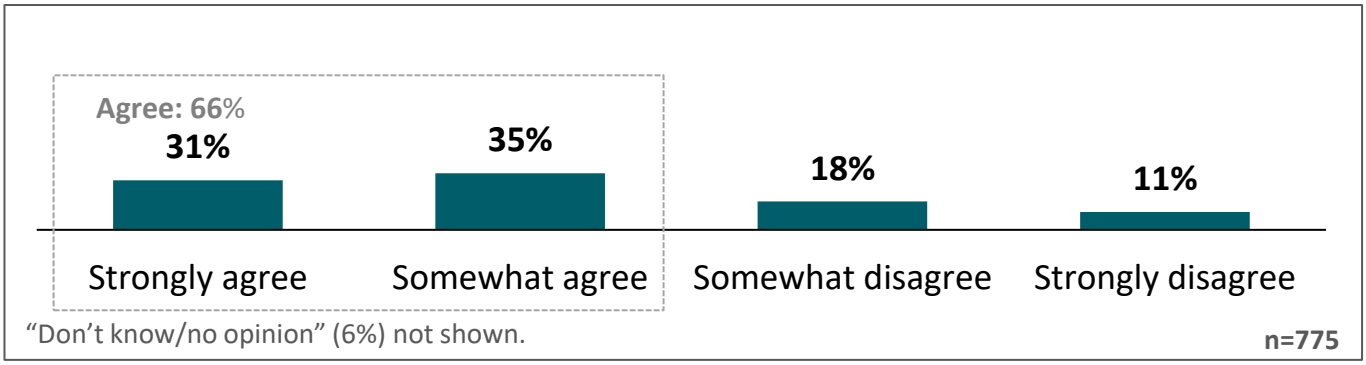
n=775

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Environmental Controls

To what extent do you agree or disagree with the following statements?

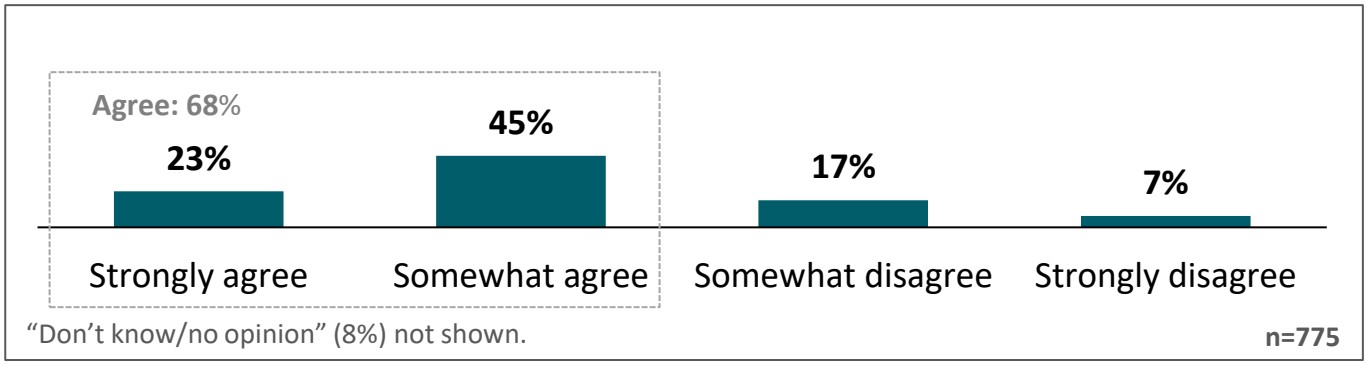
Q The cost of my electricity bill has a major impact on my and requires I do without some other important priorities.



"Don't know/no opinion" (6%) not shown.

n=775

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (8%) not shown.

n=775

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

hydro one

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



Those who complete the survey will be invited to enter a draw to win one (1) of five (5) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

INNOVATIVE RESEARCH GROUP

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by their customers. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plans, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plans.

Next year, Hydro One will present their proposed plans and input provided by customers to the OEB.

SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

First Nations On-Reserve

SURVEY PAGE

Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which delivers electricity to your home, seasonal property, or organization through a network of wires, poles and other equipment.



Hydro One does not generate electricity or set electricity prices.

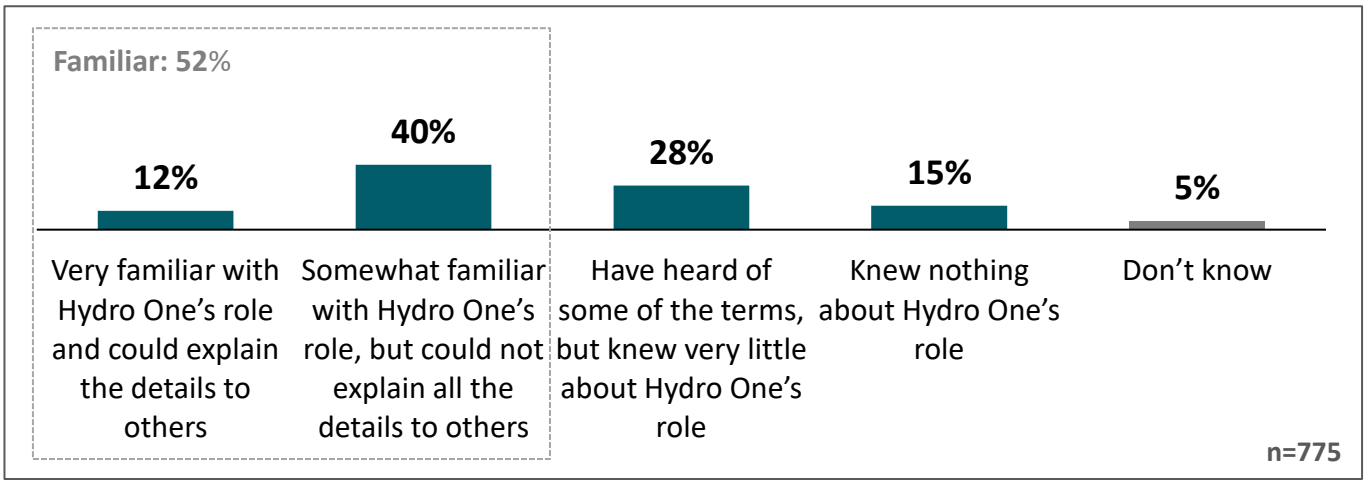
Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Familiarity & Experience

Hydro One's role in Ontario's electricity system

First Nations On-Reserve

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	West	Central	East/Central East	North
Very familiar	14%	9%	11%	13%
Somewhat familiar	42%	38%	45%	40%
Knew very little	25%	27%	30%	28%
Knew nothing	11%	20%	11%	15%
Don't know	8%	6%	4%	5%
Familiar (Very + Somewhat)	**56%**	**47%**	**56%**	**53%**

LEAP/OESP Qualification

Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	13%	9%	15%	12%	11%
Somewhat familiar	38%	43%	49%	40%	41%
Knew very little	28%	32%	22%	27%	29%
Knew nothing	17%	13%	12%	16%	13%
Don't know	4%	4%	3%	5%	5%
Familiar (Very + Somewhat)	**50%**	**51%**	**64%**	**52%**	**52%**

Familiarity & Experience

Hydro One's role in Ontario's electricity system

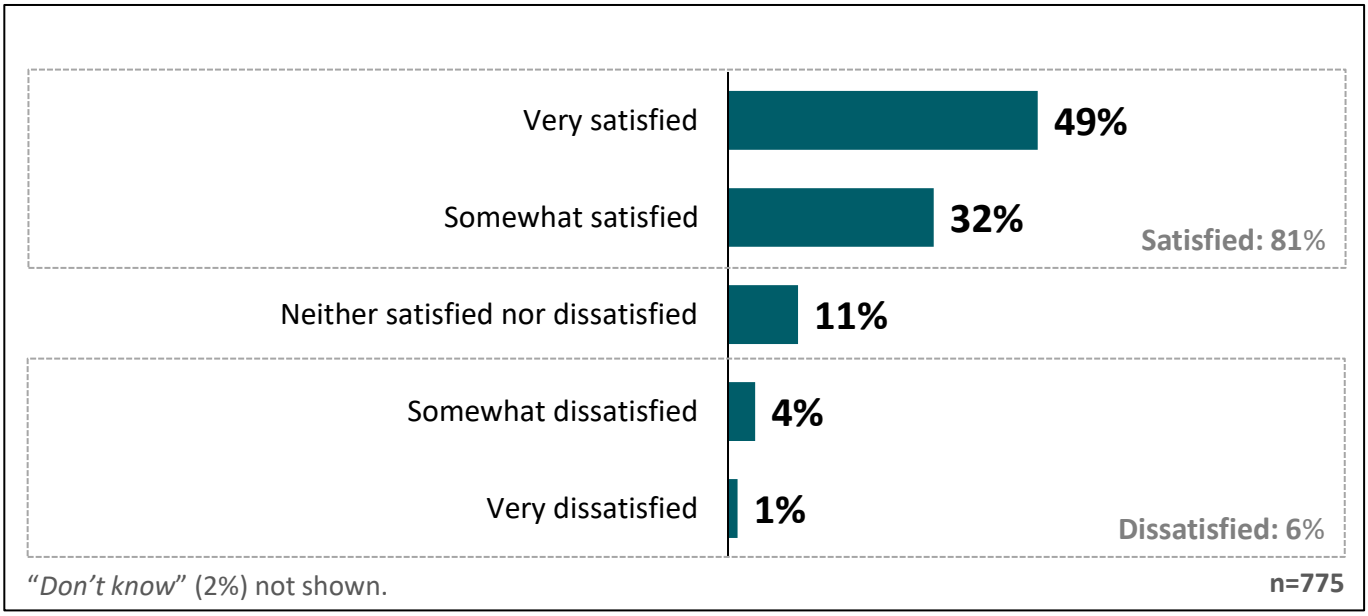
Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Very familiar	12%	11%	11%	10%	15%
Somewhat familiar	40%	45%	34%	40%	43%
Knew very little	28%	26%	32%	26%	25%
Knew nothing	15%	15%	17%	15%	13%
Don't know	5%	4%	5%	8%	4%
Familiar (Very + Somewhat)	**52%**	**56%**	**46%**	**50%**	**58%**

Familiarity & Experience

Overall satisfaction with Hydro One's service

Q Overall, how satisfied or dissatisfied are you with the service you receive from Hydro One?



"*Don't know*" (2%) not shown.

n=775

Region

	West	Central	East/Central East	North
Very satisfied	57%	57%	50%	42%
Somewhat satisfied	30%	27%	29%	37%
Neither	7%	9%	12%	13%
Somewhat dissatisfied	1%	5%	6%	4%
Very dissatisfied	1%	2%	2%	1%
Don't know	4%	<1%	2%	3%
Satisfied (Very + Somewhat)	**87%**	**84%**	**79%**	**79%**
Dissatisfied (Very + Somewhat)	**3%**	**7%**	**8%**	**5%**

Familiarity & Experience

Overall satisfaction with Hydro One's service

First Nations On-Reserve

Q Overall, how satisfied or dissatisfied are you with the service you receive from Hydro One?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very satisfied	49%	52%	48%	39%	47%	52%
Somewhat satisfied	32%	32%	29%	40%	33%	32%
Neither	11%	9%	14%	15%	11%	11%
Somewhat dissatisfied	4%	4%	5%	4%	5%	2%
Very dissatisfied	1%	2%	1%	1%	2%	1%
Don't know	2%	2%	3%	1%	2%	3%
Satisfied (Very + Somewhat)	**81%**	**84%**	**77%**	**79%**	**80%**	**84%**
Dissatisfied (Very + Somewhat)	**6%**	**6%**	**6%**	**5%**	**7%**	**3%**

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Very satisfied	56%	52%	46%	42%
Somewhat satisfied	29%	29%	36%	37%
Neither	10%	10%	12%	11%
Somewhat dissatisfied	3%	5%	2%	7%
Very dissatisfied	1%	2%	1%	1%
Don't know	2%	2%	2%	3%
Satisfied (Very + Somewhat)	**84%**	**81%**	**82%**	**79%**
Dissatisfied (Very + Somewhat)	**4%**	**7%**	**4%**	**8%**

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

First Nations On-Reserve

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, the portion of your bill that goes to Hydro One, covering distribution and transmission delivery services, is offset by the **First Nations Delivery Credit**.

As of July 1, 2025, for a typical On-Reserve First Nations residential customer, the bill credit offsets about 48% of the bill, or $123.20, per month related to the services Hydro One provides, including both distribution and transmission.

The rest of your bill payment goes to power generation companies and regulatory agencies.

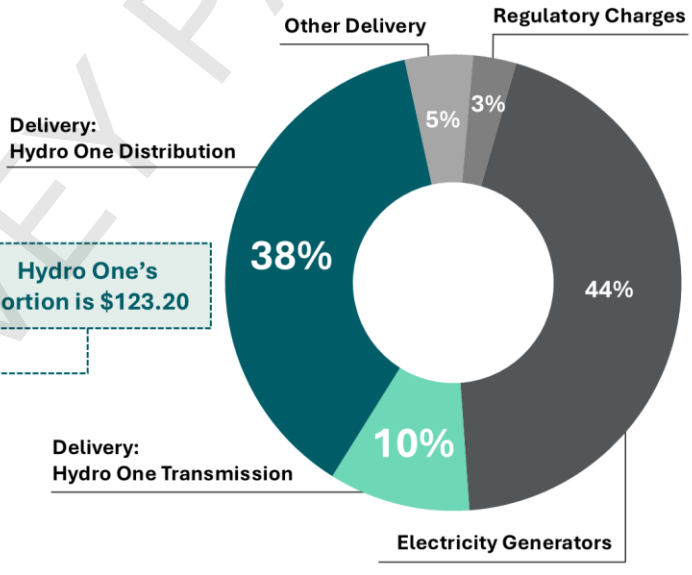
Sample Residential Monthly Bill
(based on consumption of 1,150 kWh as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	34.52
Mid-Peak (mid price) @ 12.2 c/kWh	25.25
Off-Peak (lowest price) @ 8.7 c/kWh	55.06
Delivery	135.78
First Nations Delivery Credit	-135.78
Regulatory Charges	7.87
Total Electricity Charges	$122.71
HST	---
Ontario Electricity Rebate	(-$16.08)
Total Amount	$106.64

Hydro One's portion is $123.20



The pie chart above is based on a total bill of $258.50 excluding the First Nations Delivery Credit, the Ontario Electricity Rebate, and HST. The chart may not total 100% due to rounding.

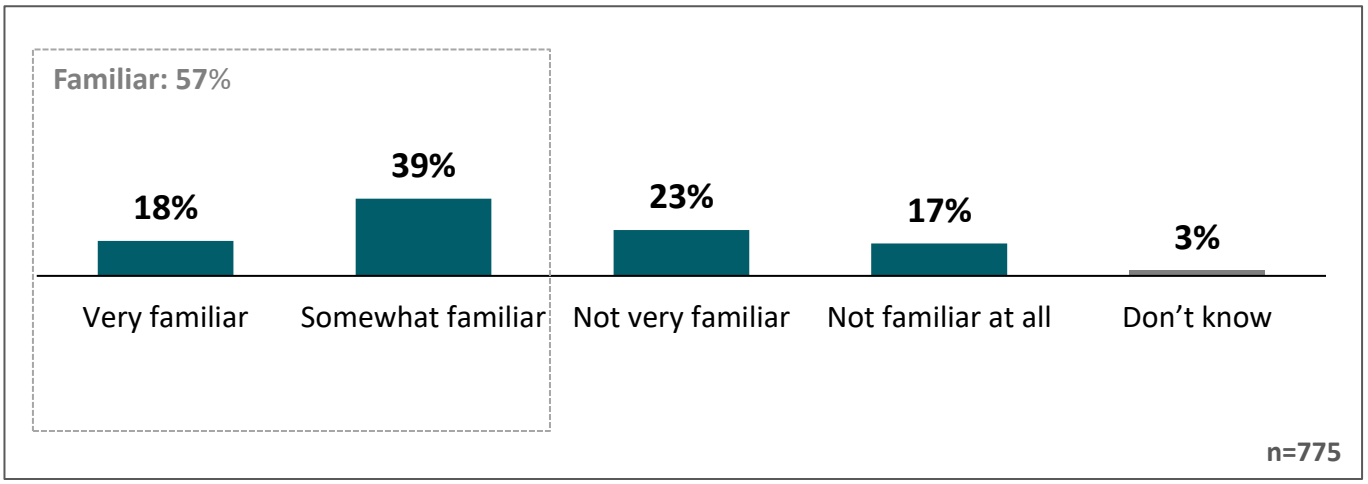
The sample bill above uses an average consumption level of 1,150kWh per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

SURVEY PAGE

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?



Region

	West	Central	East/Central East	North
Very familiar	14%	16%	17%	20%
Somewhat familiar	38%	42%	39%	38%
Not very familiar	24%	22%	29%	22%
Not familiar at all	22%	17%	12%	17%
Don't know	2%	2%	3%	3%
Familiar (Very + Somewhat)	**52%**	**58%**	**56%**	**59%**

LEAP/OESP Qualification / Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	15%	22%	24%	18%	17%
Somewhat familiar	40%	36%	40%	38%	43%
Not very familiar	24%	27%	21%	23%	24%
Not familiar at all	18%	14%	13%	18%	15%
Don't know	3%	1%	1%	3%	2%
Familiar (Very + Somewhat)	**55%**	**57%**	**64%**	**56%**	**59%**

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Very familiar	18%	17%	18%	16%	21%
Somewhat familiar	39%	39%	39%	45%	36%
Not very familiar	23%	23%	24%	21%	25%
Not familiar at all	17%	20%	16%	14%	16%
Don't know	3%	2%	3%	4%	2%
Familiar (Very + Somewhat)	**57%**	**56%**	**57%**	**61%**	**57%**

Summary of Investment Plan

How Hydro One plans

First Nations On-Reserve

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity distribution and transmission services. This feedback was used to inform planners in developing the draft investment plans.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.
3. Make **targeted investments to improve reliability** for customers experiencing significantly poorer reliability than average.
4. Make investments to make the system **more resilient to severe weather**.
5. Make investments in technology to **accommodate customer requests and improve visibility into the system** (e.g., where and how much electricity is being used).

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

First Nations On-Reserve

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations, and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

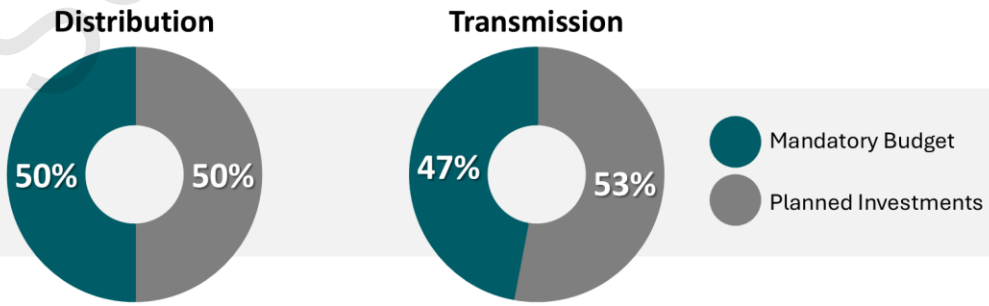
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

First Nations On-Reserve

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

While Hydro One's draft plans cover both the **distribution system** serving approximately 1.5 million customers, as well as the **transmission system** serving most Ontarians, each system has different needs and objectives.

Some of the highlights of Hydro One's draft plans include:

Distribution Objectives



1. Improving the **day-to-day reliability** of the system by addressing equipment that is at a higher risk of failure.
2. Preparing for the **impacts of severe weather** by investing in vulnerable lines, clearing more overgrown vegetation, and using technology to restore power more quickly.
3. Improving reliability for thousands of customers experiencing below average reliability by investing in **new battery storage technology**.
4. Ensuring the grid is prepared to **keep pace with evolving customer needs** and accommodate higher levels of growth.

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest distributor and transmitter of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plan include:

Shared Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

First Nations On-Reserve

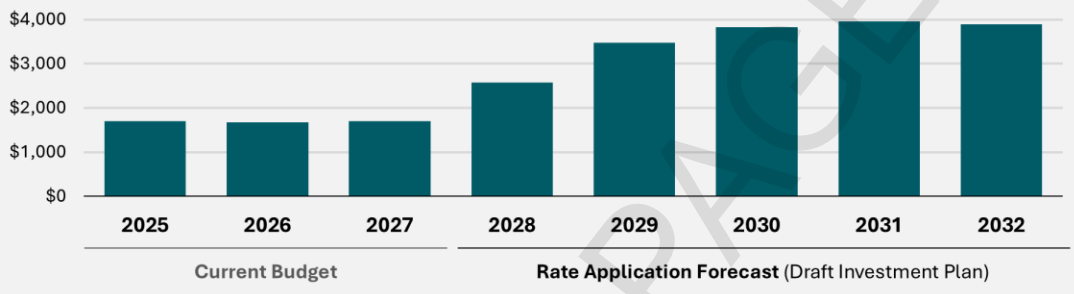
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)



The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

Because the portion of your bill that goes to Hydro One is offset by the **First Nations Delivery Credit, the costs discussed in the remainder of this survey reflect impacts for a typical residential customer living off-reserve.**

For a typical **residential customer living off-reserve** who does not receive distribution rate protection, the **distribution** portion of their **monthly bill** is estimated to increase from $78.58 in 2027 to $128.72 by the end of 2032 – an increase of **$50.14** on the monthly bill. This represents an average increase of **$10.03** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

First Nations On-Reserve

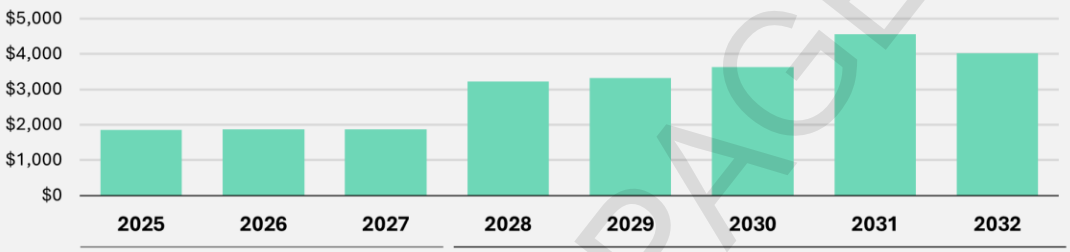
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

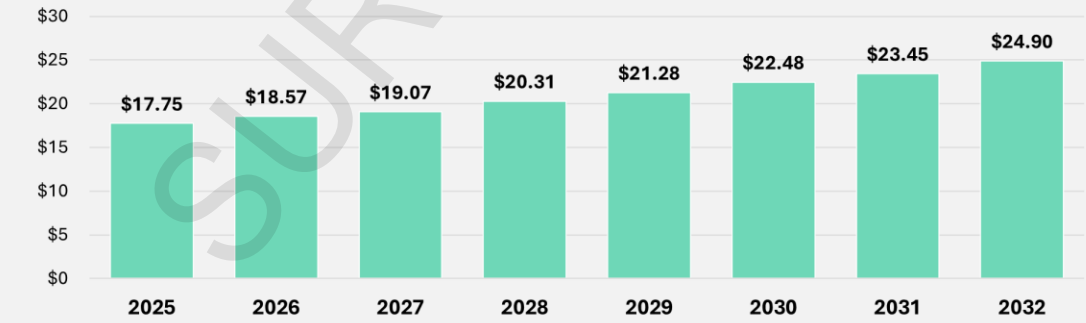


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **residential customer living off-reserve**, the **transmission** portion of their **monthly bill** is estimated to increase from $19.07 in 2027 to $24.90 by the end of 2032 – an increase of **$5.83** on the monthly bill. This represents an average increase of **$1.17** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft investment plans, plus **7 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Because the portion of your bill that goes to Hydro One is offset by the **First Nations Delivery Credit**, the estimated impacts for a **typical residential customer living off-reserve** have been used in this survey to represent the true cost of the choices.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost.



SURVEY PAGE

Summary of Investment Plan

How Hydro One's distribution grid performs

First Nations On-Reserve

Hydro One Customer Engagement Survey

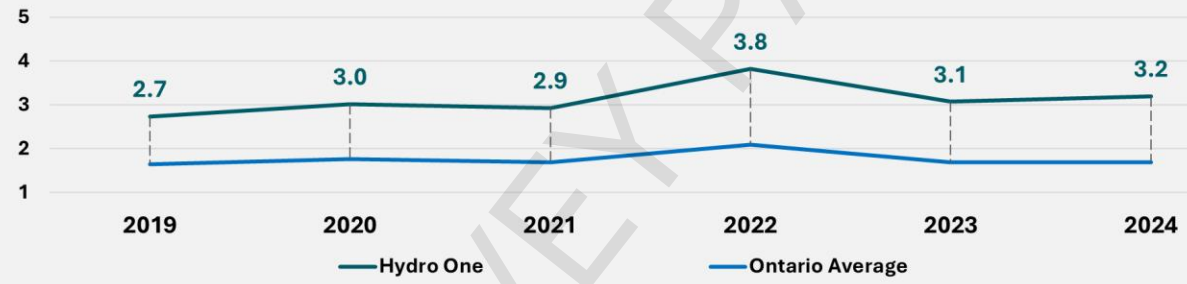
How does Hydro One's distribution grid perform?

Since most Hydro One customers live in rural areas, their distribution system looks different from other Ontario utilities. Serving more sparsely populated communities separated by significant distances means more equipment is needed, outages can take longer to locate, and power can take longer to restore.

On average, between 2019 and 2024, the typical Hydro One customer has experienced 1.4 more outages per year compared to the Ontario average.

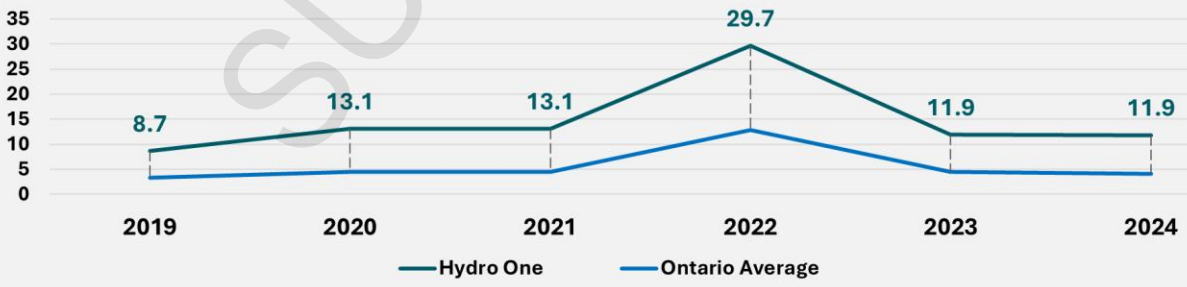


Number of Outages (Average Outages Per Customer)



When it comes to the total time spent without electricity per year, the typical Hydro One customer has been without power for 14.7 hours each year on average, which is 9.1 hours more than the Ontario average.

Duration of Outages (Average Hours Per Customer)



Severe weather, **tree contacts**, and **equipment failure** account for most of these outages. Notably, the distribution system experienced widespread outages due to severe weather in both 2022 and again in April 2025.

SURVEY PR

Investment Trade-Offs

Overall system reliability

First Nations On-Reserve

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

Hydro One typically identifies investments in equipment by taking into consideration the overall age, health, and likelihood of equipment failure.

In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

Hydro One generally tries to replace poor condition equipment before it fails. However, when equipment does fail, it can result in significant interruptions for customers.

In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$2.20 less by 2032 (average of $0.44 less each year)	Included in Draft Plan	$2.18 more by 2032 (average of $0.44 more each year)

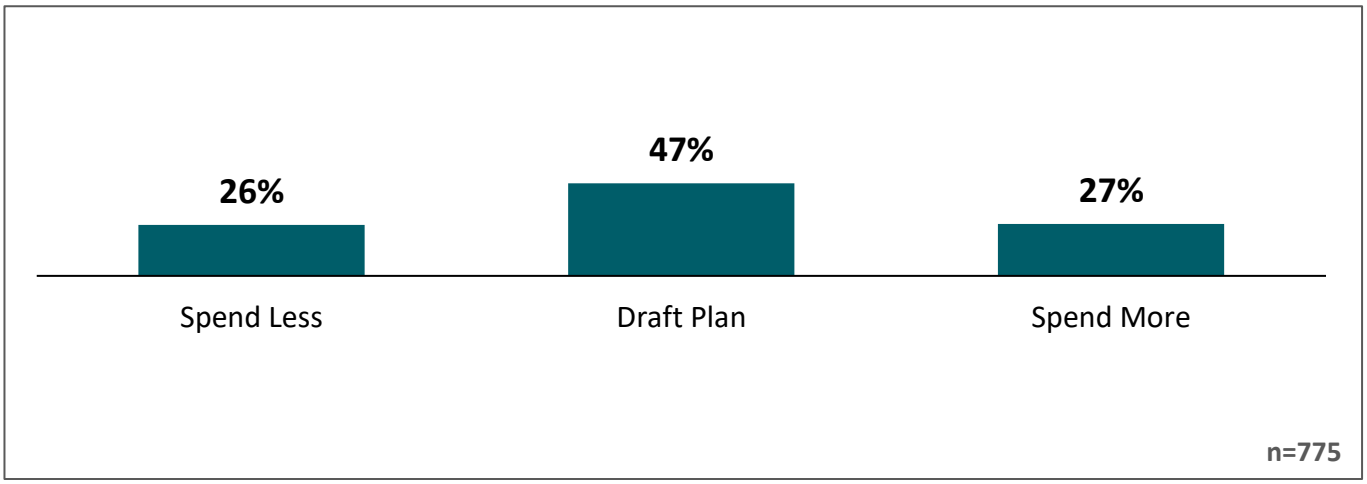
SURVEY PAGE

Investment Trade-Offs

Overall system reliability

First Nations On-Reserve

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	33%	25%	22%	27%
Draft Plan	41%	48%	47%	48%
Spend More	26%	27%	31%	25%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	26%	26%	23%	31%	16%
Draft Plan	49%	44%	45%	45%	51%
Spend More	25%	30%	32%	23%	33%

Investment Trade-Offs

Overall system reliability

First Nations On-Reserve

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	26%	22%	31%	26%	26%
Draft Plan	47%	50%	41%	52%	46%
Spend More	27%	28%	28%	22%	29%

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Investment Trade-Offs

Overall system reliability

First Nations On-Reserve

Q Additional Feedback (Optional)

Responses	%
Invest now to prepare for future/prevent future increases	1.4%
Willing to pay more for improved reliability	1.2%
Improve line maintenance/vegetation management	0.6%
Improve reliability/reduce outages	0.6%
Infrastructure needs to be upgraded	0.6%
Support the draft plan/increase is reasonable	0.6%
Against increases/costs are too expensive	0.4%
Maintain current service levels/prioritize areas of higher need	0.4%
Need more information	0.3%
Bury the lines	0.3%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Concern with severe weather	0.2%
Customers affected should pay/more equal distribution of rates	0.2%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Focus on renewable, nuclear and energy storage solutions	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Concerns around cost of living/inflation	0.1%
Other	0.3%
No comment/None/Don’t know	92.2%

Note: Only responses >0.1% shown

Investment Trade-Offs

Managing the impacts of severe weather

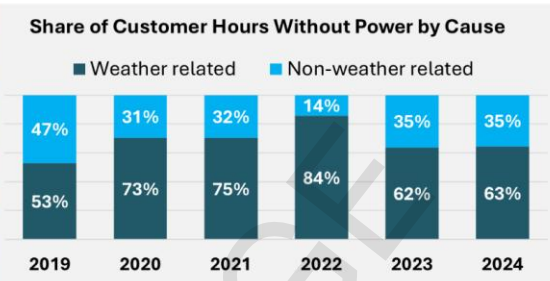
First Nations On-Reserve

Hydro One Customer Engagement Survey

Managing the impacts of severe weather

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.





In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

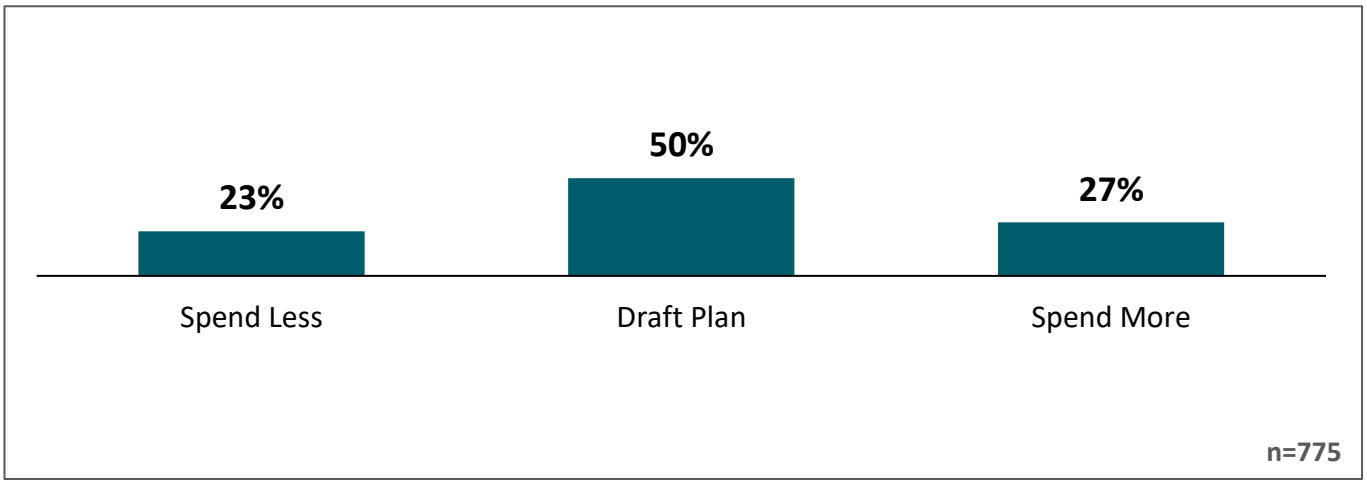
	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$1.44 less by 2032 (average of $0.29 less each year)	Included in Draft Plan	$1.43 more by 2032 (average of $0.29 more each year)

SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	29%	21%	17%	24%
Draft Plan	45%	52%	54%	49%
Spend More	26%	27%	28%	27%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	25%	18%	19%	26%	17%
Draft Plan	49%	56%	49%	51%	47%
Spend More	26%	26%	32%	23%	36%

Investment Trade-Offs

Managing the impacts of severe weather

First Nations On-Reserve

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	Low	Medium-Low	Medium-High	High
Spend Less	23%	20%	26%	25%	19%
Draft Plan	50%	49%	45%	50%	56%
Spend More	27%	30%	29%	24%	25%

Investment Trade-Offs

Managing the impacts of severe weather

First Nations On-Reserve

Q Additional Feedback (Optional)

Responses	%
Improve line maintenance/vegetation management	0.8%
Willing to pay more for improved reliability	0.7%
Invest now to prepare for future/prevent future increases	0.5%
Maintain current service levels/prioritize areas of higher need	0.5%
Improve reliability/reduce outages	0.3%
Need more information	0.3%
Infrastructure needs to be upgraded	0.3%
Focus on renewable, nuclear and energy storage solutions	0.3%
Support the draft plan/increase is reasonable	0.2%
Concern with increased frequency of severe weather	0.2%
Concerns with automated switches/limitations	0.1%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Find efficiencies/alternative funding/customers shouldn't pay	0.1%
No comment/None/Don’t know	95.7%

Note: Only responses >0.1% shown

Investment Trade-Offs

Targeted reliability improvements

Hydro One Customer Engagement Survey

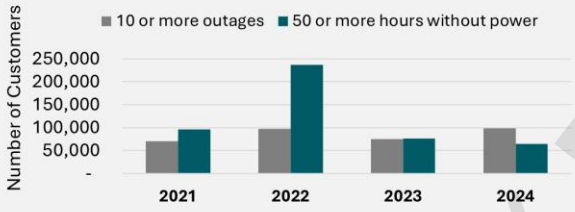
Targeted reliability improvements

Hydro One customers experience different levels of reliability depending on where they live, the design of the system, the condition of the equipment supplying them, and weather patterns.

While some Hydro One customers might not have experienced any outages in the last four years, in any given year more than **70,000 customers were without power more than 10 times**, and more than **60,000 customers were in the dark for 50 hours or more**.

Today, rural and remote communities are more likely to experience poorer reliability, and the increased frequency of severe weather events create and will continue to create further challenges.

Number of Customers Experiencing Significantly Poorer Reliability than Average





Community-scale battery storage facility outside of Thunder Bay

In a 2024 survey, a majority of customers said that they want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.

In their **current draft plan**, Hydro One has developed a program that includes a combination of larger **community-scale** batteries and smaller **individual customer** batteries, which store electricity and provide backup power if an outage does occur.

Batteries are an effective way to target reliability improvements for individual customers and communities that experience the poorest reliability.

At the rate of investment being proposed in the draft plan, Hydro One anticipates reliability improvements for around **10,000** customers. However, based on customer feedback, Hydro One could install more or fewer batteries.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$1.49 less by 2032 (average of $0.30 less each year)	Included in Draft Plan	$1.49 more by 2032 (average of $0.30 more each year)

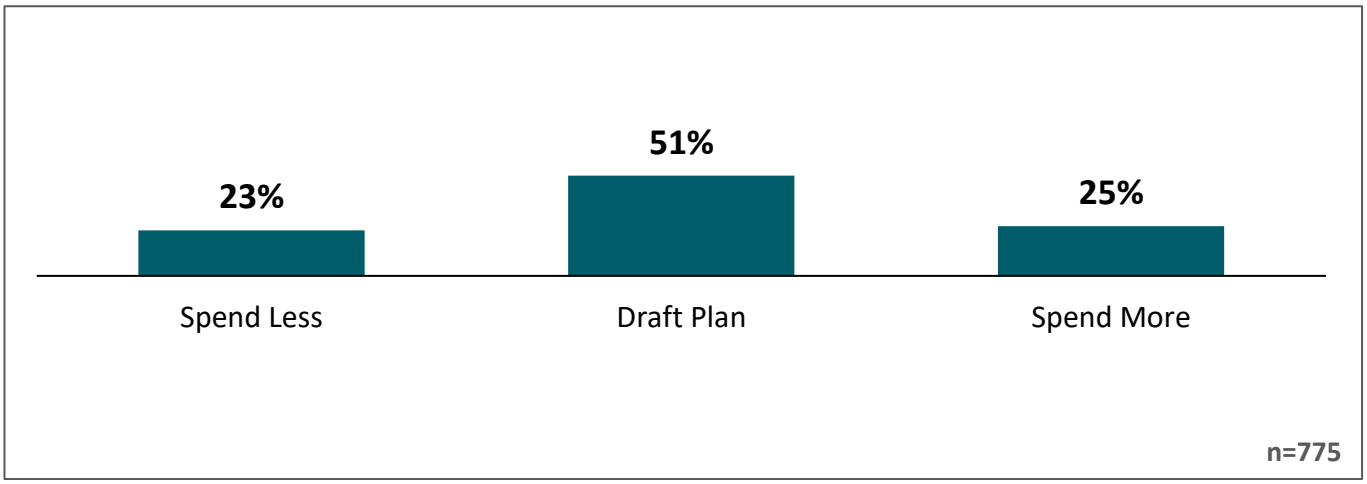
SURVEY ONLY

Investment Trade-Offs

Targeted reliability improvements

First Nations On-Reserve

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	22%	20%	21%	26%
Draft Plan	55%	55%	51%	49%
Spend More	23%	25%	28%	25%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	24%	20%	19%	28%	15%
Draft Plan	51%	54%	49%	50%	54%
Spend More	25%	26%	32%	22%	32%

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Investment Trade-Offs

Targeted reliability improvements

First Nations On-Reserve

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	23%	22%	25%	23%	23%
Draft Plan	51%	51%	49%	55%	50%
Spend More	25%	26%	25%	22%	27%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Targeted reliability improvements

First Nations On-Reserve

Q Additional Feedback (Optional)

Responses	%
Willing to pay more for improved reliability	0.6%
Need more information	0.6%
Support the draft plan/increase is reasonable	0.6%
Improve reliability/reduce outages	0.4%
Focus on home back-up sources/incentive to install	0.3%
Against increases/costs are too expensive	0.2%
Customers affected should pay/more equal distribution of rates	0.1%
Maintain current service levels/prioritize areas of higher need	0.1%
Improve line maintenance/vegetation management	0.1%
Focus on rural customers/communities	0.1%
Concerns around cost of living/inflation	0.1%
Other	0.6%
No comment/None/Don’t know	96.2%

Note: Only responses >0.1% shown

Summary of Investment Plan

Hydro One's transmission system

First Nations On-Reserve

Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

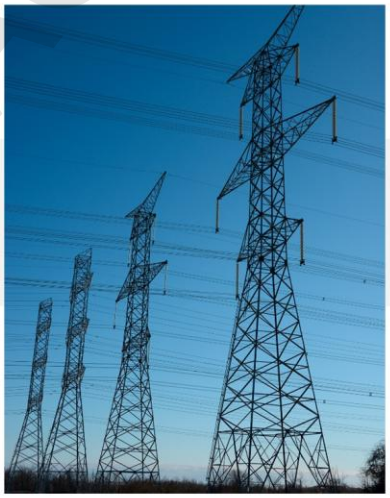
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

First Nations On-Reserve

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$0.59 less by 2032 (average of $0.12 less each year)	**Included in Draft Plan**	$0.59 more by 2032 (average of $0.12 more each year)

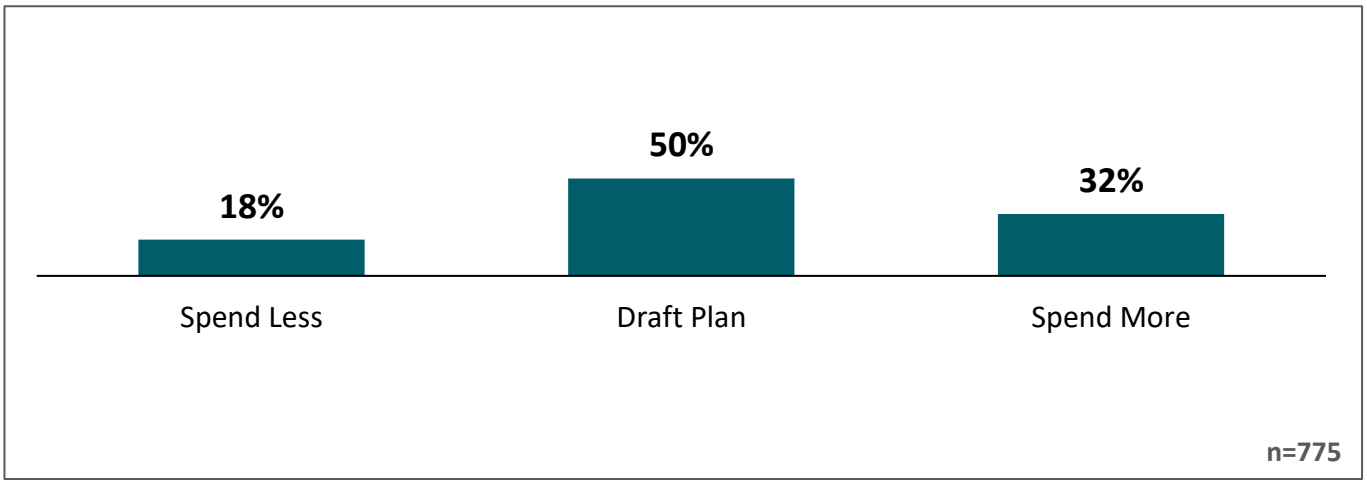
SURVEY PAPER

Investment Trade-Offs

Keeping pace with transmission renewal

First Nations On-Reserve

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	18%	18%	15%	20%
Draft Plan	56%	50%	51%	48%
Spend More	27%	32%	35%	31%

LEAP/OESP Qualification **Bill Impact**

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	21%	17%	10%	22%	12%
Draft Plan	48%	49%	54%	49%	51%
Spend More	31%	34%	36%	29%	37%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Keeping pace with transmission renewal

First Nations On-Reserve

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	Low	Medium-Low	Medium-High	High
Spend Less	18%	19%	20%	18%	16%
Draft Plan	50%	46%	47%	55%	53%
Spend More	32%	35%	33%	27%	31%

Investment Trade-Offs

Keeping pace with transmission renewal

First Nations On-Reserve

Q Additional Feedback (Optional)

Responses	%
Willing to pay more for improved reliability	0.4%
Improve reliability/reduce outages	0.4%
Focus on preventative maintenance	0.3%
Invest now to prepare for future/prevent future increases	0.3%
Financial strain on vulnerable customers (seniors, fixed income)	0.2%
Infrastructure needs to be upgraded	0.2%
Find efficiencies/alternative funding/customers shouldn't pay	0.1%
Concerns around cost of living/inflation	0.1%
Need more information	0.1%
Other	0.4%
No comment/None/Don’t know	97.5%

Note: Only responses >0.1% shown

Hydro One Customer Engagement Survey
Stewardship of the transmission system

hydro one

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$0.48 less by 2032 (average of $0.10 less each year)	**Included in Draft Plan**	$0.48 more by 2032 (average of $0.10 more each year)

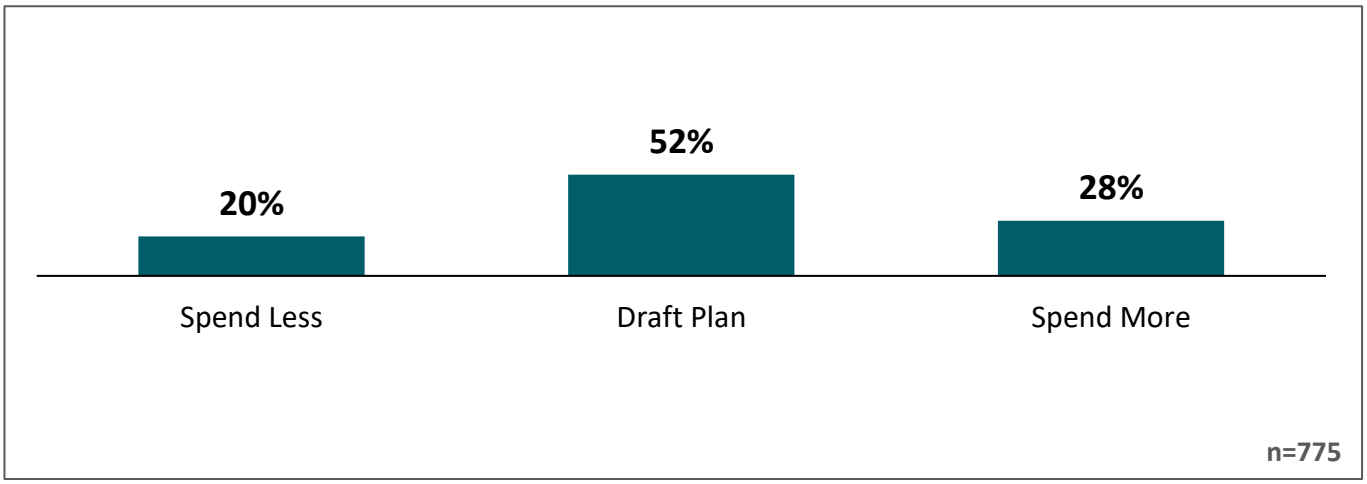
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

First Nations On-Reserve

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	22%	17%	14%	23%
Draft Plan	51%	58%	53%	48%
Spend More	27%	25%	33%	28%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	22%	18%	13%	23%	15%
Draft Plan	52%	51%	52%	53%	50%
Spend More	26%	31%	35%	24%	36%

Investment Trade-Offs

Stewardship of the transmission system

First Nations On-Reserve

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	20%	19%	23%	19%	19%
Draft Plan	52%	51%	49%	54%	53%
Spend More	28%	30%	28%	27%	28%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Stewardship of the transmission system

First Nations On-Reserve

Q Additional Feedback (Optional)

Responses	%
Improve reliability/reduce outages	0.6%
Improve line maintenance/vegetation management	0.5%
Against increases/costs are too expensive	0.4%
Willing to pay more for improved reliability	0.1%
Find efficiencies/alternative funding/customers shouldn't pay	0.1%
Concerns with severe weather	0.1%
Infrastructure needs to be upgraded	0.1%
Concerns around cost of living/inflation	0.1%
Need more information	0.1%
Other	0.1%
No comment/None/Don’t know	97.8%

Note: Only responses >0.1% shown

Investment Trade-Offs
Maintaining buildings and facilities

First Nations On-Reserve

Hydro One Customer Engagement Survey
Maintaining buildings and facilities

hydro one

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$0.34 less by 2032 (average of $0.07 less each year)	Included in Draft Plan	$0.31 more by 2032 (average of $0.06 more each year)
Average Monthly Transmission Bill Impact	$0.02 less by 2032 (average of $0.005 less each year)		$0.07 more by 2032 (average of $0.01 more each year)

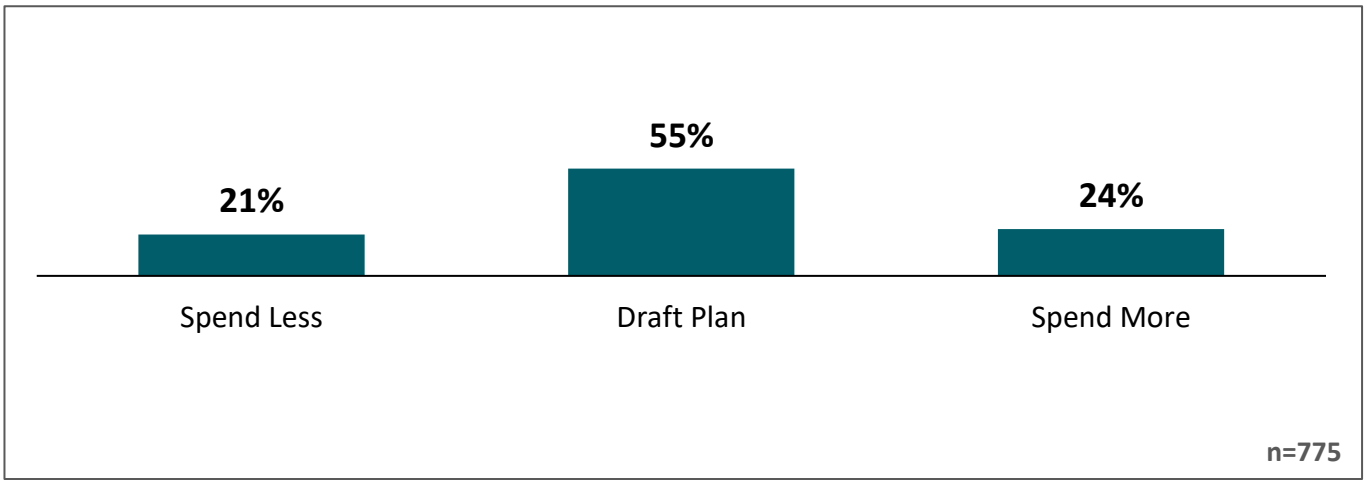
SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

First Nations On-Reserve

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	21%	17%	21%	24%
Draft Plan	59%	58%	54%	52%
Spend More	20%	25%	25%	24%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	21%	24%	18%	24%	17%
Draft Plan	56%	52%	53%	55%	54%
Spend More	23%	24%	30%	21%	29%

Investment Trade-Offs

Maintaining buildings and facilities

Q Which of the following options do you prefer?

		Consumption Quartiles			
	Overall	**Low**	**Medium-Low**	**Medium-High**	**High**
Spend Less	21%	21%	21%	22%	21%
Draft Plan	55%	53%	55%	55%	57%
Spend More	24%	26%	24%	24%	22%

Investment Trade-Offs

Maintaining buildings and facilities

First Nations On-Reserve

Q Additional Feedback (Optional)

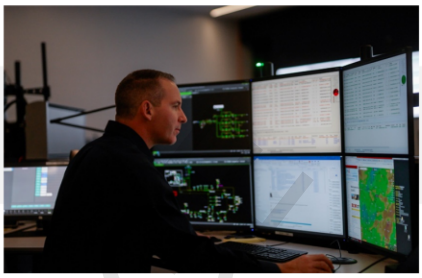
Responses	%
Support the draft plan/increase is reasonable	0.4%
Support meeting modern accessibility standards	0.4%
Find efficiencies/alternative funding/customers shouldn't pay	0.2%
Seems Hydro One didn't plan well in the past	0.1%
Against increases/costs are too expensive	0.1%
Other	0.1%
No comment/None/Don’t know	98.7%

Note: Only responses >0.1% shown

Hydro One Customer Engagement Survey
Information technology

hydro one

Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.



When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

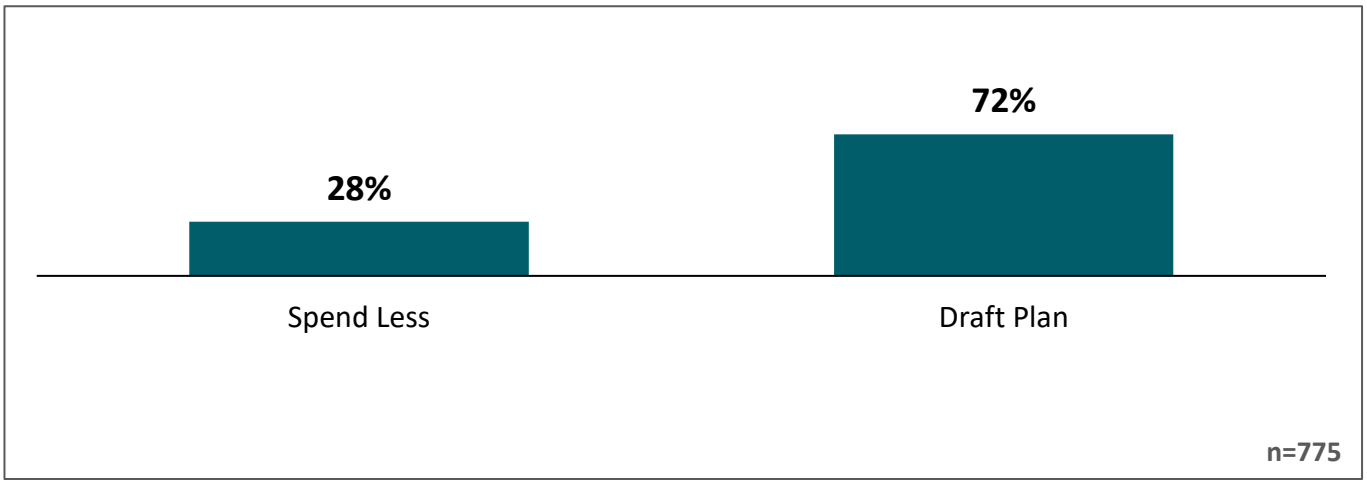
	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$0.45 less by 2032 (average of $0.09 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$0.16 less by 2032 (average of $0.03 less each year)	

SURVEY PAPER

Investment Trade-Offs
Information technology

First Nations On-Reserve

Q Which of the following options do you prefer?



Region

	West	Central	East/Central East	North
Spend Less	28%	27%	25%	28%
Draft Plan	72%	73%	75%	72%

LEAP/OESP Qualification / Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	29%	22%	22%	31%	21%
Draft Plan	71%	78%	78%	69%	79%

Consumption Quartiles

	Low	Medium-Low	Medium-High	High
Spend Less	29%	28%	26%	28%
Draft Plan	71%	72%	74%	72%

Investment Trade-Offs

Information technology

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	0.6%
Infrastructure needs to be upgraded	0.4%
Concerns with cyber attacks/prioritize cyber security	0.3%
Against increases/costs are too expensive	0.3%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Distrust in the engagement/rate increases are inevitable	0.1%
Satisfied with current customer service levels	0.1%
Need more information	0.1%
No comment/None/Don’t know	97.9%

Note: Only responses >0.1% shown

Investment Trade-Offs

Finalizing Choices

First Nations On-Reserve

SURVEY PAGE

Hydro One Customer Engagement Survey

What is the impact of my choices?

hydro one

Throughout this survey, you have been asked about 7 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers for **a typical residential customer living off-reserve**. You can change your responses if you desire, and the estimated impact will be recalculated.

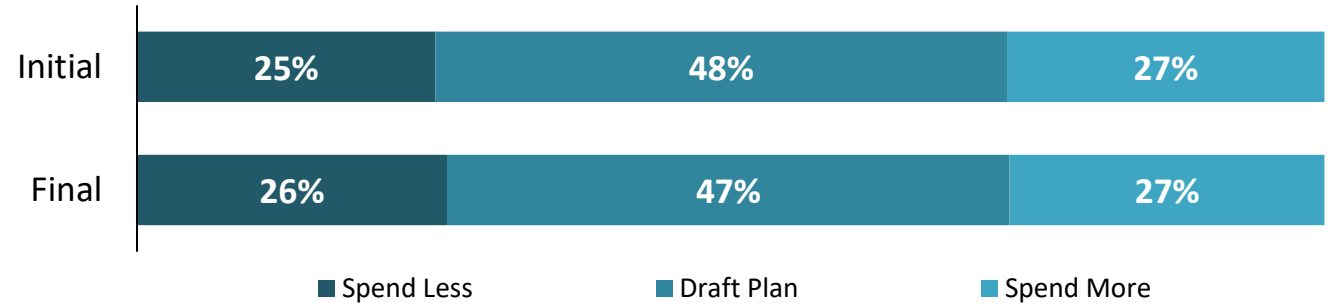
The bill impacts associated with each choice represent the average increase on the monthly bill from 2027 to 2032, followed by the average increase on the monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

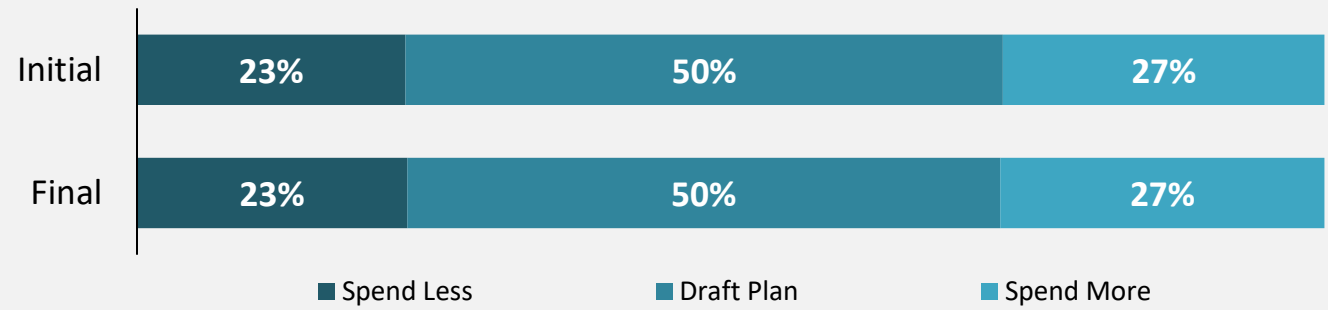
Finalizing Choices

First Nations On-Reserve

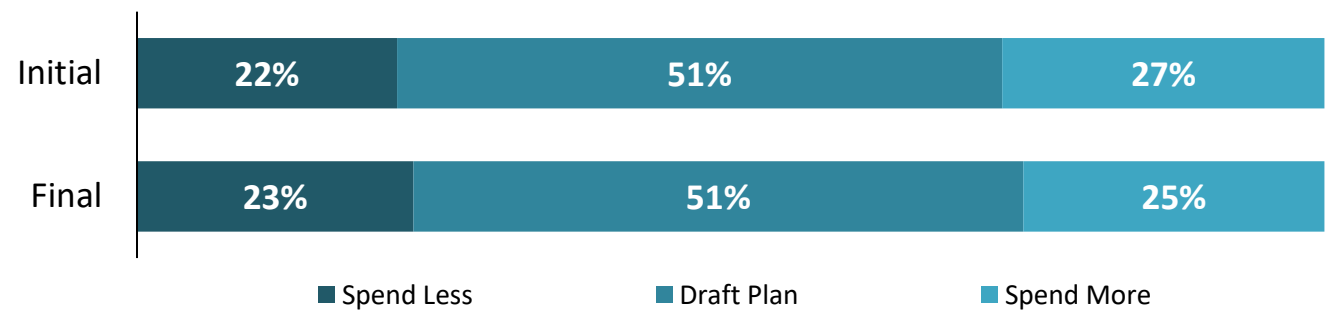
Overall system reliability



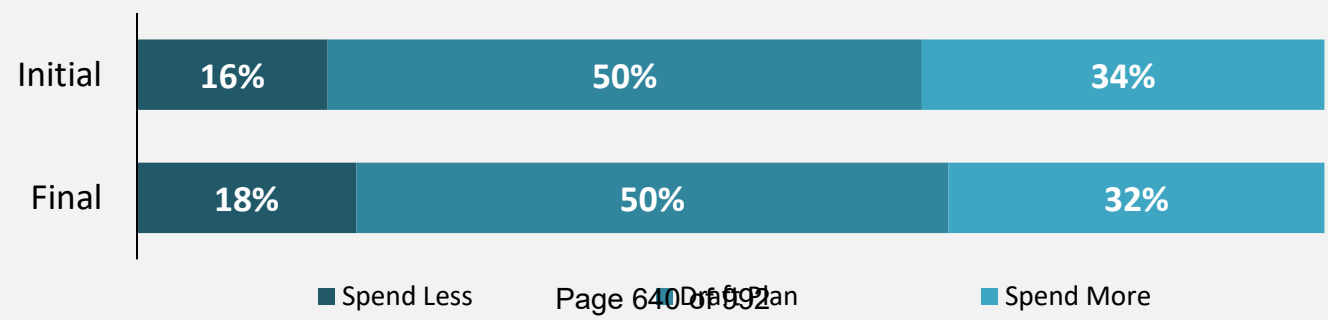
Managing the impacts of severe weather



Targeted reliability improvements



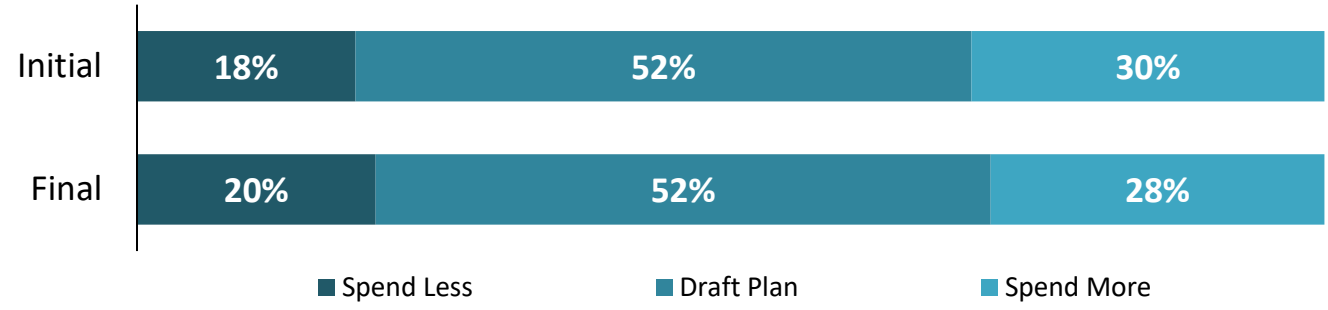
Keeping pace with transmission renewal



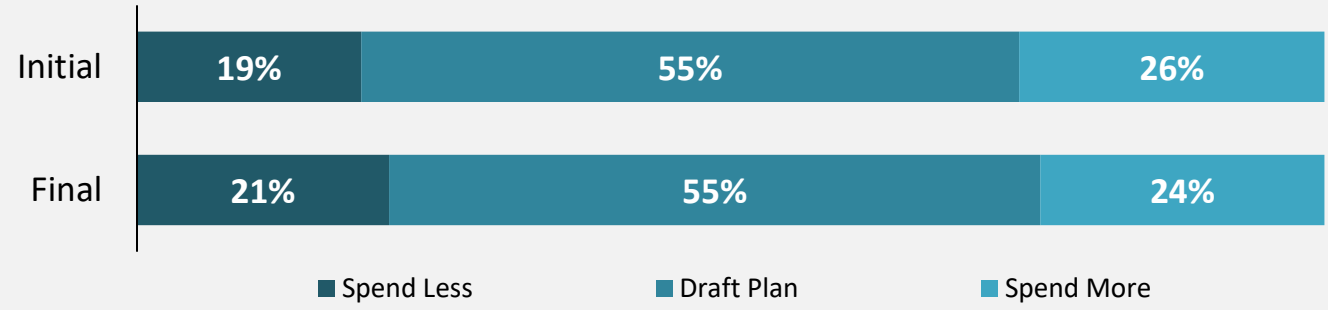
Investment Trade-Offs

Finalizing Choices

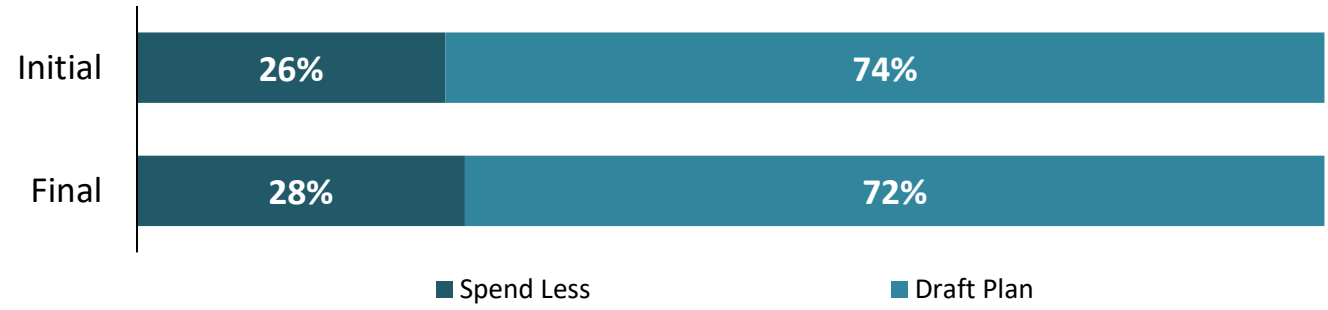
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



Investment Trade-Offs

Overall evaluation of the draft plans

First Nations On-Reserve

SURVEY PAGE

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

hydro one

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **residential customer living off-reserve** who does not receive rate protection would see:

- The **distribution** portion of their **monthly bill** increase from $78.58 in 2027 to $128.72 by the end of 2032 – an increase of **$50.14** on the monthly bill. This represents an average increase of **$10.03** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $19.07 in 2027 to $24.90 by the end of 2032 – an increase of **$5.83** on the monthly bill. This represents an average increase of **$1.17** on the monthly bill each year.

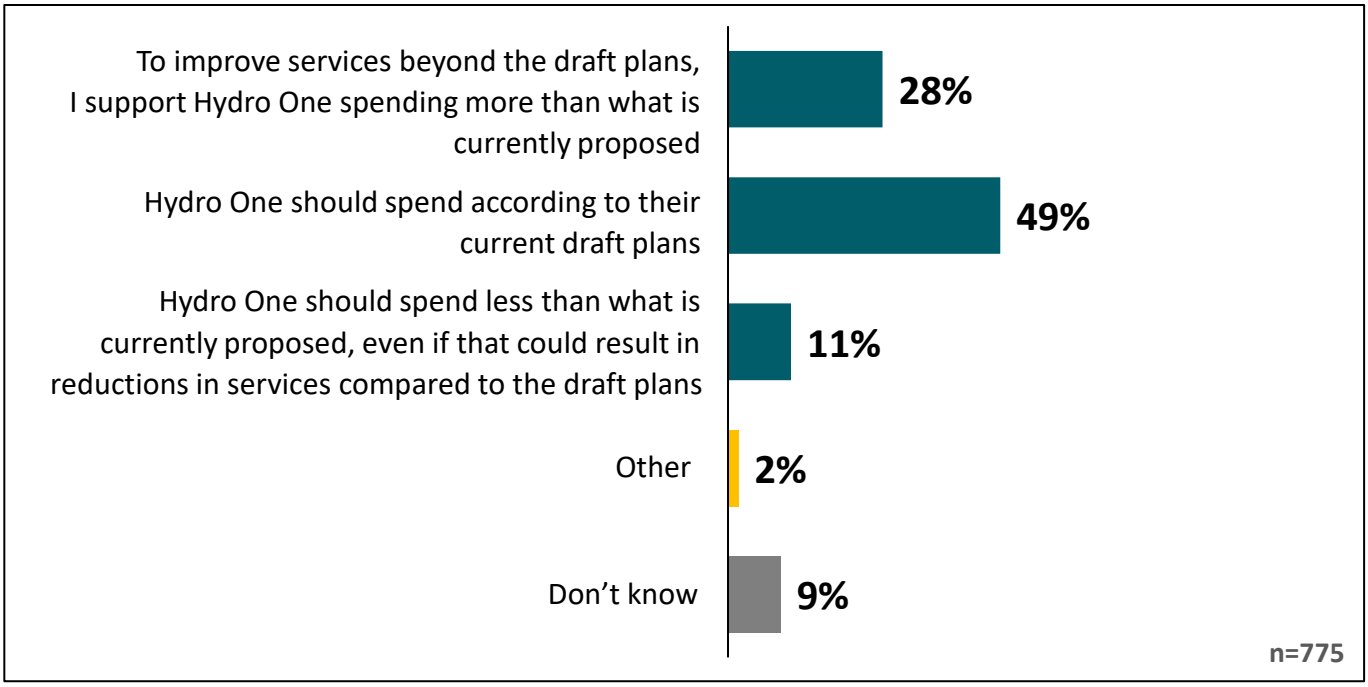
Because the portion of your bill that goes to Hydro One is offset by the **First Nations Delivery Credit**, these costs would not be reflected on your bill but still represent the true cost of the choices for a typical residential customer living off-reserve.

Investment Trade-Offs

Overall evaluation of the draft plans

First Nations On-Reserve

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?



Region

	West	Central	East/Central East	North
Spend More	23%	29%	25%	30%
Draft Plans	51%	48%	53%	48%
Spend Less	11%	11%	12%	12%
Other	3%	3%	2%	1%
Don't know	13%	10%	8%	9%

Investment Trade-Offs

Overall evaluation of the draft plans

First Nations On-Reserve

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	28%	27%	26%	37%	25%	34%
Draft Plans	49%	52%	57%	45%	52%	45%
Spend Less	11%	11%	12%	11%	12%	9%
Other	2%	2%	1%	4%	2%	1%
Don't know	9%	9%	4%	3%	9%	11%

	Consumption Quartiles			
	Low	Medium-Low	Medium-High	High
Spend More	27%	28%	28%	30%
Draft Plans	48%	47%	51%	49%
Spend Less	13%	11%	10%	12%
Other	2%	2%	2%	1%
Don't know	10%	12%	9%	8%

Investment Trade-Offs

Final comments on the draft plans

First Nations On-Reserve

Q Do you have any final comments regarding Hydro One's draft plans for 2028–2032 and the proposed rate increase? (Optional)

Responses	%
Support the increase/investments are necessary	1.3%
Lower rates/rates are too high	0.8%
Improve reliability/reduce outages	0.8%
Positive comment about Hydro One/service	0.8%
Environmental concerns/green initiatives	0.7%
Transparency on internal operations	0.5%
Invest now to prepare for future/prevent future increases	0.5%
Fair cost allocation/user-pays for system impacts/upgrades	0.5%
Be transparent/communicate about rate increases/investments	0.4%
Need more information/educate customers	0.4%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Concerns around cost of living/inflation	0.2%
Improve line maintenance/vegetation management	0.2%
Stop selling power to the US/increase price to the US	0.2%
Financial strain on vulnerable customers (seniors, fixed income)	0.2%
Hydro One is profit-driven	0.1%
Rate protection questions/eligibility	0.1%
Other	0.6%
No comment/None/Don't know	91.4%

Note: Only responses >0.1% shown

First Nations On-Reserve Customers

Survey Diagnostics



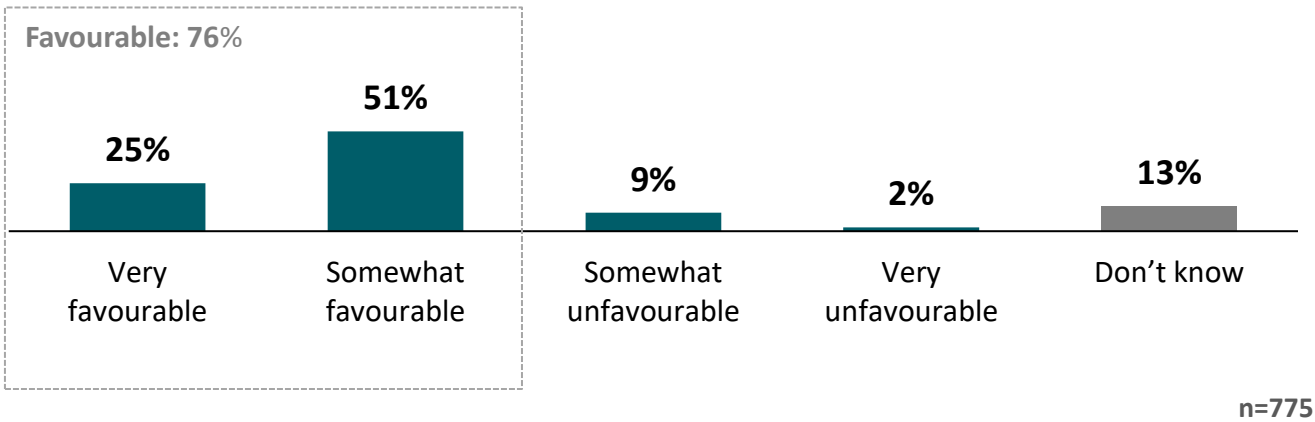
Survey Diagnostics

Favourability and amount of information

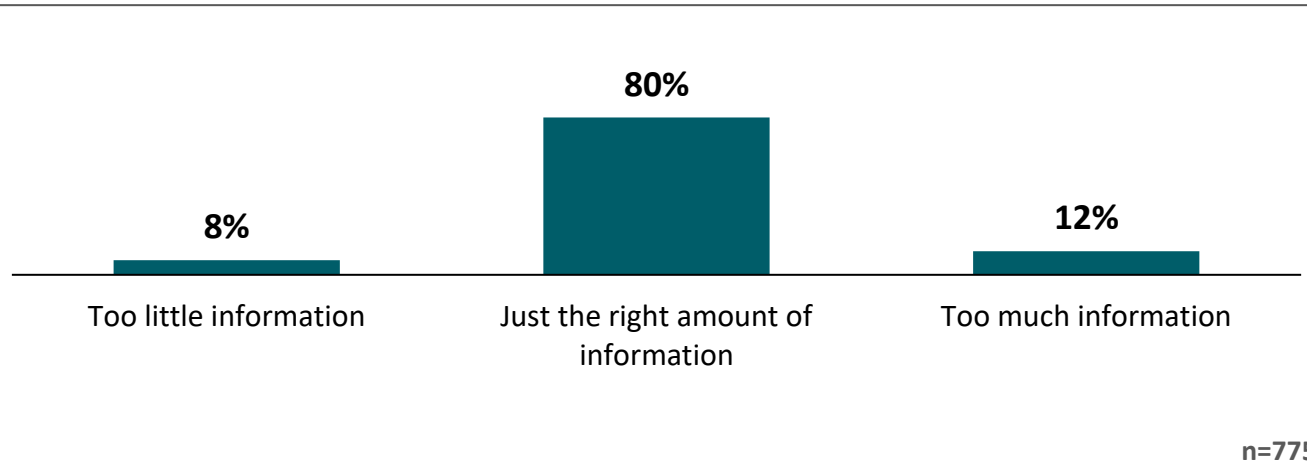
First Nations On-Reserve

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



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Survey Diagnostics
Other information not included

First Nations On-Reserve

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
More detailed information on the investments/infrastructure	1.7%
Transparency on internal operations	1.3%
Survey/engagement experience feedback - negative	0.8%
Reducing customer costs/affordability measures	0.8%
Survey/engagement experience feedback - positive	0.8%
More information/communication about rate increases	0.8%
Customer demographic comparison/region specific information	0.5%
Better outage communication/information	0.5%
Helping seniors/fixed-income individuals	0.5%
Information on energy sold to US/other countries/out of province	0.3%
Distrust in the engagement/rate increases are inevitable	0.2%
Historical data (e.g. spending, impact, cost)	0.2%
Positive comment about Hydro One/service	0.1%
More information on renewable energy	0.1%
How Hydro One's costs compare to other companies/jurisdictions	0.1%
Rate protection questions/eligibility	0.1%
Better explanation/transparency on bills	0.1%
Government involvement/subsidization	0.1%
Impact of EVs/AI/new technology	0.1%
Other	1.5%
No comment/None/Don’t know	89.3%

Note: Only responses >0.1% shown

Survey Diagnostics
Outstanding questions

First Nations On-Reserve

Q Is there anything that you would still like answered? (Optional)

Responses	%
Plans to reduce/lower customer costs	0.9%
Focus on renewable, nuclear & energy storage solutions	0.7%
Transparency on internal operations	0.6%
Different types of customers and their rates	0.5%
More detailed information on the investments/infrastructure	0.4%
Improve reliability/reduce outages	0.4%
Helping seniors/fixed-income individuals	0.3%
Survey/engagement experience feedback – negative	0.3%
Be transparent/communicate about rate increases	0.2%
Positive comment about Hydro One/service	0.2%
Better explanation/transparency on bills	0.2%
Government involvement/subsidies	0.2%
Improve customer service/communication (general/outage)	0.1%
Improve line maintenance/vegetation management	0.1%
Stop selling power to the US/increase price to the US	0.1%
Other	1.4%
No comment/None/Don’t know	93.2%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Survey Results

Section 4



Online Survey
Methodology

Field Dates

The **Small Business (GS<50) Online Survey** was sent to all Hydro One small business customers with an available email address. Customers had an opportunity to complete the survey between **November 14th and December 22nd, 2025**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the small business survey was sent to **50,003** customers from *customerexperience@hydroone.com*. A total of 3 reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Small Business Online Survey Completes

A total of **2,791** (unweighted) Hydro One small business customers completed the online survey.

Sample Weighting

The small business online survey sample was weighted to n=2,790 proportionately by consumption quartile and region in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

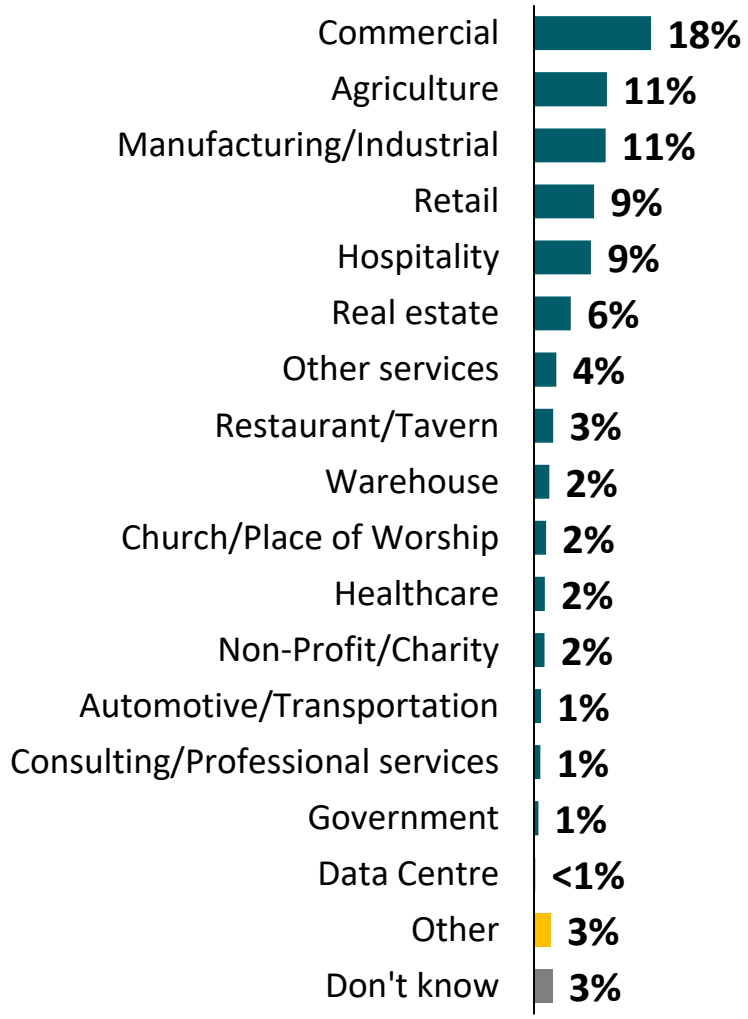
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	156 (150)	137 (136)	151 (142)	146 (145)	603 (585)
Central	176 (163)	161 (166)	173 (166)	137 (166)	664 (675)
Central East	163 (176)	182 (185)	176 (188)	142 (176)	672 (736)
East	113 (98)	108 (102)	81 (94)	84 (92)	395 (394)
North	101 (98)	123 (95)	120 (95)	105 (105)	457 (401)
Total	709 (685)	711 (685)	701 (685)	614 (685)	2,791 (2,790)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographic Breakdown

Small Business

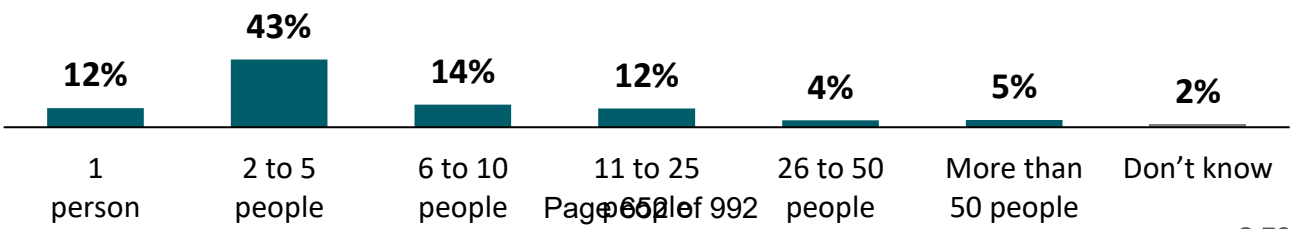
Q Business Sector



"Prefer not to say" (12%) not shown.

n=2,790

Q Business Size



"Prefer not to say" (8%) not shown.

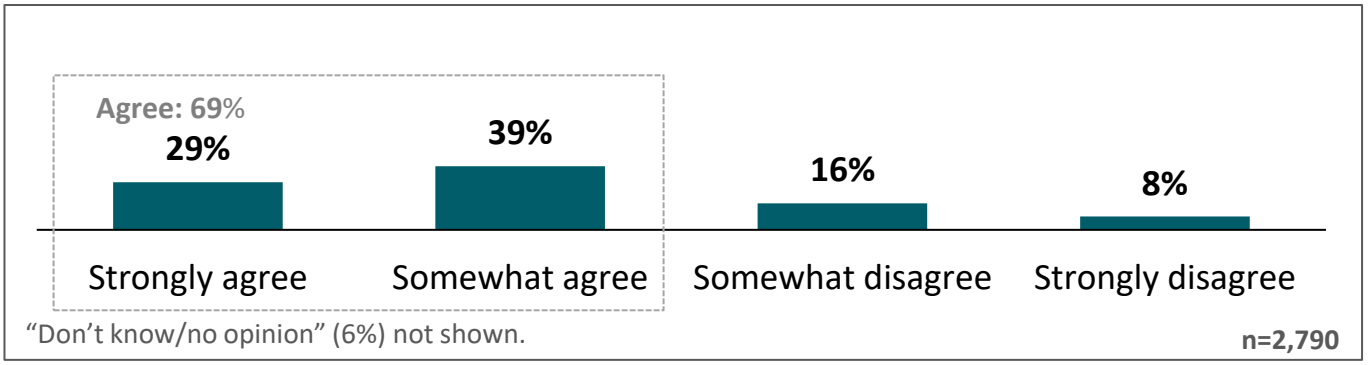
n=2,790

Environmental Controls

Small Business

To what extent do you agree or disagree with the following statements?

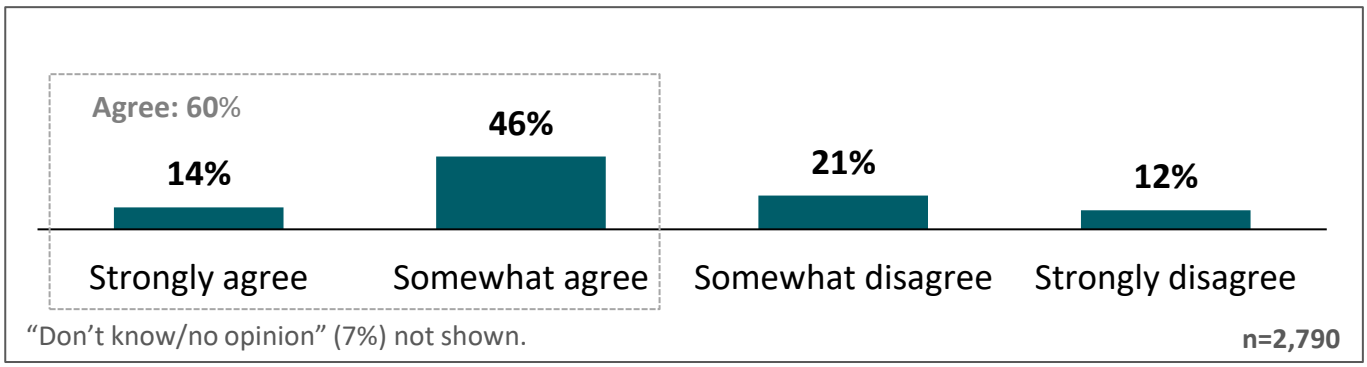
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (6%) not shown.

n=2,790

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (7%) not shown.

n=2,790

INNOVATIVE RESEARCH GROUP

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



Those who complete the survey will be invited to enter a draw to win one (1) of five (5) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by their customers. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plans, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plans.

Next year, Hydro One will present their proposed plans and input provided by customers to the OEB.

SURVEY PREVIEW

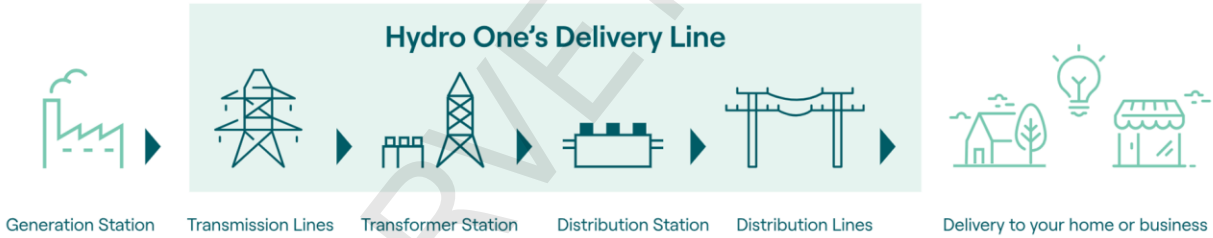
Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which delivers electricity to your home, seasonal property, or organization through a network of wires, poles and other equipment.



Hydro One does not generate electricity or set electricity prices.

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

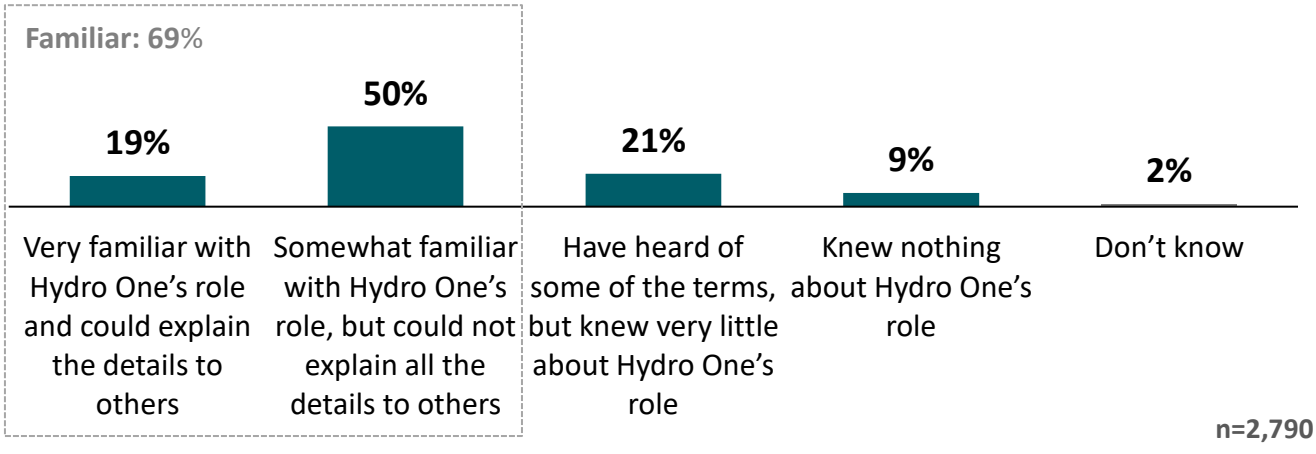
SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Small Business

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	West	Central	Central East	East	North
Very familiar	19%	19%	19%	20%	20%
Somewhat familiar	51%	51%	51%	48%	48%
Knew very little	22%	20%	19%	21%	22%
Knew nothing	7%	8%	9%	10%	9%
Don't know	1%	2%	2%	1%	1%
Familiar (Very + Somewhat)	**70%**	**69%**	**70%**	**69%**	**68%**

Consumption Quartiles / Bill Impact

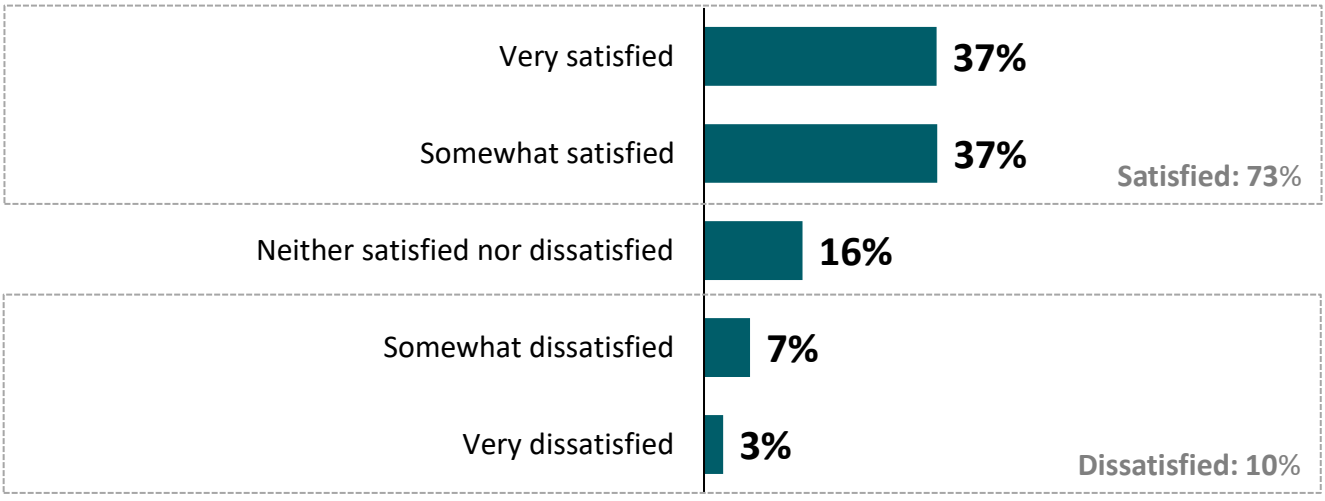
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Very familiar	18%	19%	19%	21%	19%	19%
Somewhat familiar	51%	50%	50%	50%	51%	48%
Knew very little	21%	20%	22%	18%	21%	20%
Knew nothing	7%	9%	8%	9%	8%	10%
Don't know	2%	2%	2%	1%	1%	3%
Familiar (Very + Somewhat)	**69%**	**69%**	**69%**	**71%**	**70%**	**67%**

Familiarity & Experience

Overall satisfaction with Hydro One's service

Small Business

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?



"*Don't know*" (1%) not shown.

n=2,790

Region

	West	Central	Central East	East	North
Very satisfied	35%	36%	36%	45%	33%
Somewhat satisfied	39%	36%	38%	32%	36%
Neither	16%	15%	15%	14%	18%
Somewhat dissatisfied	8%	7%	7%	7%	7%
Very dissatisfied	2%	4%	3%	2%	4%
Don't know	1%	1%	1%	<1%	1%
Satisfied (Very + Somewhat)	**74%**	**72%**	**74%**	**77%**	**70%**
Dissatisfied (Very + Somewhat)	**10%**	**11%**	**10%**	**9%**	**11%**

INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Overall satisfaction with Hydro One's service

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?

		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Very satisfied	37%	39%	42%	35%	31%	35%	41%
Somewhat satisfied	37%	37%	33%	37%	41%	38%	34%
Neither	16%	14%	15%	17%	16%	15%	16%
Somewhat dissatisfied	7%	7%	7%	6%	8%	8%	6%
Very dissatisfied	3%	2%	2%	3%	4%	3%	2%
Don't know	1%	1%	<1%	1%	1%	1%	1%
Satisfied (Very + Somewhat)	**73%**	**75%**	**75%**	**72%**	**71%**	**73%**	**75%**
Dissatisfied (Very + Somewhat)	**10%**	**10%**	**9%**	**10%**	**12%**	**11%**	**8%**

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Small Business

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical small business customer, about 49% of the bill, or $225.62, goes to Hydro One per month. This amount is split into $186.38 for distribution and $39.24 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Sample Small Business Monthly Bill
(based on consumption of 2,000 kWh as of July 1, 2025)

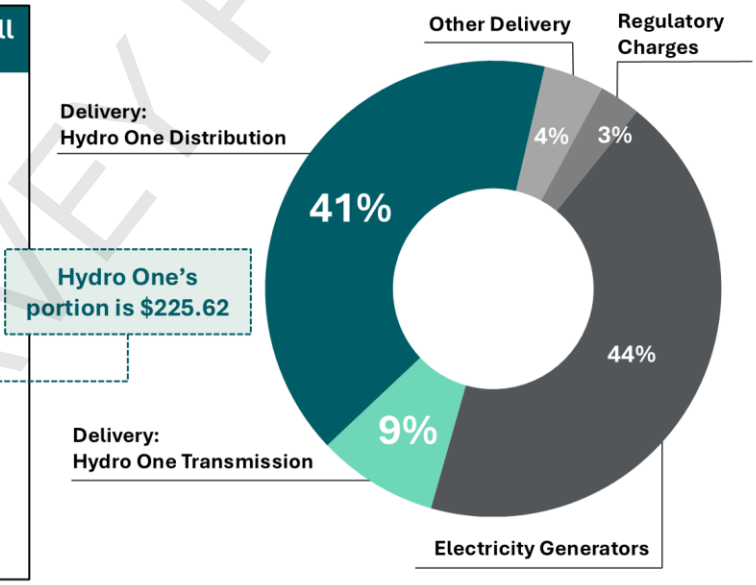
Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges

Electricity	
On-Peak (highest price) @ 18.2 c/kWh	**60.04**
Mid-Peak (mid price) @ 12.2 c/kWh	**43.92**
Off-Peak (lowest price) @ 8.7 c/kWh	**95.76**
Delivery	**245.21**
Regulatory Charges	**13.40**
Total Electricity Charges	**$458.33**
HST	59.58
Ontario Electricity Rebate	**(-$60.04)**
Total Amount	**$457.87**

Hydro One's portion is $225.62



The pie chart above is based on a total bill of $458.33 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 2,000kWh per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

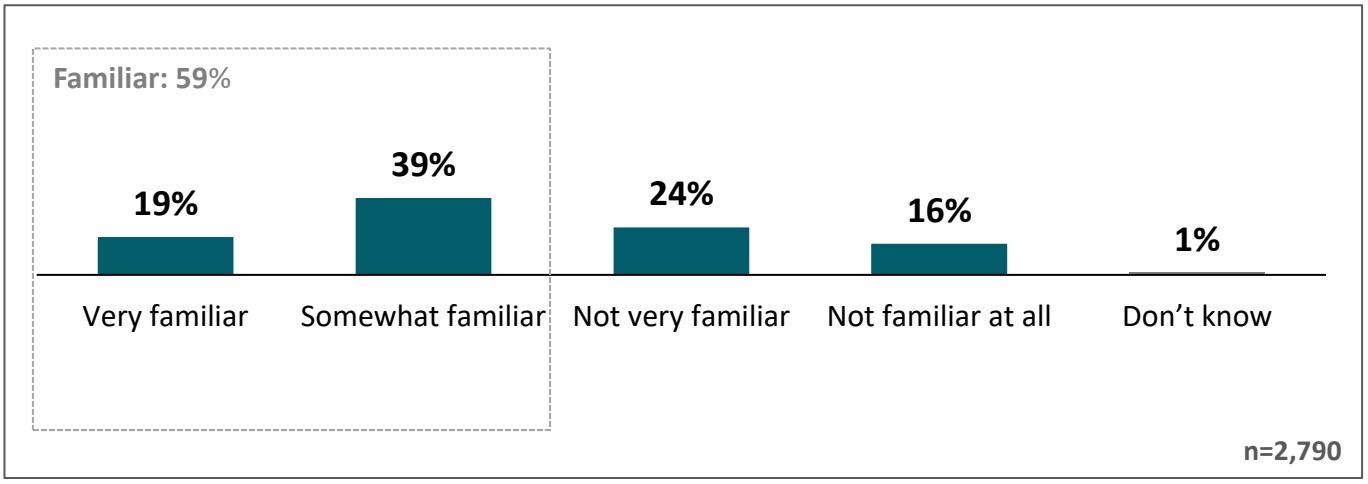
SURVEY PAGE

Familiarity & Experience

Bill familiarity

Small Business

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Hydro One?



Region

	West	Central	Central East	East	North
Very familiar	18%	18%	19%	23%	21%
Somewhat familiar	42%	41%	40%	35%	35%
Not very familiar	25%	25%	24%	23%	24%
Not familiar at all	15%	14%	16%	18%	18%
Don't know	1%	2%	1%	<1%	2%
Familiar (Very + Somewhat)	**60%**	**59%**	**59%**	**58%**	**56%**

Consumption Quartiles / Bill Impact

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Very familiar	17%	19%	18%	24%	22%	14%
Somewhat familiar	39%	41%	39%	37%	40%	38%
Not very familiar	26%	22%	27%	22%	23%	26%
Not familiar at all	17%	17%	15%	16%	14%	20%
Don't know	1%	1%	2%	1%	1%	2%
Familiar (Very + Somewhat)	**56%**	**61%**	**57%**	**61%**	**62%**	**52%**

Summary of Investment Plan

How Hydro One plans

Small Business

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity distribution and transmission services. This feedback was used to inform planners in developing the draft investment plans.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.
3. Make **targeted investments to improve reliability** for customers experiencing significantly poorer reliability than average.
4. Make investments to make the system **more resilient to severe weather**.
5. Make investments in technology to **accommodate customer requests and improve visibility into the system** (e.g., where and how much electricity is being used).

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

Small Business

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations, and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

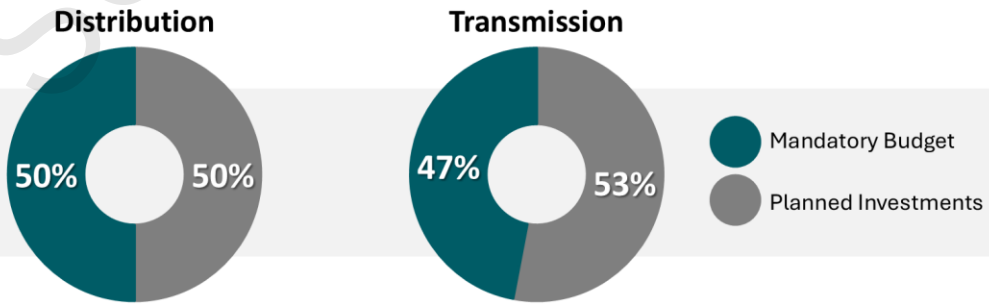
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Small Business

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

While Hydro One's draft plans cover both the **distribution system** serving approximately 1.5 million customers, as well as the **transmission system** serving most Ontarians, each system has different needs and objectives.

Some of the highlights of Hydro One's draft plans include:

Distribution Objectives



1. Improving the **day-to-day reliability** of the system by addressing equipment that is at a higher risk of failure.
2. Preparing for the **impacts of severe weather** by investing in vulnerable lines, clearing more overgrown vegetation, and using technology to restore power more quickly.
3. Improving reliability for thousands of customers experiencing below average reliability by investing in **new battery storage technology**.
4. Ensuring the grid is prepared to **keep pace with evolving customer needs** and accommodate higher levels of growth.

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest distributor and transmitter of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plan include:

Shared Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Small Business

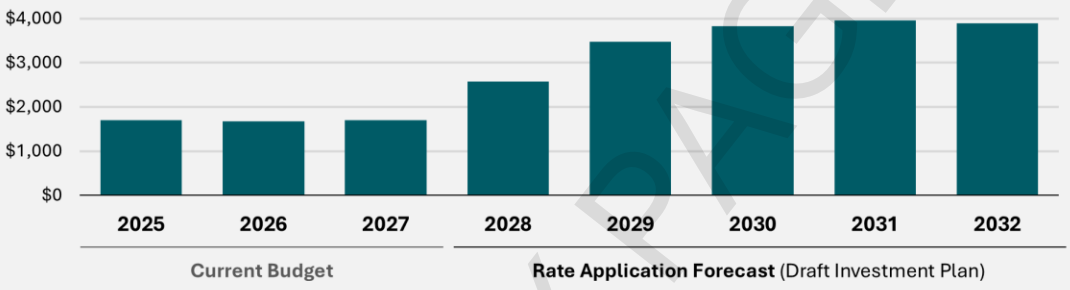
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)

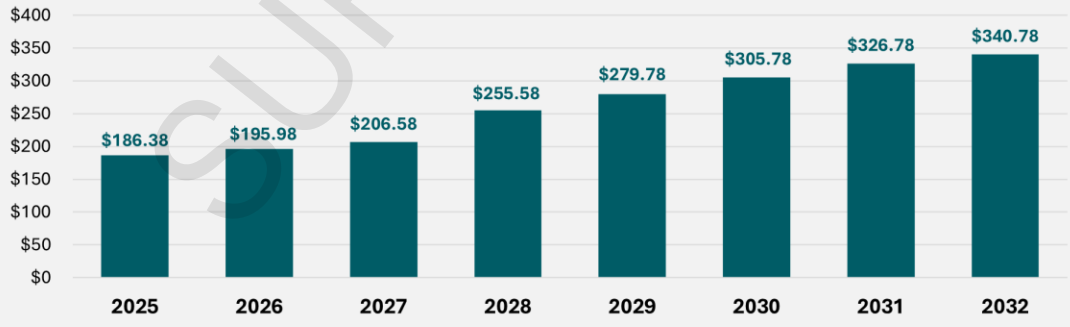


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **small business customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $206.58 in 2027 to $340.78 by the end of 2032 – an increase of **$134.20** on the monthly bill. This represents an average increase of **$26.84** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

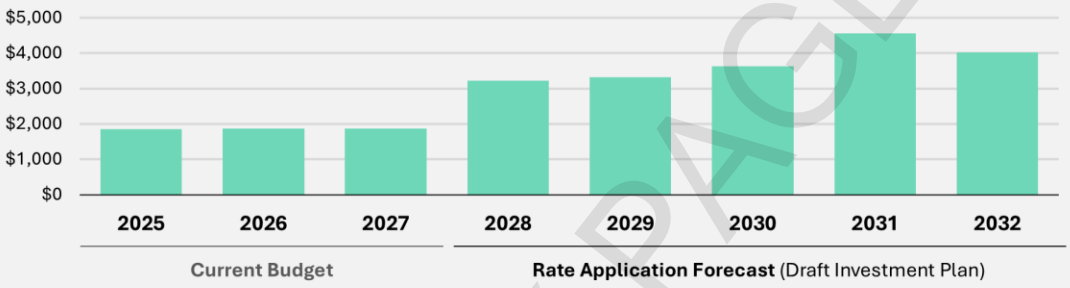
Small Business

Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

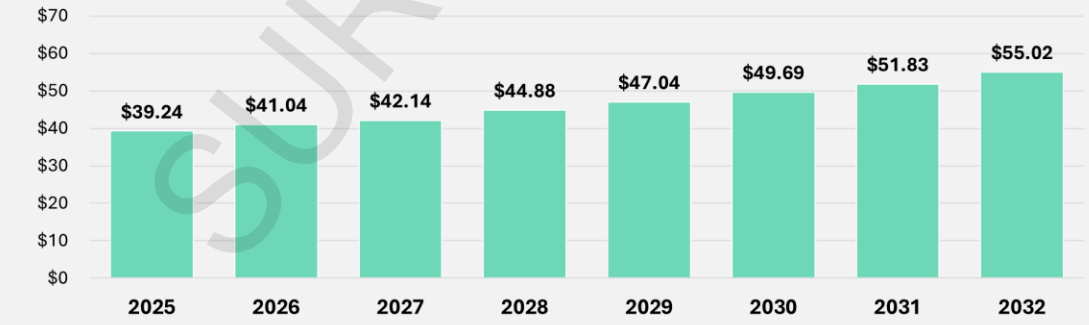


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **small business customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $42.14 in 2027 to $55.02 by the end of 2032 – an increase of **$12.88** on the monthly bill. This represents an average increase of **$2.58** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

How to make choices

Small Business

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft investment plans, plus **7 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost for you.



SURVEY PAGE

Summary of Investment Plan

How Hydro One's distribution grid performs

Small Business

Hydro One Customer Engagement Survey

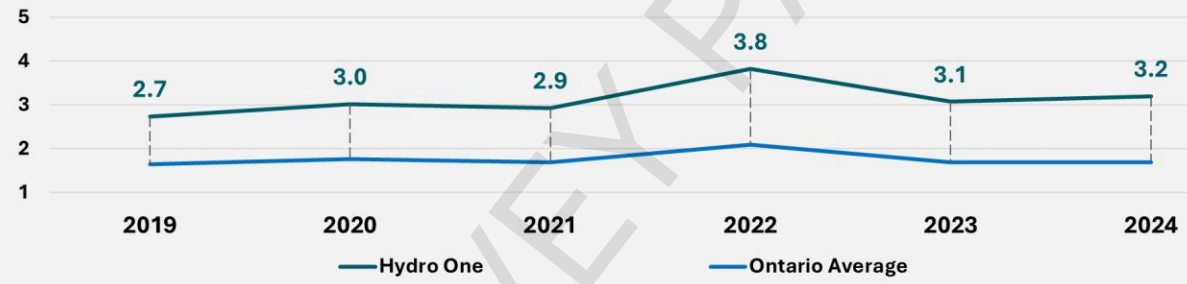
How does Hydro One's distribution grid perform?

Since most Hydro One customers live in rural areas, their distribution system looks different from other Ontario utilities. Serving more sparsely populated communities separated by significant distances means more equipment is needed, outages can take longer to locate, and power can take longer to restore.



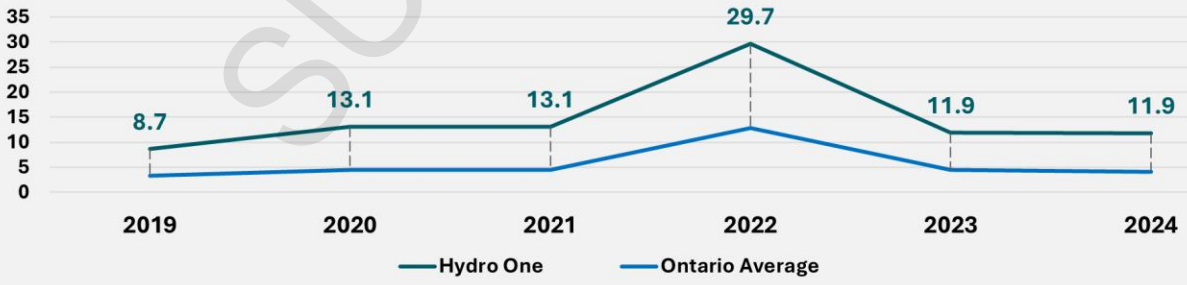
On average, between 2019 and 2024, the typical Hydro One customer has experienced 1.4 more outages per year compared to the Ontario average.

Number of Outages (Average Outages Per Customer)



When it comes to the total time spent without electricity per year, the typical Hydro One customer has been without power for 14.7 hours each year on average, which is 9.1 hours more than the Ontario average.

Duration of Outages (Average Hours Per Customer)



Severe weather, **tree contacts**, and **equipment failure** account for most of these outages. Notably, the distribution system experienced widespread outages due to severe weather in both 2022 and again in April 2025.

SURVEY PR

Investment Trade-Offs

Overall system reliability

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Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

Hydro One typically identifies investments in equipment by taking into consideration the overall age, health, and likelihood of equipment failure.

In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

Hydro One generally tries to replace poor condition equipment before it fails. However, when equipment does fail, it can result in significant interruptions for customers.

In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$5.80 less by 2032 (average of $1.16 less each year)	Included in Draft Plan	$5.80 more by 2032 (average of $1.16 more each year)

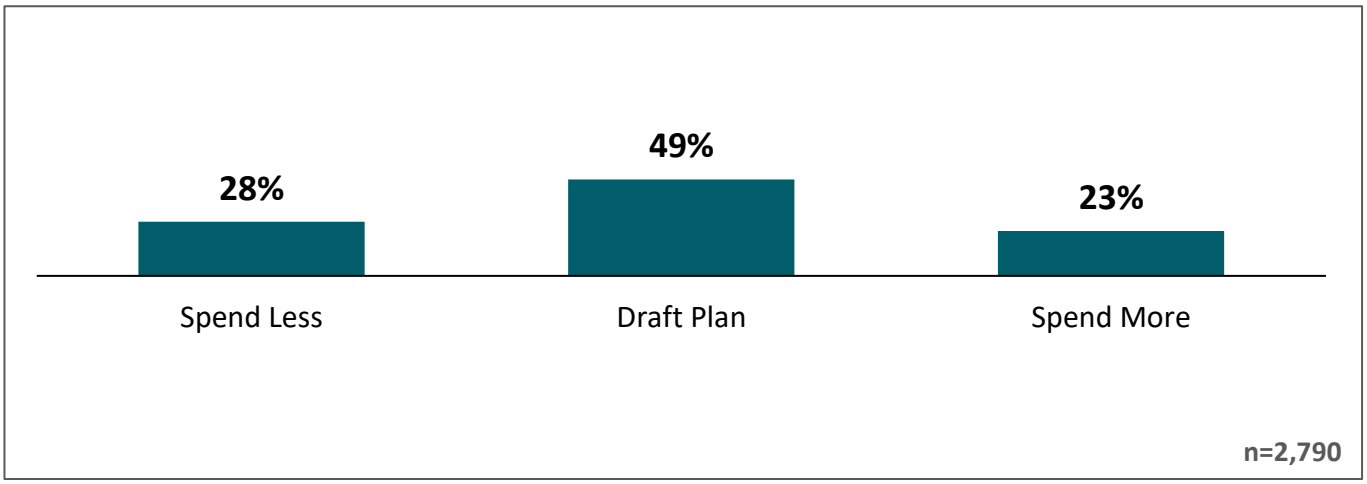
SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Small Business

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	26%	27%	28%	29%	30%
Draft Plan	53%	51%	47%	47%	48%
Spend More	21%	22%	25%	24%	22%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	27%	27%	28%	27%	31%	20%
Draft Plan	48%	49%	50%	50%	50%	49%
Spend More	24%	24%	21%	22%	19%	31%

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Investment Trade-Offs

Overall system reliability

Small Business

Q Additional Feedback (Optional)

Responses	%
Find efficiencies/alternative funding/customers shouldn't pay	1.3%
Against increases/costs are too expensive	1.3%
Improve line maintenance/vegetation management	1.2%
Improve reliability/reduce outages	1.1%
Infrastructure needs to be upgraded	0.7%
Invest now to prepare for future/prevent future increases	0.7%
Maintain current service levels/prioritize areas of higher need	0.7%
Distrust in the engagement/rate increases are inevitable	0.6%
Concerns around cost of living/inflation	0.6%
Willing to pay more for improved reliability	0.5%
Need more information	0.5%
Feel the investment is necessary, but try to minimize costs	0.3%
Support the draft plan/increase is reasonable	0.3%
Concern with severe weather	0.3%
Focus on renewable, nuclear and energy storage solutions	0.2%
Customers affected should pay/more equal distribution of rates	0.1%
Bury the lines	0.1%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Other	0.4%
No comment/None/Don’t know	88.9%

Note: Only responses >0.1% shown

Investment Trade-Offs

Managing the impacts of severe weather

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Hydro One Customer Engagement Survey

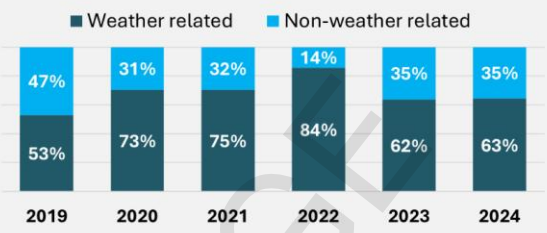
Managing the impacts of severe weather

hydro one

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.



Share of Customer Hours Without Power by Cause



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$3.80 less by 2032 (average of $0.76 less each year)	Included in Draft Plan	$3.80 more by 2032 (average of $0.76 more each year)

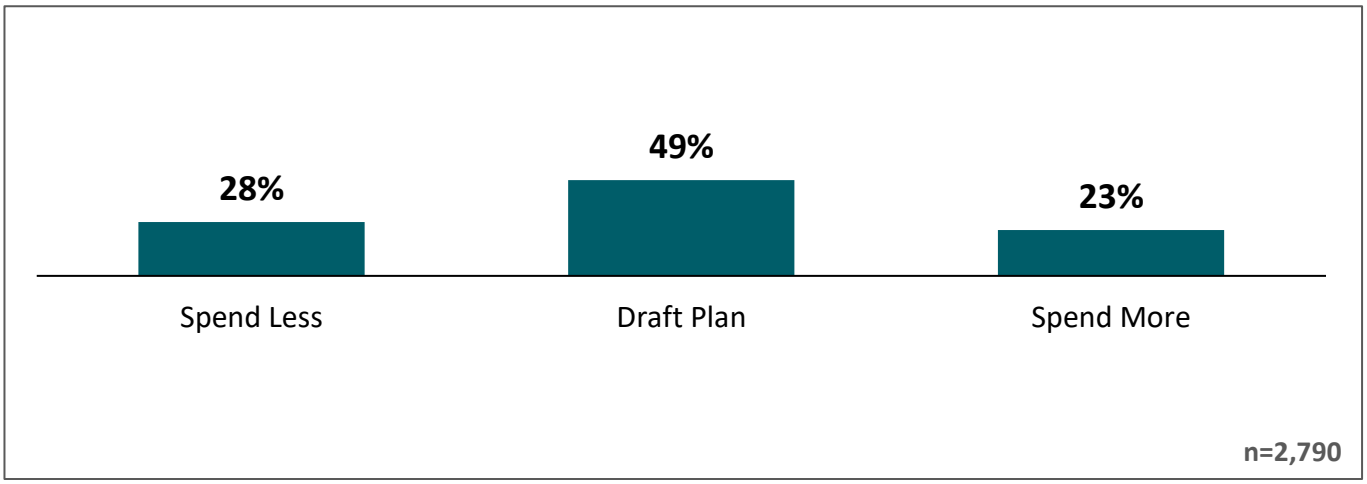
SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

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Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	28%	27%	26%	29%	29%
Draft Plan	52%	50%	48%	46%	48%
Spend More	20%	22%	26%	25%	23%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	27%	27%	29%	28%	31%	20%
Draft Plan	49%	50%	48%	49%	49%	49%
Spend More	24%	23%	23%	23%	20%	31%

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Investment Trade-Offs

Managing the impacts of severe weather

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Q Additional Feedback (Optional)

Responses	%
Improve line maintenance/vegetation management	1.7%
Find efficiencies/alternative funding/customers shouldn't pay	0.8%
Against increases/costs are too expensive	0.8%
Maintain current service levels/prioritize areas of higher need	0.5%
Bury the lines	0.3%
Distrust in the engagement/rate increases are inevitable	0.3%
Support the draft plan/increase is reasonable	0.3%
Infrastructure needs to be upgraded	0.3%
Improve reliability/reduce outages	0.2%
Invest now to prepare for future/prevent future increases	0.2%
Willing to pay more for improved reliability	0.2%
Need more information	0.1%
Customers affected should pay/more equal distribution of rates	0.1%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Concern with increased frequency of severe weather	0.1%
Focus on renewable, nuclear and energy storage solutions	0.1%
Concerns around cost of living/inflation	0.1%
Other	0.4%
No comment/None/Don’t know	93.6%

Note: Only responses >0.1% shown

Investment Trade-Offs

Targeted reliability improvements

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Hydro One Customer Engagement Survey

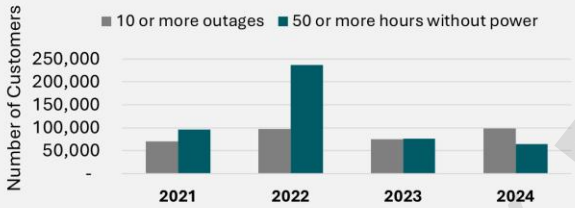
Targeted reliability improvements

Hydro One customers experience different levels of reliability depending on where they live, the design of the system, the condition of the equipment supplying them, and weather patterns.

While some Hydro One customers might not have experienced any outages in the last four years, in any given year more than **70,000 customers were without power more than 10 times**, and more than **60,000 customers were in the dark for 50 hours or more**.

Today, rural and remote communities are more likely to experience poorer reliability, and the increased frequency of severe weather events create and will continue to create further challenges.

Number of Customers Experiencing Significantly Poorer Reliability than Average





Community-scale battery storage facility outside of Thunder Bay

In a 2024 survey, a majority of customers said that they want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.

In their **current draft plan**, Hydro One has developed a program that includes a combination of larger **community-scale** batteries and smaller **individual customer** batteries, which store electricity and provide backup power if an outage does occur.

Batteries are an effective way to target reliability improvements for individual customers and communities that experience the poorest reliability.

At the rate of investment being proposed in the draft plan, Hydro One anticipates reliability improvements for around **10,000** customers. However, based on customer feedback, Hydro One could install more or fewer batteries.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$4.00 less by 2032 (average of $0.80 less each year)	Included in Draft Plan	$4.00 more by 2032 (average of $0.80 more each year)

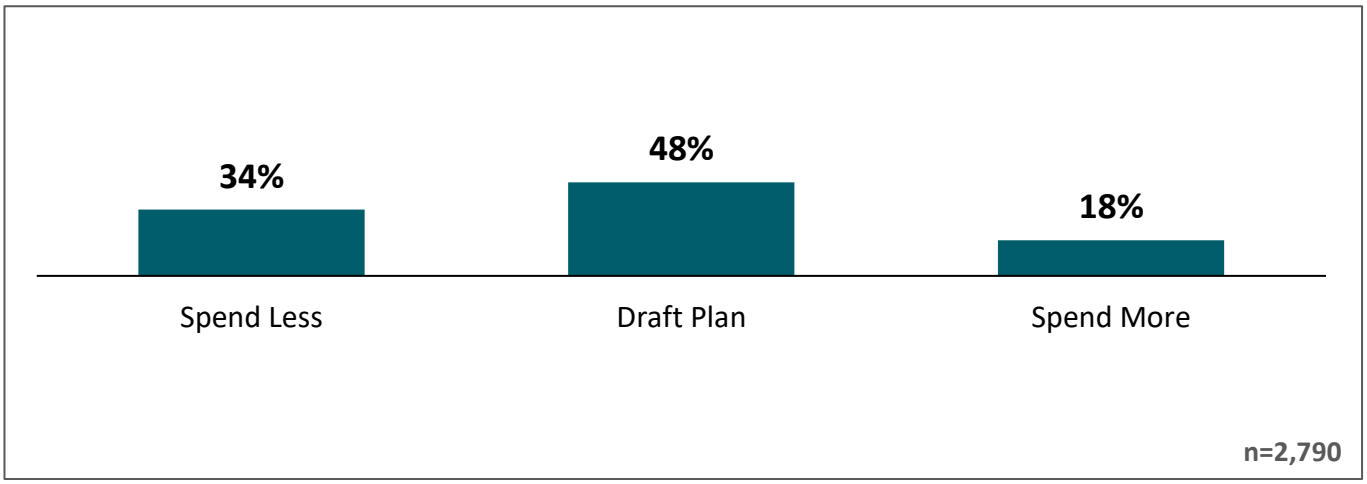
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Investment Trade-Offs

Targeted reliability improvements

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Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	33%	36%	32%	34%	36%
Draft Plan	50%	47%	48%	47%	47%
Spend More	17%	17%	21%	19%	17%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	34%	33%	34%	35%	37%	26%
Draft Plan	49%	47%	48%	47%	47%	50%
Spend More	17%	20%	17%	19%	16%	24%

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Investment Trade-Offs

Targeted reliability improvements

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Q Additional Feedback (Optional)

Responses	%
Need more information	0.9%
Concerns over community-scale battery storage facilities/limitations	0.7%
Against increases/costs are too expensive	0.5%
Find efficiencies/alternative funding/customers shouldn't pay	0.4%
Improve reliability/reduce outages	0.4%
Focus on home back-up sources/incentive to install	0.3%
Focus on renewable, nuclear and energy storage solution	0.3%
Customers affected should pay/more equal distribution of rates	0.3%
Distrust in the engagement/rate increases are inevitable	0.2%
Support the draft plan/increase is reasonable	0.2%
Infrastructure needs to be upgraded	0.2%
Improve line maintenance/vegetation management	0.1%
Willing to pay more for improved reliability	0.1%
Maintain current service levels/prioritize areas of higher need	0.1%
Other	1.2%
No comment/None/Don’t know	93.9%

Note: Only responses >0.1% shown

Summary of Investment Plan

Hydro One's transmission system

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Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

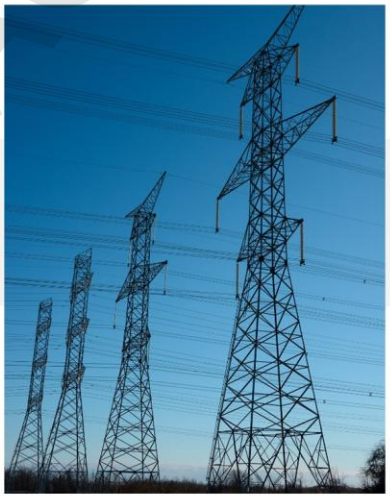
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

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Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$1.31 less by 2032 (average of $0.26 less each year)	**Included in Draft Plan**	$1.31 more by 2032 (average of $0.26 more each year)

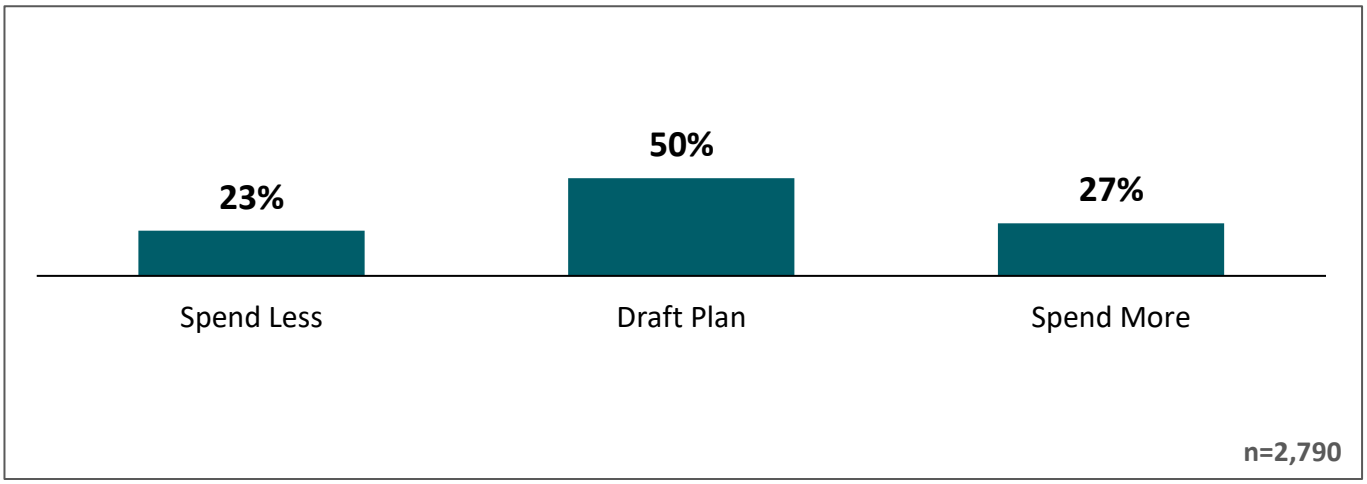
SURVEY PAPER

Investment Trade-Offs

Keeping pace with transmission renewal

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Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	21%	22%	24%	23%	25%
Draft Plan	53%	51%	47%	47%	52%
Spend More	25%	27%	29%	30%	23%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	23%	22%	25%	23%	26%	16%
Draft Plan	50%	50%	49%	50%	50%	49%
Spend More	27%	28%	26%	28%	23%	35%

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Investment Trade-Offs

Keeping pace with transmission renewal

Small Business

Q Additional Feedback (Optional)

Responses	%
Find efficiencies/alternative funding/customers shouldn't pay	0.9%
Against increases/costs are too expensive	0.7%
Infrastructure needs to be upgraded	0.7%
Focus on preventative maintenance	0.4%
Need more information	0.3%
Improve reliability/reduce outages	0.3%
Support the draft plan/increase is reasonable	0.2%
Invest now to prepare for future/prevent future increases	0.2%
Willing to pay more for improved reliability	0.2%
Bury the lines	0.1%
Maintain current service levels/prioritize areas of higher need	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Concerns around cost of living/inflation	0.1%
Focus on renewable, nuclear and energy storage solutions	0.1%
Other	0.6%
No comment/None/Don’t know	95.0%

Note: Only responses >0.1% shown

Hydro One Customer Engagement Survey
Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$1.05 less by 2032 (average of $0.21 less each year)	**Included in Draft Plan**	$1.05 more by 2032 (average of $0.21 more each year)

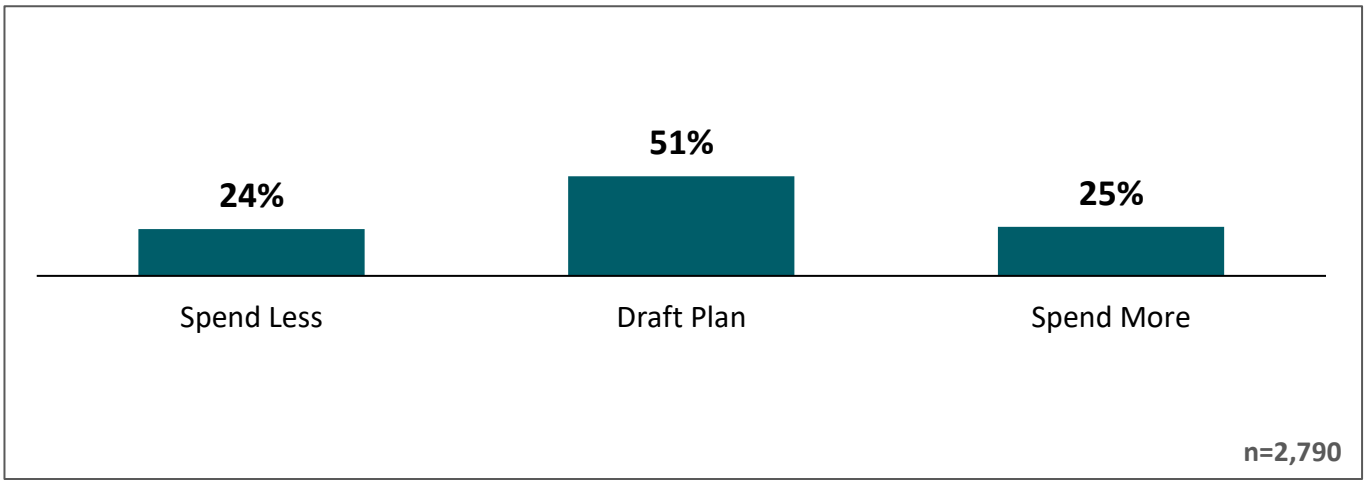
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

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Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	24%	23%	24%	24%	26%
Draft Plan	56%	53%	48%	47%	50%
Spend More	21%	23%	28%	30%	24%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	23%	24%	25%	23%	27%	17%
Draft Plan	51%	49%	53%	50%	51%	51%
Spend More	26%	26%	22%	27%	22%	32%

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Investment Trade-Offs

Stewardship of the transmission system

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Q Additional Feedback (Optional)

Responses	%
Improve line maintenance/vegetation management	0.7%
Find efficiencies/alternative funding/customers shouldn't pay	0.6%
Against increases/costs are too expensive	0.5%
Bury the lines	0.4%
Infrastructure needs to be upgraded	0.3%
Replace wood poles with stronger/more durable materials	0.3%
Improve reliability/reduce outages	0.2%
Distrust in the engagement/rate increases are inevitable	0.2%
Willing to pay more for improved reliability	0.2%
Concerns with satellite technology/limitations	0.1%
Concerns with severe weather	0.1%
Support the draft plan/increase is reasonable	0.1%
Other	0.3%
No comment/None/Don’t know	96.1%

Note: Only responses >0.1% shown

Investment Trade-Offs

Maintaining buildings and facilities

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Hydro One Customer Engagement Survey

Maintaining buildings and facilities

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$1.00 less by 2032 (average of $0.20 less each year)	Included in Draft Plan	$0.80 more by 2032 (average of $0.16 more each year)
Average Monthly Transmission Bill Impact	$0.05 less by 2032 (average of $0.01 less each year)		$0.16 more by 2032 (average of $0.03 more each year)

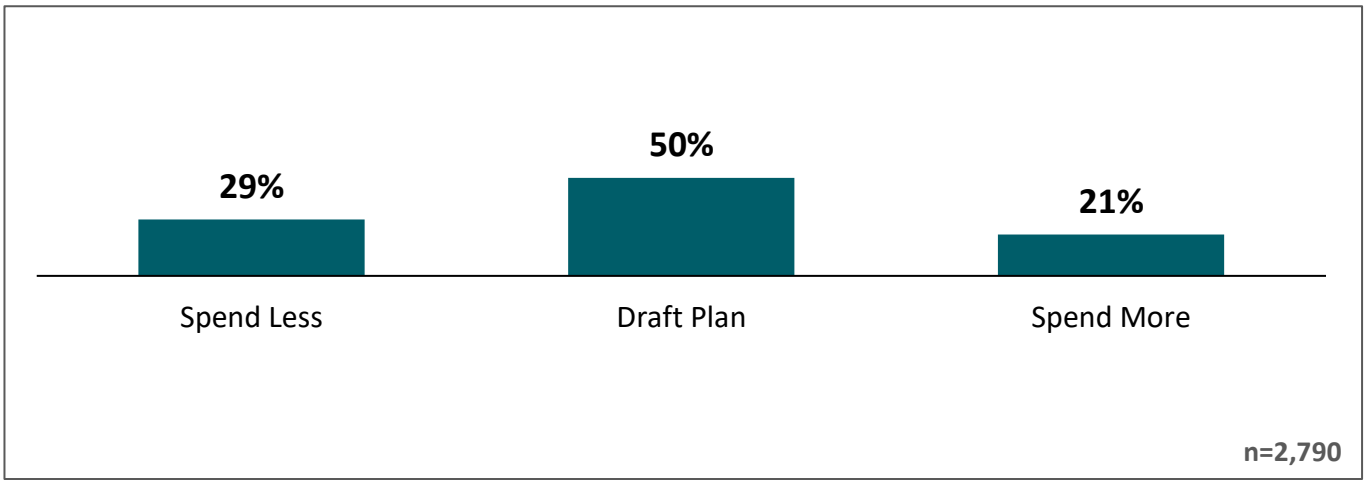
SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Small Business

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	26%	29%	29%	29%	33%
Draft Plan	54%	53%	47%	48%	47%
Spend More	20%	19%	24%	24%	20%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	26%	29%	29%	31%	33%	20%
Draft Plan	51%	50%	52%	48%	49%	51%
Spend More	23%	21%	19%	22%	18%	28%

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Investment Trade-Offs

Maintaining buildings and facilities

Small Business

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	0.9%
Against increases/costs are too expensive	0.5%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Seems Hydro One didn't plan well in the past	0.2%
Infrastructure needs to be upgraded	0.1%
Support meeting modern accessibility standards	0.1%
Improve reliability/reduce outages	0.1%
Other	0.8%
No comment/None/Don’t know	96.8%

Note: Only responses >0.1% shown

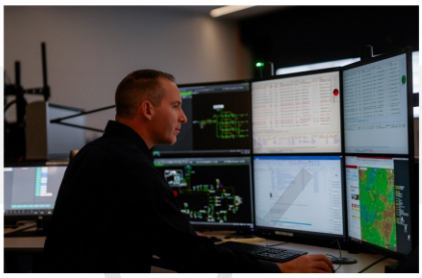
Investment Trade-Offs
Information technology

Small Business

Hydro One Customer Engagement Survey
Information technology

hydro one

Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.



When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$1.20 less by 2032 (average of $0.24 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$0.34 less by 2032 (average of $0.07 less each year)	

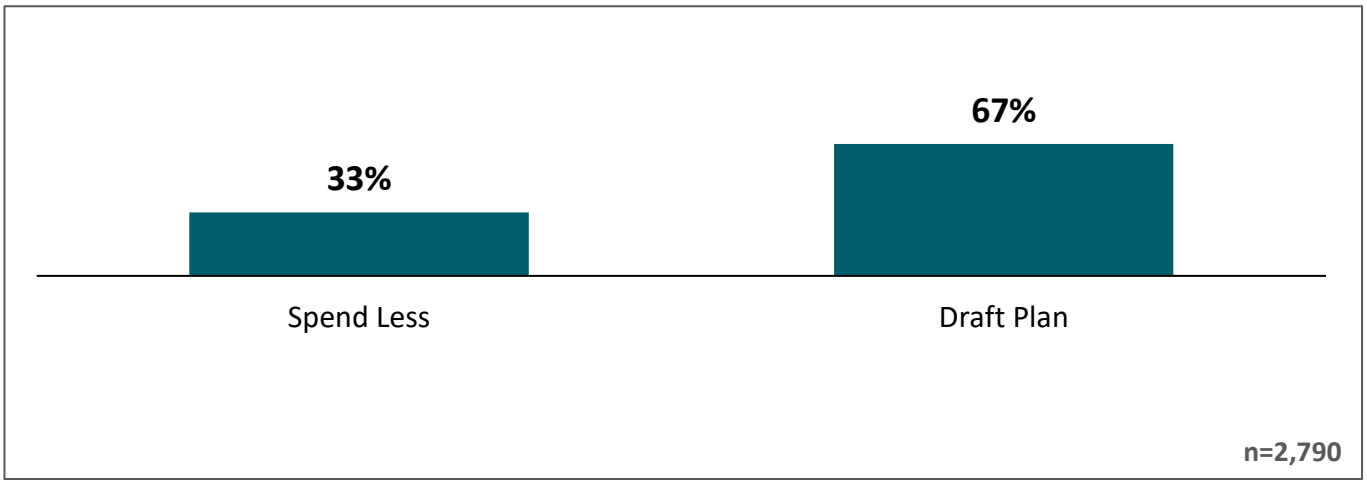
SURVEY PACKET

Investment Trade-Offs

Information technology

Small Business

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	30%	33%	34%	31%	36%
Draft Plan	70%	67%	66%	69%	64%

Consumption Quartiles / Bill Impact

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	30%	31%	35%	33%	36%	25%
Draft Plan	70%	69%	65%	67%	64%	75%

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Investment Trade-Offs

Information technology

Small Business

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	0.7%
Satisfied with current customer service levels	0.5%
Concerns with cyber attacks/prioritize cyber security	0.5%
Against increases/costs are too expensive	0.4%
Find efficiencies/alternative funding/customers shouldn't pay	0.4%
Infrastructure needs to be upgraded	0.3%
Need more information	0.2%
Concerns with AI/limitations	0.1%
IT investments should reduce other administrative and operational costs	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Supportive of AI	0.1%
Other	0.3%
No comment/None/Don’t know	96.5%

Note: Only responses >0.1% shown

Investment Trade-Offs

Finalizing Choices

Small Business

SURVEY PAGE

Hydro One Customer Engagement Survey

What is the impact of my choices?

hydro one

Throughout this survey, you have been asked about 7 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on your bill will be recalculated.

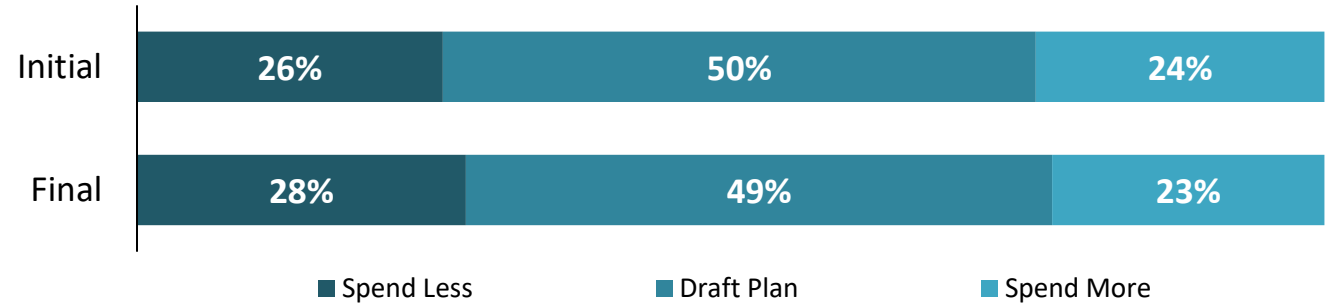
The bill impacts associated with each choice represent the average increase on your monthly bill from 2027 to 2032, followed by the average increase on your monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

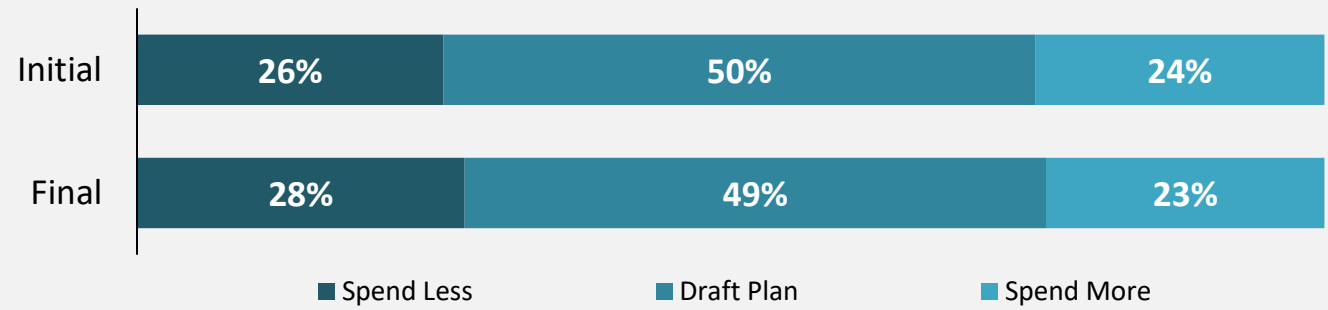
Finalizing Choices

Small Business

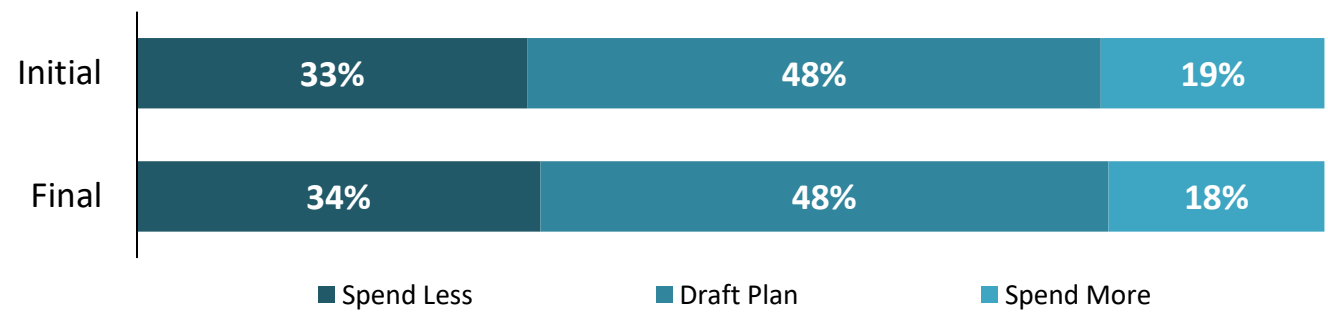
Overall system reliability



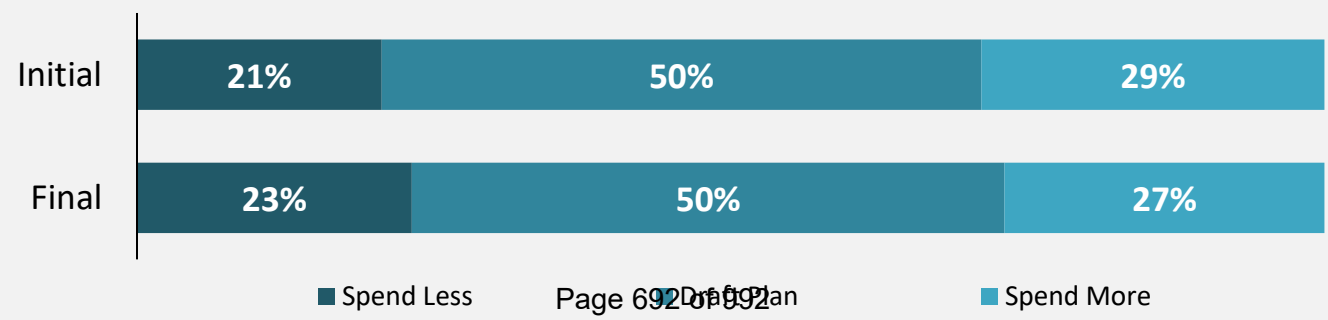
Managing the impacts of severe weather



Targeted reliability improvements



Keeping pace with transmission renewal

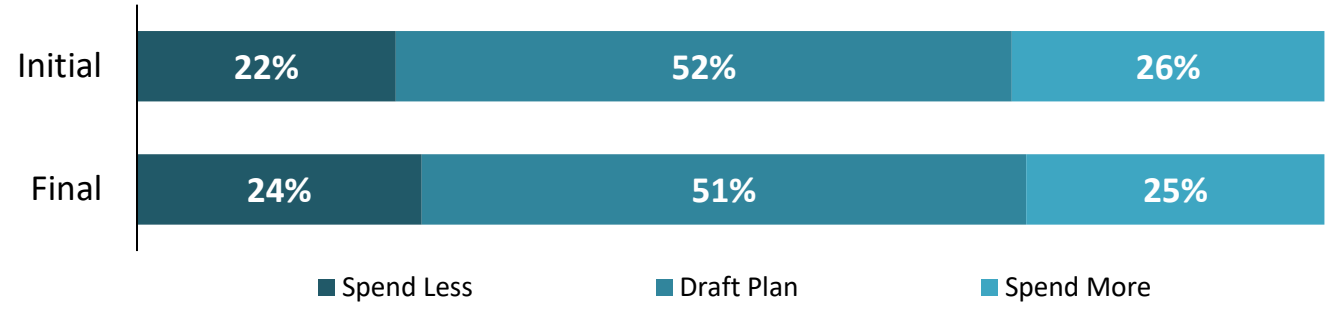


Investment Trade-Offs

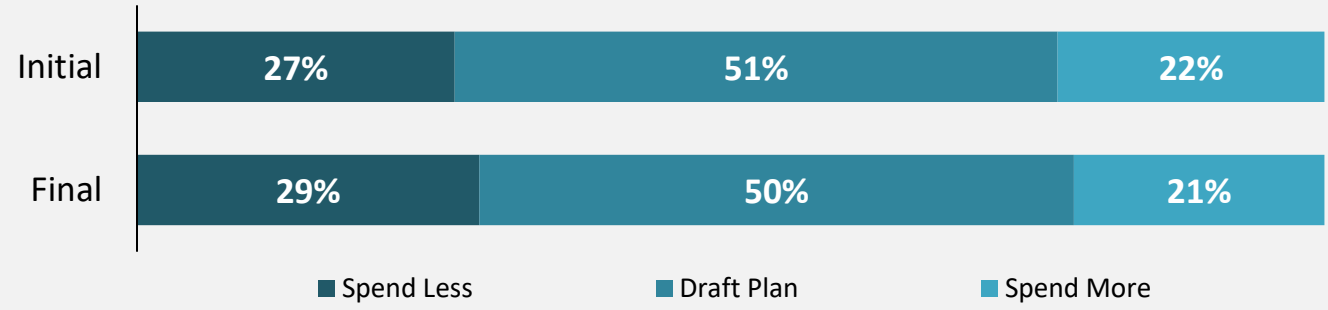
Finalizing Choices

Small Business

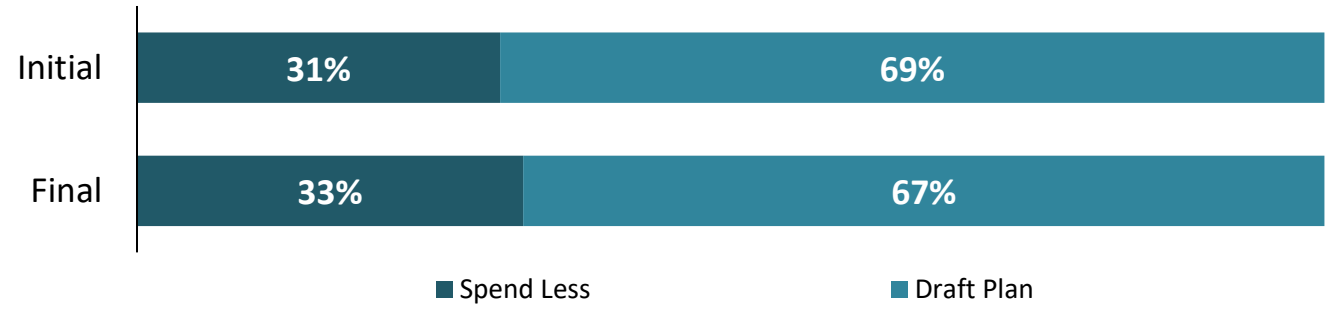
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



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Investment Trade-Offs

Overall evaluation of the draft plans

Small Business

SURVEY PAGE

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **small business customer** would see:

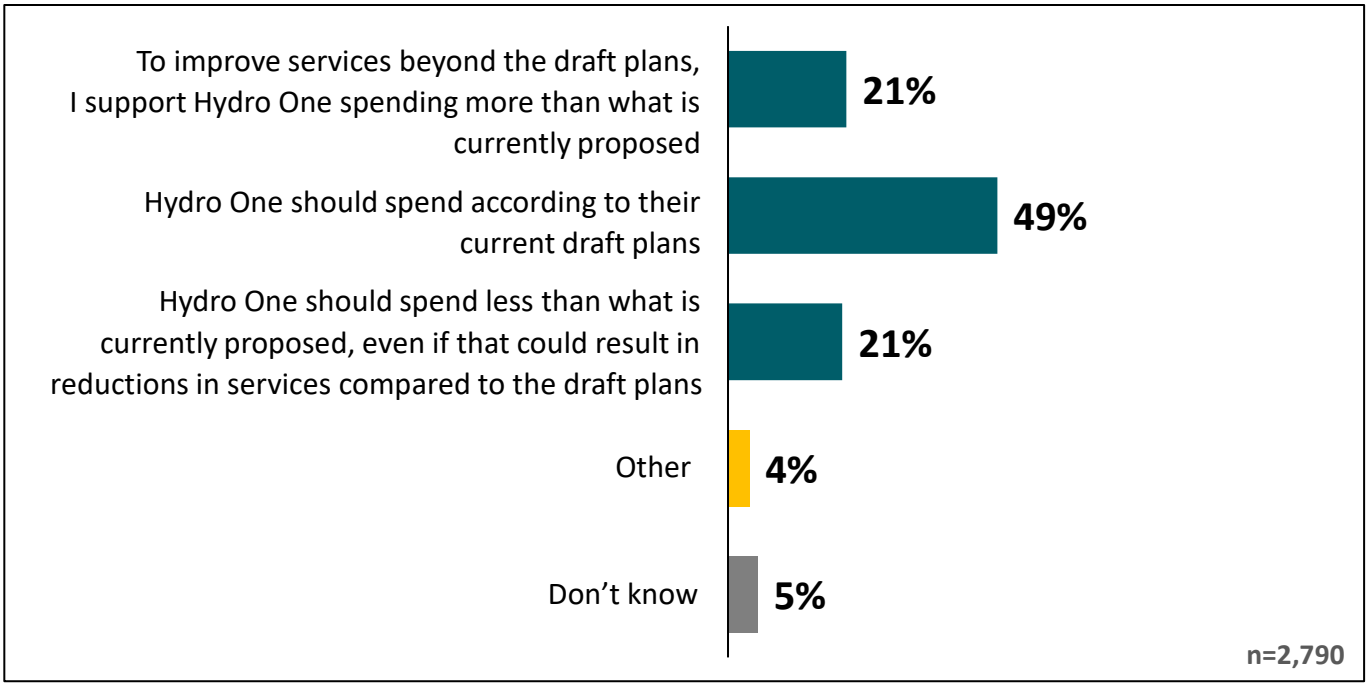
- The **distribution** portion of their **monthly bill** increase from $206.58 in 2027 to $340.78 by the end of 2032 – an increase of **$134.20** on the monthly bill. This represents an average increase of **$26.84** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $42.14 in 2027 to $55.02 by the end of 2032 – an increase of **$12.88** on the monthly bill. This represents an average increase of **$2.58** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plans

Small Business

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?



Region

	West	Central	Central East	East	North
Spend More	18%	22%	24%	22%	19%
Draft Plans	54%	48%	46%	48%	48%
Spend Less	20%	22%	20%	21%	22%
Other	3%	3%	4%	4%	5%
Don't know	5%	5%	6%	6%	6%

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Investment Trade-Offs

Overall evaluation of the draft plans

Small Business

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?

		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend More	21%	20%	19%	22%	25%	18%	30%
Draft Plans	49%	51%	51%	47%	46%	50%	46%
Spend Less	21%	21%	21%	23%	18%	24%	14%
Other	4%	2%	4%	3%	6%	4%	2%
Don't know	5%	5%	5%	6%	5%	4%	7%

Investment Trade-Offs

Final comments on the draft plans

Small Business

Q Do you have any final comments regarding Hydro One's draft plans for 2028–2032 and the proposed rate increase? (Optional)

Responses	%
Lower rates/rates are too high	2.7%
Find efficiencies/alternative funding/customers shouldn't pay	2.6%
Support the increase/investments are necessary	1.6%
Improve reliability/reduce outages	1.5%
Transparency on internal operations	1.5%
Invest now to prepare for future/prevent future increases	0.8%
Need more information/educate customers	0.7%
Distrust in the engagement/rate increases are inevitable	0.7%
Environmental concerns/green initiatives	0.6%
Positive comment about Hydro One/service	0.5%
Concerns around cost of living/inflation	0.4%
Financial strain on vulnerable customers (seniors, fixed income)	0.3%
Be transparent/communicate about rate increases/investments	0.3%
Maintain current service levels/prioritize areas of higher need	0.3%
Improve line maintenance/vegetation management	0.2%
Fair cost allocation/user-pays for system impacts/upgrades	0.2%
Hydro One is profit-driven	0.1%
Stop selling power to the US/increase price to the US	0.1%
Other	0.9%
No comment/None/Don't know	83.7%

Note: Only responses >0.1% shown

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Small Business Customers

Survey Diagnostics



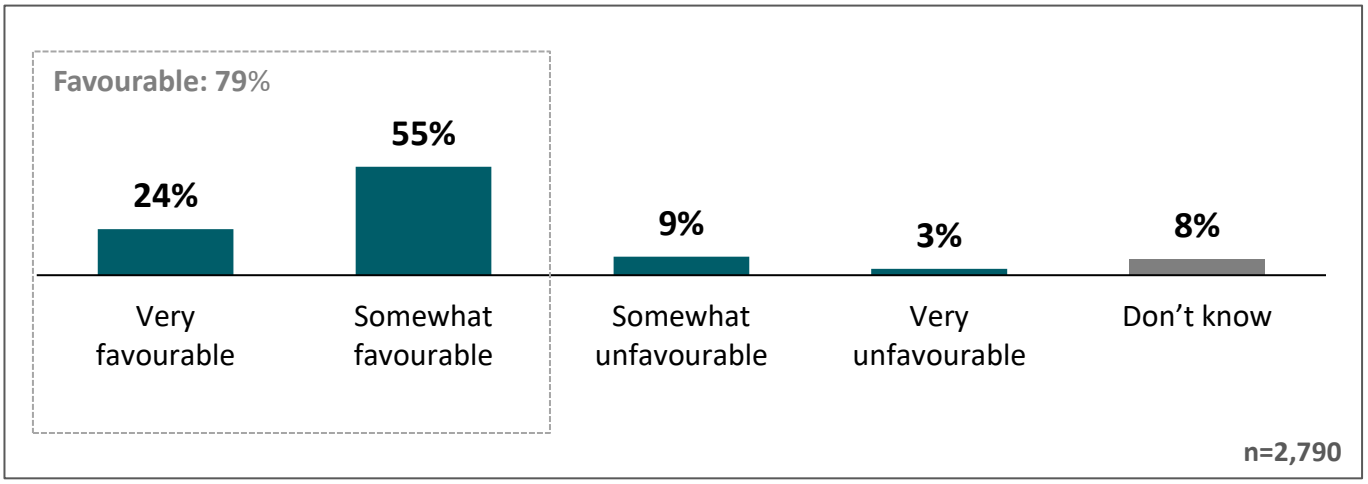
Survey Diagnostics

Favourability and amount of information

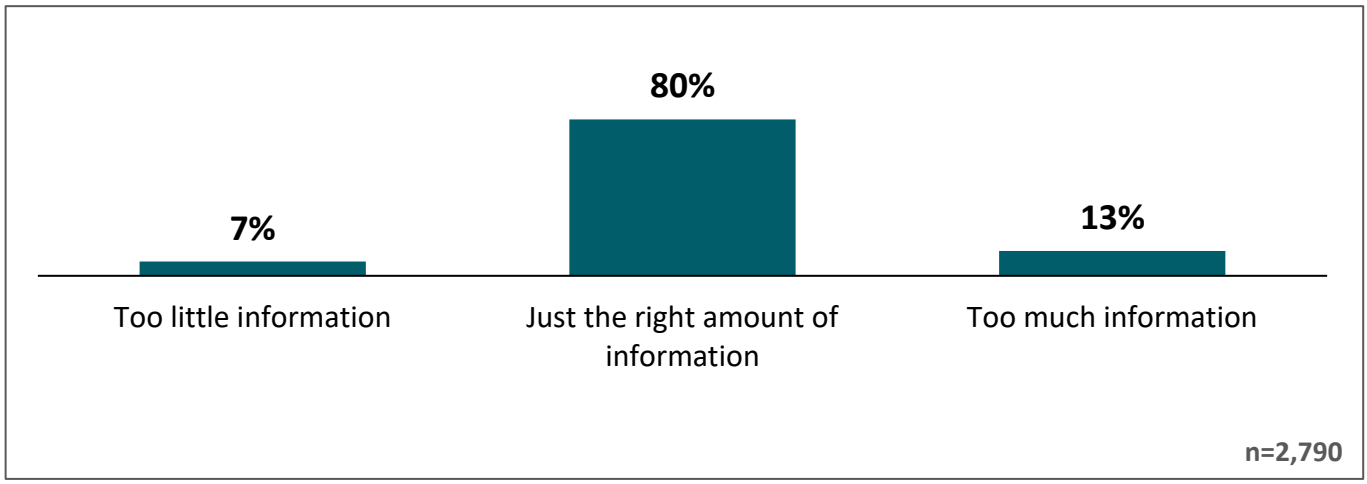
Small Business

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



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Survey Diagnostics

Other information not included

Small Business

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
Transparency on internal operations	2.6%
Reducing customer costs/affordability measures	1.8%
Distrust in the engagement/rate increases are inevitable	1.1%
More detailed information on the investments/infrastructure	1.0%
More information on renewable energy	0.9%
Better outage communication/information	0.7%
Customer demographic comparison/region specific information	0.5%
More information/communication about rate increases	0.4%
Survey/engagement experience feedback - negative	0.4%
Survey/engagement experience feedback - positive	0.4%
Focus on renewable, nuclear and energy storage solution	0.4%
Impact of EVs/AI/new technology	0.4%
Better explanation/transparency on bills	0.4%
Positive comment about Hydro One/service	0.2%
How Hydro One's costs compare to other companies/jurisdictions	0.2%
Helping seniors/fixed-income individuals	0.2%
Historical data (e.g. spending, impact, cost)	0.1%
Government involvement/subsidization	0.1%
Information on energy sold to US/other countries/out of province	0.1%
Other	1.3%
No comment/None/Don’t know	86.8%

Note: Only responses >0.1% shown

Survey Diagnostics
Outstanding questions

Small Business

Q Is there anything that you would still like answered? (Optional)

Responses	%
Plans to reduce/lower customer costs	1.6%
Transparency on internal operations	1.4%
Focus on renewable, nuclear & energy storage solution	1.1%
More detailed information on the investments/infrastructure	0.9%
Improve reliability/reduce outages	0.5%
Better explanation/transparency on bills	0.5%
Different types of customers and their rates	0.4%
Be transparent/communicate about rate increases	0.3%
Improve customer service/communication (general/outage)	0.3%
Survey/engagement experience feedback - positive	0.2%
Government involvement/subsidies	0.2%
Helping seniors/fixed-income individuals	0.1%
How Hydro One's costs compare to other companies/jurisdictions	0.1%
Survey/engagement experience feedback - negative	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Improve line maintenance/vegetation management	0.1%
Positive comment about Hydro One/service	0.1%
Stop selling power to the US/increase price to the US	0.1%
Other	0.7%
No comment/None/Don’t know	91.0%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Online Survey Results

Section 5



Online Survey
Methodology

Field Dates

The **Commercial & Industrial Online Survey** was sent to all Hydro One commercial & industrial customers with an available email address. Customers had an opportunity to complete the survey between **November 14th and December 22nd, 2025**.

Each customer received a unique URL that could be linked back to their average monthly demand, region and rate class. Survey pages that differed by customer type are identified as GSd (general service demand), ST-Low (sub transmission low), ST-Med (sub transmission medium), and ST-High (sub transmission high) versions throughout this report.

In total, the commercial & industrial survey was sent to **5,105** customers from *customerexperience@hydroone.com*. A total of four reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Commercial & Industrial Online Survey Completes

A total of **368** (unweighted) Hydro One commercial & industrial customers completed the online survey.

Sample Weighting

The commercial & industrial online survey sample was weighted to n=350 proportionately by consumption quartile and region in order to be representative of the broader Hydro One customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values as some customers are missing region or consumption quartile information. Weights are calculated based off of all available information for a given customer.

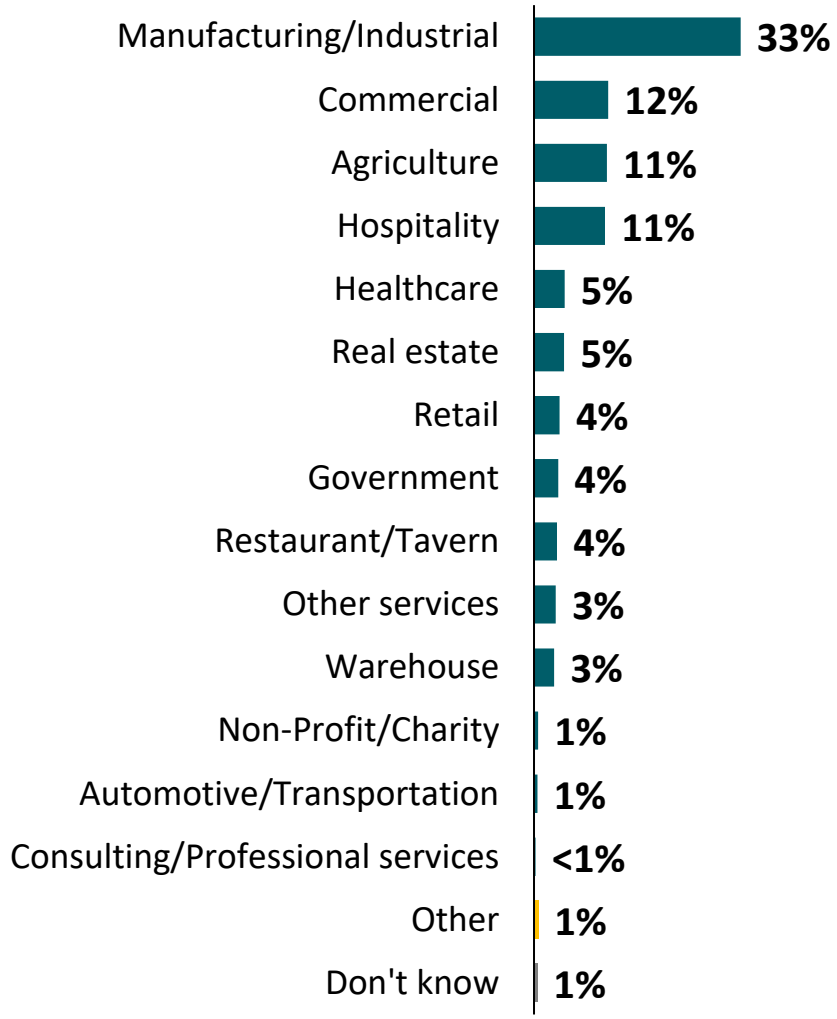
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
West	32 (25)	28 (27)	30 (22)	34 (24)	124 (98)
Central	28 (25)	20 (21)	26 (23)	24 (21)	98 (90)
Central East	20 (22)	13 (17)	21 (24)	15 (16)	69 (78)
East	10 (9)	10 (11)	8 (7)	18 (15)	46 (43)
North	6 (7)	8 (11)	8 (11)	9 (12)	31 (40)
Total	96 (88)	79 (87)	93 (87)	100 (88)	368 (350)

Note: *Graphs and tables may not always total 100% due to rounding values other than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographic Breakdown

Commercial & Industrial

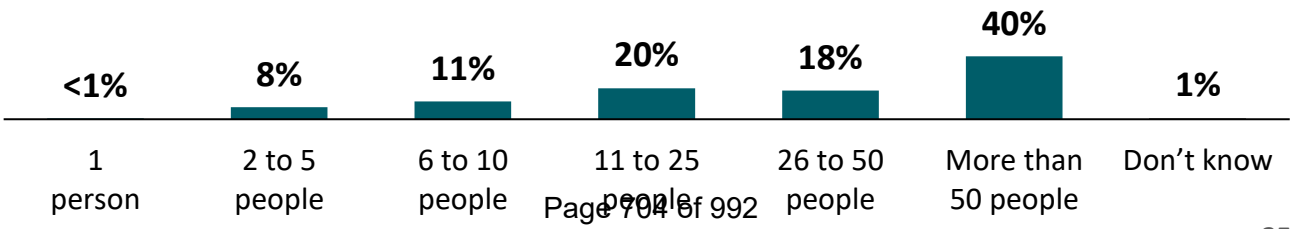
Q Business Sector



"Prefer not to say" (3%) not shown.

n=350

Q Business Size



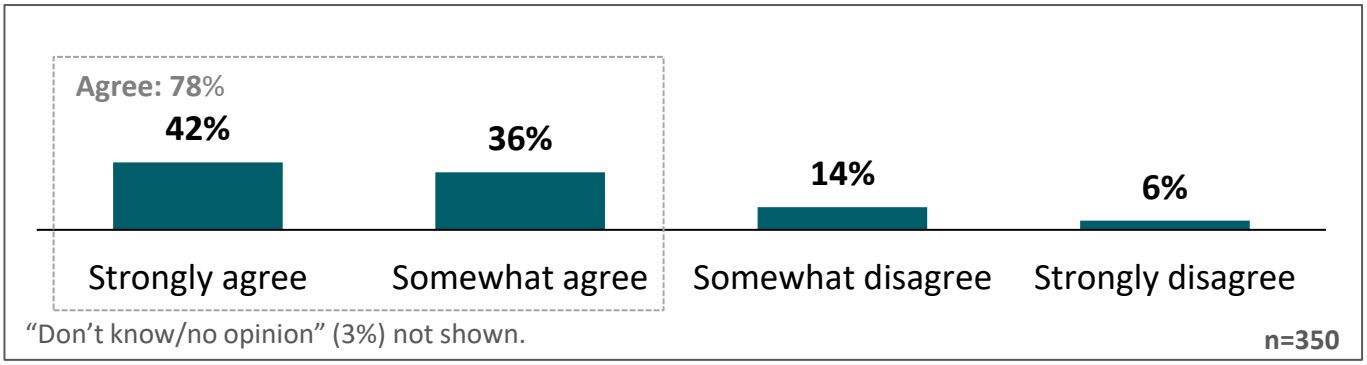
"Prefer not to say" (2%) not shown.

n=350

Environmental Controls

To what extent do you agree or disagree with the following statements?

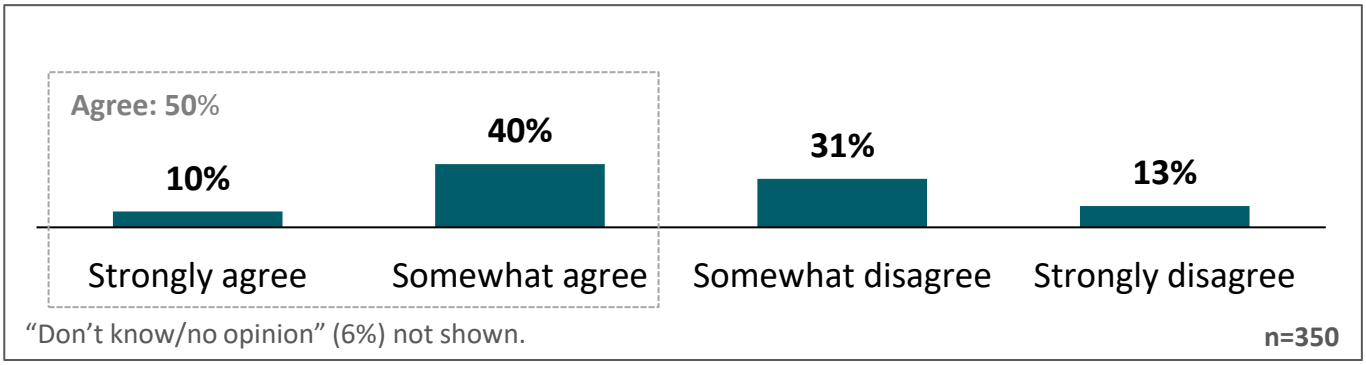
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (3%) not shown.

n=350

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (6%) not shown.

n=350

GSd Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large business customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the general service demand rate class with an average monthly demand of 110 kW and average monthly consumption of 34,334 kWh.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

ST-Low Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large business customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the sub-transmission low consumption rate class with an average monthly demand of 500 kW and average monthly consumption of 88,780 kWh.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

INNOVATIVE RESEARCH GROUP

SURVEY PAGE

ST-Med Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large business customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the sub-transmission average consumption rate class with an average monthly demand of 2,808 kW and average monthly consumption of 1,373,443 kWh.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

INNOVATIVE RESEARCH GROUP

SURVEY PAGE

ST-High Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large business customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the sub-transmission high consumption rate class with an average monthly demand of 13,730 kW and average monthly consumption of 2,641,420 kWh.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by their customers. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plans, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plans.

Next year, Hydro One will present their proposed plans and input provided by customers to the OEB.

SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Commercial & Industrial

SURVEY PAGE

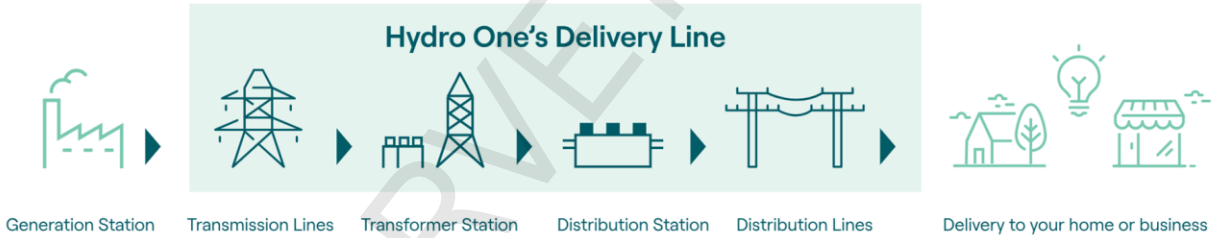
Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which delivers electricity to your home, seasonal property, or organization through a network of wires, poles and other equipment.



Hydro One does not generate electricity or set electricity prices.

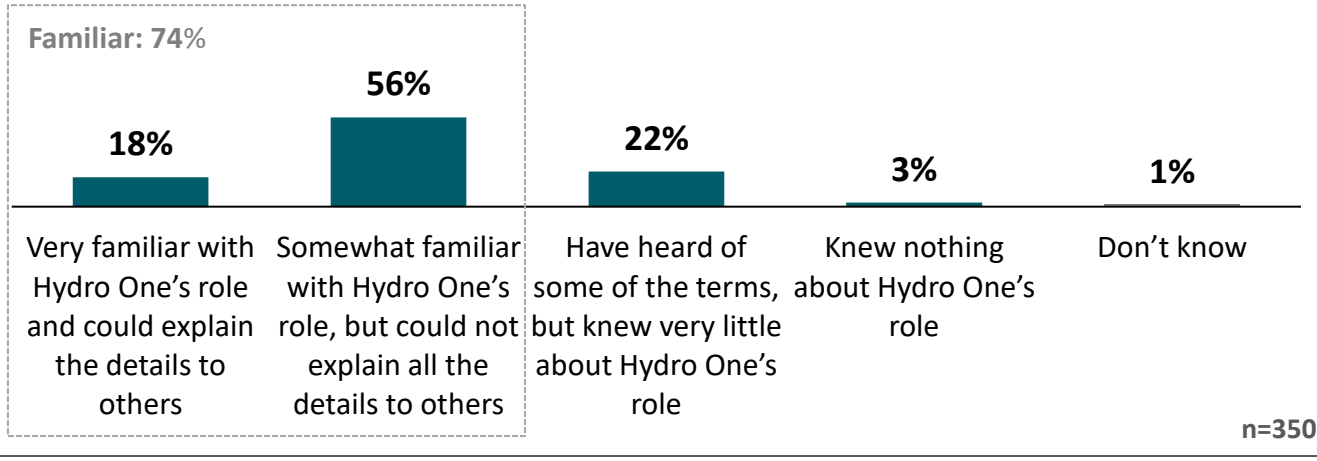
Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Commercial & Industrial

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	West	Central	Central East	East	North
Very familiar	16%	17%	27%	8%	19%
Somewhat familiar	58%	63%	41%	72%	45%
Knew very little	22%	15%	30%	13%	32%
Knew nothing	3%	3%	--	4%	3%
Don't know	1%	2%	1%	3%	--
Familiar (Very + Somewhat)	**74%**	**80%**	**68%**	**81%**	**65%**

Consumption Quartiles

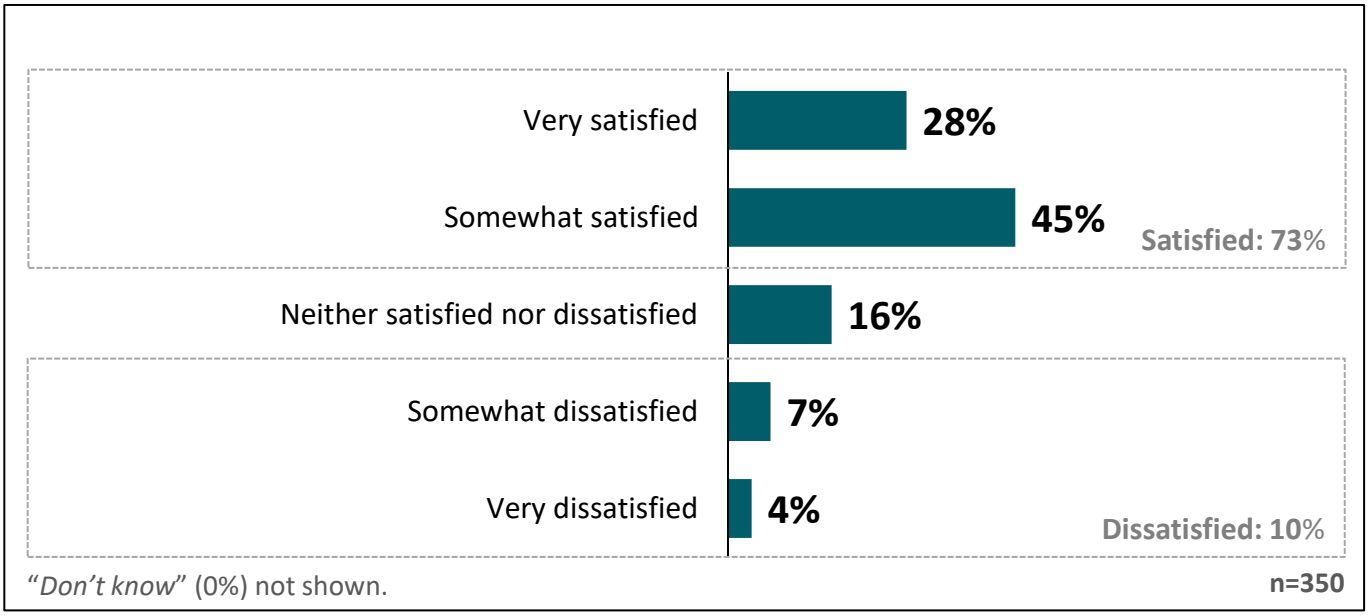
Bill Impact

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Very familiar	21%	16%	23%	14%	19%	17%
Somewhat familiar	44%	60%	55%	65%	54%	61%
Knew very little	29%	21%	18%	19%	24%	16%
Knew nothing	4%	1%	2%	3%	3%	2%
Don't know	2%	1%	2%	--	1%	4%
Familiar (Very + Somewhat)	**65%**	**76%**	**78%**	**78%**	**73%**	**78%**

Familiarity & Experience

Overall satisfaction with Hydro One's service

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?



"*Don't know*" (0%) not shown.

n=350

Region

	West	Central	Central East	East	North
Very satisfied	22%	28%	27%	37%	36%
Somewhat satisfied	50%	54%	38%	43%	32%
Neither	17%	12%	19%	16%	20%
Somewhat dissatisfied	8%	5%	9%	2%	7%
Very dissatisfied	3%	1%	7%	2%	6%
Don't know	--	--	--	--	--
Satisfied (Very + Somewhat)	**72%**	**82%**	**65%**	**80%**	**68%**
Dissatisfied (Very + Somewhat)	**12%**	**6%**	**16%**	**4%**	**13%**

Familiarity & Experience

Overall satisfaction with Hydro One's service

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?

		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Very satisfied	28%	26%	28%	32%	27%	26%	36%
Somewhat satisfied	45%	48%	44%	41%	48%	46%	44%
Neither	16%	13%	20%	16%	17%	17%	14%
Somewhat dissatisfied	7%	5%	7%	9%	6%	7%	7%
Very dissatisfied	4%	8%	1%	3%	3%	5%	--
Don't know	--	--	--	--	--	--	--
Satisfied (Very + Somewhat)	**73%**	**74%**	**72%**	**73%**	**75%**	**72%**	**79%**
Dissatisfied (Very + Somewhat)	**10%**	**13%**	**8%**	**12%**	**9%**	**11%**	**7%**

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Commercial & Industrial

GSd Version

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

hydro one

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical general service demand customer, about 43% of the bill, or $3,093.42, goes to Hydro One per month. This amount is split into $2,459.41 for distribution and $634.01 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

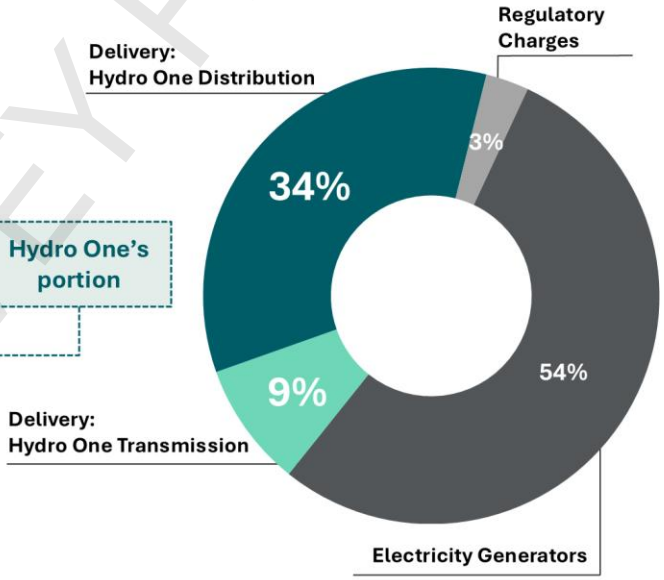
Sample Monthly Bill
(based on consumption of 34,334 kWh and demand of 110 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	3,856.35
Delivery	3,093.42
Regulatory Charges	218.82
Total Electricity Charges	$7,168.59
HST	931.92
Total Amount	$8,100.51

Hydro One's portion



The pie chart above is based on a total bill of $7,168.59 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 34,334 kWh and demand of 110 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

SURVEY PAGE

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Commercial & Industrial

ST-Low Version

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

hydro one

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical sub transmission low consumption customer, about 41% of the bill, or $7,011.07, goes to Hydro One per month. This amount is split into $2,096.67 for distribution and $4,914.40 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

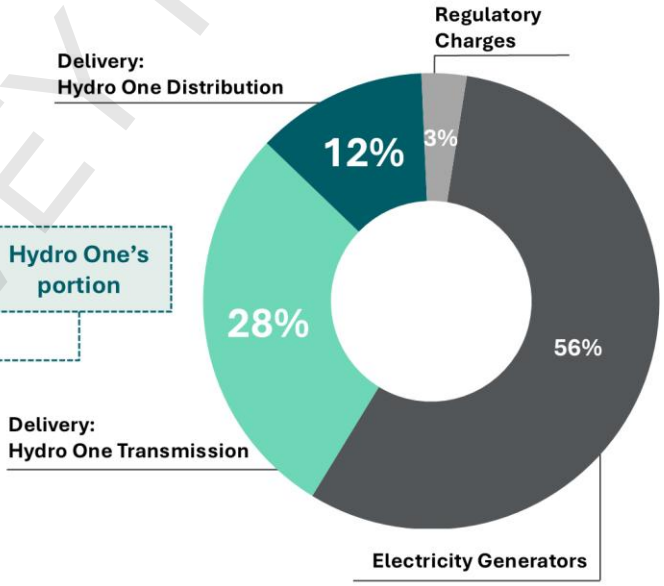
Sample Monthly Bill
(based on consumption of 88,780 kWh and demand of 500 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	9,717.90
Delivery	7,011.07
Regulatory Charges	551.04
Total Electricity Charges	$17,280.01
HST	2,246.40
Total Amount	$19,526.41

Hydro One's portion



The pie chart above is based on a total bill of $17,280.01 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 88,780 kWh and demand of 500 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

SURVEY PAGE

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical sub transmission average consumption customer, about 17% of the bill, or $33,641.70, goes to Hydro One per month. This amount is split into $6,042.43 for distribution and $27,599.27 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

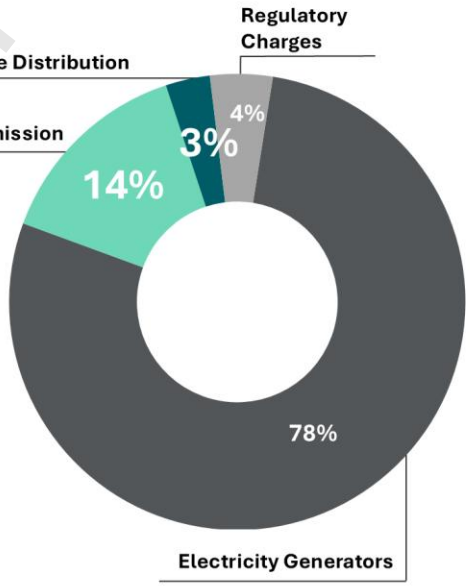
Sample Monthly Bill
(based on consumption of 1,373,443 kWh and demand of 2,808 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	150,337.73
Delivery	33,641.70
Regulatory Charges	8,521.09
Total Electricity Charges	$192,500.52
HST	25,025.07
Total Amount	$217,525.59

Hydro One's portion



The pie chart above is based on a total bill of $192,500.52 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 1,373,443 kWh and demand of 2,808 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

SURVEY PAGE

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Commercial & Industrial

ST-High Version

SURVEY PAGE

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical sub transmission high consumption customer, about 34% of the bill, or $159,644.10, goes to Hydro One per month. This amount is split into $24,714.68 for distribution and $134,949.42 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

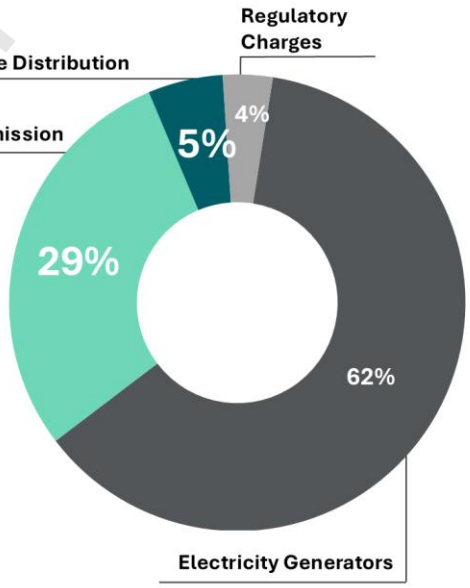
Sample Monthly Bill
(based on consumption of 2,641,420 kWh and demand of 13,730 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	**289,131.10**
Delivery	**159,664.10**
Regulatory Charges	**16,387.62**
Total Electricity Charges	**$465,182.83**
HST	60,473.77
Total Amount	**$525,656.59**

Hydro One's portion



The pie chart above is based on a total bill of $465,182.83 excluding HST. The chart may not total 100% due to rounding.

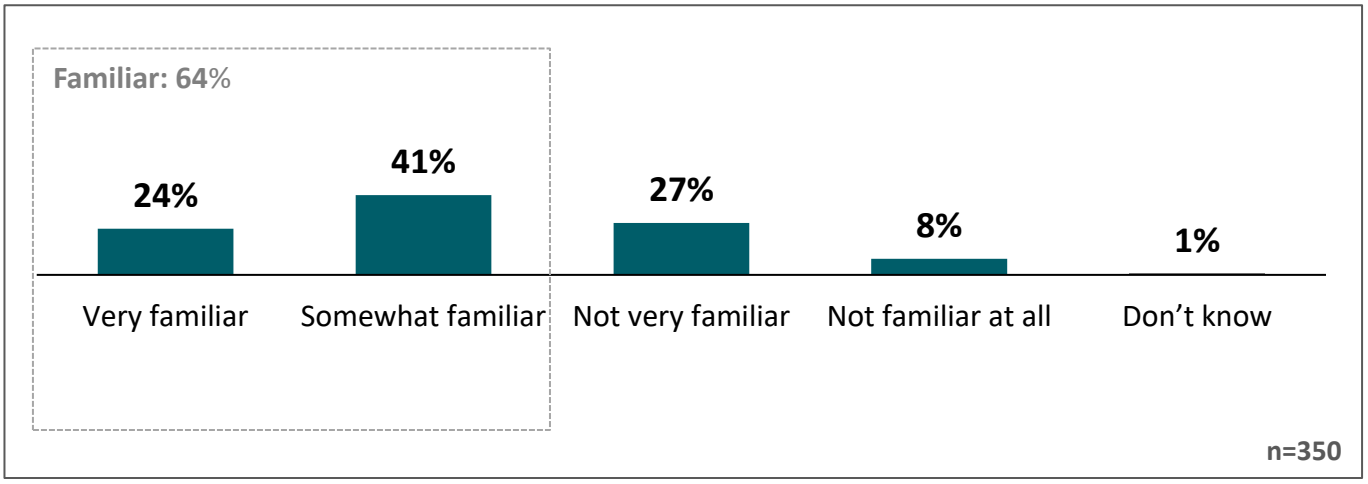
The sample bill above uses an average consumption level of 2,641,420 kWh and demand of 13,730 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

Familiarity & Experience

Bill familiarity

Commercial & Industrial

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Hydro One?



Region

	West	Central	Central East	East	North
Very familiar	22%	26%	24%	24%	20%
Somewhat familiar	45%	47%	35%	38%	32%
Not very familiar	24%	19%	31%	31%	35%
Not familiar at all	7%	8%	10%	4%	13%
Don't know	2%	--	--	2%	--
Familiar (Very + Somewhat)	**67%**	**73%**	**59%**	**63%**	**52%**

Consumption Quartiles / Bill Impact

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Very familiar	30%	18%	27%	20%	24%	21%
Somewhat familiar	34%	45%	40%	44%	42%	38%
Not very familiar	24%	30%	27%	26%	26%	28%
Not familiar at all	13%	7%	6%	8%	7%	12%
Don't know	--	1%	--	2%	1%	1%
Familiar (Very + Somewhat)	**64%**	**62%**	**67%**	**64%**	**66%**	**59%**

Summary of Investment Plan

How Hydro One plans

Commercial & Industrial

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity distribution and transmission services. This feedback was used to inform planners in developing the draft investment plans.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.
3. Make **targeted investments to improve reliability** for customers experiencing significantly poorer reliability than average.
4. Make investments to make the system **more resilient to severe weather**.
5. Make investments in technology to **accommodate customer requests and improve visibility into the system** (e.g., where and how much electricity is being used).

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

Commercial & Industrial

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations, and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

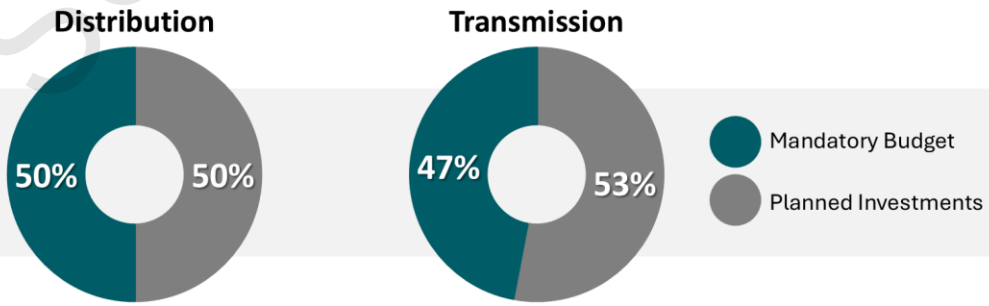
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Commercial & Industrial

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

While Hydro One's draft plans cover both the **distribution system** serving approximately 1.5 million customers, as well as the **transmission system** serving most Ontarians, each system has different needs and objectives.

Some of the highlights of Hydro One's draft plans include:

Distribution Objectives



1. Improving the **day-to-day reliability** of the system by addressing equipment that is at a higher risk of failure.
2. Preparing for the **impacts of severe weather** by investing in vulnerable lines, clearing more overgrown vegetation, and using technology to restore power more quickly.
3. Improving reliability for thousands of customers experiencing below average reliability by investing in **new battery storage technology**.
4. Ensuring the grid is prepared to **keep pace with evolving customer needs** and accommodate higher levels of growth.

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest distributor and transmitter of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plan include:

Shared Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Commercial & Industrial

GSd Version

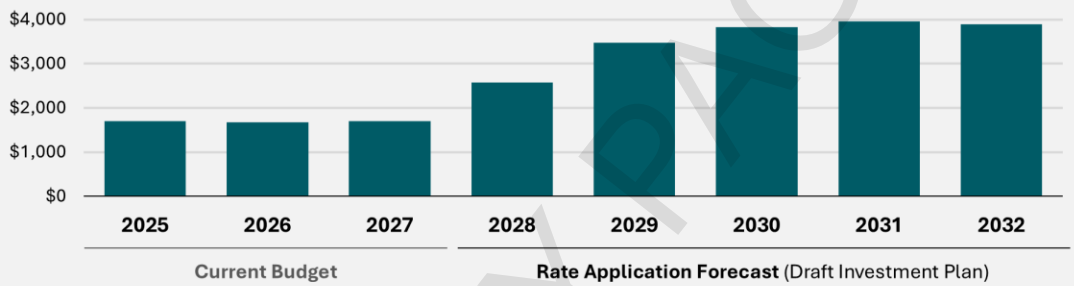
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)

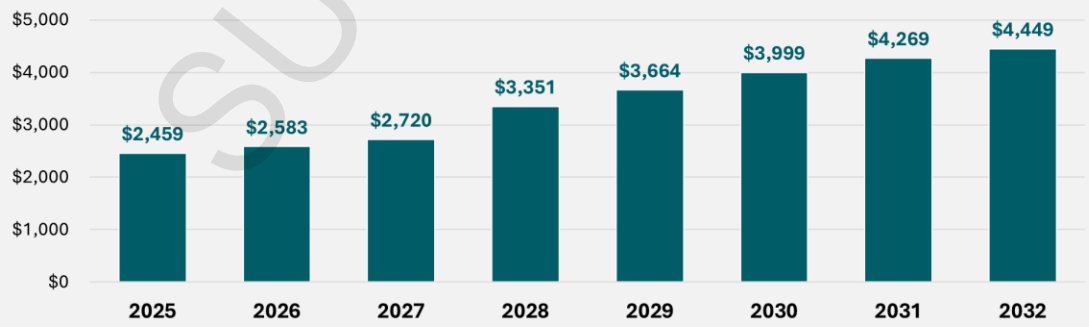


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **general service demand customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $2,720 in 2027 to $4,449 by the end of 2032 – an increase of **$1,729** on the monthly bill. This represents an average increase of **$346** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Commercial & Industrial

ST-Low Version

SURVEY PAGE

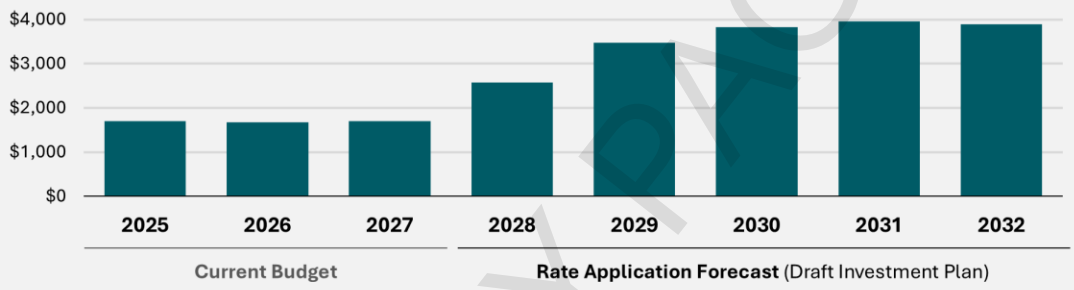
Hydro One Customer Engagement Survey

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Distribution Budget: Current and Forecasted ($ millions)

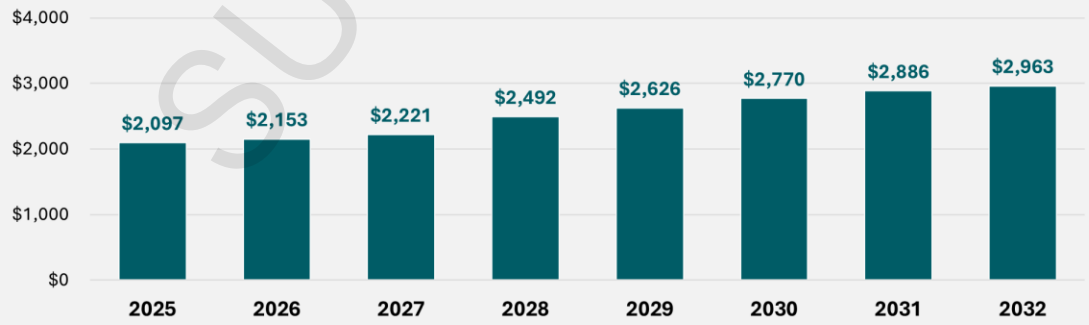


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **sub-transmission low consumption customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $2,221 in 2027 to $2,963 by the end of 2032 – an increase of **$742** on the monthly bill. This represents an average increase of **$148** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Commercial & Industrial

ST-Med Version

SURVEY PAGE

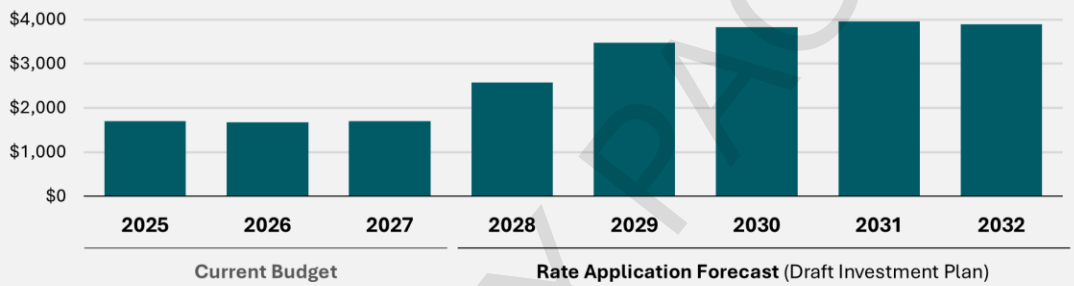
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)

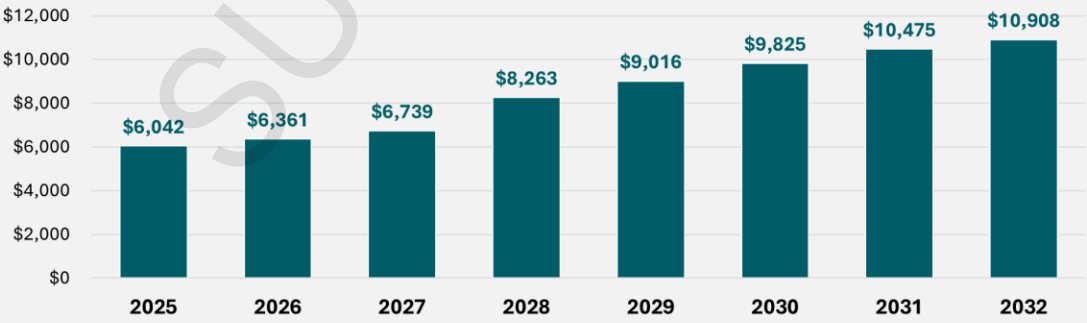


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **sub-transmission average consumption customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $6,739 in 2027 to $10,908 by the end of 2032 – an increase of **$4,169** on the monthly bill. This represents an average increase of **$834** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Commercial & Industrial

ST-High Version

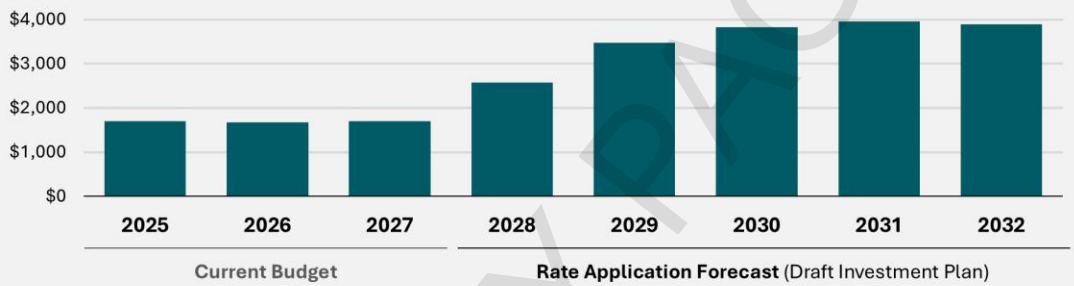
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)

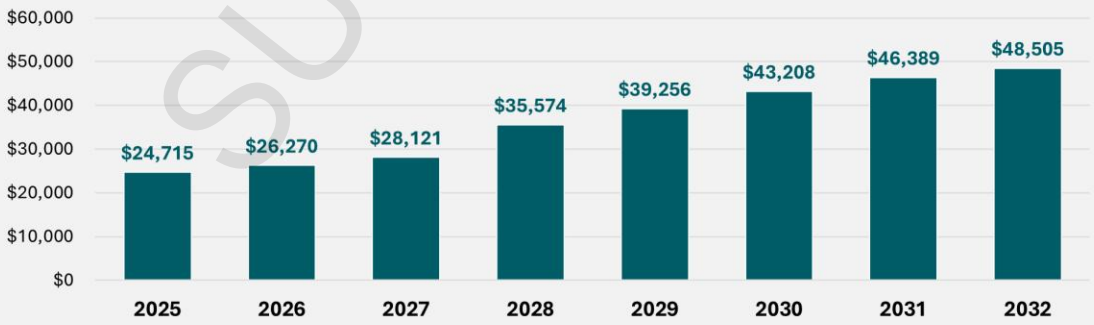


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **sub-transmission high consumption customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $28,121 in 2027 to $48,505 by the end of 2032 – an increase of **$20,384** on the monthly bill. This represents an average increase of **$4,077** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Commercial & Industrial

GSd Version

SURVEY PAGE

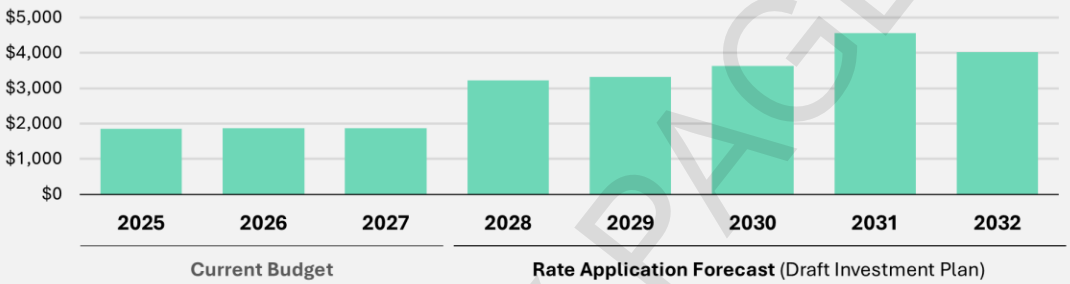
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

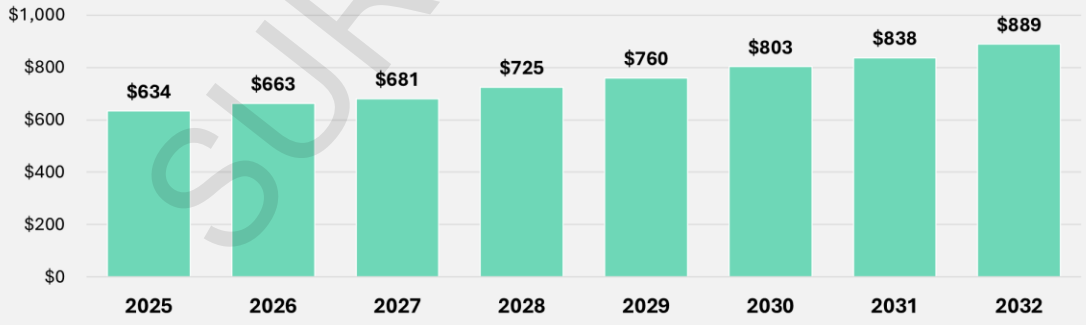


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **general service demand customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $681 in 2027 to $889 by the end of 2032 – an increase of **$208** on the monthly bill. This represents an average increase of **$42** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Commercial & Industrial

ST-Low Version

SURVEY PAGE

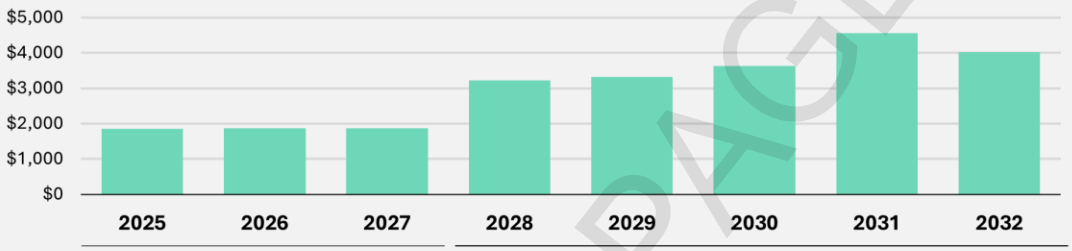
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

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For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

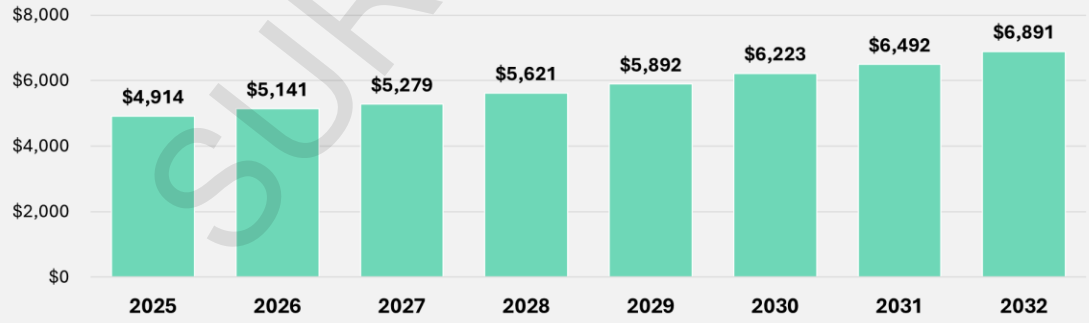


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **sub-transmission low consumption customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $5,279 in 2027 to $6,891 by the end of 2032 – an increase of **$1,613** on the monthly bill. This represents an average increase of **$323** on the monthly bill each year.

Transmission Portion of Monthly Bill



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Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Commercial & Industrial

ST-Med Version

SURVEY PAGE

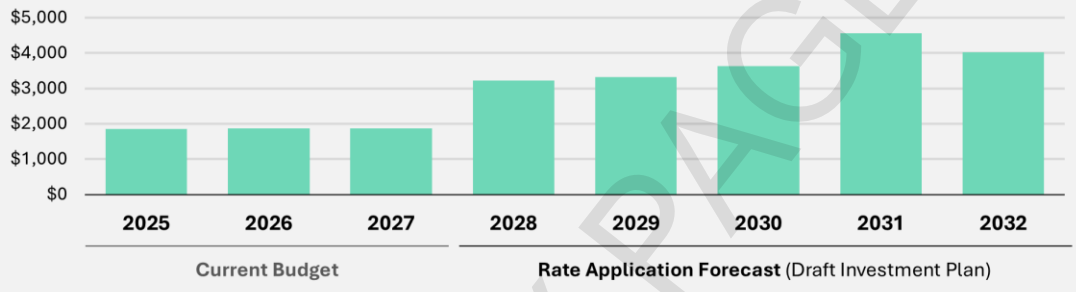
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

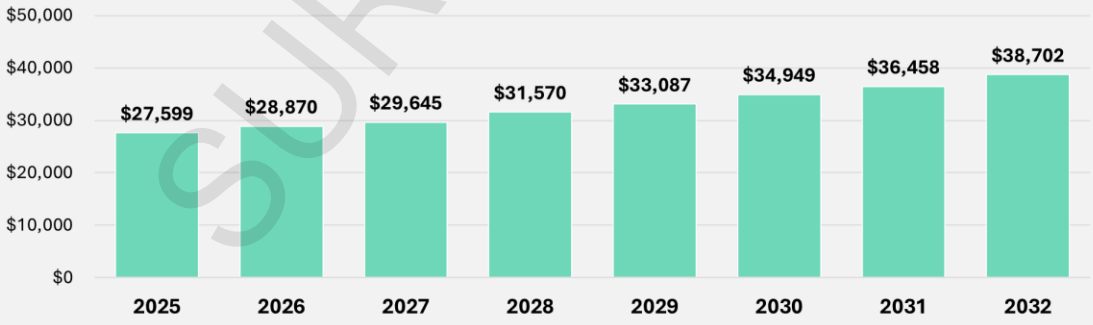


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **sub-transmission average consumption customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $29,645 in 2027 to $38,702 by the end of 2032 – an increase of **$9,058** on the monthly bill. This represents an average increase of **$1,812** on the monthly bill each year.

Transmission Portion of Monthly Bill



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Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Commercial & Industrial

ST-High Version

SURVEY PAGE

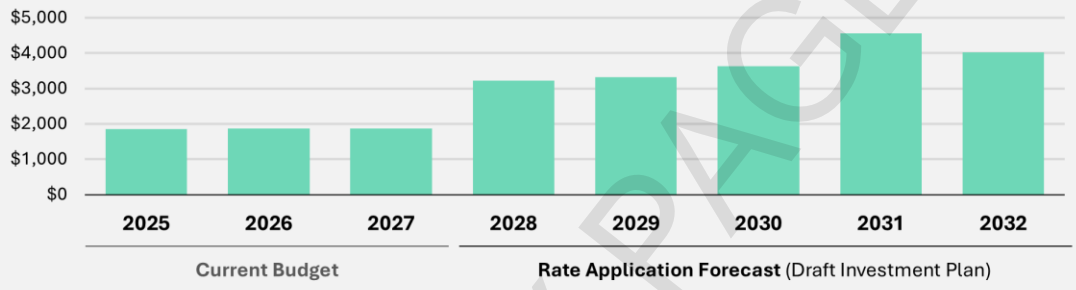
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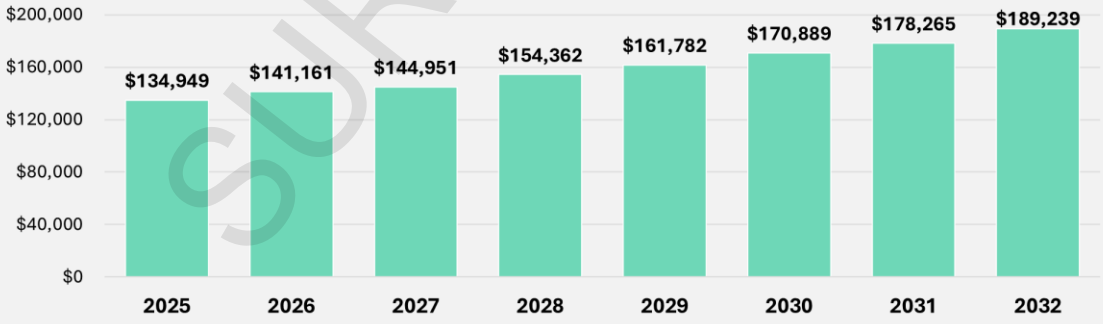


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **sub-transmission high consumption customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $144,951 in 2027 to $189,239 by the end of 2032 – an increase of **$44,289** on the monthly bill. This represents an average increase of **$8,858** on the monthly bill each year.

Transmission Portion of Monthly Bill



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Summary of Investment Plan

How to make choices

Commercial & Industrial

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

hydro one

The remainder of this survey asks for your input on the total cost of the draft investment plans, plus **7 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost for you.



SURVEY PAGE

Hydro One Customer Engagement Survey

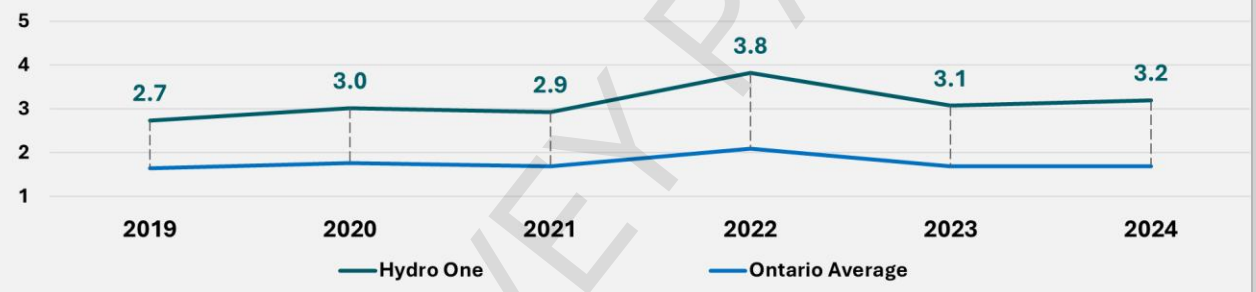
How does Hydro One's distribution grid perform?

Since most Hydro One customers live in rural areas, their distribution system looks different from other Ontario utilities. Serving more sparsely populated communities separated by significant distances means more equipment is needed, outages can take longer to locate, and power can take longer to restore.

On average, between 2019 and 2024, the typical Hydro One customer has experienced 1.4 more outages per year compared to the Ontario average.

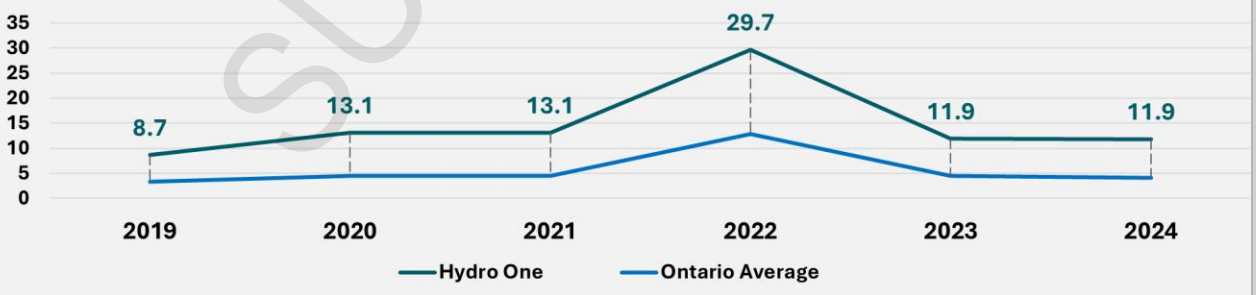


Number of Outages (Average Outages Per Customer)



When it comes to the total time spent without electricity per year, the typical Hydro One customer has been without power for 14.7 hours each year on average, which is 9.1 hours more than the Ontario average.

Duration of Outages (Average Hours Per Customer)



Severe weather, **tree contacts**, and **equipment failure** account for most of these outages. Notably, the distribution system experienced widespread outages due to severe weather in both 2022 and again in April 2025.

SURVEY P

Investment Trade-Offs

Overall system reliability

Commercial & Industrial

GSd Version

SURVEY PAGE

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

Hydro One typically identifies investments in equipment by taking into consideration the overall age, health, and likelihood of equipment failure.

In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

Hydro One generally tries to replace poor condition equipment before it fails. However, when equipment does fail, it can result in significant interruptions for customers.

In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$75 less by 2032 (average of $15 less each year)	Included in Draft Plan	$75 more by 2032 (average of $15 more each year)

Investment Trade-Offs

Overall system reliability

Commercial & Industrial

ST-Low Version

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

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Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$32 less by 2032 (average of $6 less each year)	Included in Draft Plan	$32 more by 2032 (average of $6 more each year)

SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

Hydro One typically identifies investments in equipment by taking into consideration the overall age, health, and likelihood of equipment failure.

In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

Hydro One generally tries to replace poor condition equipment before it fails. However, when equipment does fail, it can result in significant interruptions for customers.

In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.

Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.



Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$182 less by 2032 (average of $36 less each year)	Included in Draft Plan	$182 more by 2032 (average of $36 more each year)

SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Commercial & Industrial

ST-High Version

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

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In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

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Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
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Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$888 less by 2032 (average of $178 less each year)	Included in Draft Plan	$890 more by 2032 (average of $178 more each year)

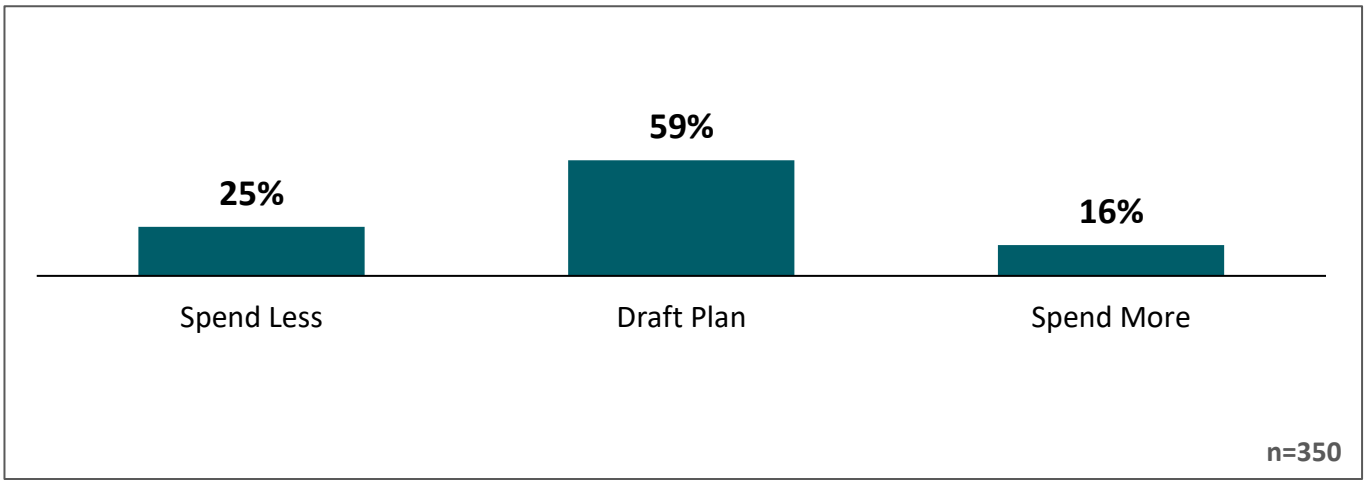
SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	24%	23%	31%	27%	19%
Draft Plan	59%	60%	59%	56%	61%
Spend More	17%	18%	10%	17%	20%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	30%	23%	23%	25%	28%	16%
Draft Plan	52%	64%	56%	64%	59%	60%
Spend More	18%	13%	21%	11%	14%	24%

Investment Trade-Offs

Overall system reliability

Commercial & Industrial

Q Additional Feedback (Optional)

Responses	%
Improve reliability/reduce outages	1.7%
Bury the lines	1.4%
Distrust in the engagement/rate increases are inevitable	1.1%
Find efficiencies/alternative funding/customers shouldn't pay	0.9%
Feel the investment is necessary, but try to minimize costs	0.9%
Infrastructure needs to be upgraded	0.9%
Concerns around cost of living/inflation	0.7%
Maintain current service levels/prioritize areas of higher need	0.6%
Invest now to prepare for future/prevent future increases	0.4%
Willing to pay more for improved reliability	0.3%
Against increases/costs are too expensive	0.3%
Improve line maintenance/vegetation management	0.3%
Need more information	0.3%
Focus on renewable, nuclear and energy storage solutions	0.2%
Other	0.8%
No comment/None/Don’t know	89.1%

Note: Only responses >0.1% shown

Investment Trade-Offs

Managing the impacts of severe weather

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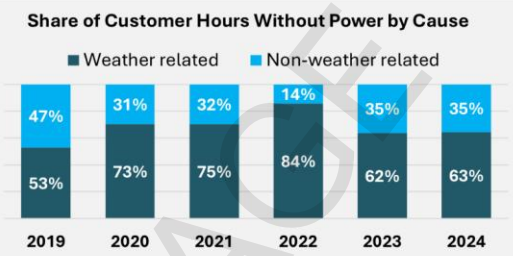
Hydro One Customer Engagement Survey

Managing the impacts of severe weather

hydro one

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.





In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$50 less by 2032 (average $10 less each year)	Included in Draft Plan	$50 more by 2032 (average of $10 more each year)

Investment Trade-Offs

Managing the impacts of severe weather

Commercial & Industrial

ST-Low Version

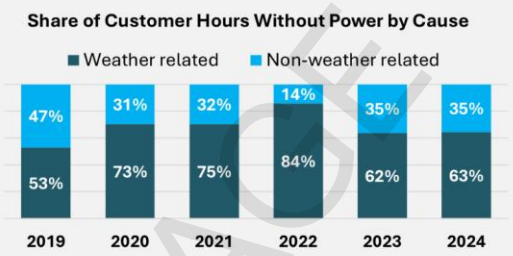
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Managing the impacts of severe weather

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	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$21 less by 2032 (average of $4 less each year)	Included in Draft Plan	$21 more by 2032 (average of $4 more each year)

SURVEY PACK

Investment Trade-Offs

Managing the impacts of severe weather

Commercial & Industrial

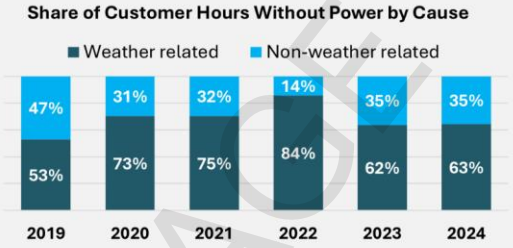
ST-Med Version

Hydro One Customer Engagement Survey

Managing the impacts of severe weather

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.





In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$119 less by 2032 (average of $24 less each year)	Included in Draft Plan	$119 more by 2032 (average of $24 more each year)

SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Commercial & Industrial

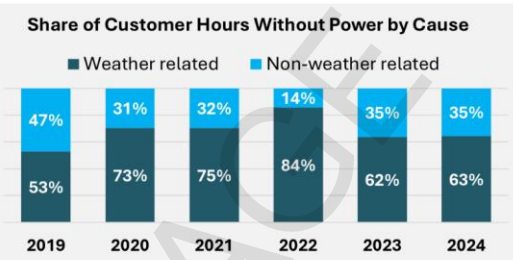
ST-High Version

Hydro One Customer Engagement Survey

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	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$584 less by 2032 (average of $117 less each year)	Included in Draft Plan	$584 more by 2032 (average of $117 more each year)

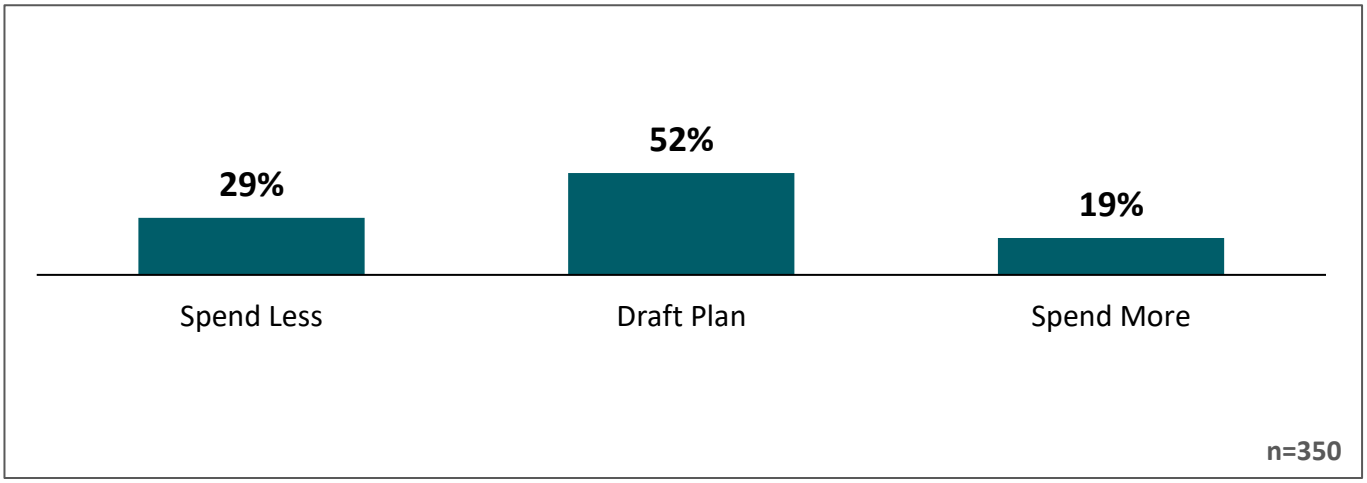
SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	29%	26%	29%	32%	32%
Draft Plan	48%	53%	56%	47%	58%
Spend More	23%	21%	15%	21%	10%

	Consumption Quartiles				Bill Impact	
	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	35%	26%	28%	27%	33%	17%
Draft Plan	48%	56%	50%	54%	51%	55%
Spend More	17%	17%	22%	19%	16%	28%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Managing the impacts of severe weather

Commercial & Industrial

Q Additional Feedback (Optional)

Responses	%
Bury the lines	1.3%
Maintain current service levels/prioritize areas of higher need	0.8%
Distrust in the engagement/rate increases are inevitable	0.8%
Find efficiencies/alternative funding/customers shouldn't pay	0.8%
Improve line maintenance/vegetation management	0.7%
Improve reliability/reduce outages	0.5%
Against increases/costs are too expensive	0.4%
Need more information	0.3%
Focus on renewable, nuclear and energy storage solutions	0.3%
Concerns around cost of living/inflation	0.3%
Support the draft plan/increase is reasonable	0.2%
Other	0.5%
No comment/None/Don’t know	93.2%

Note: Only responses >0.1% shown

Investment Trade-Offs

Targeted reliability improvements

Commercial & Industrial

GSd Version

SURVEY PAGE

Hydro One Customer Engagement Survey

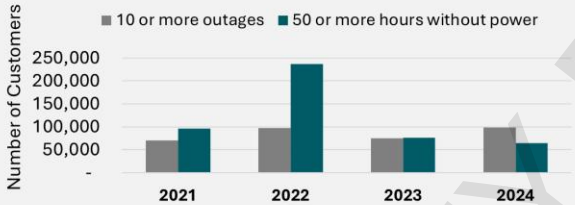
Targeted reliability improvements

Hydro One customers experience different levels of reliability depending on where they live, the design of the system, the condition of the equipment supplying them, and weather patterns.

While some Hydro One customers might not have experienced any outages in the last four years, in any given year more than **70,000 customers were without power more than 10 times**, and more than **60,000 customers were in the dark for 50 hours or more**.

Today, rural and remote communities are more likely to experience poorer reliability, and the increased frequency of severe weather events create and will continue to create further challenges.

Number of Customers Experiencing Significantly Poorer Reliability than Average





Community-scale battery storage facility outside of Thunder Bay

In a 2024 survey, a majority of customers said that they want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.

In their **current draft plan**, Hydro One has developed a program that includes a combination of larger **community-scale** batteries and smaller **individual customer** batteries, which store electricity and provide backup power if an outage does occur.

Batteries are an effective way to target reliability improvements for individual customers and communities that experience the poorest reliability.

At the rate of investment being proposed in the draft plan, Hydro One anticipates reliability improvements for around **10,000** customers. However, based on customer feedback, Hydro One could install more or fewer batteries.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$51 less by 2032 (average of $10 less each year)	Included in Draft Plan	$51 more by 2032 (average of $10 more each year)

Investment Trade-Offs

Targeted reliability improvements

Commercial & Industrial

ST-Low Version

SURVEY PAGE

Hydro One Customer Engagement Survey

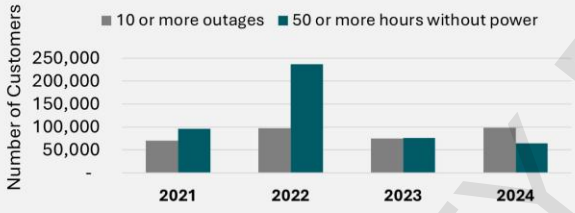
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	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$22 less by 2032 (average of $4 less each year)	Included in Draft Plan	$22 more by 2032 (average of $4 more each year)

Investment Trade-Offs

Targeted reliability improvements

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

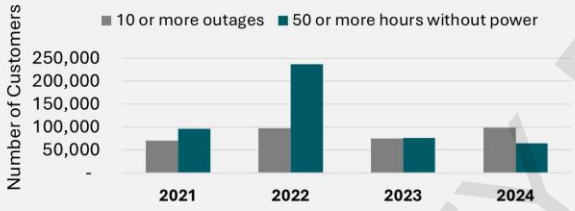
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	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$124 less by 2032 (average of $25 less each year)	Included in Draft Plan	$124 more by 2032 (average of $25 more each year)

SURVEY PAGE

Investment Trade-Offs

Targeted reliability improvements

Commercial & Industrial

ST-High Version

Hydro One Customer Engagement Survey

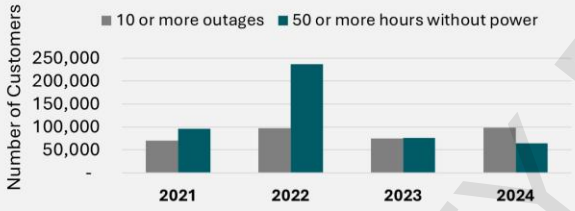
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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$605 less by 2032 (average of $121 less each year)	Included in Draft Plan	$605 more by 2032 (average of $121 more each year)

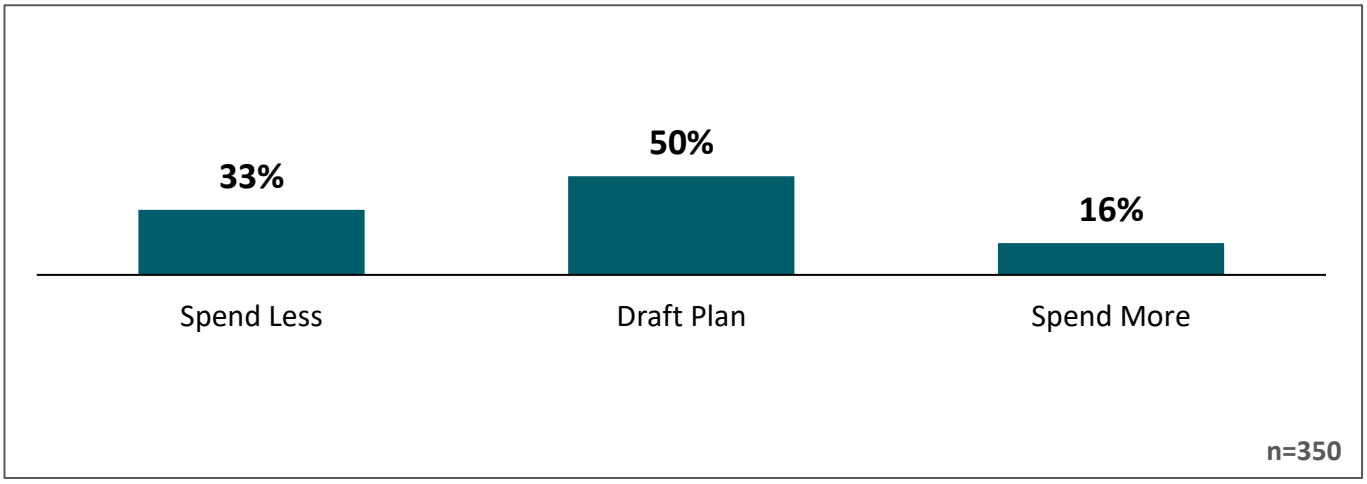
SURVEY PAGE

Investment Trade-Offs

Targeted reliability improvements

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	35%	35%	36%	30%	26%
Draft Plan	50%	40%	56%	54%	61%
Spend More	15%	26%	8%	16%	13%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	38%	28%	36%	31%	37%	22%
Draft Plan	43%	56%	47%	55%	51%	50%
Spend More	19%	16%	17%	13%	13%	28%

Investment Trade-Offs

Targeted reliability improvements

Commercial & Industrial

Q Additional Feedback (Optional)

Responses	%
Find efficiencies/alternative funding/customers shouldn't pay	1.1%
Concerns over community-scale battery storage facilities/limitations	1.0%
Need more information	1.0%
Focus on home back-up sources/incentive to install	0.8%
Support the draft plan/increase is reasonable	0.7%
Bury the lines	0.5%
Willing to pay more for improved reliability	0.4%
Against increases/costs are too expensive	0.4%
Improve reliability/reduce outages	0.3%
Focus on renewable, nuclear and energy storage solutions	0.3%
Focus on rural customers/communities	0.2%
Other	0.2%
No comment/None/Don’t know	93.1%

Note: Only responses >0.1% shown

Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

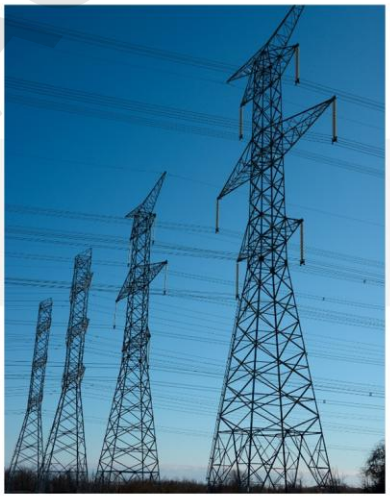
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

Commercial & Industrial

GSd Version

SURVEY PROOF

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$21 less by 2032 (average of $4 less each year)	**Included in Draft Plan**	$21 more by 2032 (average of $4 more each year)

Investment Trade-Offs

Keeping pace with transmission renewal

Commercial & Industrial

ST-Low Version

SURVEY DRAFT

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$164 less by 2032 (average of $33 less each year)	**Included in Draft Plan**	$164 more by 2032 (average of $33 more each year)

Investment Trade-Offs

Keeping pace with transmission renewal

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

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- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

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	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$923 less by 2032 (average of $185 less each year)	**Included in Draft Plan**	$921 more by 2032 (average of $184 more each year)

SURVEY PROOF

Investment Trade-Offs

Keeping pace with transmission renewal

Commercial & Industrial

ST-High Version

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

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Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$4,511 less by 2032 (average of $902 less each year)	**Included in Draft Plan**	$4,505 more by 2032 (average of $901 more each year)

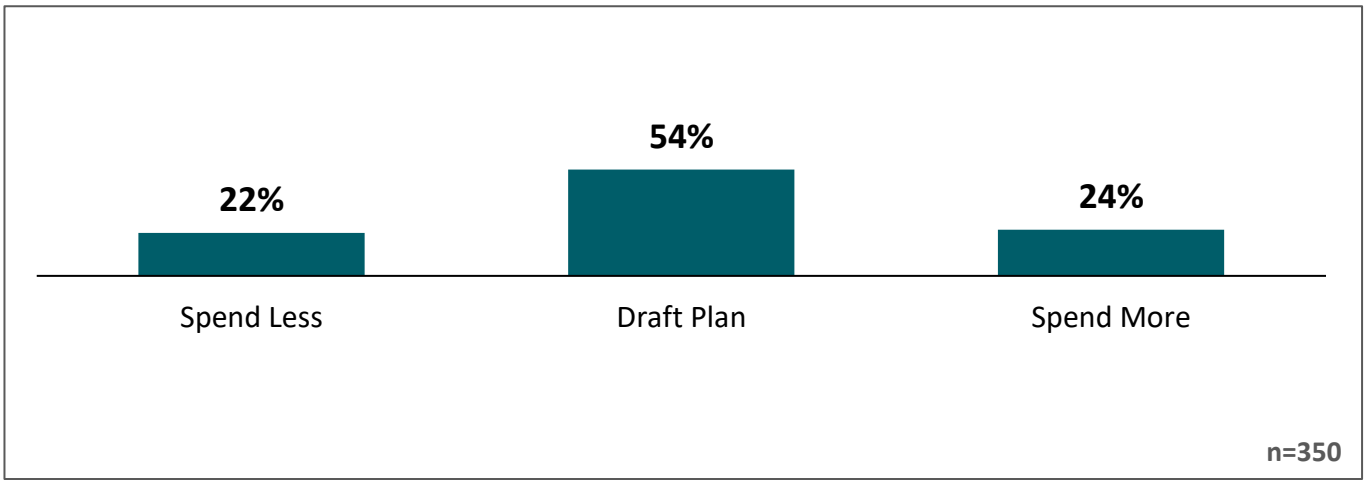
SURVEY PROOF

Investment Trade-Offs

Keeping pace with transmission renewal

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	23%	18%	26%	18%	22%
Draft Plan	58%	51%	48%	58%	62%
Spend More	19%	30%	26%	24%	16%

Consumption Quartiles

Bill Impact

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	29%	18%	19%	23%	25%	11%
Draft Plan	46%	63%	56%	53%	54%	56%
Spend More	25%	19%	26%	24%	21%	32%

Investment Trade-Offs

Keeping pace with transmission renewal

Commercial & Industrial

Q Additional Feedback (Optional)

Responses	%
Find efficiencies/alternative funding/customers shouldn't pay	0.6%
Invest now to prepare for future/prevent future increases	0.6%
Improve reliability/reduce outages	0.6%
Need more information	0.5%
Against increases/costs are too expensive	0.4%
Support the draft plan/increase is reasonable	0.3%
Distrust in the engagement/rate increases are inevitable	0.3%
Focus on preventative maintenance	0.2%
Willing to pay more for improved reliability	0.2%
No comment/None/Don’t know	96.3%

Note: Only responses >0.1% shown

Investment Trade-Offs

Stewardship of the transmission system

Commercial & Industrial

GSd Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$17 less by 2032 (average of $3 less each year)	Included in Draft Plan	$17 more by 2032 (average of $3 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Commercial & Industrial

ST-Low Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

hydro one

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$132 less by 2032 (average of $26 less each year)	Included in Draft Plan	$132 more by 2032 (average of $26 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

hydro one

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These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$741 less by 2032 (average of $148 less each year)	Included in Draft Plan	$741 more by 2032 (average of $148 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Commercial & Industrial

ST-High Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

hydro one

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These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$3,625 less by 2032 (average of $725 less each year)	Included in Draft Plan	$3,624 more by 2032 (average of $725 more each year)

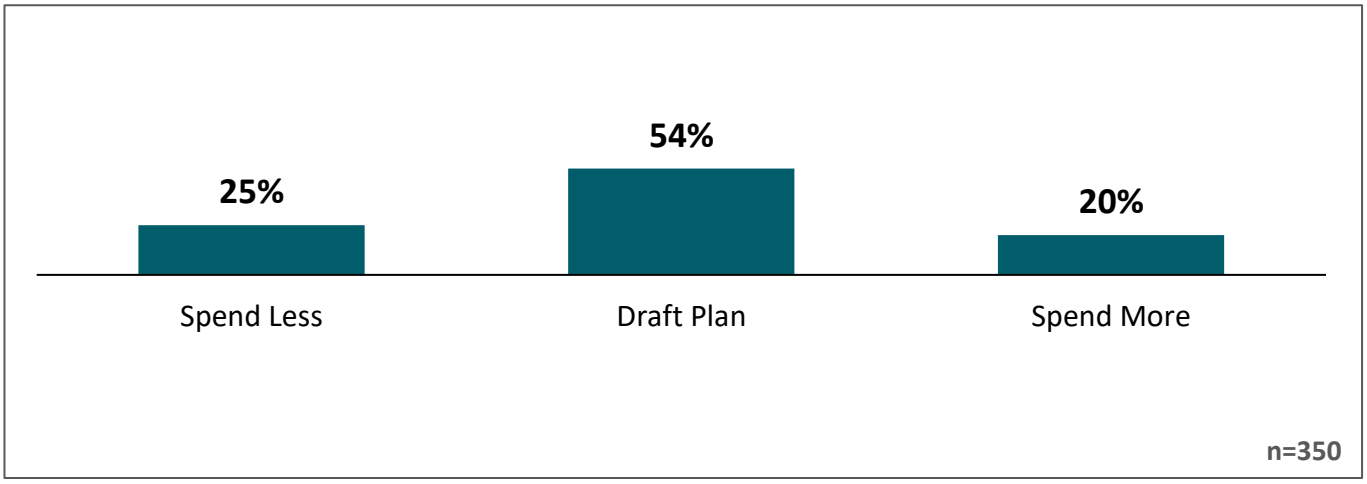
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	25%	19%	31%	25%	29%
Draft Plan	59%	51%	53%	58%	49%
Spend More	16%	30%	16%	17%	23%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	25%	24%	28%	24%	28%	18%
Draft Plan	52%	58%	53%	55%	54%	56%
Spend More	23%	18%	19%	21%	19%	27%

Investment Trade-Offs

Stewardship of the transmission system

Commercial & Industrial

Q Additional Feedback (Optional)

Responses	%
Bury the lines	0.8%
Find efficiencies/alternative funding/customers shouldn't pay	0.6%
Against increases/costs are too expensive	0.4%
Replace wood poles with stronger/more durable materials	0.3%
Need more information	0.3%
Distrust in the engagement/rate increases are inevitable	0.3%
Improve line maintenance/vegetation management	0.2%
No comment/None/Don’t know	97.1%

Note: Only responses >0.1% shown

Investment Trade-Offs

Maintaining buildings and facilities

Commercial & Industrial

GSd Version

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$11 less by 2032 (average of $2 less each year)	Included in Draft Plan	$11 more by 2032 (average of $2 more each year)
Average Monthly Transmission Bill Impact	$1 less by 2032 (average of $0.17 less each year)		$3 more by 2032 (average of $1 more each year)

SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Commercial & Industrial

ST-Low Version

SURVEY PAGE

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

hydro one

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$5 less by 2032 (average of $1 less each year)	Included in Draft Plan	$5 more by 2032 (average of $1 more each year)
Average Monthly Transmission Bill Impact	$7 less by 2032 (average of $1 less each year)		$21 more by 2032 (average of $4 more each year)

Investment Trade-Offs

Maintaining buildings and facilities

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$28 less by 2032 (average of $6 less each year)	Included in Draft Plan	$26 more by 2032 (average of $5 more each year)
Average Monthly Transmission Bill Impact	$38 less by 2032 (average of $8 less each year)		$115 more by 2032 (average of $23 more each year)

SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Commercial & Industrial

ST-High Version

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

hydro one

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	Spend Less	Draft Plan	Spend More
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	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$135 less by 2032 (average of $27 less each year)	Included in Draft Plan	$125 more by 2032 (average of $25 more each year)
Average Monthly Transmission Bill Impact	$183 less by 2032 (average of $37 less each year)		$564 more by 2032 (average of $113 more each year)

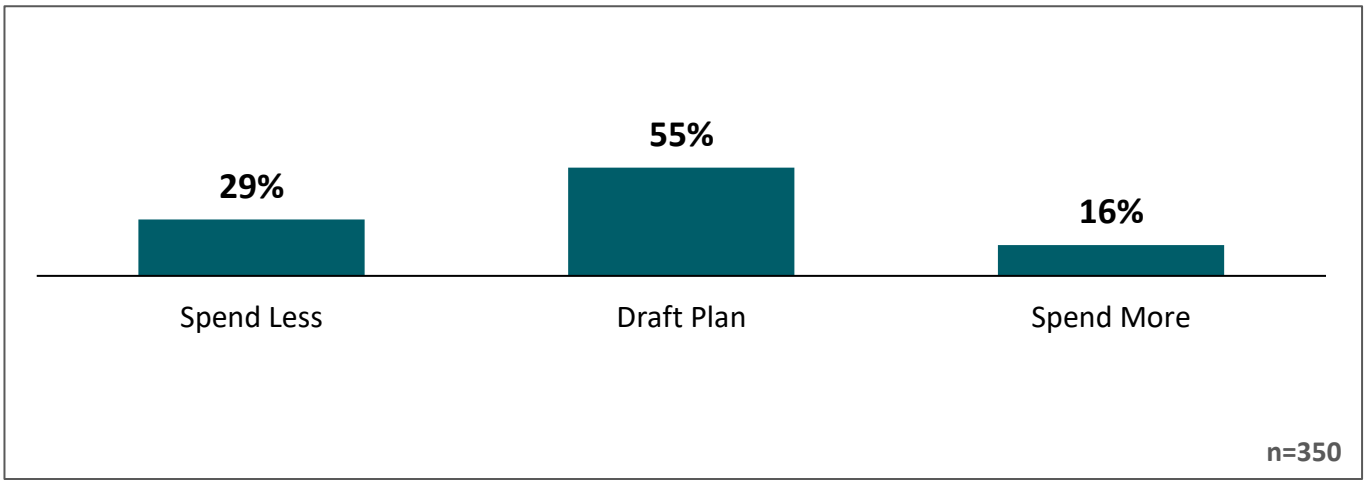
SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	35%	24%	29%	20%	32%
Draft Plan	49%	57%	58%	58%	58%
Spend More	15%	19%	13%	22%	10%

Consumption Quartiles **Bill Impact**

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	29%	25%	34%	27%	31%	21%
Draft Plan	55%	62%	48%	56%	56%	53%
Spend More	16%	12%	17%	17%	13%	27%

Investment Trade-Offs

Maintaining buildings and facilities

Commercial & Industrial

Q Additional Feedback (Optional)

Responses	%
Against increases/costs are too expensive	0.9%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Concerns around cost of living/inflation	0.3%
Other	0.6%
No comment/None/Don’t know	97.9%

Note: Only responses >0.1% shown

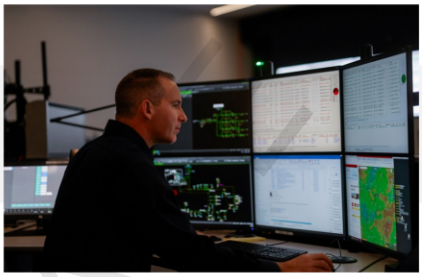
Investment Trade-Offs
Information technology

Commercial & Industrial

GSd Version

Hydro One Customer Engagement Survey
Information technology

hydro one



Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.

When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$16 less by 2032 (average of $3 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$6 less by 2032 (average of $1 less each year)	

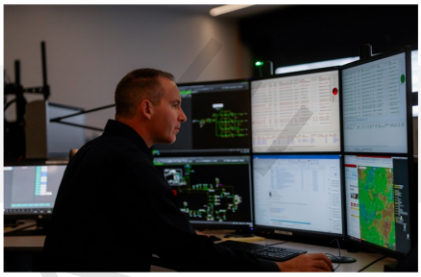
SURVEY PACKET

Investment Trade-Offs
Information technology

Commercial & Industrial

ST-Low Version

Hydro One Customer Engagement Survey
Information technology



Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.

When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
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Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$7 less by 2032 (average of $1 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$43 less by 2032 (average of $9 less each year)	

SURVEY PAGE

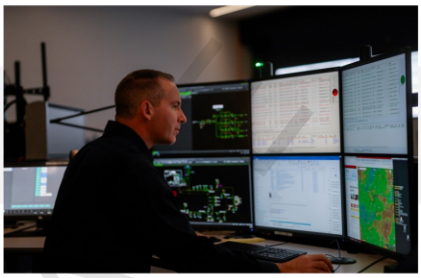
Investment Trade-Offs
Information technology

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey
Information technology

hydro one



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Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$38 less by 2032 (average of $8 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$242 less by 2032 (average of $48 less each year)	

SURVEY PAPER

Investment Trade-Offs
Information technology

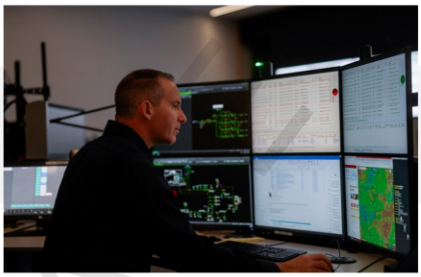
Commercial & Industrial

ST-High Version

Hydro One Customer Engagement Survey
Information technology

hydro one

Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.



When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

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Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$185 less by 2032 (average of $37 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$1,183 less by 2032 (average of $237 less each year)	

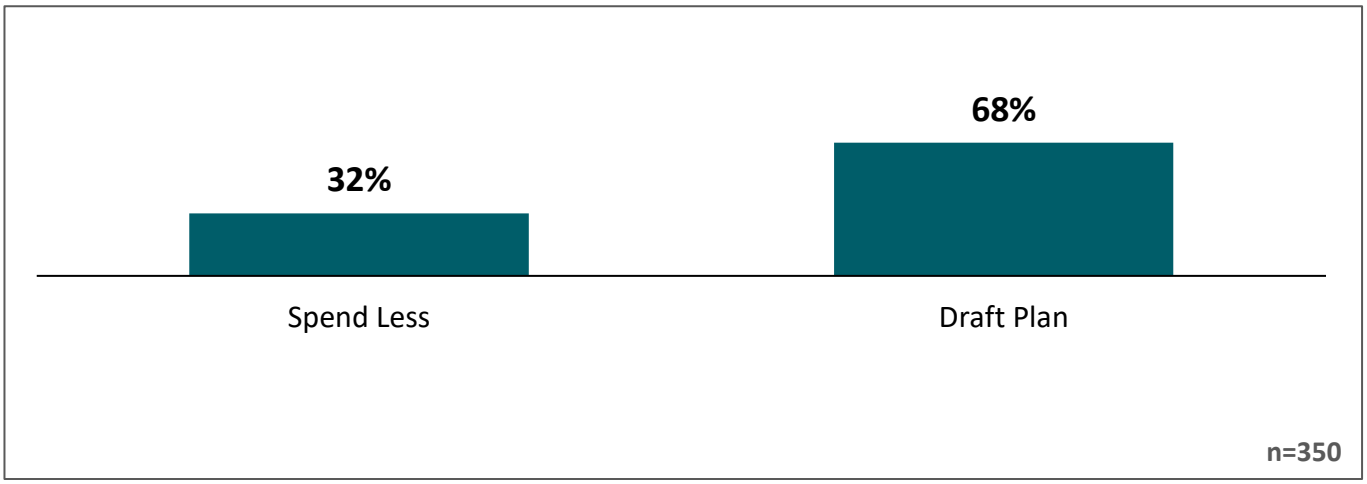
SURVEY PACKET

Investment Trade-Offs

Information technology

Commercial & Industrial

Q Which of the following options do you prefer?



Region

	West	Central	Central East	East	North
Spend Less	29%	28%	39%	35%	32%
Draft Plan	71%	72%	61%	65%	68%

Consumption Quartiles

Bill Impact

	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend Less	36%	29%	34%	29%	36%	19%
Draft Plan	64%	71%	66%	71%	64%	81%

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Investment Trade-Offs
Information technology

Q Additional Feedback (Optional)

Responses	%
Find efficiencies/alternative funding/customers shouldn't pay	0.8%
Against increases/costs are too expensive	0.8%
Support the draft plan/increase is reasonable	0.8%
Infrastructure needs to be upgraded	0.6%
Distrust in the engagement/rate increases are inevitable	0.3%
Other	0.2%
No comment/None/Don’t know	96.5%

Note: Only responses >0.1% shown



SURVEY PAGE

Hydro One Customer Engagement Survey
What is the impact of my choices?

hydro one

Throughout this survey, you have been asked about 7 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on your bill will be recalculated.

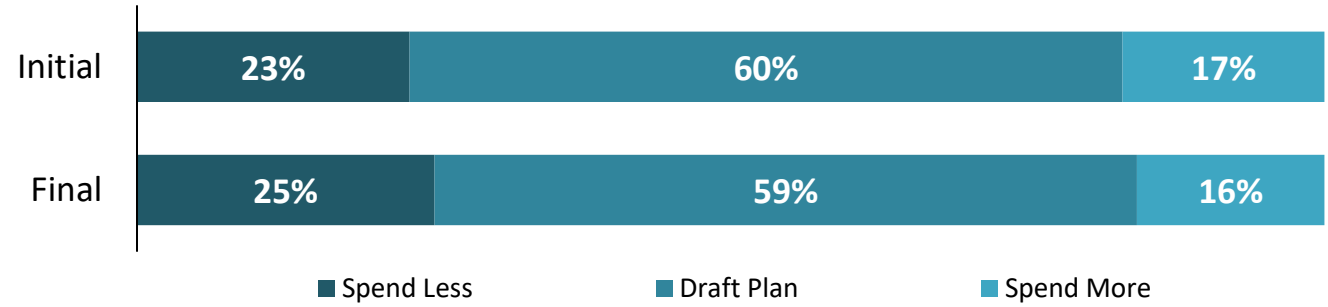
The bill impacts associated with each choice represent the average increase on your monthly bill from 2027 to 2032, followed by the average increase on your monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

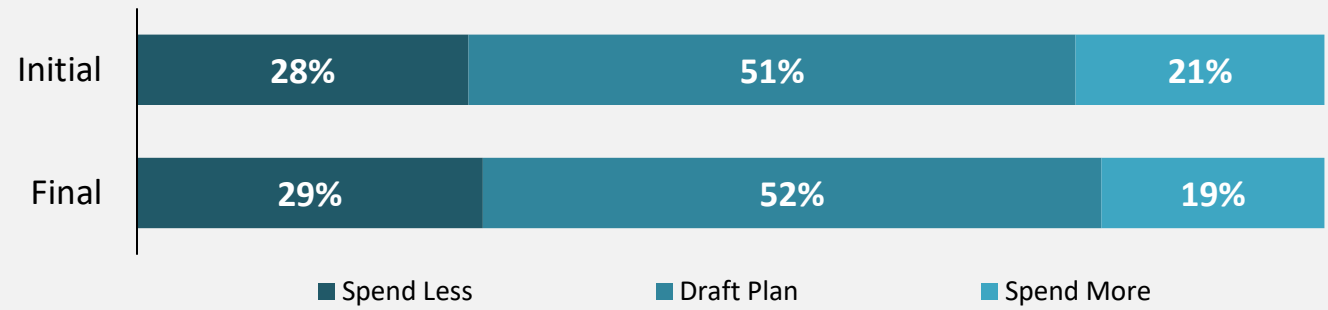
Finalizing Choices

Commercial & Industrial

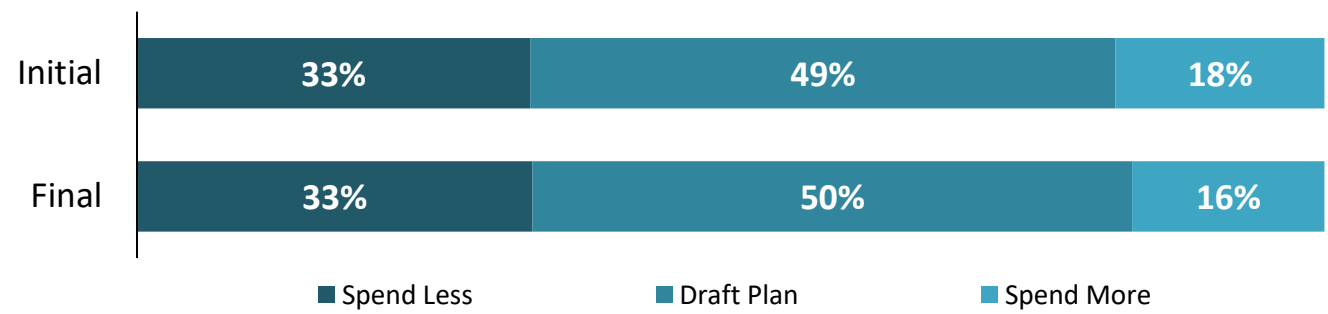
Overall system reliability



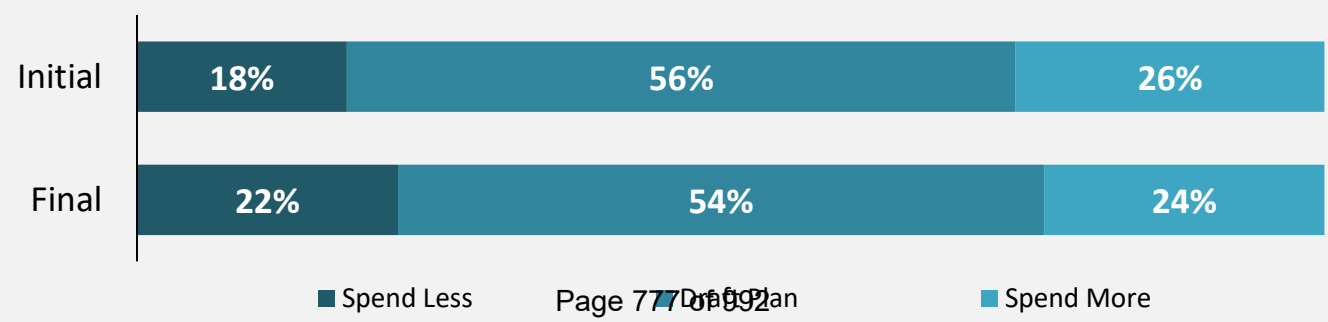
Managing the impacts of severe weather



Targeted reliability improvements



Keeping pace with transmission renewal

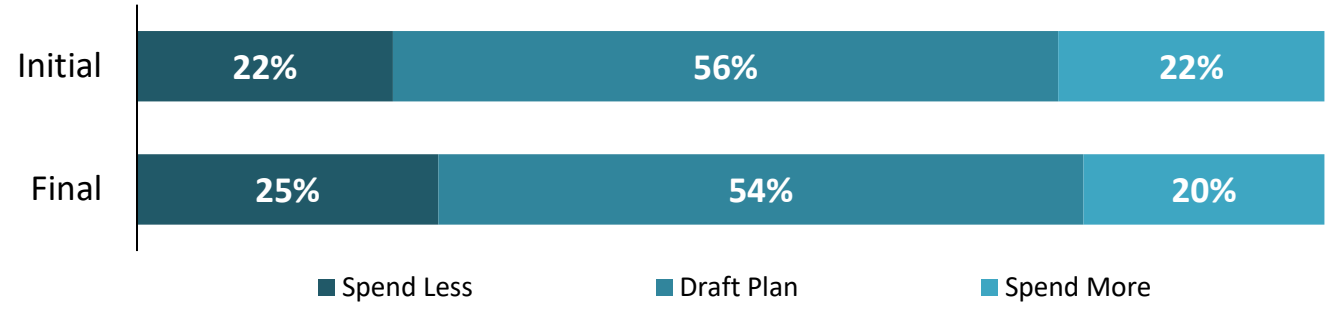


Investment Trade-Offs

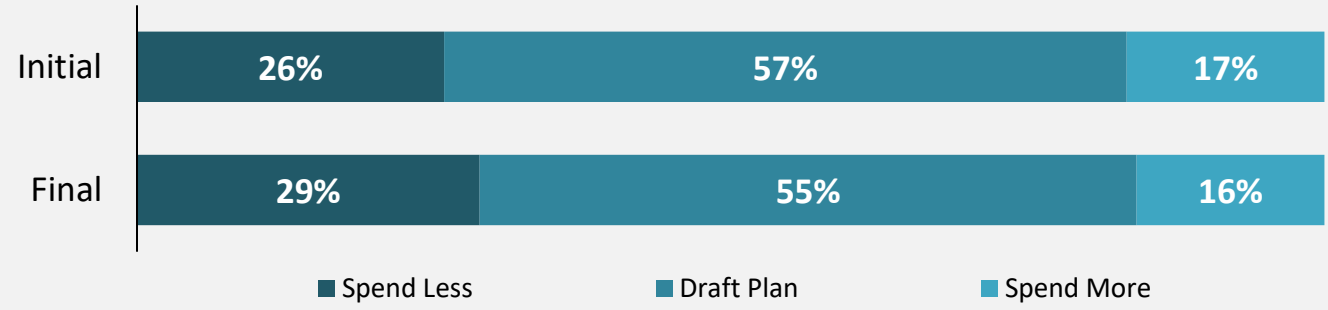
Finalizing Choices

Commercial & Industrial

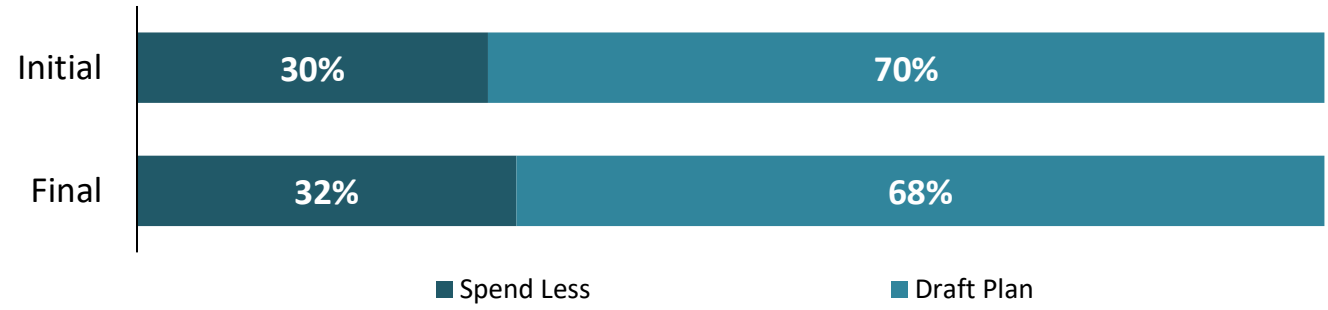
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



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Investment Trade-Offs

Overall evaluation of the draft plans

Commercial & Industrial

GSd Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **general service demand customer** would see:

- The **distribution** portion of their **monthly bill** increase from $2,720 in 2027 to $4,449 by the end of 2032 – an increase of **$1,729** on the monthly bill. This represents an average increase of **$346** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $681 in 2027 to $889 by the end of 2032 – an increase of **$208** on the monthly bill. This represents an average increase of **$42** on the monthly bill each year.

SURVEY PAGE

ST-Low Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **sub-transmission low consumption customer** would see:

- The **distribution** portion of their **monthly bill** increase from $2,221 in 2027 to $2,963 by the end of 2032 – an increase of **$742** on the monthly bill. This represents an average increase of **$148** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $5,279 in 2027 to $6,891 by the end of 2032 – an increase of **$1,613** on the monthly bill. This represents an average increase of **$323** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plans

Commercial & Industrial

ST-Med Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **sub-transmission average consumption customer** would see:

- The **distribution** portion of their **monthly bill** increase from $6,739 in 2027 to $10,908 by the end of 2032 – an increase of **$4,169** on the monthly bill. This represents an average increase of **$834** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $29,645 in 2027 to $38,702 by the end of 2032 – an increase of **$9,058** on the monthly bill. This represents an average increase of **$1,812** on the monthly bill each year.

SURVEY PAGE

ST-High Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **sub-transmission high consumption customer** would see:

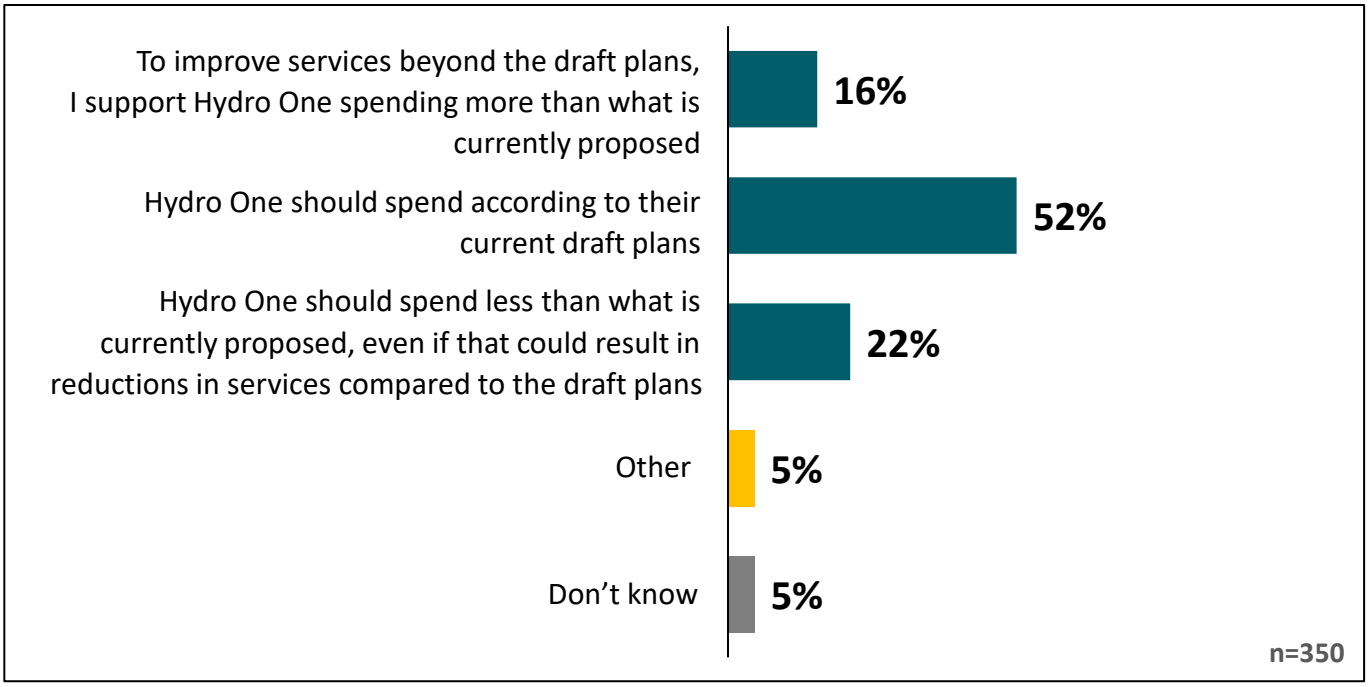
- The **distribution** portion of their **monthly bill** increase from $28,121 in 2027 to $48,505 by the end of 2032 – an increase of **$20,384** on the monthly bill. This represents an average increase of **$4,077** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $144,951 in 2027 to $189,239 by the end of 2032 – an increase of **$44,289** on the monthly bill. This represents an average increase of **$8,858** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plans

Commercial & Industrial

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?



Region

	West	Central	Central East	East	North
Spend More	21%	17%	11%	17%	10%
Draft Plans	46%	54%	56%	49%	61%
Spend Less	23%	20%	19%	26%	29%
Other	6%	3%	10%	--	--
Don't know	4%	6%	4%	8%	--

Investment Trade-Offs

Overall evaluation of the draft plans

Commercial & Industrial

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?

		Consumption Quartiles				Bill Impact	
	Overall	Low	Medium-Low	Medium-High	High	Major Impact	No Major Impact
Spend More	16%	20%	14%	16%	15%	14%	23%
Draft Plans	52%	46%	65%	47%	51%	52%	52%
Spend Less	22%	25%	16%	23%	25%	24%	14%
Other	5%	4%	5%	7%	2%	5%	4%
Don't know	5%	5%	1%	7%	6%	4%	7%

Investment Trade-Offs

Final comments on the draft plans

Commercial & Industrial

Q Do you have any final comments regarding Hydro One's draft plans for 2028–2032 and the proposed rate increase? (Optional)

Responses	%
Find efficiencies/alternative funding/customers shouldn't pay	3.4%
Lower rates/rates are too high	2.1%
Improve reliability/reduce outages	1.7%
Transparency on internal operations	1.3%
Distrust in the engagement/rate increases are inevitable	0.9%
Environmental concerns/green initiatives	0.8%
Support the increase/investments are necessary	0.5%
Improve line maintenance/vegetation management	0.5%
Positive comment about Hydro One/service	0.3%
Maintain current service levels/prioritize areas of higher need	0.2%
Concerns around cost of living/inflation	0.2%
Stop selling power to the US/increase price to the US	0.2%
Other	0.6%
No comment/None/Don't know	87.2%

Note: Only responses >0.1% shown

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Commercial & Industrial Customers

Survey Diagnostics



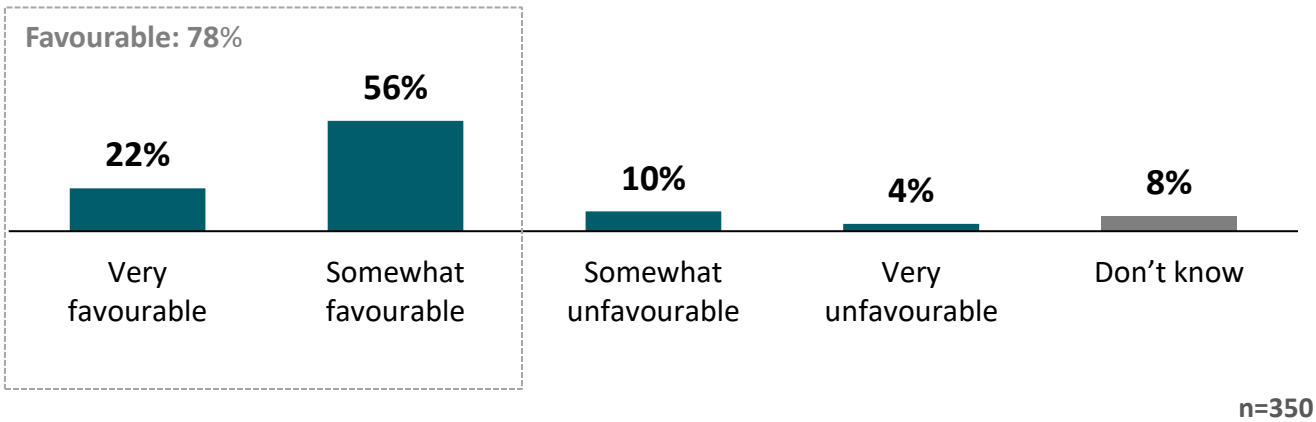
Survey Diagnostics

Favourability and amount of information

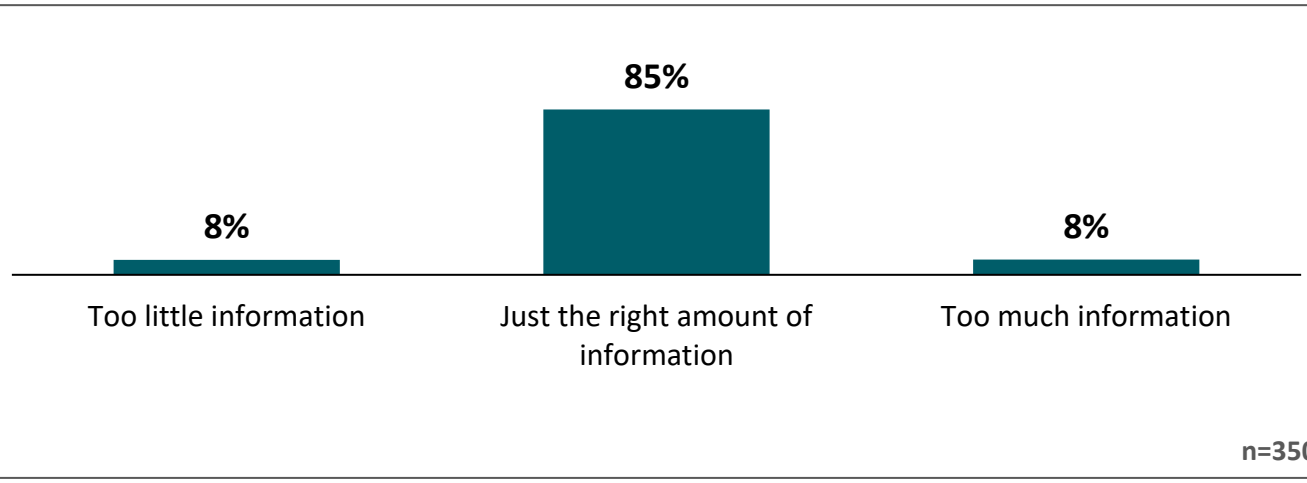
Commercial & Industrial

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



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Survey Diagnostics
Other information not included

Commercial & Industrial

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
Transparency on internal operations	2.8%
Better outage communication/information	1.3%
Distrust in the engagement/rate increases are inevitable	0.9%
Reducing customer costs/affordability measures	0.9%
Better explanation/transparency on bills	0.8%
More information on renewable energy	0.7%
More detailed information on the investments/infrastructure	0.7%
More information/communication about rate increases	0.7%
Survey/engagement experience feedback - positive	0.5%
Customer demographic comparison/region specific information	0.3%
Government involvement/subsidization	0.3%
Survey/engagement experience feedback - negative	0.2%
Focus on renewable, nuclear and energy storage solution	0.2%
Other	1.2%
No comment/None/Don’t know	88.4%

Note: Only responses >0.1% shown

Survey Diagnostics
Outstanding questions

Commercial & Industrial

Q Is there anything that you would still like answered? (Optional)

Responses	%
Transparency on internal operations	1.3%
Improve reliability/reduce outages	1.1%
Be transparent/communicate about rate increases	0.9%
Better explanation/transparency on bills	0.8%
Distrust in the engagement/rate increases are inevitable	0.8%
Focus on renewable, nuclear & energy storage solutions	0.5%
Survey/engagement experience feedback - positive	0.3%
Improve customer service/communication (general/outage)	0.3%
Plans to reduce/lower customer costs	0.3%
Helping seniors/fixed-income individuals	0.2%
Government involvement/subsidies	0.2%
More detailed information on the investments/infrastructure	0.2%
Other	0.5%
No comment/None/Don't know	92.5%

Note: Only responses >0.1% shown

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Large Distribution Account Customers

Online Survey Results

Section 6



Field Dates

The **Large Distribution Account Customer Online Survey** was sent to all large distribution customers with an available email address. Customers had an opportunity to complete the survey between **November 14th and December 22nd, 2025**.

Each customer received a unique URL that could be linked back to their average monthly demand, region and rate class. Survey pages that differed by customer type are identified as GSd (general service demand), ST-Low (sub transmission low), ST-Med (sub transmission medium), and ST-High (sub transmission high) versions throughout this report.

In total, the large distribution account customer survey was sent to **313** customers from *customerexperience@hydroone.com*. A total of four reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Commercial & Industrial Online Survey Completes

A total of **53** (unweighted) Hydro One large distribution account customers completed the online survey.

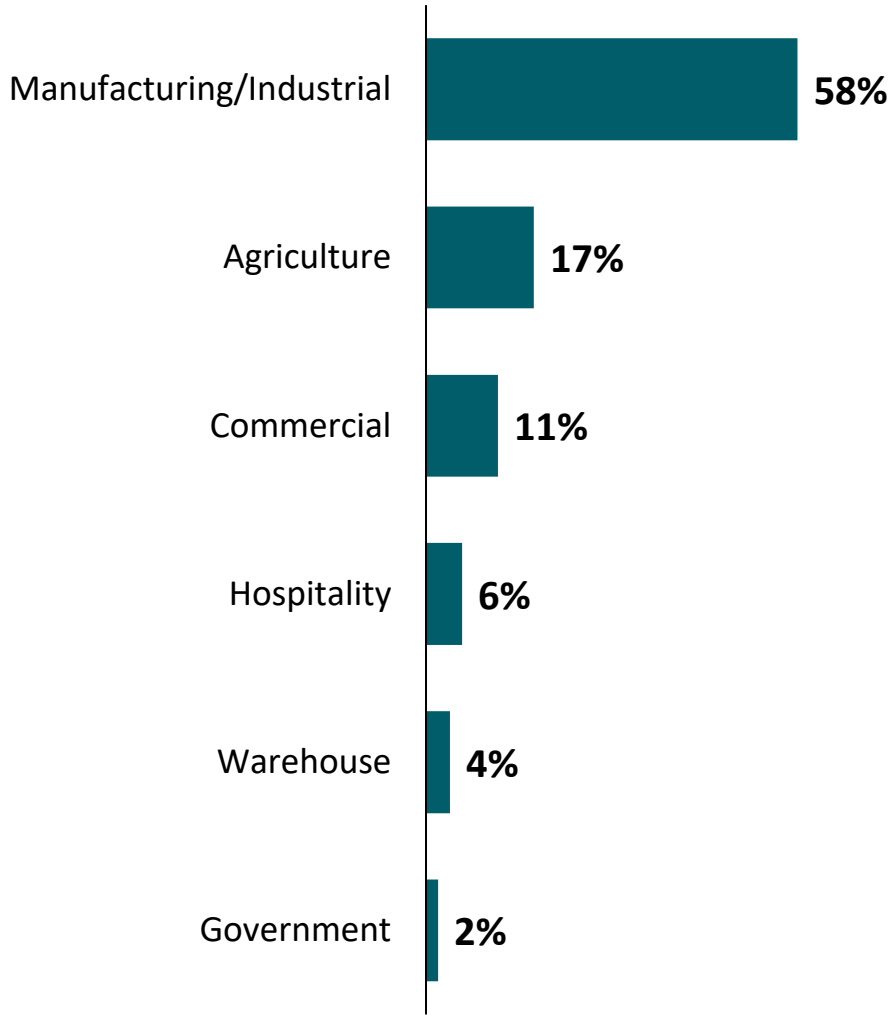
Sample Weighting

The large distribution account online survey sample was not weighted.

Firmographic Breakdown

Large Distribution

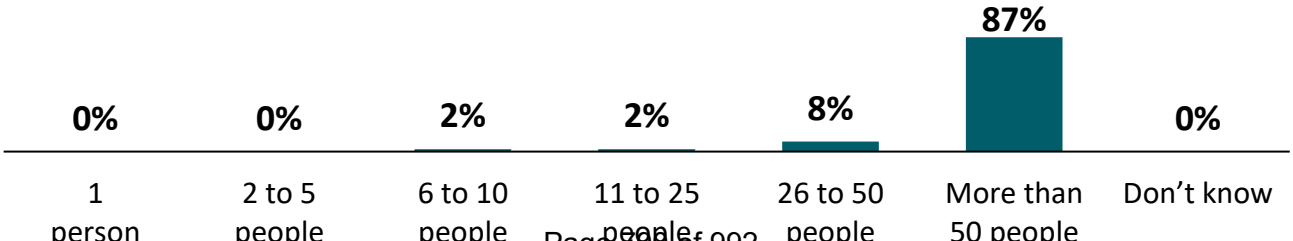
Q Business Sector



"Prefer not to say" (2%) not shown.

n=53

Q Business Size



"Prefer not to say" (2%) not shown.

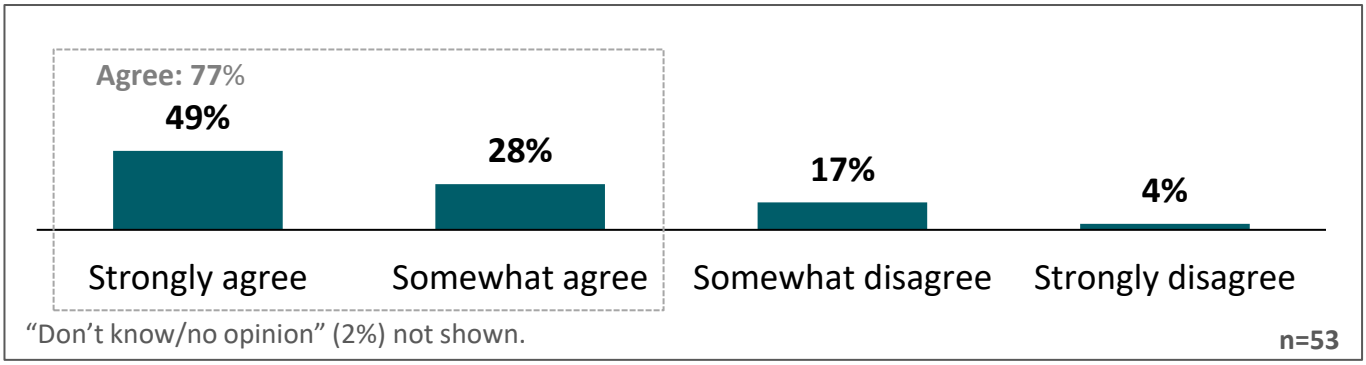
n=53

Environmental Controls

Large Distribution

To what extent do you agree or disagree with the following statements?

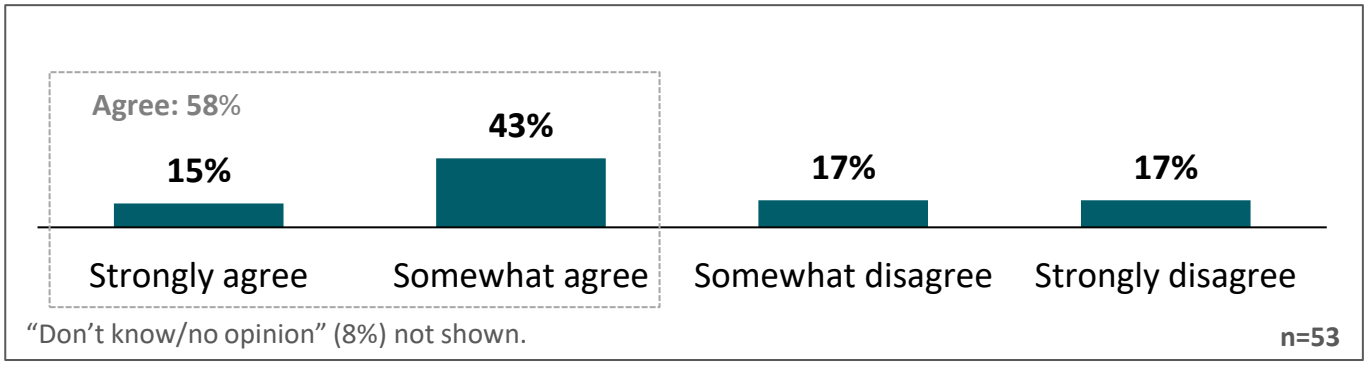
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (2%) not shown.

n=53

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (8%) not shown.

n=53

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GSd Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large business customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the general service demand rate class with an average monthly demand of 110 kW and average monthly consumption of 34,334 kWh.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

ST-Low Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plans** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 20-30 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a large business customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the sub-transmission low consumption rate class with an average monthly demand of 500 kW and average monthly consumption of 88,780 kWh.

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INNOVATIVE RESEARCH GROUP

SURVEY PAGE

ST-Med Version

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SURVEY PAGE

ST-High Version

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Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

For the purpose of this exercise, the estimates are based on a typical customer in the sub-transmission high consumption rate class with an average monthly demand of 13,730 kW and average monthly consumption of 2,641,420 kWh.

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INNOVATIVE RESEARCH GROUP

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by their customers. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plans, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plans.

Next year, Hydro One will present their proposed plans and input provided by customers to the OEB.

SURVEY PAGE

Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, including your own, **Hydro One** is also responsible for the local distribution system, which delivers electricity to your home, seasonal property, or organization through a network of wires, poles and other equipment.



Hydro One does not generate electricity or set electricity prices.

Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

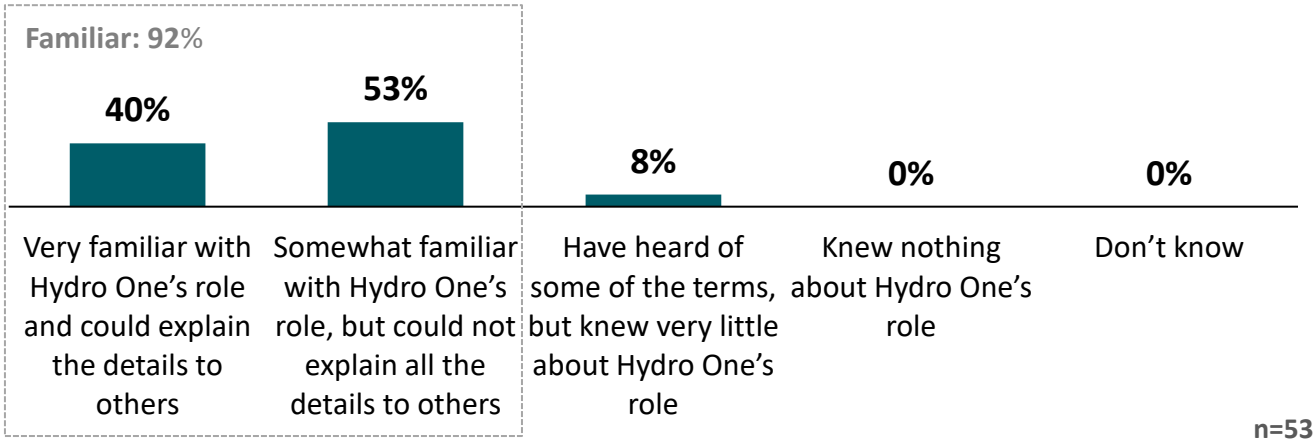
SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Large Distribution

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?

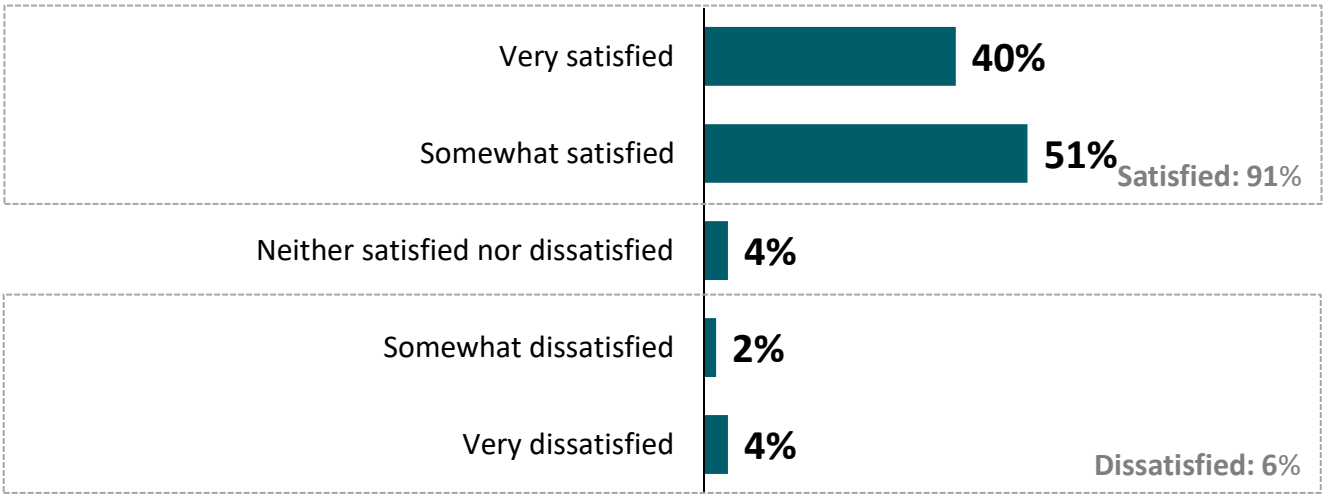


INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Overall satisfaction with Hydro One's service

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?



"*Don't know*" (0%) not shown.

n=53

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Large Distribution

GSd Version

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical general service demand customer, about 43% of the bill, or $3,093.42, goes to Hydro One per month. This amount is split into $2,459.41 for distribution and $634.01 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

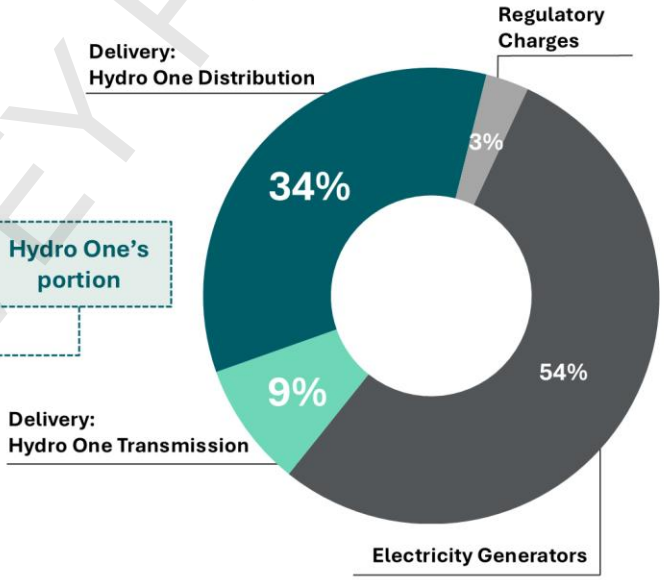
Sample Monthly Bill
(based on consumption of 34,334 kWh and demand of 110 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	3,856.35
Delivery	3,093.42
Regulatory Charges	218.82
Total Electricity Charges	$7,168.59
HST	931.92
Total Amount	$8,100.51

Hydro One's portion



The pie chart above is based on a total bill of $7,168.59 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 34,334 kWh and demand of 110 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

SURVEY PAGE

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Large Distribution

ST-Low Version

SURVEY PAGE

Hydro One Customer Engagement Survey

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Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical sub transmission low consumption customer, about 41% of the bill, or $7,011.07, goes to Hydro One per month. This amount is split into $2,096.67 for distribution and $4,914.40 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

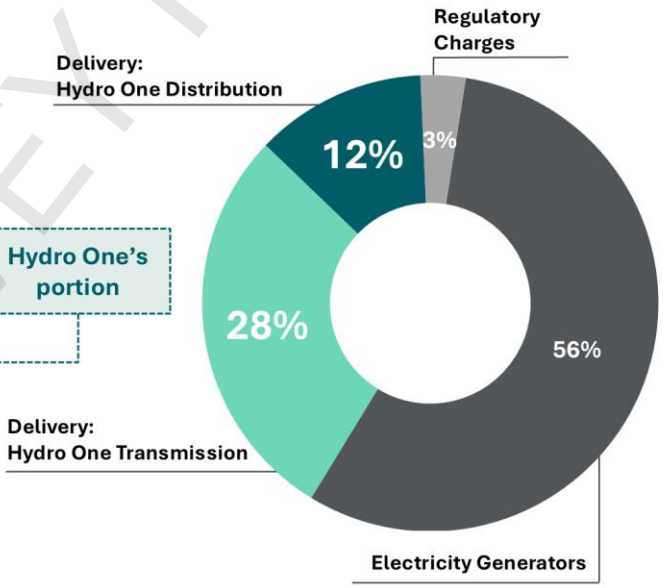
Sample Monthly Bill
(based on consumption of 88,780 kWh and demand of 500 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	9,717.90
Delivery	7,011.07
Regulatory Charges	551.04
Total Electricity Charges	$17,280.01
HST	2,246.40
Total Amount	$19,526.41

Hydro One's portion



The pie chart above is based on a total bill of $17,280.01 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 88,780 kWh and demand of 500 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Large Distribution

ST-Med Version

SURVEY PAGE

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical sub transmission average consumption customer, about 17% of the bill, or $33,641.70, goes to Hydro One per month. This amount is split into $6,042.43 for distribution and $27,599.27 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

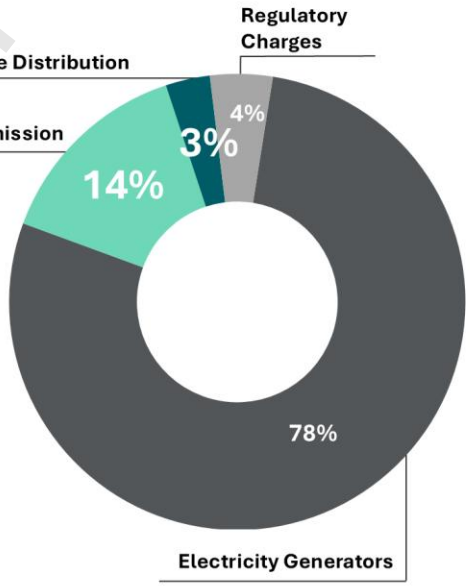
Sample Monthly Bill
(based on consumption of 1,373,443 kWh and demand of 2,808 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	150,337.73
Delivery	33,641.70
Regulatory Charges	8,521.09
Total Electricity Charges	$192,500.52
HST	25,025.07
Total Amount	$217,525.59

Hydro One's portion



The pie chart above is based on a total bill of $192,500.52 excluding HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 1,373,443 kWh and demand of 2,808 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

Although **Hydro One** is responsible for collecting payment from you for your entire electricity bill, only a portion goes to Hydro One. As of **July 1, 2025**, for a typical sub transmission high consumption customer, about 34% of the bill, or $159,644.10, goes to Hydro One per month. This amount is split into $24,714.68 for distribution and $134,949.42 for transmission.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

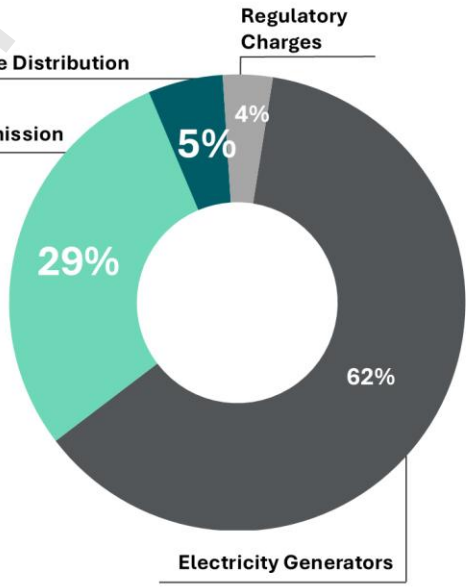
Sample Monthly Bill
(based on consumption of 2,641,420 kWh and demand of 13,730 kW as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	**289,131.10**
Delivery	**159,664.10**
Regulatory Charges	**16,387.62**
Total Electricity Charges	**$465,182.83**
HST	60,473.77
Total Amount	**$525,656.59**

Hydro One's portion



The pie chart above is based on a total bill of $465,182.83 excluding HST. The chart may not total 100% due to rounding.

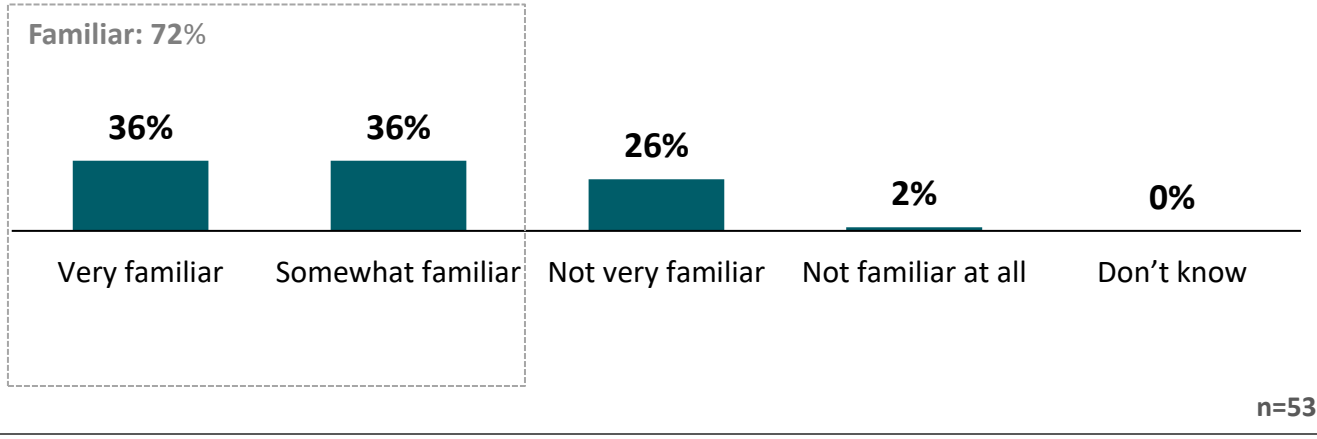
The sample bill above uses an average consumption level of 2,641,420 kWh and demand of 13,730 kW per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity charges.

SURVEY PAGE

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Hydro One?



Summary of Investment Plan

How Hydro One plans

Large Distribution

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity distribution and transmission services. This feedback was used to inform planners in developing the draft investment plans.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.
3. Make **targeted investments to improve reliability** for customers experiencing significantly poorer reliability than average.
4. Make investments to make the system **more resilient to severe weather**.
5. Make investments in technology to **accommodate customer requests and improve visibility into the system** (e.g., where and how much electricity is being used).

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

Large Distribution

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations, and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

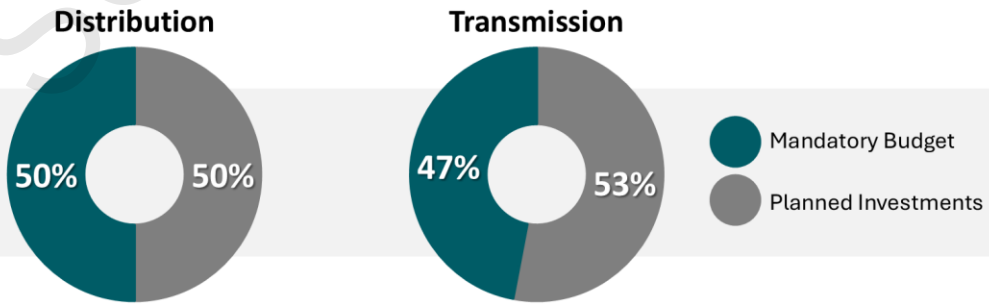
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Large Distribution

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

While Hydro One's draft plans cover both the **distribution system** serving approximately 1.5 million customers, as well as the **transmission system** serving most Ontarians, each system has different needs and objectives.

Some of the highlights of Hydro One's draft plans include:

Distribution Objectives



1. Improving the **day-to-day reliability** of the system by addressing equipment that is at a higher risk of failure.
2. Preparing for the **impacts of severe weather** by investing in vulnerable lines, clearing more overgrown vegetation, and using technology to restore power more quickly.
3. Improving reliability for thousands of customers experiencing below average reliability by investing in **new battery storage technology**.
4. Ensuring the grid is prepared to **keep pace with evolving customer needs** and accommodate higher levels of growth.

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest distributor and transmitter of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plan include:

Shared Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Large Distribution

GSd Version

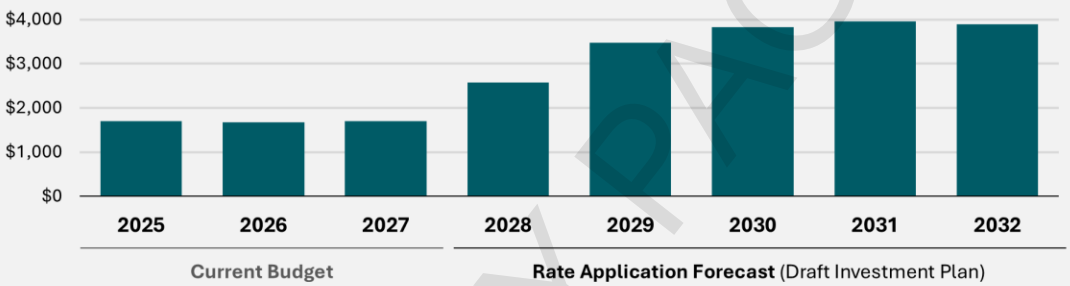
Hydro One Customer Engagement Survey

How much will Hydro One's draft distribution plan cost?

Hydro One has calculated the cost of their draft investment plans, which aim to achieve the objectives highlighted previously and meet Hydro One's legal and regulatory requirements.

The costs for **distribution system** investments are spread among all of Hydro One's 1.5 million distribution customers.

Distribution Budget: Current and Forecasted ($ millions)

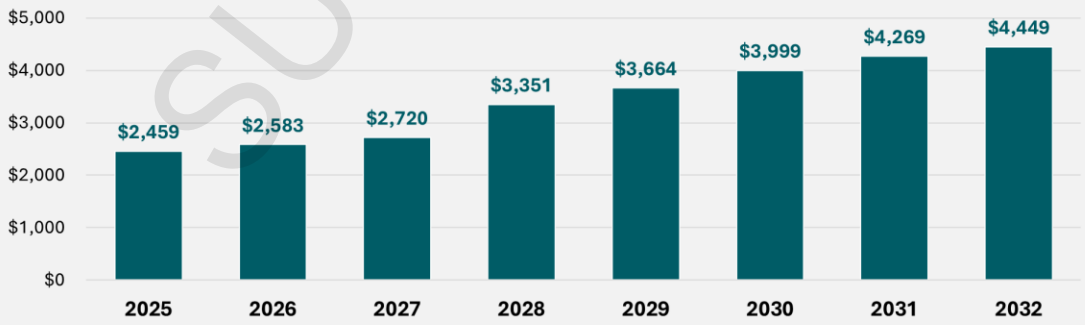


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **general service demand customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $2,720 in 2027 to $4,449 by the end of 2032 – an increase of **$1,729** on the monthly bill. This represents an average increase of **$346** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Large Distribution

ST-Low Version

SURVEY PAGE

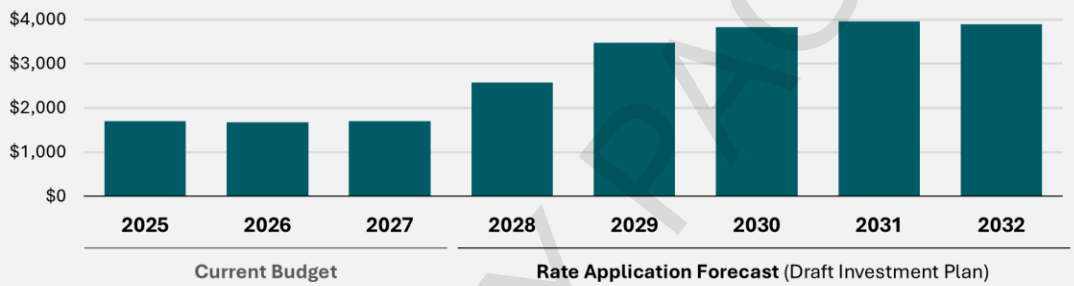
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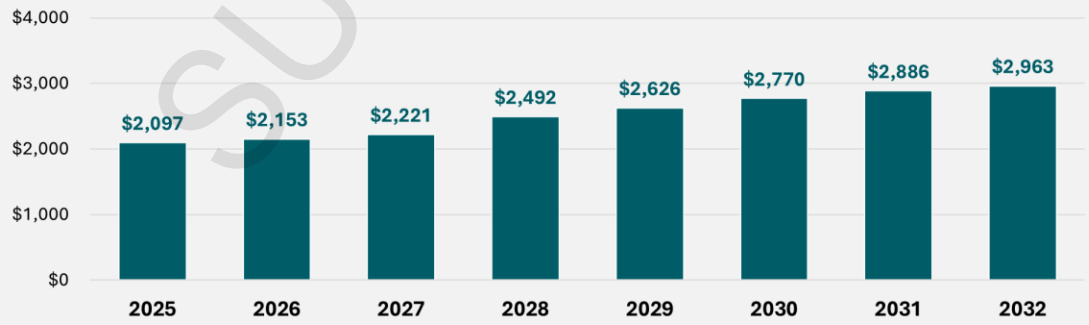


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **sub-transmission low consumption customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $2,221 in 2027 to $2,963 by the end of 2032 – an increase of **$742** on the monthly bill. This represents an average increase of **$148** on the monthly bill each year.

Distribution Portion of Monthly Bill



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Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Large Distribution

ST-Med Version

SURVEY PAGE

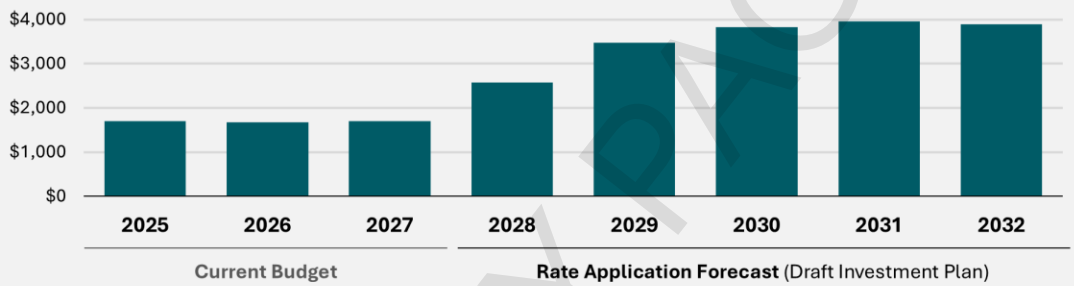
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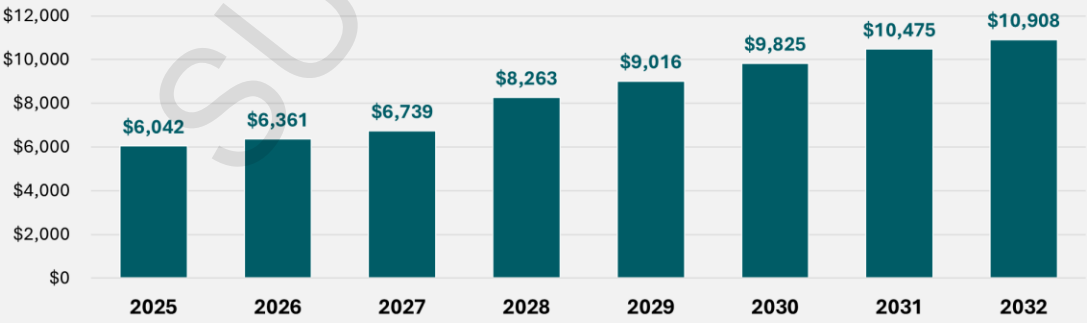


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **sub-transmission average consumption customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $6,739 in 2027 to $10,908 by the end of 2032 – an increase of **$4,169** on the monthly bill. This represents an average increase of **$834** on the monthly bill each year.

Distribution Portion of Monthly Bill



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Summary of Investment Plan

Cost of Hydro One's draft distribution plan

Large Distribution

ST-High Version

SURVEY PAGE

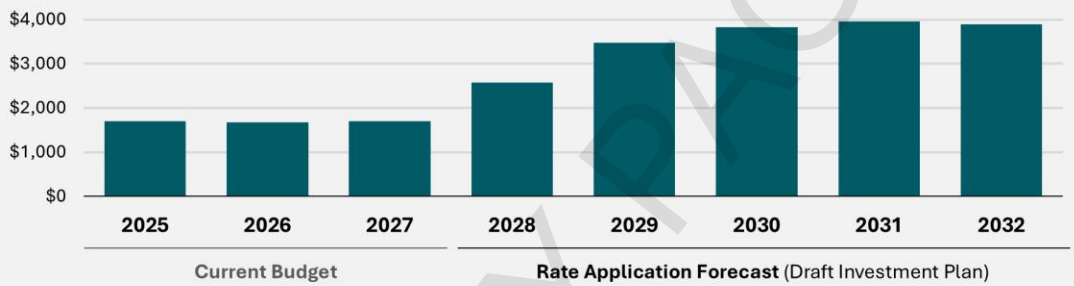
Hydro One Customer Engagement Survey

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Distribution Budget: Current and Forecasted ($ millions)

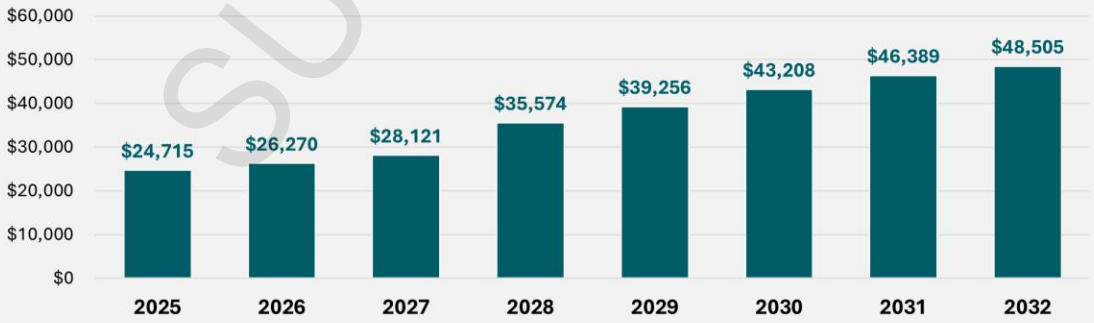


The draft distribution investment plan would result in an average annual funding requirement of **$3.5 billion** for **distribution** for 2028-2032.

How will this plan impact the distribution portion of customer bills?

For a typical **sub-transmission high consumption customer**, the **distribution** portion of their **monthly bill** is estimated to increase from $28,121 in 2027 to $48,505 by the end of 2032 – an increase of **$20,384** on the monthly bill. This represents an average increase of **$4,077** on the monthly bill each year.

Distribution Portion of Monthly Bill



Note:
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- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Large Distribution

GSd Version

SURVEY PAGE

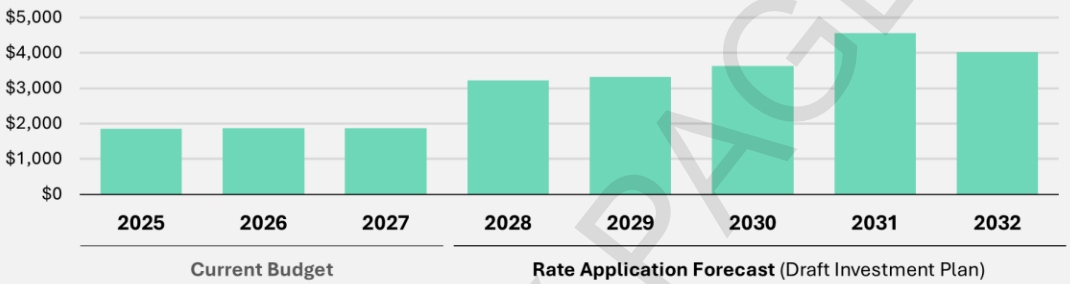
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

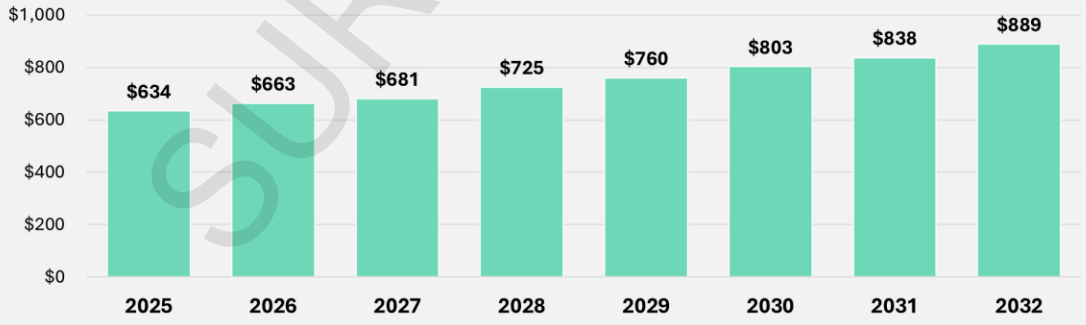


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **general service demand customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $681 in 2027 to $889 by the end of 2032 – an increase of **$208** on the monthly bill. This represents an average increase of **$42** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Large Distribution

ST-Low Version

SURVEY PAGE

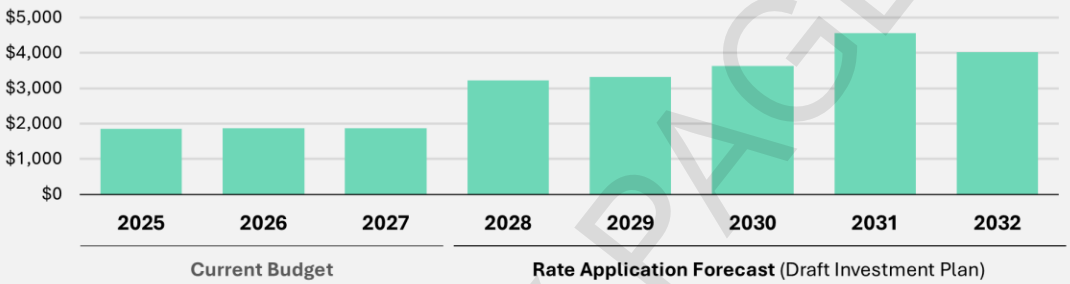
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

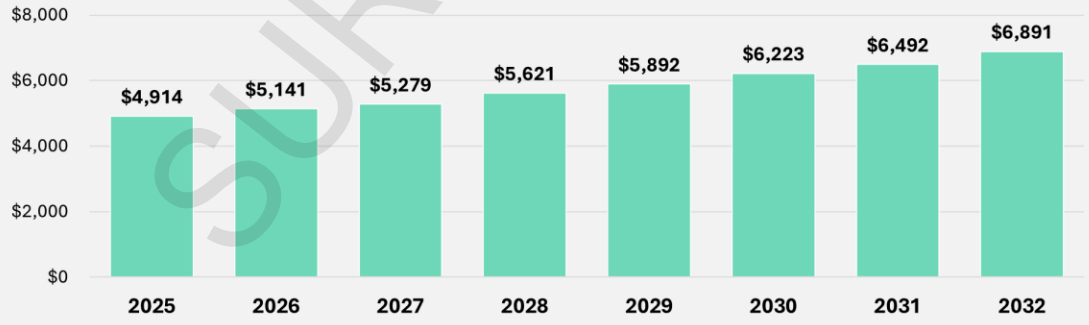


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **sub-transmission low consumption customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $5,279 in 2027 to $6,891 by the end of 2032 – an increase of **$1,613** on the monthly bill. This represents an average increase of **$323** on the monthly bill each year.

Transmission Portion of Monthly Bill



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Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Large Distribution

ST-Med Version

SURVEY PAGE

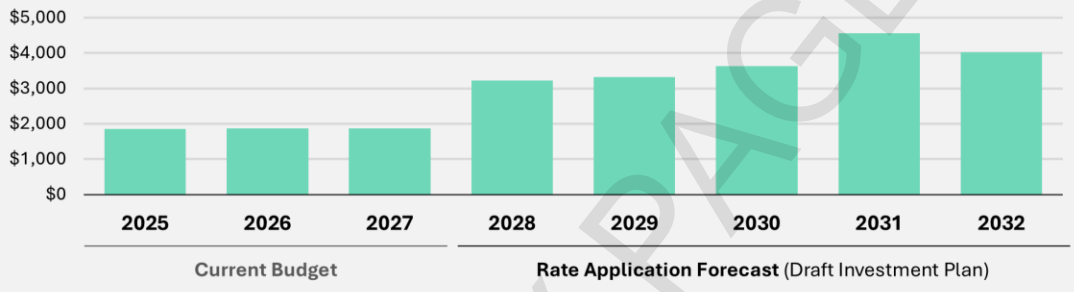
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

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Transmission Budget: Current and Forecasted ($ millions)

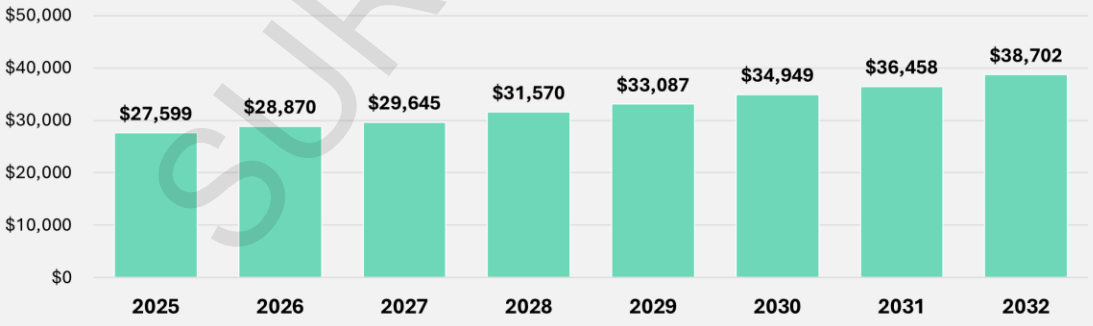


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **sub-transmission average consumption customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $29,645 in 2027 to $38,702 by the end of 2032 – an increase of **$9,058** on the monthly bill. This represents an average increase of **$1,812** on the monthly bill each year.

Transmission Portion of Monthly Bill



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- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Large Distribution

ST-High Version

SURVEY PAGE

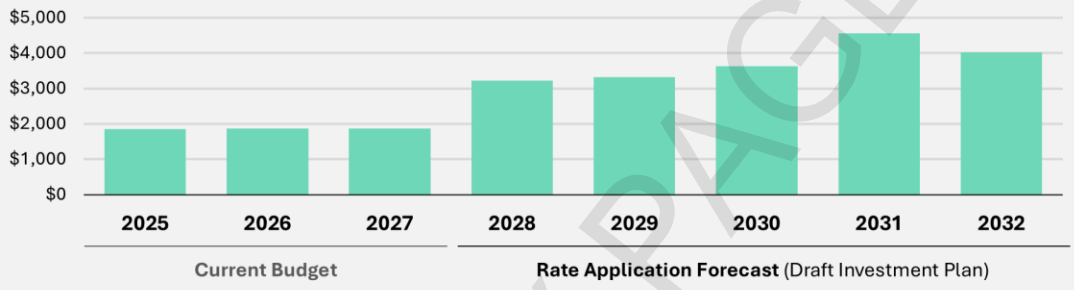
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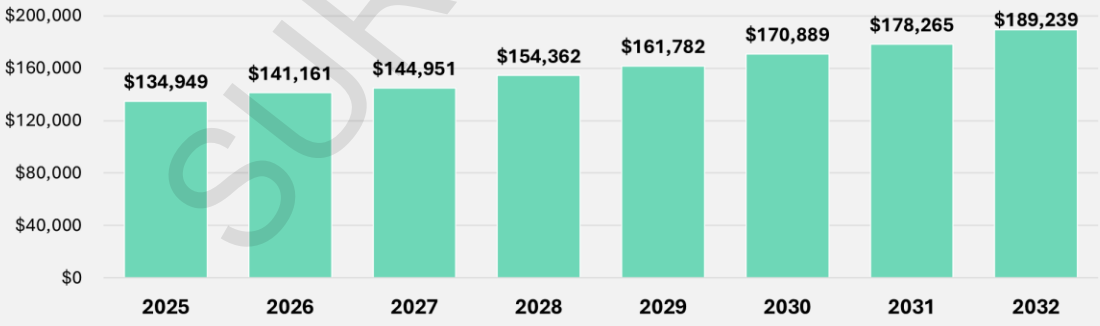


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **sub-transmission high consumption customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $144,951 in 2027 to $189,239 by the end of 2032 – an increase of **$44,289** on the monthly bill. This represents an average increase of **$8,858** on the monthly bill each year.

Transmission Portion of Monthly Bill



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Summary of Investment Plan

How to make choices

Large Distribution

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft investment plans, plus **7 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost for you.



SURVEY PAGE

Hydro One Customer Engagement Survey

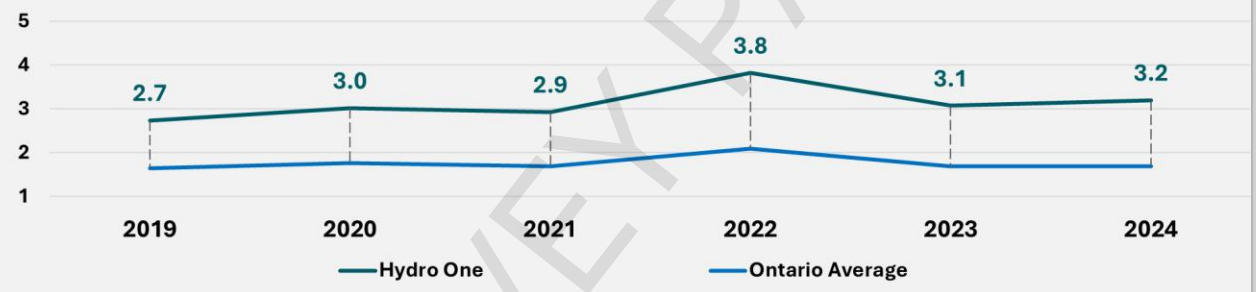
How does Hydro One's distribution grid perform?

Since most Hydro One customers live in rural areas, their distribution system looks different from other Ontario utilities. Serving more sparsely populated communities separated by significant distances means more equipment is needed, outages can take longer to locate, and power can take longer to restore.

On average, between 2019 and 2024, the typical Hydro One customer has experienced 1.4 more outages per year compared to the Ontario average.

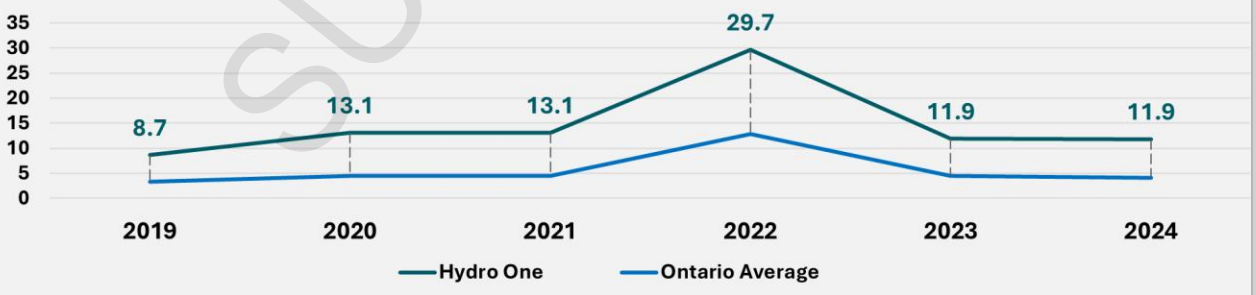


Number of Outages (Average Outages Per Customer)



When it comes to the total time spent without electricity per year, the typical Hydro One customer has been without power for 14.7 hours each year on average, which is 9.1 hours more than the Ontario average.

Duration of Outages (Average Hours Per Customer)



Severe weather, **tree contacts**, and **equipment failure** account for most of these outages. Notably, the distribution system experienced widespread outages due to severe weather in both 2022 and again in April 2025.

SURVEY P

Investment Trade-Offs

Overall system reliability

Large Distribution

GSd Version

Hydro One Customer Engagement Survey

Overall system reliability

hydro one

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

Hydro One typically identifies investments in equipment by taking into consideration the overall age, health, and likelihood of equipment failure.

In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

Hydro One generally tries to replace poor condition equipment before it fails. However, when equipment does fail, it can result in significant interruptions for customers.

In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$75 less by 2032 (average of $15 less each year)	Included in Draft Plan	$75 more by 2032 (average of $15 more each year)

SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Large Distribution

ST-Low Version

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

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In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

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- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
- **Replacing or repairing underground cables:** Hydro One has identified around 13% of all underground cables that are at increased risk of failure. In their current draft plan, Hydro One is proposing to replace or repair 10% of underground cables to reduce the risk of prolonged outages.



Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$32 less by 2032 (average of $6 less each year)	Included in Draft Plan	$32 more by 2032 (average of $6 more each year)

SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Large Distribution

ST-Med Version

Hydro One Customer Engagement Survey

Overall system reliability

hydro one

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

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In the past five years, outside of severe weather events, equipment failure has accounted for about 36% of all hours that Hydro One customers have been without power.

Hydro One's **current draft plan** is focused on improving the day-to-day reliability of the system, outside of severe weather events, by:

- **Repairing or replacing overhead line defects**: Over their 110,000km network of overhead lines, Hydro One has identified close to 500,000 defects such as broken or damaged support cables, leaning poles, or damaged insulators.
- **Maintaining, repairing, or replacing major stations' equipment:** Hydro One operates and maintains approximately 1,000 distribution stations that convert electricity to a lower voltage for safe delivery to homes and businesses. Over **250** of these stations' transformers are in poor condition and at increased risk of failure.
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Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.



Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$182 less by 2032 (average of $36 less each year)	Included in Draft Plan	$182 more by 2032 (average of $36 more each year)

SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey

Overall system reliability

The first investment category is related to the **day-to-day reliability** of Hydro One's **distribution system** that delivers electricity to homes and businesses.

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In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either improve or maintain current levels of reliability related to the distribution grid.

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Additionally, Hydro One has identified 2% of their approximately 1.6 million wooden poles to be refurbished to extend their useful life.



Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace. Doing less of these types of investments now could lead to more frequent or longer outages and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain current levels of day-to-day reliability	Improve day-to-day reliability by 2032	Further reduce the risk of outages by 2032
	Main Differences Between Plans		
Repairing or replacing overhead line defects	10% of known defects	40% of known defects	70% of known defects
Addressing stations transformers	60 poor condition transformers	90 poor condition transformers	120 poor condition transformers
Replacing or repairing underground cables	7% of all underground cables	10% of all underground cables	13% of all underground cables
Average Monthly Distribution Bill Impact	$888 less by 2032 (average of $178 less each year)	Included in Draft Plan	$890 more by 2032 (average of $178 more each year)

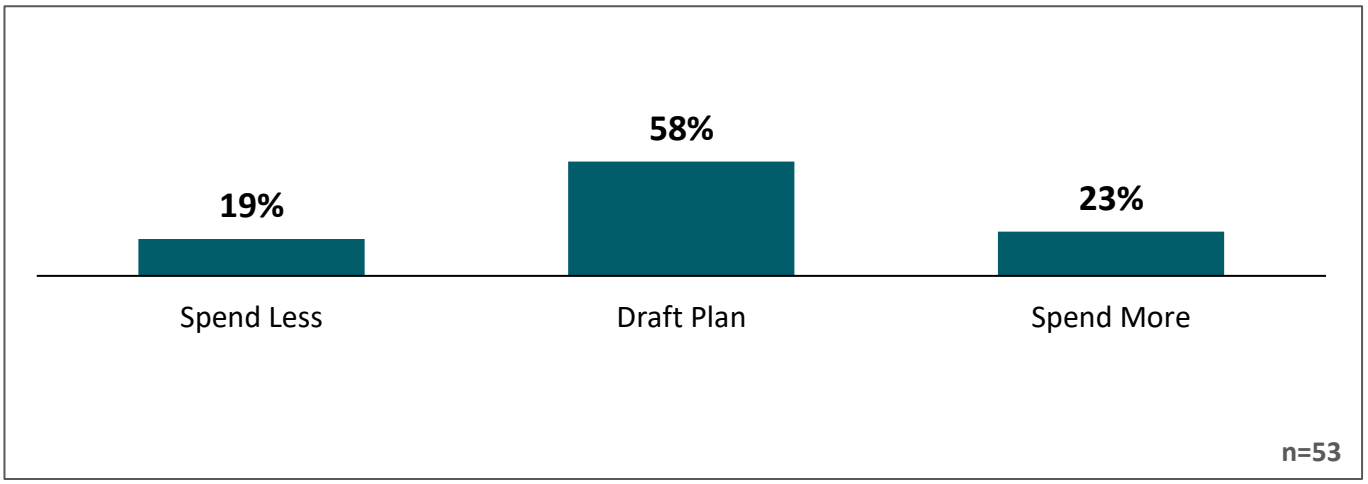
SURVEY PAGE

Investment Trade-Offs

Overall system reliability

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Verbatim comments (91% No comment)
"Can't afford power anymore. I consume [REDACTED] mil kW per year, and with Hydro One's increased delivery, I will have to shut off power."
"In today's economic climate, minimizing the average Ontarian's bill is critical."
"It will never be cheaper than now to fix the grid."
"Our site relies on a consistent power supply and any chance to improve that we would support."
"The need for reliable electricity is paramount to today's world."

Investment Trade-Offs

Managing the impacts of severe weather

Large Distribution

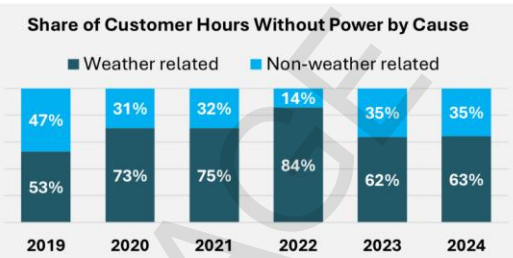
GSd Version

Hydro One Customer Engagement Survey

Managing the impacts of severe weather

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.





In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$50 less by 2032 (average $10 less each year)	Included in Draft Plan	$50 more by 2032 (average of $10 more each year)

SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Large Distribution

ST-Low Version

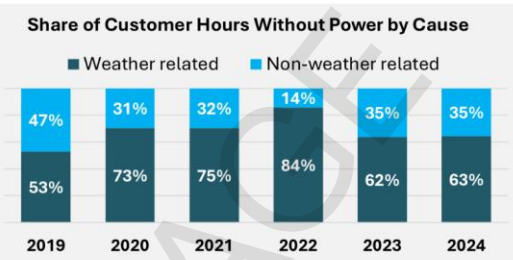
Hydro One Customer Engagement Survey

Managing the impacts of severe weather

hydro one

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Which of the following options do you prefer?

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Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$21 less by 2032 (average of $4 less each year)	Included in Draft Plan	$21 more by 2032 (average of $4 more each year)

SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Large Distribution

ST-Med Version

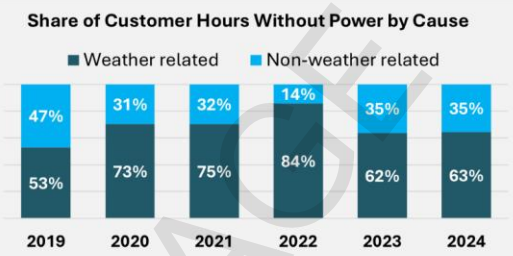
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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$119 less by 2032 (average of $24 less each year)	Included in Draft Plan	$119 more by 2032 (average of $24 more each year)

SURVEY PACK

Investment Trade-Offs

Managing the impacts of severe weather

Large Distribution

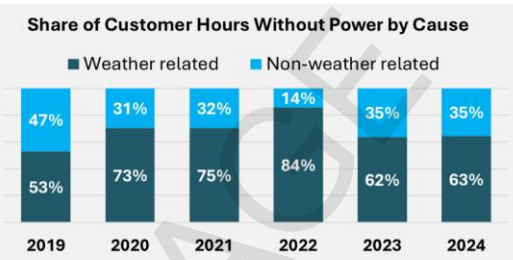
ST-High Version

Hydro One Customer Engagement Survey

Managing the impacts of severe weather

On average, between 2019 and 2024, severe weather events, such as ice storms, windstorms or thunderstorms, have contributed to 68% of all hours that the typical customer has been without power per year.





In a 2024 survey, a majority of customers said that they want Hydro One to make investments to make the system more resilient to severe weather.

While some weather-related outages will likely be inevitable, in their **current draft plan**, Hydro One is proposing investments in making the system more resilient to severe weather events and generally perform better overall, including:

- **Relocating or reinforcing vulnerable power lines:** Hydro One has identified power lines that are more vulnerable to severe weather. Relocating or reinforcing these lines with more resilient equipment can help reduce future outage risks.
- **Clearing more overgrown trees and brush than historically:** Increasing the rate of clearing trees and brush can help reduce the risk of outages, the leading cause of weather-related outages.
- **Installing more automated "intelligent" switches:** In their draft plan, Hydro One proposes deploying 1,200 new automated switches that can help restore power more quickly from a control room rather than sending a repair crew to patrol the lines. There are currently approximately 1,100 intelligent switches operating across Hydro One's service territory.

While storms will continue to happen, making these proactive investments will help limit the impact of outages. Reducing these types of investments could leave the distribution system more vulnerable to widespread outages and more costly emergency repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Maintain the current risk of outages and restoration times related to severe weather	Reduce the risk of outages and shorten restoration times related to severe weather	Further reduce the risk of outages and shorten restoration times related to severe weather
	Main Differences Between Plans		
Relocating or reinforcing vulnerable power lines	3% of all power lines	6% of all power lines	9% of all power lines
Clearing overgrown trees and brush	Clear 25% of overgrown vegetation each year	Clear 30% of overgrown vegetation each year	Clear 35% of overgrown vegetation each year
Installing automated switches	750 new switches	1,200 new switches	1,650 new switches
Average Monthly Distribution Bill Impact	$584 less by 2032 (average of $117 less each year)	Included in Draft Plan	$584 more by 2032 (average of $117 more each year)

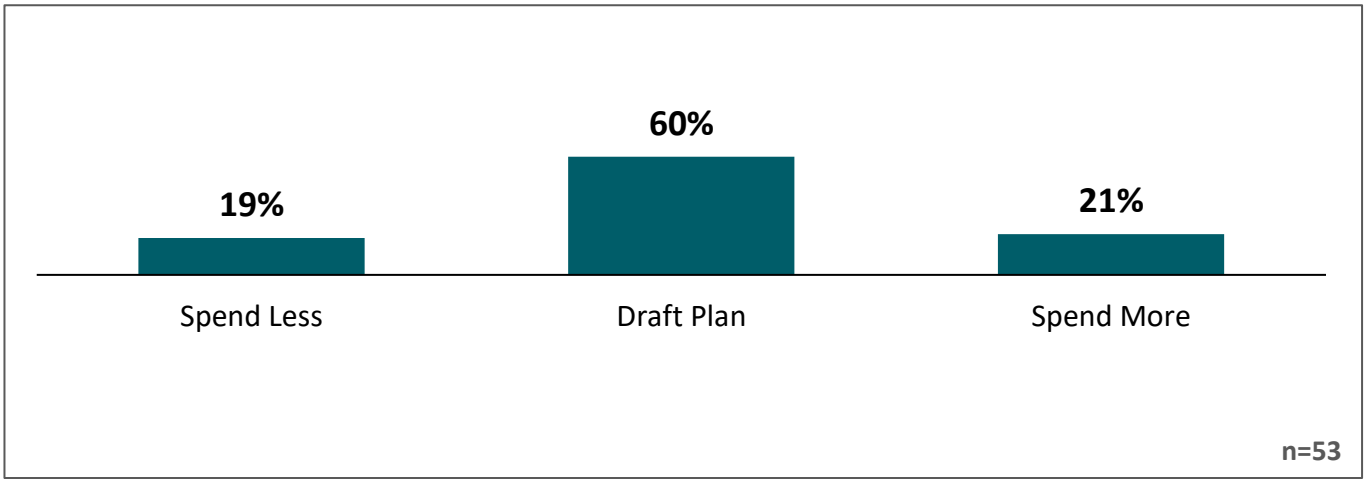
SURVEY PAGE

Investment Trade-Offs

Managing the impacts of severe weather

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Verbatim comments (94% No comment)
"Doubling distribution costs in 7 years is too steep. The options presented in these slides are somewhat tilted towards getting folks to click "included in draft plan". There needs to be a more nuanced approach to prioritizing dist/tx investments that balances cost with reliability. As a [REDACTED] customer at both our Ontario sites, reliability is OK. Our full electricity bills have risen dramatically due to electricity market price inflation and erosion of GA/ICI program savings with decreases in GA. To remain competitive with other jurisdictions, Hydro One needs to stabilize and lower the rate of bill inflation for industrial customers."
"Is there an option to maintain vegetation below power lines through community responsibility or an alternate resource up to a point where the work would not be hazardous? I expect the cost for Hydro One to maintain vegetation levels could be much higher than other options, but Hydro One would be required once the work involves an electrical hazard."
"Same as last comment. Too expensive."

Investment Trade-Offs

Targeted reliability improvements

Large Distribution

GSd Version

SURVEY PAGE

Hydro One Customer Engagement Survey

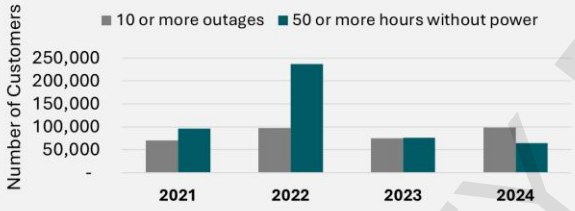
Targeted reliability improvements

Hydro One customers experience different levels of reliability depending on where they live, the design of the system, the condition of the equipment supplying them, and weather patterns.

While some Hydro One customers might not have experienced any outages in the last four years, in any given year more than **70,000 customers were without power more than 10 times**, and more than **60,000 customers were in the dark for 50 hours or more**.

Today, rural and remote communities are more likely to experience poorer reliability, and the increased frequency of severe weather events create and will continue to create further challenges.

Number of Customers Experiencing Significantly Poorer Reliability than Average





Community-scale battery storage facility outside of Thunder Bay

In a 2024 survey, a majority of customers said that they want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.

In their **current draft plan**, Hydro One has developed a program that includes a combination of larger **community-scale** batteries and smaller **individual customer** batteries, which store electricity and provide backup power if an outage does occur.

Batteries are an effective way to target reliability improvements for individual customers and communities that experience the poorest reliability.

At the rate of investment being proposed in the draft plan, Hydro One anticipates reliability improvements for around **10,000** customers. However, based on customer feedback, Hydro One could install more or fewer batteries.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$51 less by 2032 (average of $10 less each year)	Included in Draft Plan	$51 more by 2032 (average of $10 more each year)

Investment Trade-Offs

Targeted reliability improvements

Large Distribution

ST-Low Version

SURVEY PURPOSE

Hydro One Customer Engagement Survey

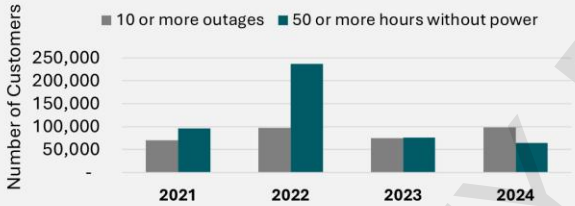
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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$22 less by 2032 (average of $4 less each year)	Included in Draft Plan	$22 more by 2032 (average of $4 more each year)

Investment Trade-Offs

Targeted reliability improvements

Large Distribution

ST-Med Version

SURVEY PURPOSE

Hydro One Customer Engagement Survey

Targeted reliability improvements

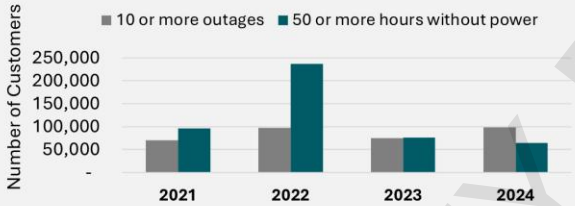
hydro one

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$124 less by 2032 (average of $25 less each year)	Included in Draft Plan	$124 more by 2032 (average of $25 more each year)

Investment Trade-Offs

Targeted reliability improvements

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey

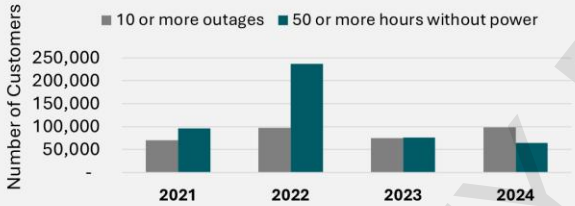
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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Improve reliability for around 3,500 customers	Improve reliability for around 10,000 customers	Improve reliability for around 13,500 customers
	Main Differences Between Plans		
Community-scale batteries	10 battery systems	30 battery systems	50 battery systems
Individual customer batteries	2,000 battery systems	5,000 battery systems	8,000 battery systems
Average Monthly Distribution Bill Impact	$605 less by 2032 (average of $121 less each year)	Included in Draft Plan	$605 more by 2032 (average of $121 more each year)

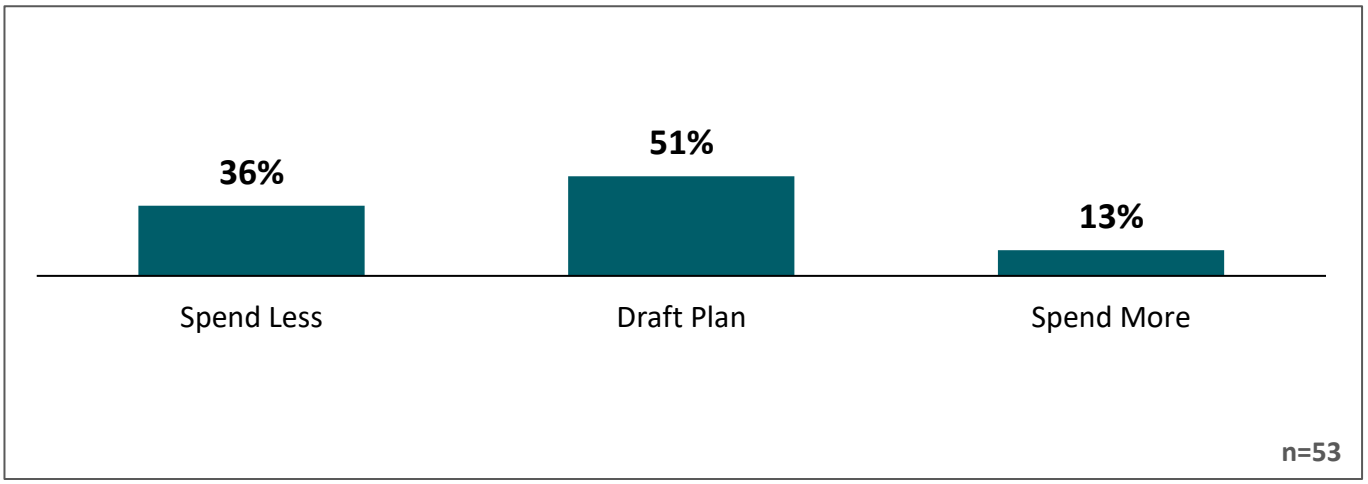
SURVEY PURPOSE

Investment Trade-Offs

Targeted reliability improvements

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Verbatim comments (94% No comment)
"Battery systems sound like a good short-term plan, but I suggest the batteries themselves will have a relatively short life, and the cost of chemical battery disposal should be carefully considered."
"Not enough information in here to make a choice. How much do batteries save or defer on capital investment? Without this information, it's really hard to pick. Battery investments should have a net benefit to the rate base...here it's presented as a straight-up cost."
"Same as last."

INNOVATIVE RESEARCH GROUP

Summary of Investment Plan

Hydro One's transmission system

Large Distribution

Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

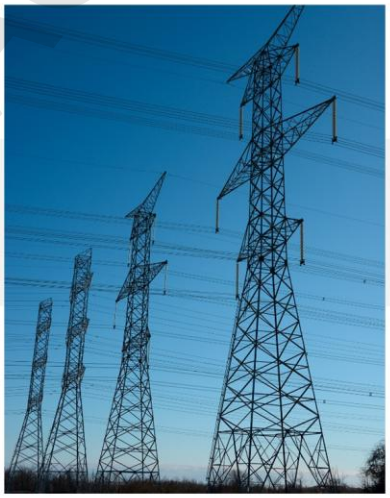
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

Large Distribution

GSd Version

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$21 less by 2032 (average of $4 less each year)	**Included in Draft Plan**	$21 more by 2032 (average of $4 more each year)

SURVEY PROOF

Investment Trade-Offs

Keeping pace with transmission renewal

Large Distribution

ST-Low Version

SURVEY DRAFT

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$164 less by 2032 (average of $33 less each year)	**Included in Draft Plan**	$164 more by 2032 (average of $33 more each year)

Investment Trade-Offs

Keeping pace with transmission renewal

Large Distribution

ST-Med Version

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$923 less by 2032 (average of $185 less each year)	**Included in Draft Plan**	$921 more by 2032 (average of $184 more each year)

SURVEY PROOF

Investment Trade-Offs

Keeping pace with transmission renewal

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

hydro one

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Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$4,511 less by 2032 (average of $902 less each year)	**Included in Draft Plan**	$4,505 more by 2032 (average of $901 more each year)

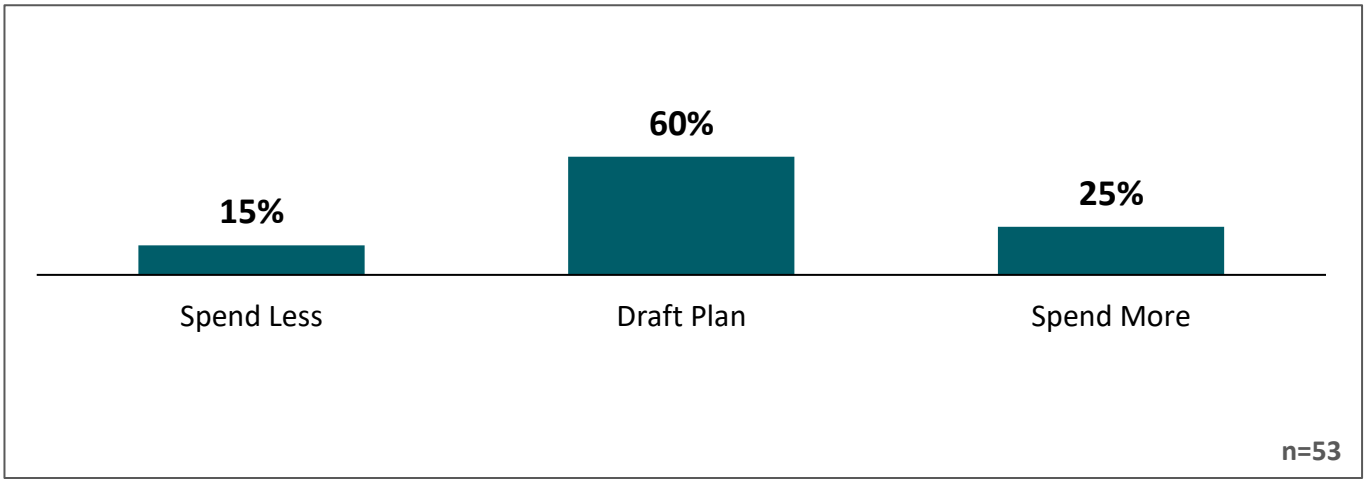
SURVEY PROOF

Investment Trade-Offs

Keeping pace with transmission renewal

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Verbatim comments (98% No comment)

"Prioritize based on Customer profile, i.e. High priority business, Business and Residential."

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Stewardship of the transmission system

Large Distribution

GSd Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$17 less by 2032 (average of $3 less each year)	Included in Draft Plan	$17 more by 2032 (average of $3 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Large Distribution

ST-Low Version

Hydro One Customer Engagement Survey

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Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$132 less by 2032 (average of $26 less each year)	Included in Draft Plan	$132 more by 2032 (average of $26 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Large Distribution

ST-Med Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

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	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$741 less by 2032 (average of $148 less each year)	Included in Draft Plan	$741 more by 2032 (average of $148 more each year)

SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

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	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$3,625 less by 2032 (average of $725 less each year)	Included in Draft Plan	$3,624 more by 2032 (average of $725 more each year)

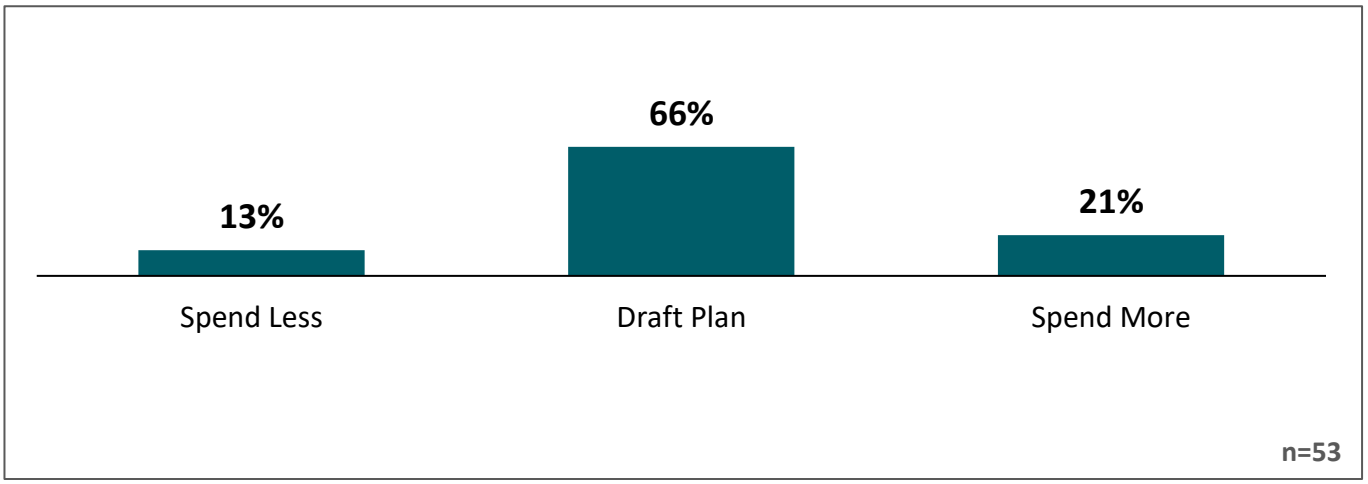
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Verbatim comments (98% No comment)

"Priority based on risk."

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Maintaining buildings and facilities

Large Distribution

GSd Version

SURVEY PAGE

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$11 less by 2032 (average of $2 less each year)	Included in Draft Plan	$11 more by 2032 (average of $2 more each year)
Average Monthly Transmission Bill Impact	$1 less by 2032 (average of $0.17 less each year)		$3 more by 2032 (average of $1 more each year)

Investment Trade-Offs

Maintaining buildings and facilities

Large Distribution

ST-Low Version

Hydro One Customer Engagement Survey

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	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$5 less by 2032 (average of $1 less each year)	Included in Draft Plan	$5 more by 2032 (average of $1 more each year)
Average Monthly Transmission Bill Impact	$7 less by 2032 (average of $1 less each year)		$21 more by 2032 (average of $4 more each year)

SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Large Distribution

ST-Med Version

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

hydro one

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	Main Differences Between Plans		
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Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$28 less by 2032 (average of $6 less each year)	Included in Draft Plan	$26 more by 2032 (average of $5 more each year)
Average Monthly Transmission Bill Impact	$38 less by 2032 (average of $8 less each year)		$115 more by 2032 (average of $23 more each year)

SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey

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hydro one

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	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Distribution Bill Impact	$135 less by 2032 (average of $27 less each year)	Included in Draft Plan	$125 more by 2032 (average of $25 more each year)
Average Monthly Transmission Bill Impact	$183 less by 2032 (average of $37 less each year)		$564 more by 2032 (average of $113 more each year)

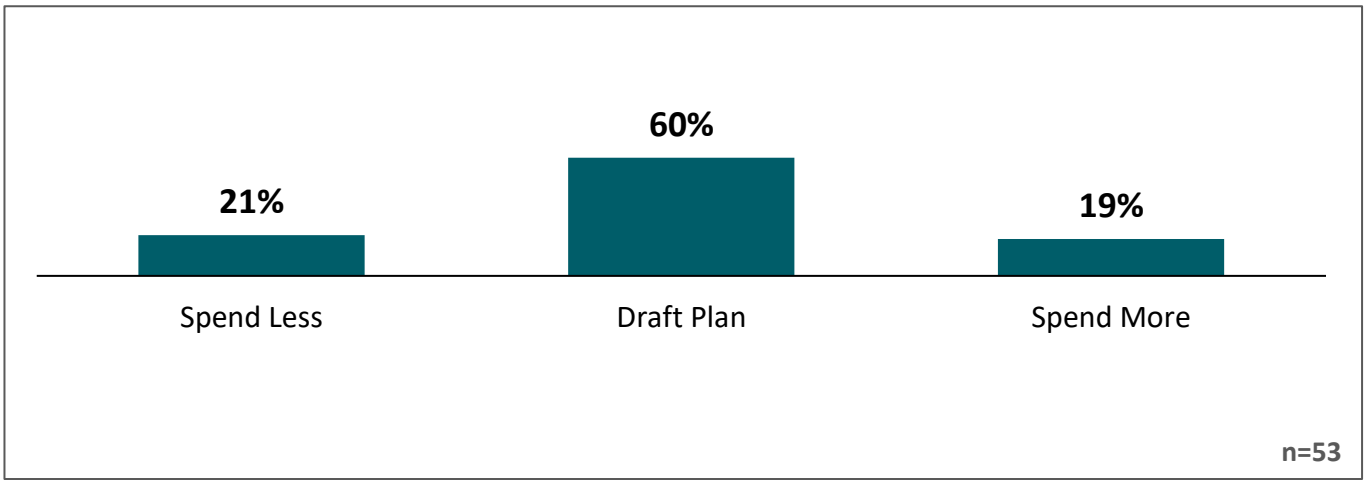
SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

No comments

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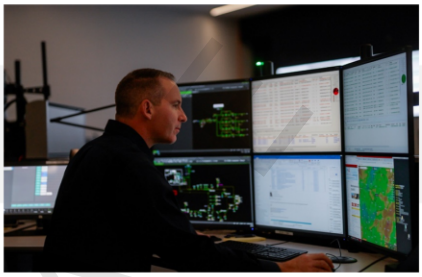
Investment Trade-Offs
Information technology

Large Distribution

GSd Version

Hydro One Customer Engagement Survey
Information technology

hydro one



Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.

When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$16 less by 2032 (average of $3 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$6 less by 2032 (average of $1 less each year)	

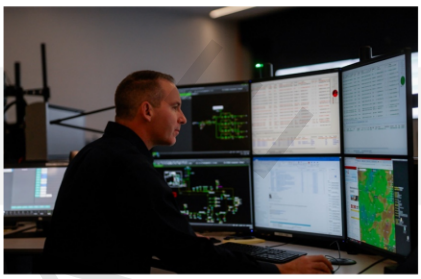
SURVEY PAPER

Investment Trade-Offs
Information technology

Large Distribution

ST-Low Version

Hydro One Customer Engagement Survey
Information technology



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	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$7 less by 2032 (average of $1 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$43 less by 2032 (average of $9 less each year)	

SURVEY PAGE

Investment Trade-Offs
Information technology

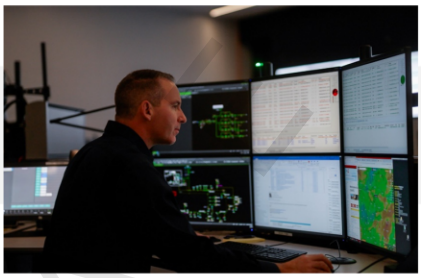
Large Distribution

ST-Med Version

Hydro One Customer Engagement Survey
Information technology

hydro one

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	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$38 less by 2032 (average of $8 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$242 less by 2032 (average of $48 less each year)	

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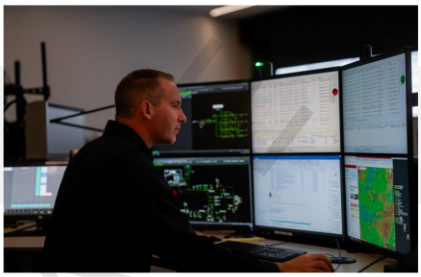
Investment Trade-Offs
Information technology

Large Distribution

ST-High Version

Hydro One Customer Engagement Survey
Information technology

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	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Distribution Bill Impact	$185 less by 2032 (average of $37 less each year)	**Included in Draft Plan**
Average Monthly Transmission Bill Impact	$1,183 less by 2032 (average of $237 less each year)	

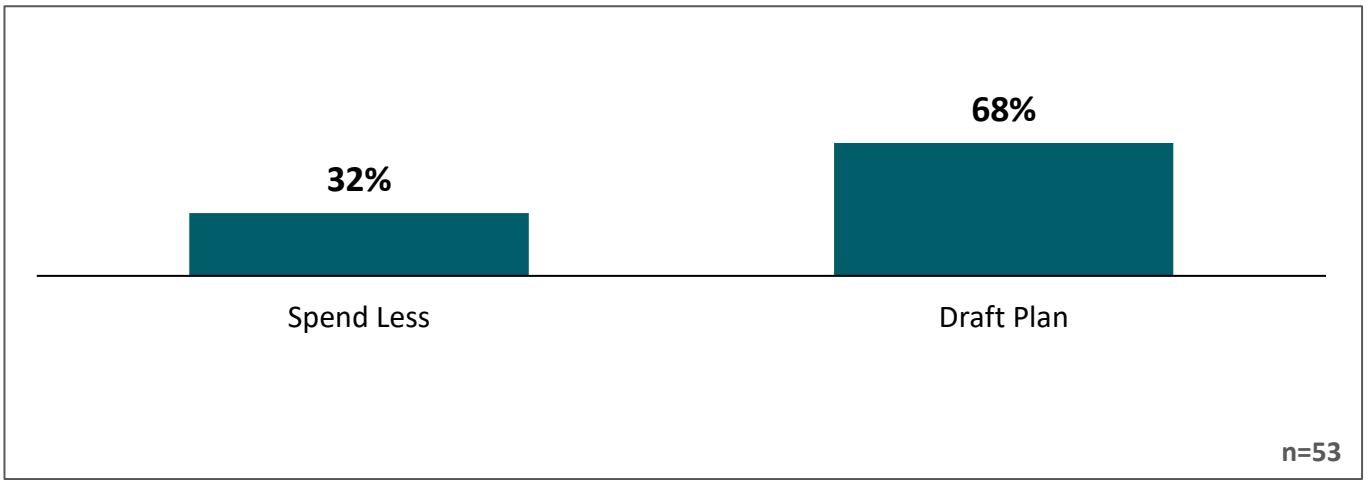
SURVEY PREVIEW

Investment Trade-Offs

Information technology

Large Distribution

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

No comments

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SURVEY PAGE

Hydro One Customer Engagement Survey

What is the impact of my choices?

hydro one

Throughout this survey, you have been asked about 7 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on your bill will be recalculated.

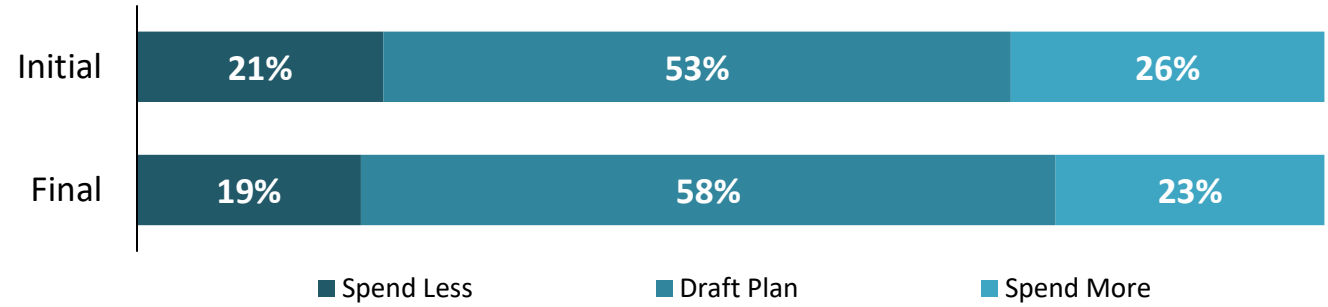
The bill impacts associated with each choice represent the average increase on your monthly bill from 2027 to 2032, followed by the average increase on your monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

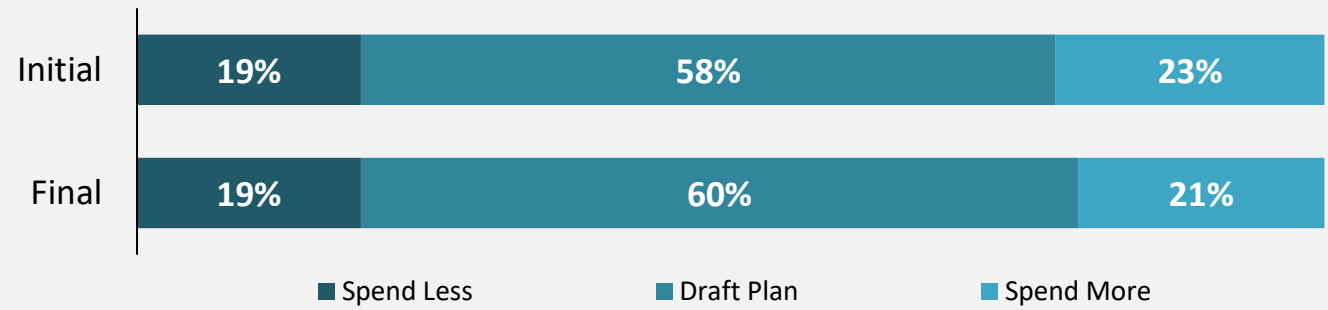
Finalizing Choices

Large Distribution

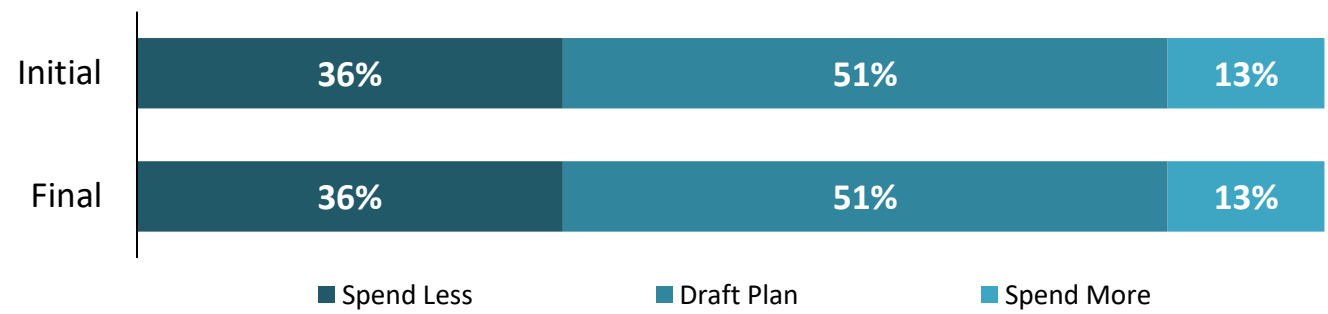
Overall system reliability



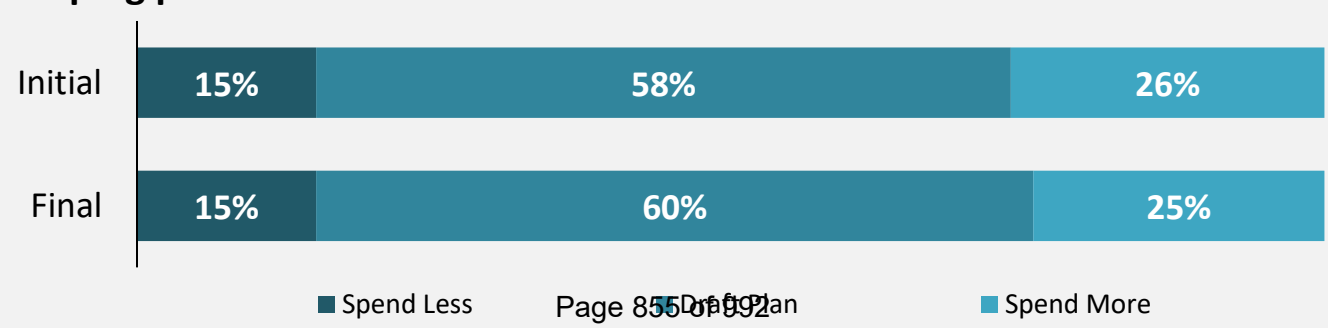
Managing the impacts of severe weather



Targeted reliability improvements



Keeping pace with transmission renewal

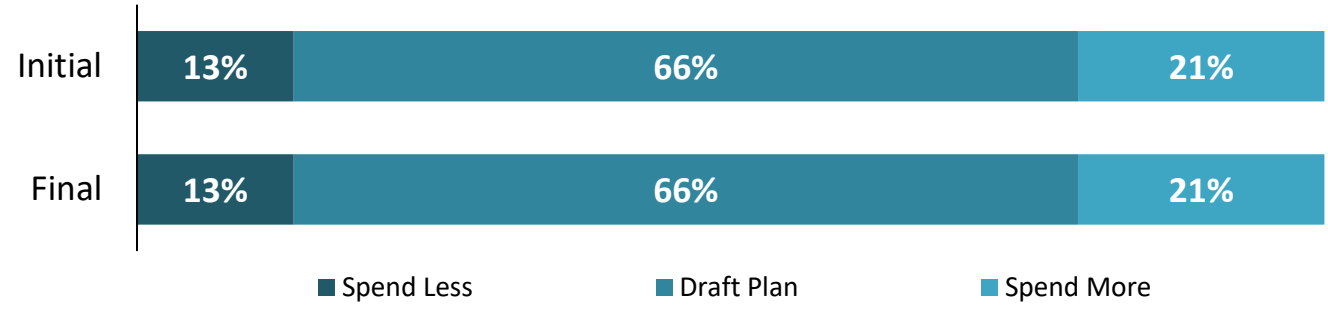


Investment Trade-Offs

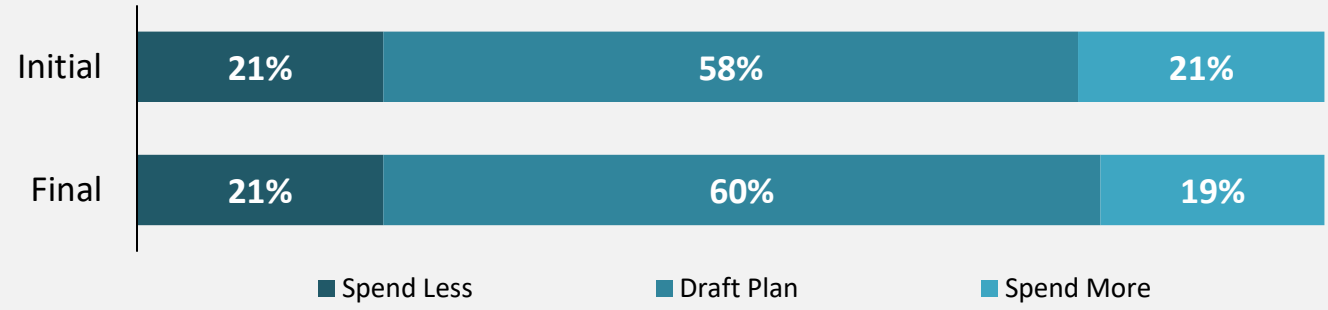
Finalizing Choices

Large Distribution

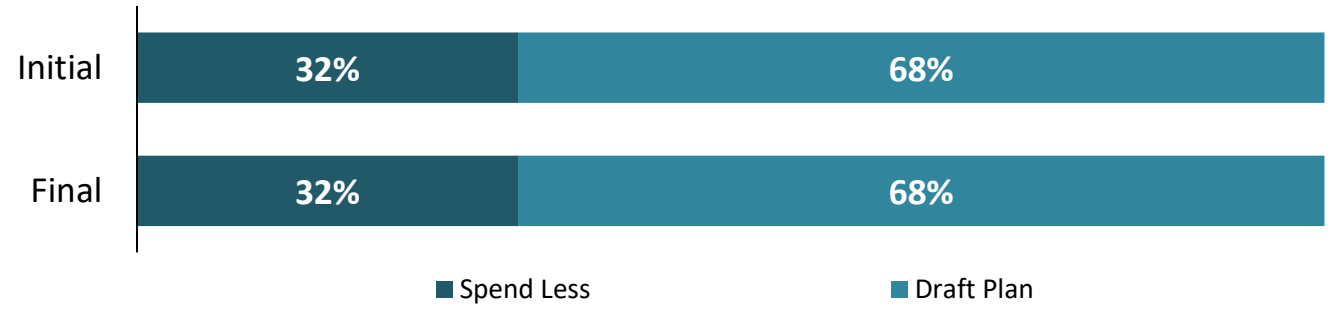
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



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Investment Trade-Offs

Overall evaluation of the draft plans

Large Distribution

GSd Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **general service demand customer** would see:

- The **distribution** portion of their **monthly bill** increase from $2,720 in 2027 to $4,449 by the end of 2032 – an increase of **$1,729** on the monthly bill. This represents an average increase of **$346** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $681 in 2027 to $889 by the end of 2032 – an increase of **$208** on the monthly bill. This represents an average increase of **$42** on the monthly bill each year.

ST-Low Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **sub-transmission low consumption customer** would see:

- The **distribution** portion of their **monthly bill** increase from $2,221 in 2027 to $2,963 by the end of 2032 – an increase of **$742** on the monthly bill. This represents an average increase of **$148** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $5,279 in 2027 to $6,891 by the end of 2032 – an increase of **$1,613** on the monthly bill. This represents an average increase of **$323** on the monthly bill each year.

SURVEY PAGE

Investment Trade-Offs

Overall evaluation of the draft plans

ST-Med Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **sub-transmission average consumption customer** would see:

- The **distribution** portion of their **monthly bill** increase from $6,739 in 2027 to $10,908 by the end of 2032 – an increase of **$4,169** on the monthly bill. This represents an average increase of **$834** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $29,645 in 2027 to $38,702 by the end of 2032 – an increase of **$9,058** on the monthly bill. This represents an average increase of **$1,812** on the monthly bill each year.

SURVEY PAGE

ST-High Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plans. While the plans may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plans.

It is estimated that a typical **sub-transmission high consumption customer** would see:

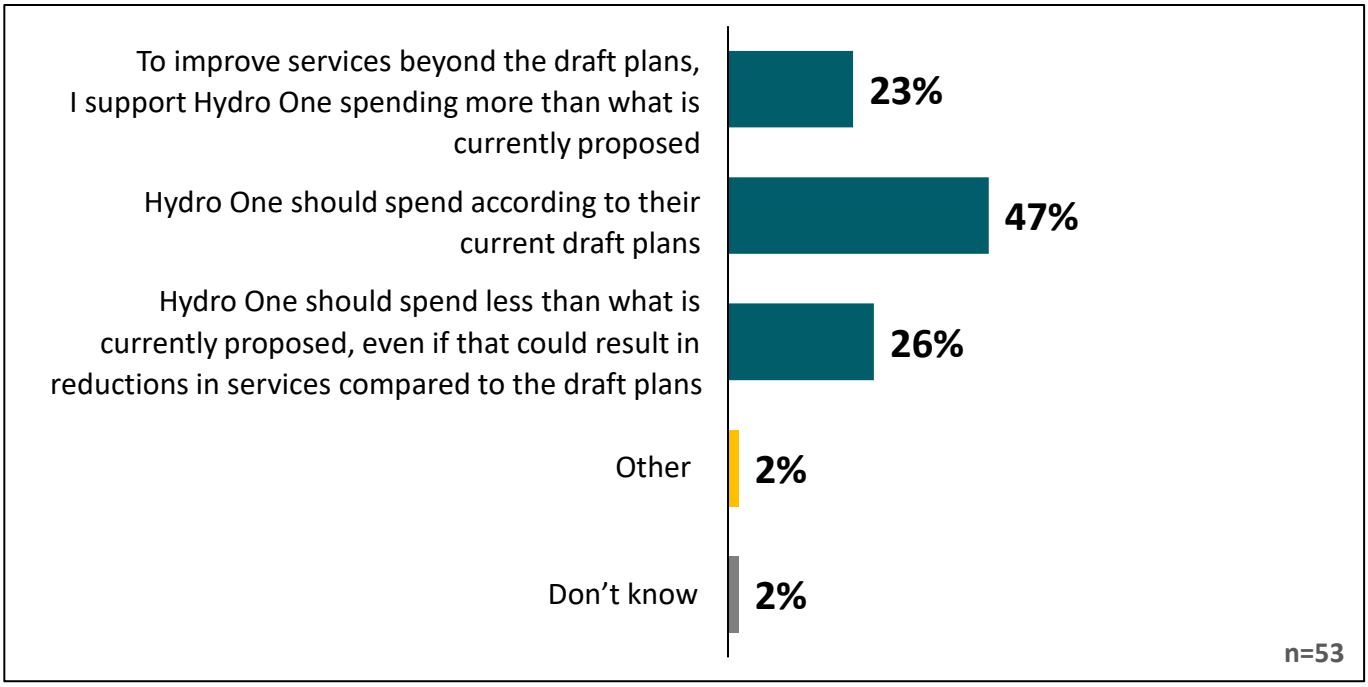
- The **distribution** portion of their **monthly bill** increase from $28,121 in 2027 to $48,505 by the end of 2032 – an increase of **$20,384** on the monthly bill. This represents an average increase of **$4,077** on the monthly bill each year.
- The **transmission** portion of their **monthly bill** increase from $144,951 in 2027 to $189,239 by the end of 2032 – an increase of **$44,289** on the monthly bill. This represents an average increase of **$8,858** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plans

Large Distribution

Q Considering what you have learned about Hydro One's 2028–2032 draft plans, which of the following best represents your point of view?



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Investment Trade-Offs

Final comments on the draft plans

Large Distribution

Q Do you have any final comments regarding Hydro One's draft plans for 2028–2032 and the proposed rate increase? (Optional)

Verbatim comments (92% No comment)
"Access to electrical power is a benefit with a related cost to the people of Ontario. While some people could afford a higher cost for a better level of service, I expect it is not practical to provide a "two-tiered" level of service. I suggest the spending plan take into account the level of service that the average person in Ontario could reasonably afford."
"The draft plans could already be over ambitious and not realistic if there is not resource availability to execute. I do not know Hydro One's history on meeting planned maintenance and project work. I would assume that any over collection – i.e. not being able to meet plans would mean returning that funding to customers – typical what occurs in a rate regulated environment. We support the draft plan assuming proper oversight and accountability to reasonably meet the targets in the draft plans."
"The rate increases will have a negative impact on manufacturing companies. Forecasted increases will help with future budgeting."
"We must make improvements for overall reliability, but we can't stay in business if our rates increase dramatically. I think the draft plan is middle of the road and the appropriate action."

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Large Distribution Account Customers

Survey Diagnostics



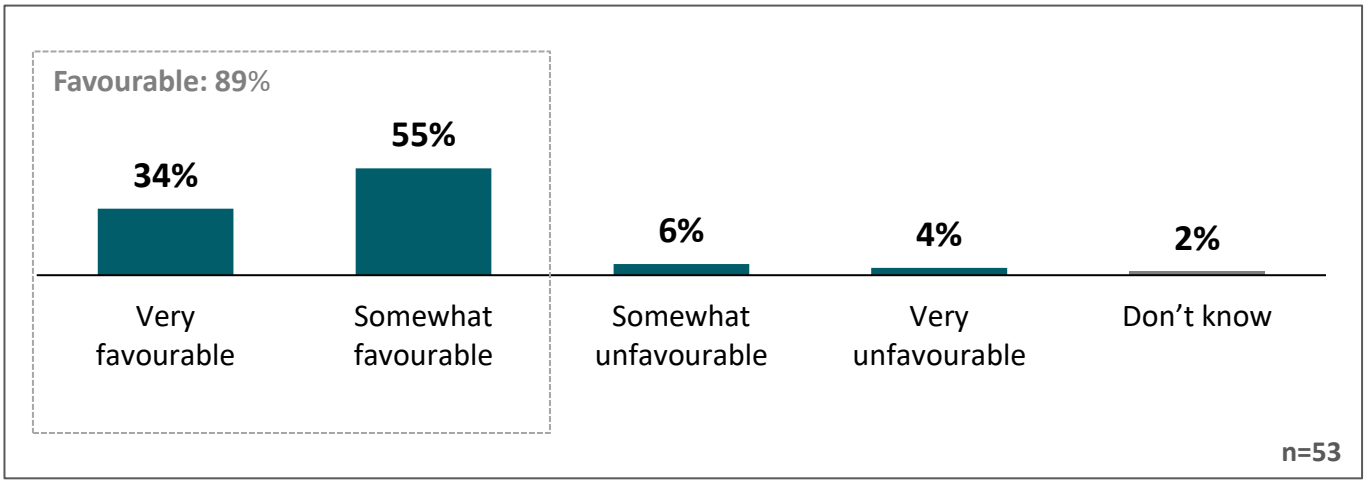
Survey Diagnostics

Favourability and amount of information

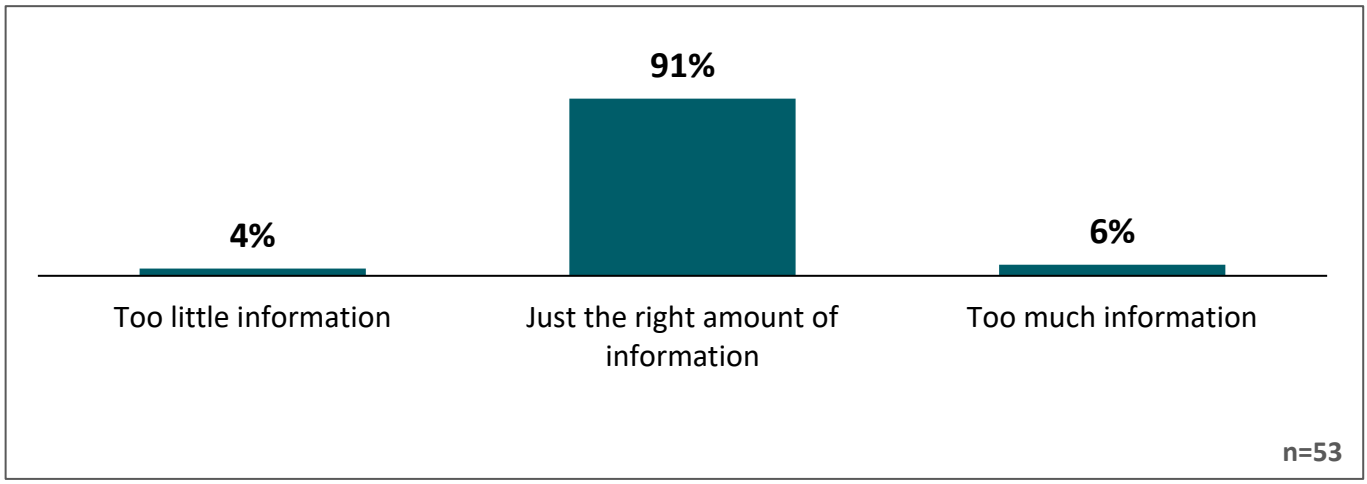
Large Distribution

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



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Survey Diagnostics
Other information not included

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Verbatim comments (87% No comment)
"Can add some electricity generation cost and estimation of GA to create grate picture."
"How Hydro One plans to increase capacity and an improved system to evaluate business opportunities that need specific power commitments."
"Hydro One and OPG employee salaries are the highest in the province. How much do these inflated salaries contribute to the cost of electricity and the increasing cost of electricity?"
"I'd like to see the projected increase as a percent increase, rather than doing that math in my head. If it's a 5%/year, say that rather than example of XX$ to XX$."
"No info is just enough. It could be a good idea based on Class A and Class B and Residential customers."
"No risk analysis, no qualitative comparison of benefits of the different options. The options were presented in such a way that the average/reasonable person would pick "draft plan" - I would have liked to see costs, benefits, and risks, quantified for each option (i.e. battery investments should defer or be more cost effective than distribution system expansion). The proposed doubling of distribution rates in 5 years, against a background of ballooning electricity commodity prices, is not well received. There is too much political interference in the Ontario power market, a bill structure that is opaque with incentives for conservation that have been eroded, and a rate structure that makes prediction of future costs very difficult to predict compared to other jurisdictions."
"We are in desperate need of more power in our area so we can expand our operations. There was no question in regards to expanding capacity. Bringing power to companies that would like to grow and create jobs should be a top priority."

Survey Diagnostics
Outstanding questions

Q Is there anything that you would still like answered? (Optional)

Verbatim comments (89% No comment)
"An improved system to evaluate business opportunities that need specific power requirements."
"Comparison of the overall cost of electricity (generation, delivery, administration) across Canada. There may be opportunities to learn how to be more efficient from other electrical systems."
"Contract pricing for agricultural greenhouse, cannot compete at current prices."
"Just accurate forecasting of increases so companies can budget accordingly."
"We seem to experience momentary power blips frequently. I have been told that additional reclosure switches will help isolate us from some of them is that a true fact. Thank you."
"Yes, we would like to see more done to bring new power lines to companies like ourselves that are looking to grow and create jobs."

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Hydro One Transmission-Only Customer Results



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Other LDC Residential Customers

Online Survey Results

Section 7



Online Survey
Methodology

Field Dates

To obtain feedback from **Other LDC Residential customers**, a random sample of online panelists were invited to complete the survey from a set of partner panels based on the Lucid exchange platform.

In order to qualify to complete the survey, respondents must be Ontarians 18+ who at least share responsibility for paying the electricity bill in their household, excluding Hydro One distribution customers.

Survey responses were collected between **December 4th and December 16th, 2025**.

Other LDC Residential Online Survey Completes

A total of **2,071** (unweighted) other LDC residential customers completed the online survey.

Sample Weighting

The Other LDC Residential online survey sample was weighted to n=2,000 proportionately by age, gender, region and education in order to be representative of the broader Ontario population based on Census data.

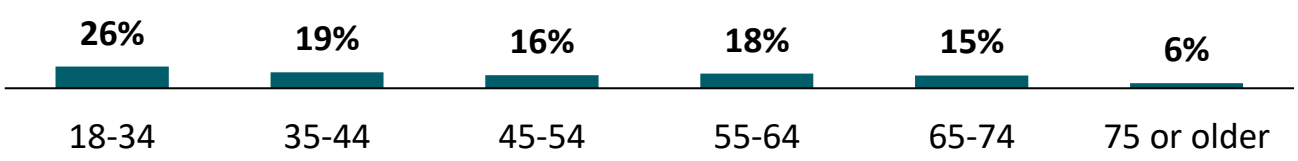
The table below summarizes the unweighted and weighted (in brackets) sample breakdown by age, gender, and region. Totals may not correspond with cell values, as some respondents prefer to self-describe their gender. Weights are calculated based off of all available information for a given respondent.

Region	Age-Gender						Total
	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+	
Toronto	66 (68)	90 (75)	81 (73)	64 (65)	93 (90)	87 (83)	481 (454)
Rest of GTA	78 (83)	118 (113)	125 (117)	66 (65)	105 (109)	120 (117)	612 (605)
South/West	69 (78)	104 (99)	113 (101)	56 (52)	86 (88)	119 (116)	548 (535)
North/East	55 (62)	77 (69)	96 (87)	51 (45)	58 (56)	93 (87)	430 (406)
Total	268 (292)	389 (356)	415 (378)	237 (227)	342 (343)	419 (403)	2,071 (2,000)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

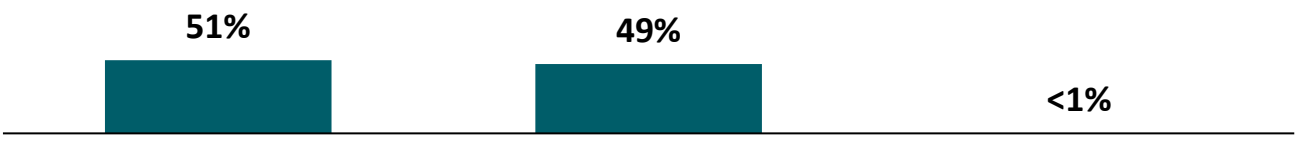
Demographic Breakdown

Q Age



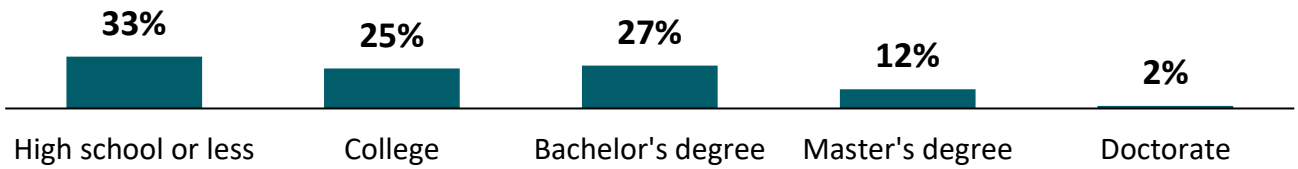
n=2,000

Q Gender



n=2,000

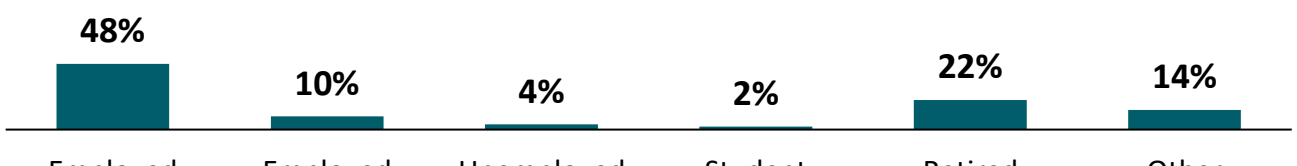
Q Education



"Other" (1%) and "Prefer not to say" (1%) not shown.

n=2,000

Q Employment Status

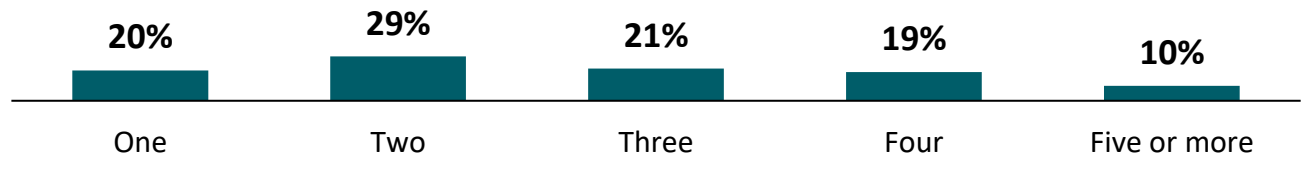


"Prefer not to say" (1%) not shown.

n=2,000

Demographic Breakdown
Continued

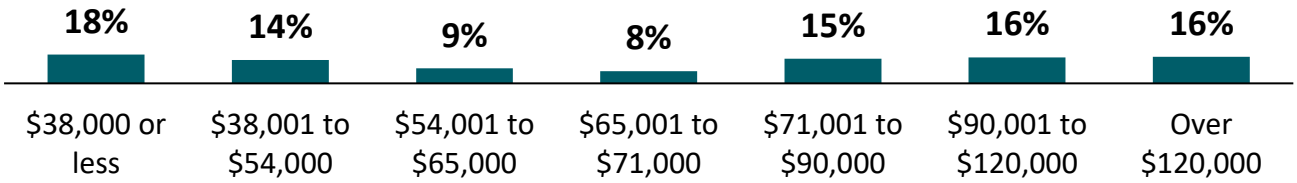
Q Household Size



"Prefer not to say" (<1%) not shown.

n=2,000

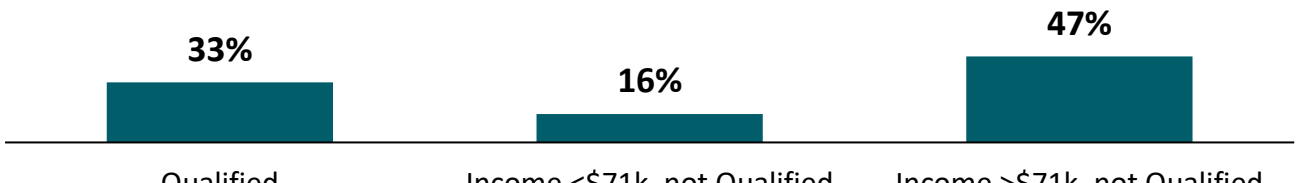
Q After Tax Household Income



"Prefer not to say" (4%) not shown.

n=2,000

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (4%) not shown.

n=2,000

Demographic Breakdown
Continued

Other LDC Residential

Are you:

Q First Nations



"Prefer not to say" (2%) not shown.

n=2,000

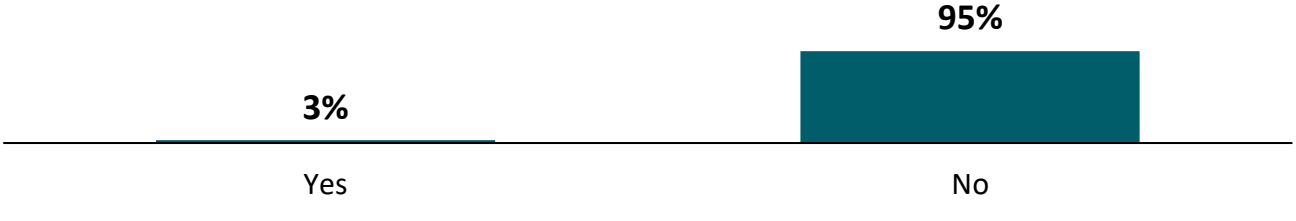
Q Métis



"Prefer not to say" (2%) not shown.

n=2,000

Q Inuk



"Prefer not to say" (3%) not shown.

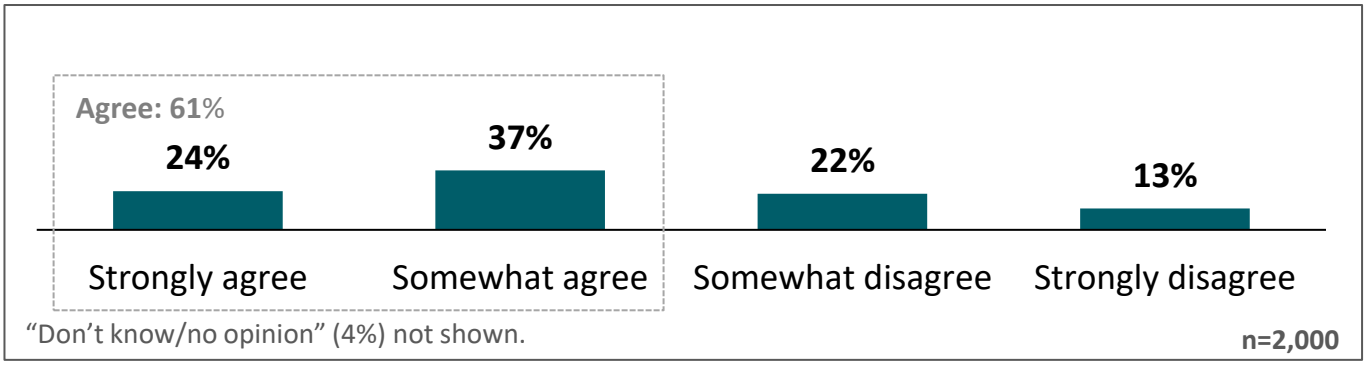
n=2,000

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Environmental Controls

To what extent do you agree or disagree with the following statements?

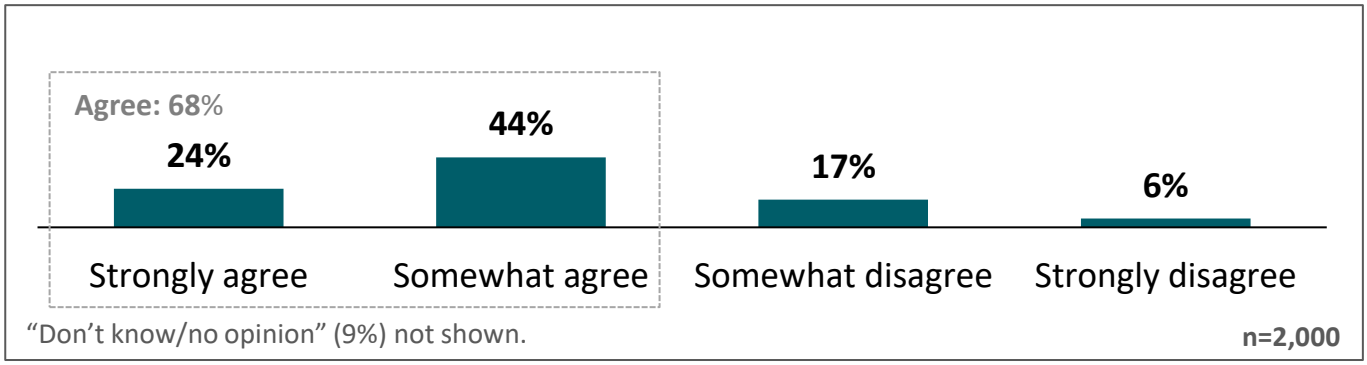
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=2,000

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (9%) not shown.

n=2,000

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plan** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 10-15 minutes to complete. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by most Ontarians. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plan, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plan.

Next year, Hydro One will present their proposed plan and input provided by customers to the OEB.

SURVEY PDF

Familiarity & Experience

Hydro One's role in Ontario's electricity system

SURVEY PAGE

Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, **Hydro One** is also responsible for the local distribution system, which delivers electricity to homes, seasonal properties, or organizations through a network of wires, poles and other equipment.



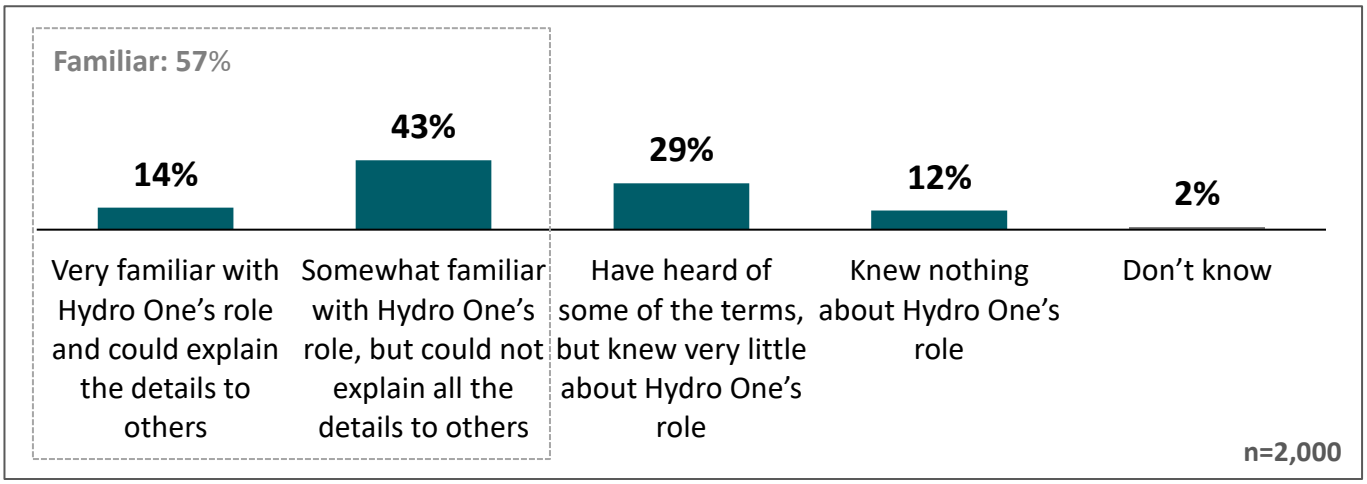
Hydro One does not generate electricity or set electricity prices.

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Other LDC Residential

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Region

	Toronto	Rest of GTA	South/West	North/East
Very familiar	17%	12%	11%	16%
Somewhat familiar	42%	48%	40%	44%
Knew very little	26%	30%	34%	26%
Knew nothing	14%	10%	14%	11%
Don't know	2%	1%	1%	4%
Familiar (Very + Somewhat)	**59%**	**60%**	**51%**	**60%**

LEAP/OESP Qualification

Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	11%	14%	17%	17%	8%
Somewhat familiar	43%	40%	45%	44%	43%
Knew very little	32%	32%	26%	26%	33%
Knew nothing	12%	13%	11%	11%	14%
Don't know	2%	1%	1%	2%	2%
Familiar (Very + Somewhat)	**54%**	**55%**	**62%**	**61%**	**51%**

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Other LDC Residential

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

As of **July 1, 2025**, for a typical Ontario residential customer, about 11% of the bill, or $15.03, goes to Hydro One per month to pay for the transmission of electricity from generation stations to your local electricity distributor.

The rest of your bill payment goes to your local electricity distributor, power generation companies, taxes, and regulatory agencies.

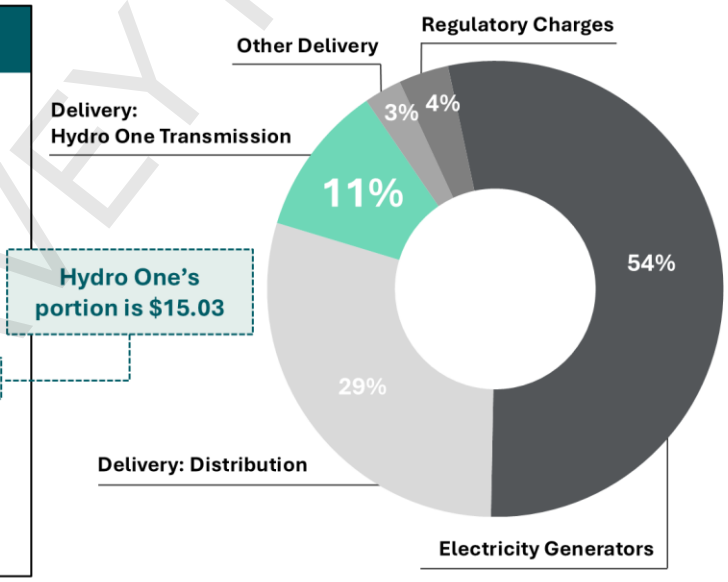
Sample Residential Monthly Bill
(based on consumption of 750 kWh as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	22.52
Mid-Peak (mid price) @ 12.2 c/kWh	16.47
Off-Peak (lowest price) @ 8.7 c/kWh	35.91
Delivery	59.79
Regulatory Charges	4.95
Total Electricity Charges	$139.63
HST	18.15
Ontario Electricity Rebate	(-$18.29)
Total Amount	$139.49

Hydro One's portion is $15.03



The pie chart above is based on a total bill of $139.63 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

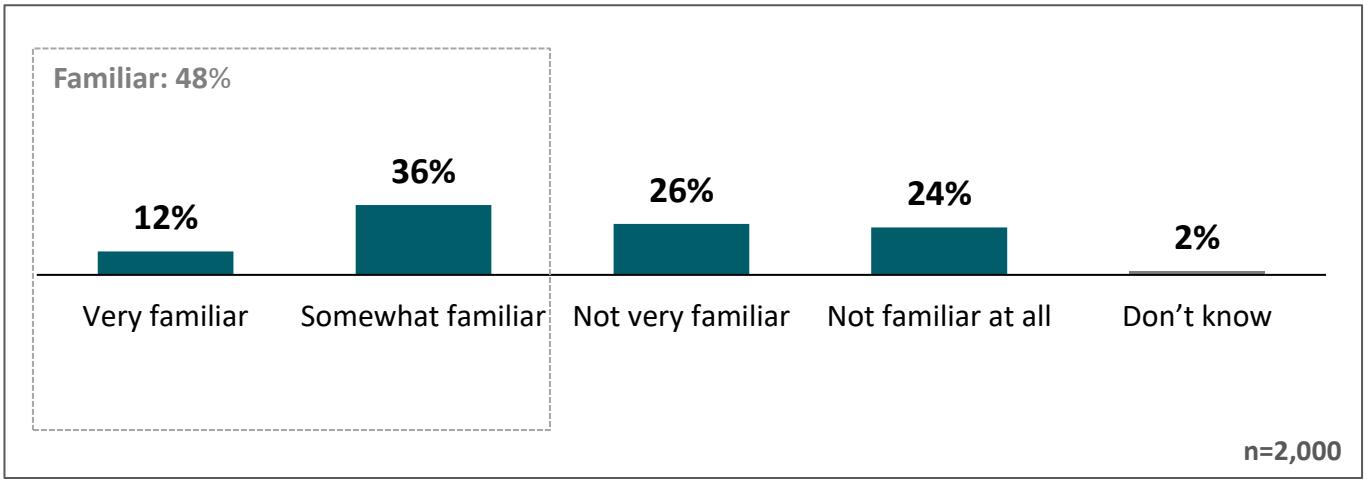
The sample bill above uses an average consumption level of 750kWh per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

SURVEY PAGE

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?



Region

	Toronto	Rest of GTA	South/West	North/East
Very familiar	14%	11%	10%	14%
Somewhat familiar	34%	41%	35%	30%
Not very familiar	25%	25%	26%	29%
Not familiar at all	24%	21%	27%	26%
Don't know	3%	1%	2%	1%
Familiar (Very + Somewhat)	**48%**	**53%**	**45%**	**44%**

LEAP/OESP Qualification

Bill Impact

	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	11%	11%	14%	15%	7%
Somewhat familiar	34%	30%	40%	41%	28%
Not very familiar	26%	31%	25%	23%	30%
Not familiar at all	27%	27%	20%	20%	31%
Don't know	2%	1%	1%	1%	3%
Familiar (Very + Somewhat)	**45%**	**41%**	**54%**	**56%**	**35%**

Summary of Investment Plan

How Hydro One plans

Other LDC Residential

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity transmission services. This feedback was used to inform planners in developing the draft investment plan.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

Other LDC Residential

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

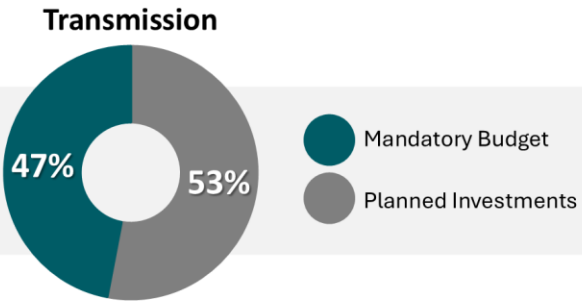
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Other LDC Residential

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

hydro one

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

Hydro One's draft plans cover both the **transmission system** serving most Ontarians and the **distribution system** serving their approximately 1.5 million customers.

Some of the highlights of Hydro One's draft plans include:

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest transmitter and distributor of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plans include:

Shared Transmission and Distribution Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

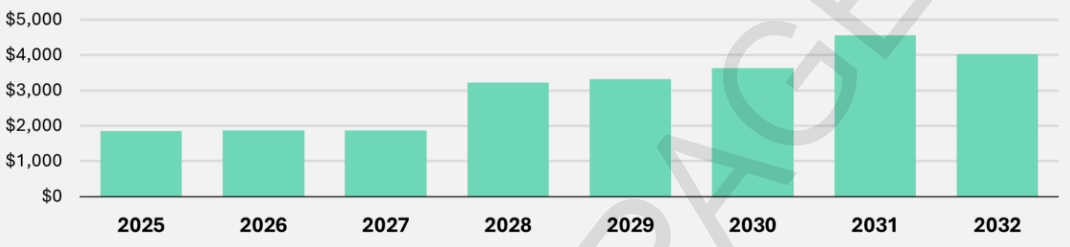
Other LDC Residential

Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

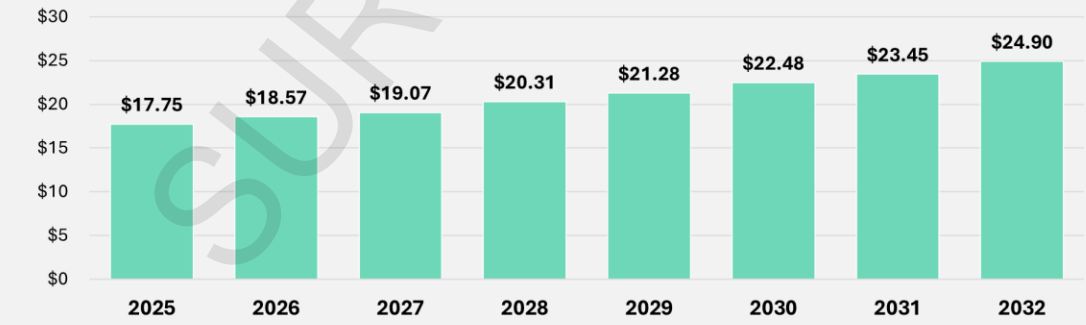


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical Ontario **residential customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $19.07 in 2027 to $24.90 by the end of 2032 – an increase of **$5.83** on the monthly bill. This represents an average increase of **$1.17** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- The transmission portion of the monthly bill and associated estimated bill impacts are based on a typical Hydro One residential customer for illustrative purposes.
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

How to make choices

Other LDC Residential

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft transmission investment plan, plus **4 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost for you.



SURVEY PAGE

Summary of Investment Plan

Hydro One's transmission system

Other LDC Residential

Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

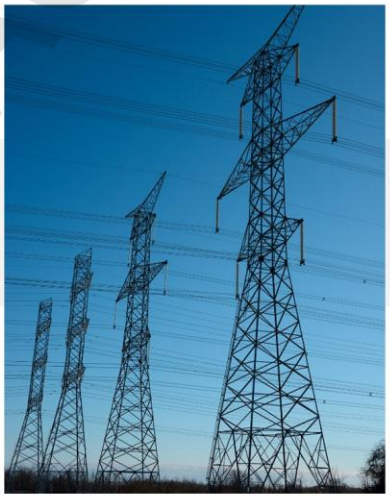
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Hydro One Customer Engagement Survey
Keeping pace with transmission renewal

hydro one

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$0.59 less by 2032 (average of $0.12 less each year)	**Included in Draft Plan**	$0.59 more by 2032 (average of $0.12 more each year)

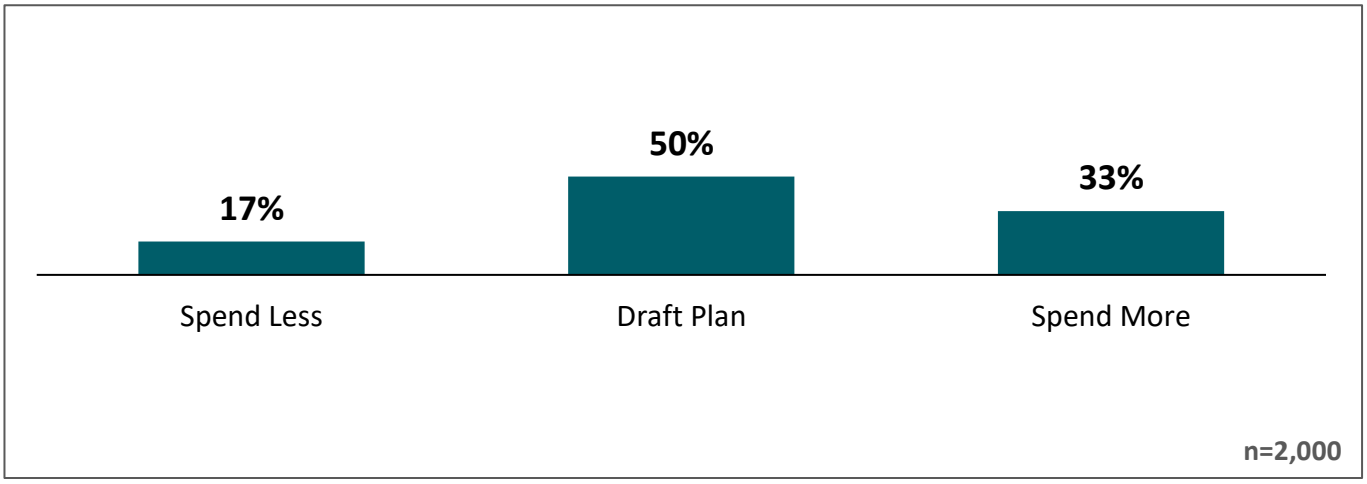
SURVEY PAPER

Investment Trade-Offs

Keeping pace with transmission renewal

Other LDC Residential

Q Which of the following options do you prefer?



Region

	Toronto	Rest of GTA	South/West	North/East
Spend Less	18%	15%	18%	18%
Draft Plan	51%	52%	48%	49%
Spend More	31%	33%	34%	33%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	20%	16%	15%	22%	9%
Draft Plan	52%	45%	51%	54%	44%
Spend More	29%	39%	34%	23%	47%

Investment Trade-Offs

Keeping pace with transmission renewal

Other LDC Residential

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	2.0%
Willing to pay more for improved reliability	1.2%
Invest now to prepare for future/prevent future increases	1.1%
Against increases/costs are too expensive	0.6%
Find efficiencies/alternative funding/customers shouldn't pay	0.6%
Need more information	0.4%
Infrastructure needs to be upgraded	0.4%
Focus on renewable, nuclear and energy storage solutions	0.2%
Concerns around cost of living/inflation	0.2%
Maintain current service levels/prioritize areas of higher need	0.2%
Focus on preventative maintenance	0.2%
Bury the lines	0.1%
Improve reliability/reduce outages	0.1%
Other	1.1%
No comment/None/Don’t know	91.6%

Note: Only responses >0.1% shown

Hydro One Customer Engagement Survey
Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$0.48 less by 2032 (average of $0.10 less each year)	**Included in Draft Plan**	$0.48 more by 2032 (average of $0.10 more each year)

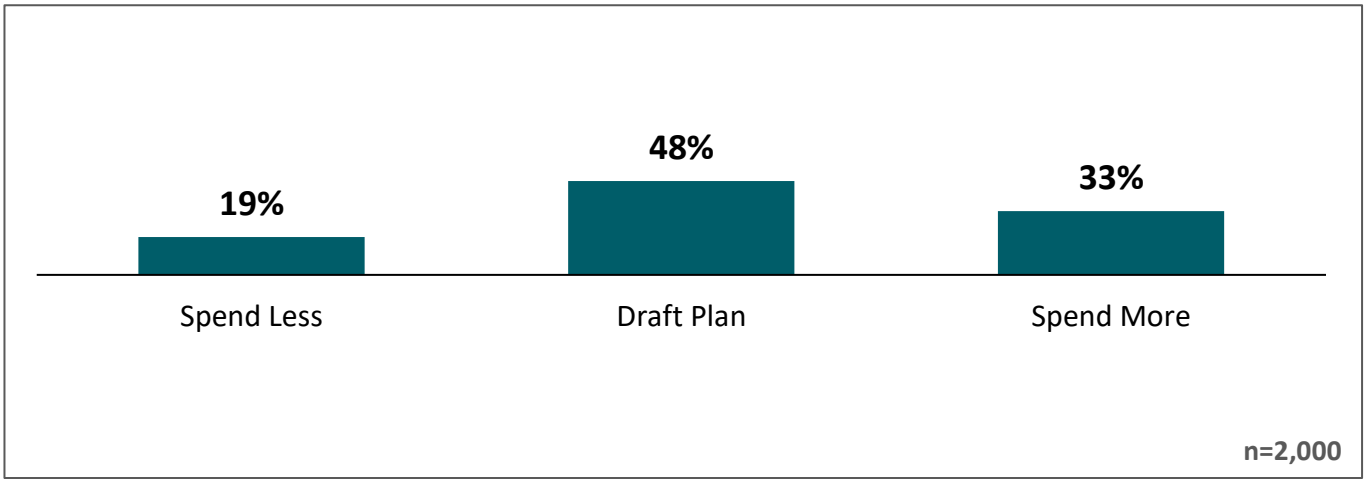
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Other LDC Residential

Q Which of the following options do you prefer?



Region

	Toronto	Rest of GTA	South/West	North/East
Spend Less	21%	19%	17%	21%
Draft Plan	45%	51%	49%	45%
Spend More	33%	30%	34%	34%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	21%	18%	19%	24%	12%
Draft Plan	51%	45%	47%	51%	44%
Spend More	28%	37%	34%	25%	44%

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Investment Trade-Offs

Stewardship of the transmission system

Other LDC Residential

Q Additional Feedback (Optional)

Responses	%
Willing to pay more for improved reliability	1.3%
Support the draft plan/increase is reasonable	0.8%
Against increases/costs are too expensive	0.7%
Infrastructure needs to be upgraded	0.4%
Improve line maintenance/vegetation management	0.3%
Improve reliability/reduce outages	0.2%
Maintain current service levels/prioritize areas of higher need	0.2%
Need climate-resilient infrastructure	0.2%
Need more information	0.2%
Find efficiencies/alternative funding/customers shouldn't pay	0.1%
Replace wood poles with stronger/more durable materials	0.1%
Concerns with severe weather	0.1%
Concerns around cost of living/inflation	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Bury the lines	0.1%
Other	0.8%
No comment/None/Don’t know	94.5%

Note: Only responses >0.1% shown

Investment Trade-Offs
Maintaining buildings and facilities

Other LDC Residential

Hydro One Customer Engagement Survey
Maintaining buildings and facilities

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One distribution customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Transmission Bill Impact	$0.02 less by 2032 (average of $0.005 less each year)	**Included in Draft Plan**	$0.07 more by 2032 (average of $0.01 more each year)

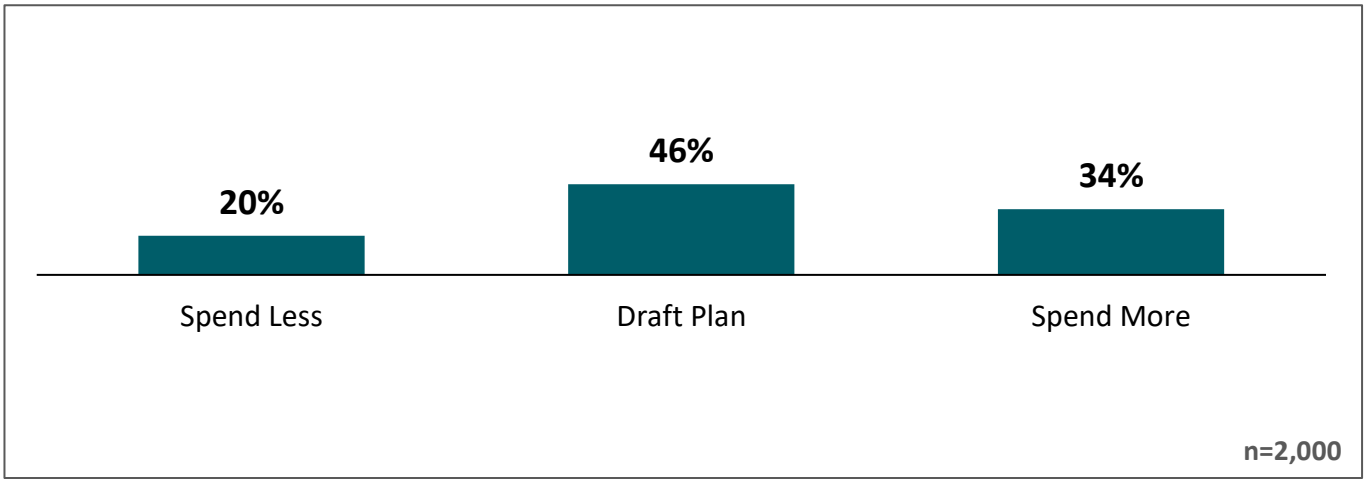
SURVEY PACK

Investment Trade-Offs

Maintaining buildings and facilities

Other LDC Residential

Q Which of the following options do you prefer?



Region

	Toronto	Rest of GTA	South/West	North/East
Spend Less	22%	20%	20%	17%
Draft Plan	43%	47%	47%	48%
Spend More	34%	33%	33%	35%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	22%	20%	19%	25%	13%
Draft Plan	48%	44%	46%	49%	42%
Spend More	31%	36%	35%	26%	45%

Investment Trade-Offs

Maintaining buildings and facilities

Other LDC Residential

Q Additional Feedback (Optional)

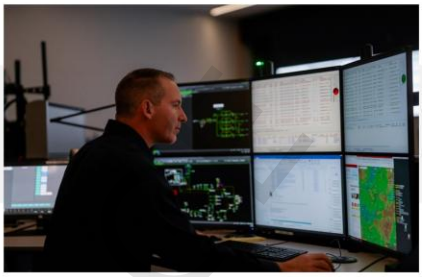
Responses	%
Support the draft plan/increase is reasonable	2.2%
Against increases/costs are too expensive	0.6%
Seems Hydro One didn't plan well in the past	0.2%
Infrastructure needs to be upgraded	0.1%
Improve reliability/reduce outages	0.1%
Support meeting modern accessibility standards	0.1%
Find efficiencies/alternative funding/customers shouldn't pay	0.1%
Other	1.0%
No comment/None/Don’t know	95.6%

Note: Only responses >0.1% shown

Investment Trade-Offs
Information technology

Hydro One Customer Engagement Survey
Information technology

Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.



When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

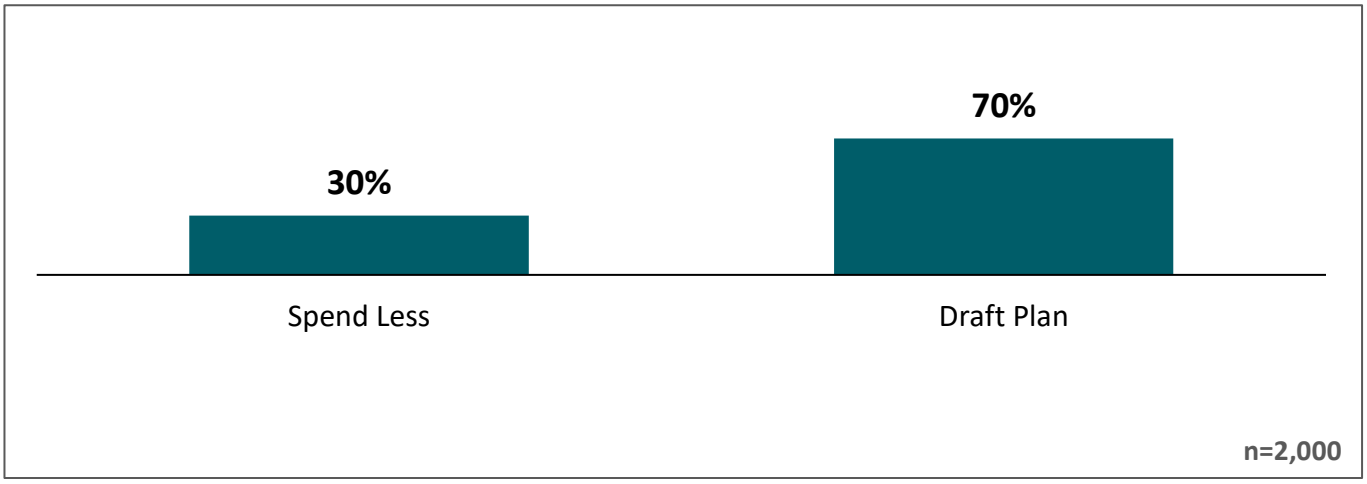
	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Transmission Bill Impact	$0.16 less by 2032 (average of $0.03 less each year)	**Included in Draft Plan**

SURVEY PAC

Investment Trade-Offs
Information technology

Other LDC Residential

Q Which of the following options do you prefer?



Region

	Toronto	Rest of GTA	South/West	North/East
Spend Less	33%	32%	26%	29%
Draft Plan	67%	68%	74%	71%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend Less	33%	30%	28%	36%	21%
Draft Plan	67%	70%	72%	64%	79%

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Investment Trade-Offs

Information technology

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	1.7%
Against increases/costs are too expensive	0.7%
Infrastructure needs to be upgraded	0.3%
Find efficiencies/alternative funding/customers shouldn't pay	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
IT investments should reduce other administrative and operational costs	0.1%
Satisfied with current customer service levels	0.1%
Other	0.3%
No comment/None/Don’t know	96.6%

Note: Only responses >0.1% shown

SURVEY PAGE

Hydro One Customer Engagement Survey

What is the impact of my choices?

Throughout this survey, you have been asked about 4 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on the monthly bill will be recalculated.

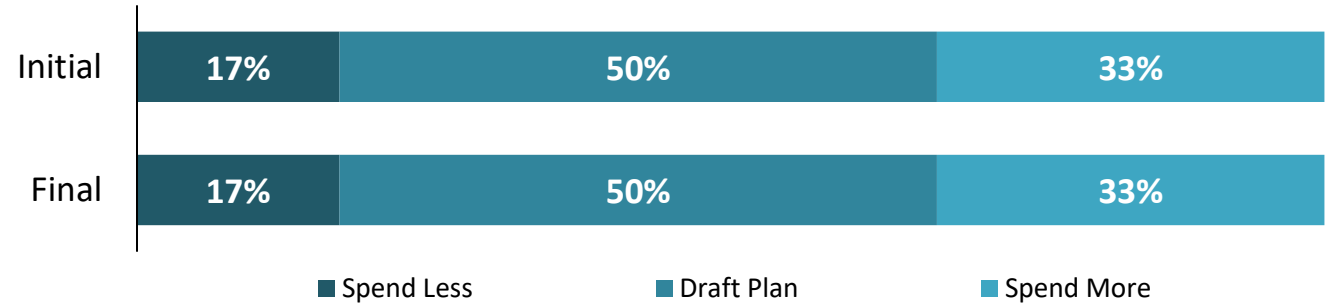
The bill impacts associated with each choice represent the average estimated increase on the transmission portion of the monthly bill from 2027 to 2032, followed by the average estimated increase on the transmission portion of the monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

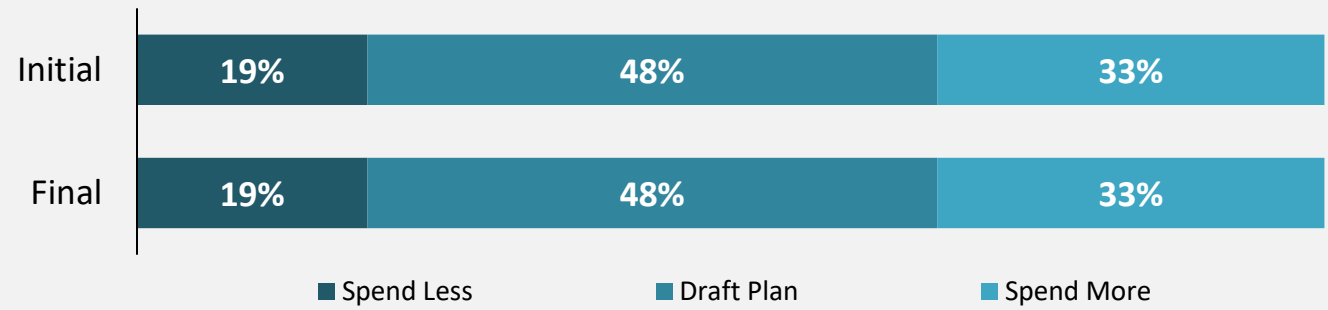
Finalizing Choices

Other LDC Residential

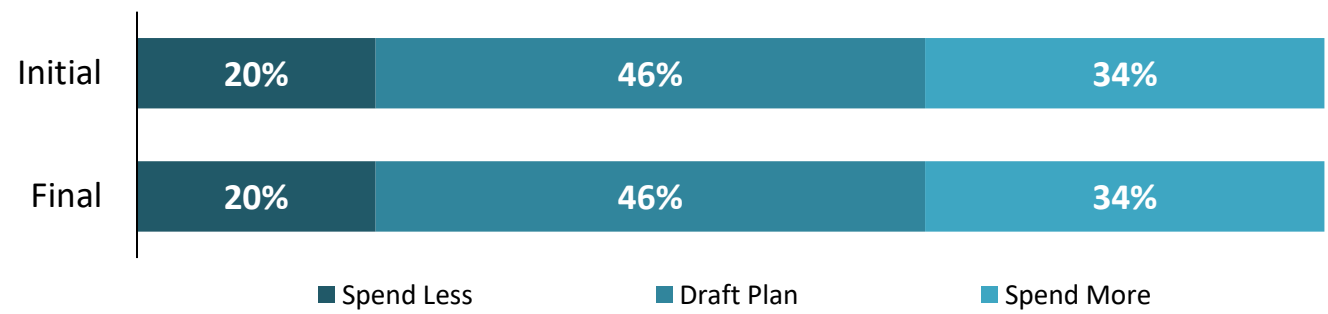
Keeping pace with transmission renewal



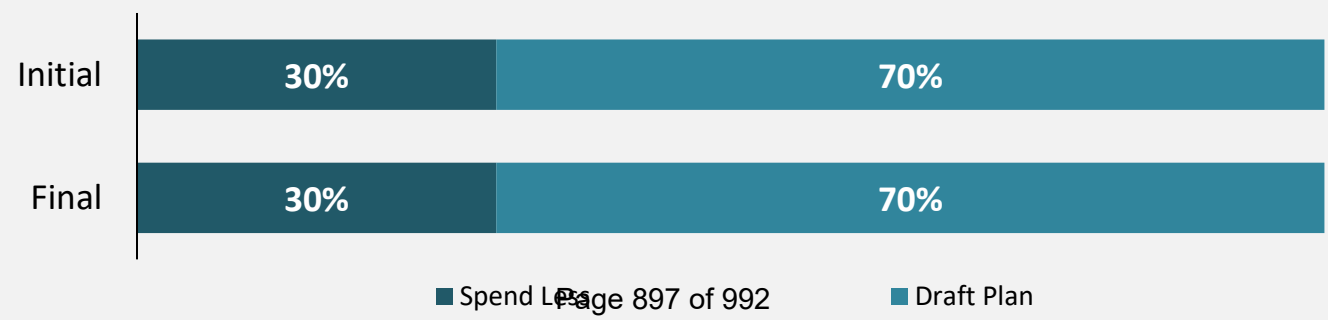
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



Investment Trade-Offs

Overall evaluation of the draft plan

Other LDC Residential

SURVEY PAGE

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plan. While the plan may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plan.

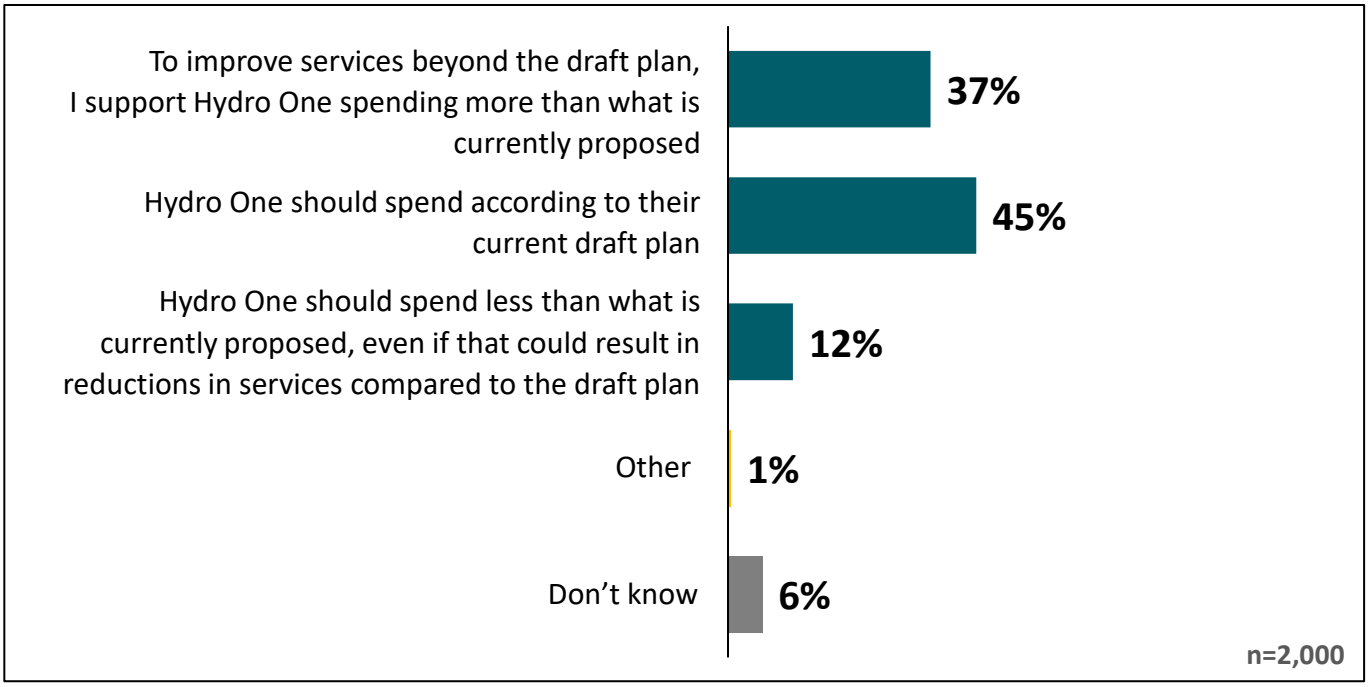
It is estimated that a typical Ontario **residential customer** would see the **transmission** portion of their **monthly bill** increase from $19.07 in 2027 to $24.90 by the end of 2032 – an increase of **$5.83** on the monthly bill. This represents an average increase of **$1.17** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plan

Other LDC Residential

Q Considering what you have learned about Hydro One's 2028–2032 draft plan, which of the following best represents your point of view?



Region

	Toronto	Rest of GTA	South/West	North/East
Spend More	38%	34%	39%	37%
Draft Plan	42%	47%	48%	41%
Spend Less	13%	13%	8%	14%
Other	1%	<1%	<1%	<1%
Don't know	6%	6%	6%	7%

Investment Trade-Offs

Overall evaluation of the draft plan

Other LDC Residential

Q Considering what you have learned about Hydro One's 2028–2032 draft plan, which of the following best represents your point of view?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	37%	32%	42%	39%	32%	43%
Draft Plan	45%	45%	43%	45%	48%	40%
Spend Less	12%	13%	11%	11%	14%	8%
Other	1%	<1%	<1%	1%	<1%	1%
Don't know	6%	9%	3%	4%	5%	8%

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Investment Trade-Offs

Final comments on the draft plan

Other LDC Residential

Q Do you have any final comments regarding Hydro One's draft plan for 2028–2032 and the proposed rate increase? (Optional)

Responses	%
Support the increase/investments are necessary	3.4%
Invest now to prepare for future/prevent future increases	1.2%
Lower rates/rates are too high	0.9%
Positive comment about Hydro One/service	0.8%
Find efficiencies/alternative funding/customers shouldn't pay	0.7%
Improve reliability/reduce outages	0.6%
Need more information/educate customers	0.5%
Environmental concerns/green initiatives	0.4%
Transparency on internal operations	0.4%
Distrust in the engagement/rate increases are inevitable	0.3%
Concerns around cost of living/inflation	0.2%
Be transparent/communicate about rate increases/investments	0.2%
Fair cost allocation/user-pays for system impacts/upgrades	0.1%
Stop selling power to the US/increase price to the US	0.1%
Financial strain on vulnerable customers (seniors, fixed income)	0.1%
Other	0.4%
No comment/None/Don't know	89.6%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Other LDC Residential Customers

Survey Diagnostics

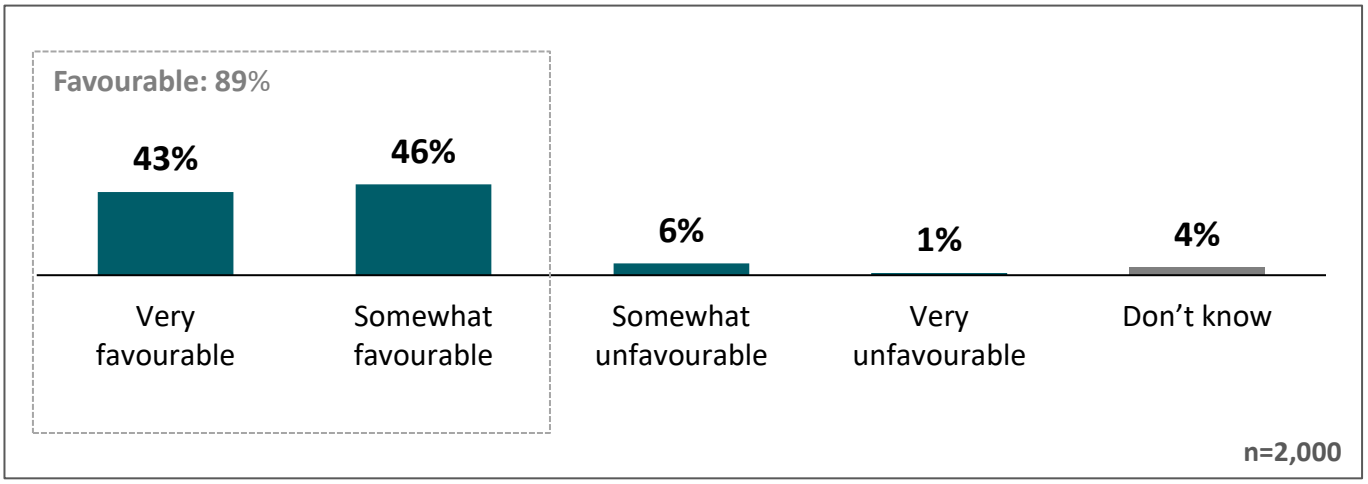


Survey Diagnostics

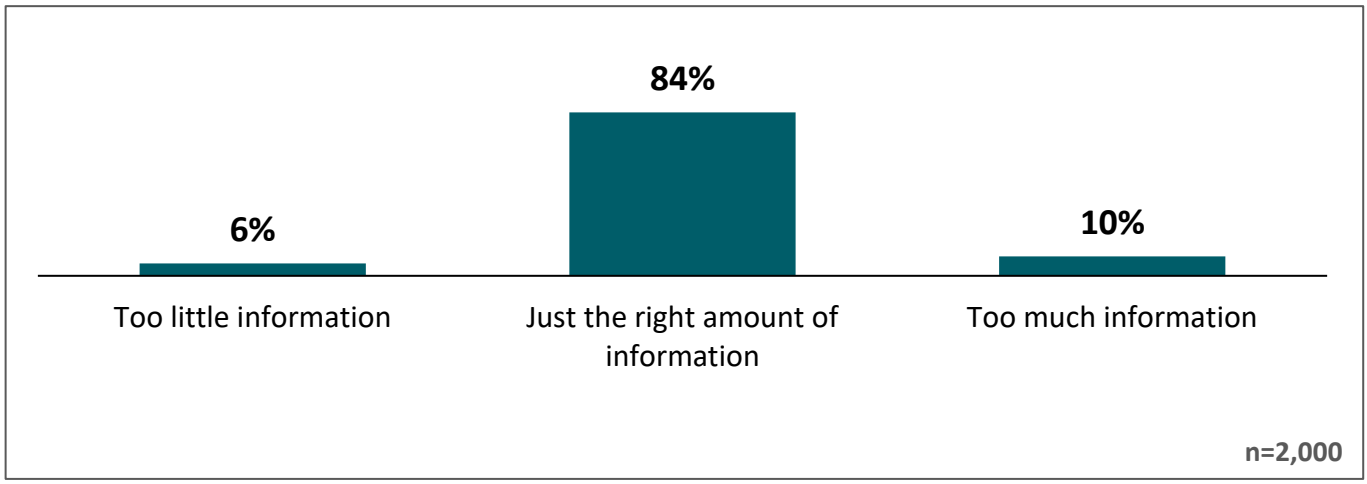
Favourability and amount of information

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



Survey Diagnostics
Other information not included

Other LDC Residential

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
Survey/engagement experience feedback - positive	1.3%
Reducing customer costs/affordability measures	1.0%
Transparency on internal operations	0.9%
More information/communication about rate increases	0.7%
Survey/engagement experience feedback - negative	0.6%
More detailed information on the investments/infrastructure	0.6%
Positive comment about Hydro One/service	0.5%
Impact on the environment/wildlife	0.2%
Distrust in the engagement/rate increases are inevitable	0.2%
More information on renewable energy	0.2%
How Hydro One's costs compare to other companies/jurisdictions	0.2%
Information on energy sold to US/other countries/out of province	0.1%
Better explanation/transparency on bills	0.1%
Helping seniors/fixed-income individuals	0.1%
Historical data (e.g. spending, impact, cost)	0.1%
Focus on renewable, nuclear and energy storage solutions	0.1%
Better outage communication/information	0.1%
Other	0.4%
No comment/None/Don’t know	92.7%

Note: Only responses >0.1% shown

Survey Diagnostics
Outstanding questions

Other LDC Residential

Q Is there anything that you would still like answered? (Optional)

Responses	%
Plans to reduce/lower customer costs	1.0%
Survey/engagement experience feedback - positive	0.7%
Transparency on internal operations	0.5%
More detailed information on the investments/infrastructure	0.4%
Be transparent/communicate about rate increases	0.4%
Positive comment about Hydro One/service	0.4%
Focus on renewable, nuclear & energy storage solutions	0.3%
Survey/engagement experience feedback - negative	0.3%
Better explanation/transparency on bills	0.1%
Improve reliability/reduce outages	0.1%
Improve customer service/communication (general/outage)	0.1%
Stop selling power to the US/increase price to the US	0.1%
Other	0.7%
No comment/None/Don't know	95.0%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Other LDC Small Business Customers

Online Survey Results

Section 8



Online Survey
Methodology

Field Dates

To obtain feedback from **Other LDC Small Business (GS<50) customers**, a random sample of online panelists were invited to complete the survey from a set of partner panels based on the Dynata exchange platform.

In order to qualify to complete the survey, respondents must satisfy each of the following conditions:

- Represent an organization with fewer than 50 employees
- At least share responsibility for the electricity bill or engage in electricity decision-making at their organization (dealing with electrical utility companies, understanding and selecting electricity-based equipment, or managing electricity use)
- Receive electrical service from a company other than Hydro One

Survey responses were collected between **December 4th and December 16th, 2025**.

Other LDC Small Business Online Survey Completes

A total of **305** (unweighted) businesses completed the online survey.

Note: *Graphs and tables may not always total 100% due to rounding values other than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey
Methodology (Cont'd)

Sample Weighting

The Other LDC Small Business online survey sample was weighted to n=300 proportionately by sector, region, and business size in order to be representative of the broader population of Ontario businesses based on Census data.

The tables below summarize the unweighted and weighted (in brackets) sample breakdown by sector, size, and region.

Sector	Count
Resource-based	8 (5)
Construction	45 (36)
Manufacturing	18 (14)
Retail and wholesale	51 (47)
Transportation and warehousing	7 (7)
Knowledge and professional services	81 (89)
Education, health care, and social services	28 (33)
Leisure, hospitality, and other services	50 (53)
Public administration	2 (1)
Other	15 (16)
Total	305 (300)

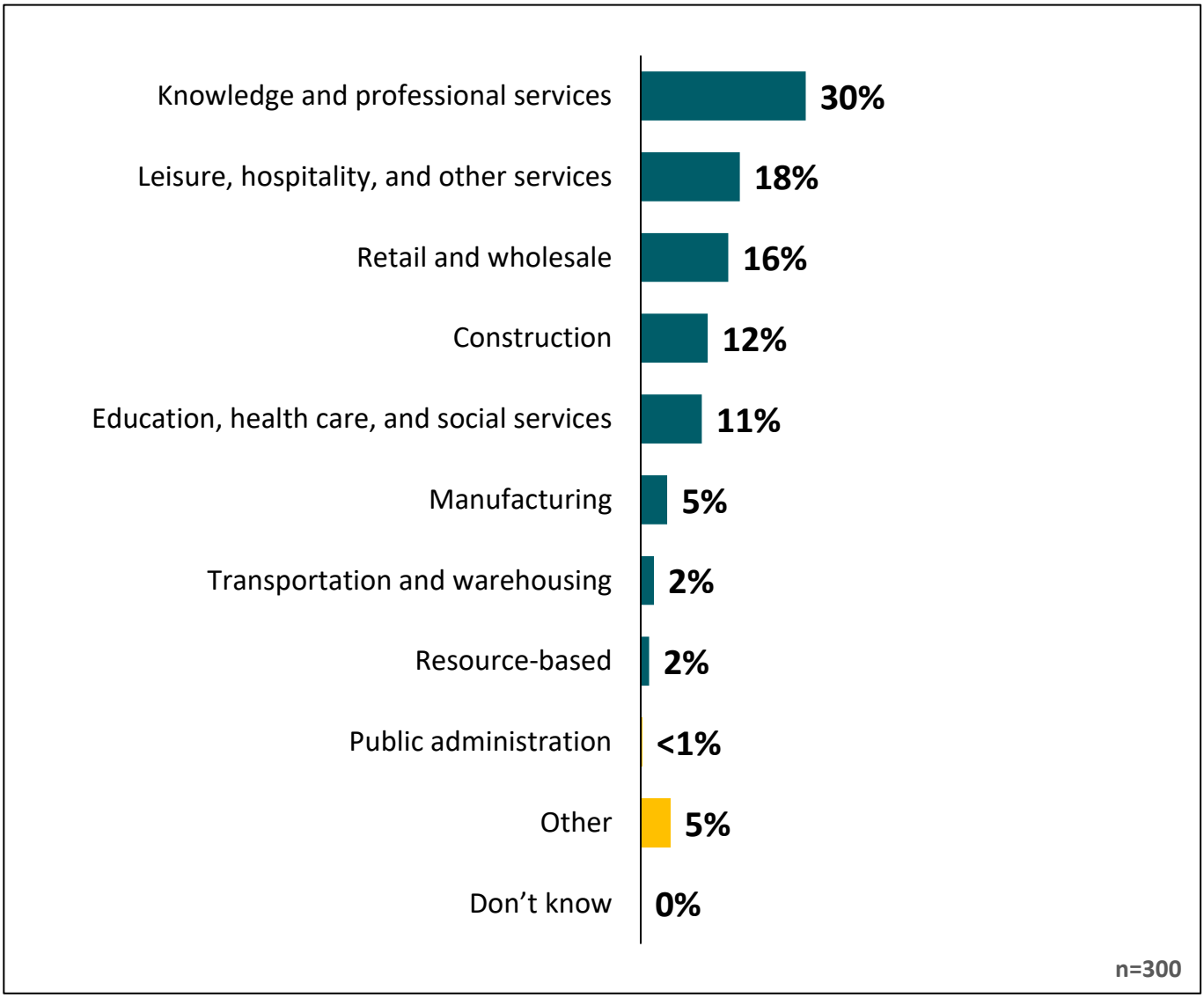
Size	Count
1 person	73 (87)
2 to 4 people	83 (93)
5 to 9 people	45 (50)
10 to 19 people	52 (40)
20 to 49 people	52 (29)
Total	305 (300)

Region	Count
Toronto	84 (67)
Rest of GTA	76 (87)
South/West	82 (87)
North/East	63 (59)
Total	305 (300)

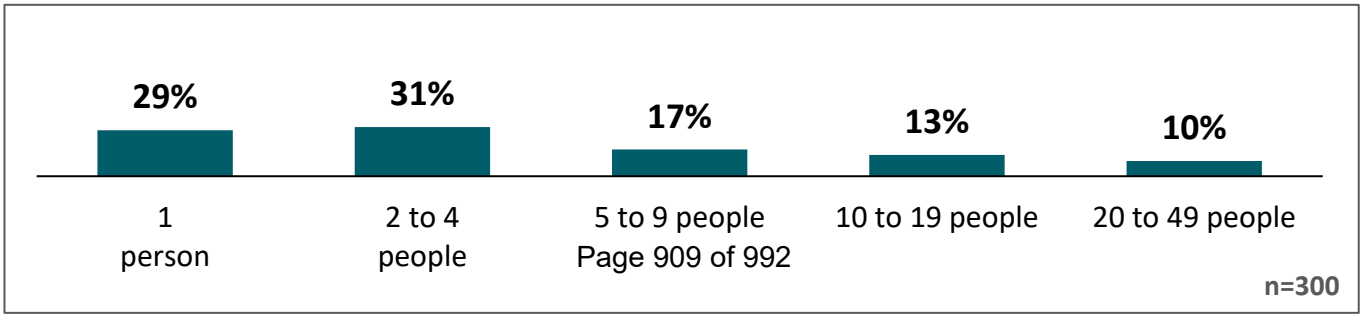
Note: *Graphs and tables may not always total 100% due to rounding values other than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographic Breakdown

Q Business Sector



Q Business Size

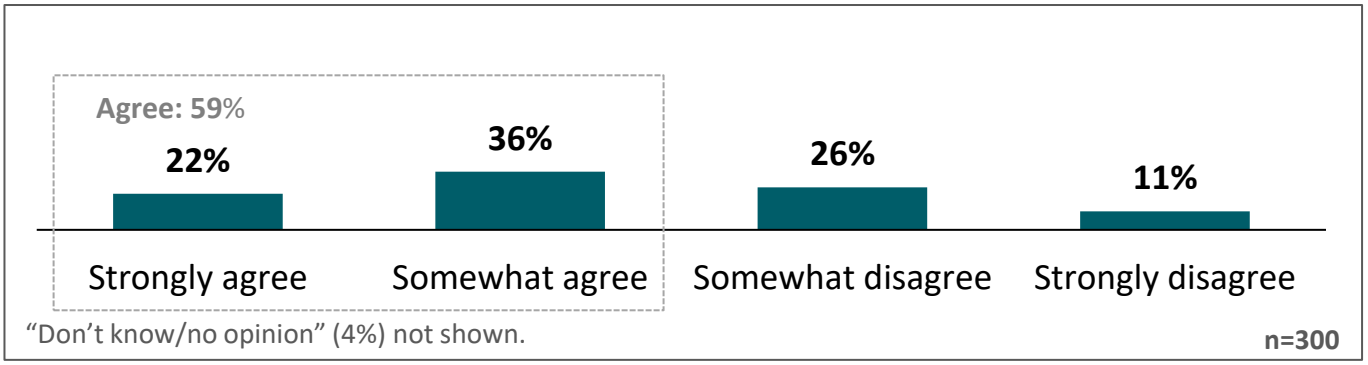


Environmental Controls

Other LDC Small Business

To what extent do you agree or disagree with the following statements?

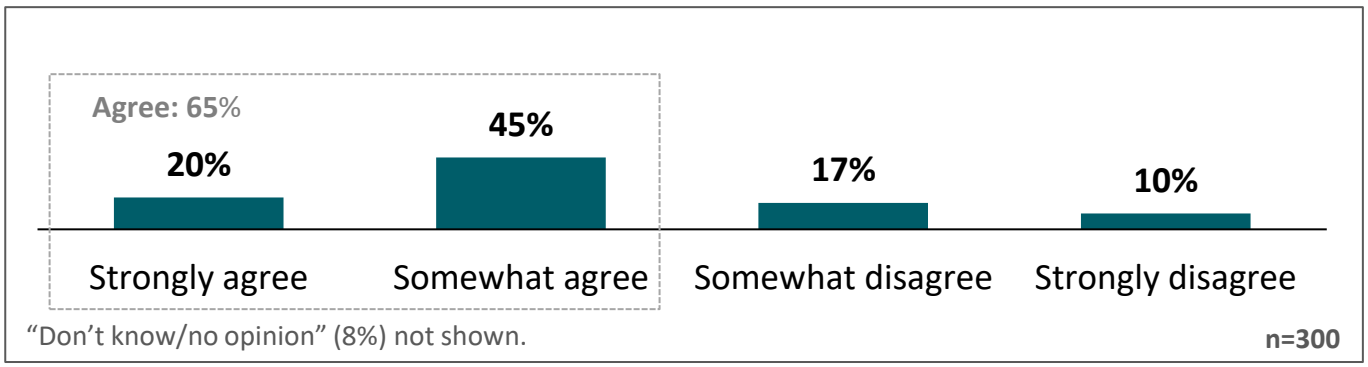
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (4%) not shown.

n=300

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (8%) not shown.

n=300

INNOVATIVE RESEARCH GROUP

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

hydro one

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plan** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 10-15 minutes to complete. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

INNOVATIVE RESEARCH GROUP

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by most Ontarians. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plan, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plan.

Next year, Hydro One will present their proposed plan and input provided by customers to the OEB.

SURVEY PREVIEW

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Other LDC
Small Business

SURVEY PAGE

Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

hydro one

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, **Hydro One** is also responsible for the local distribution system, which delivers electricity to homes, seasonal properties, or organizations through a network of wires, poles and other equipment.



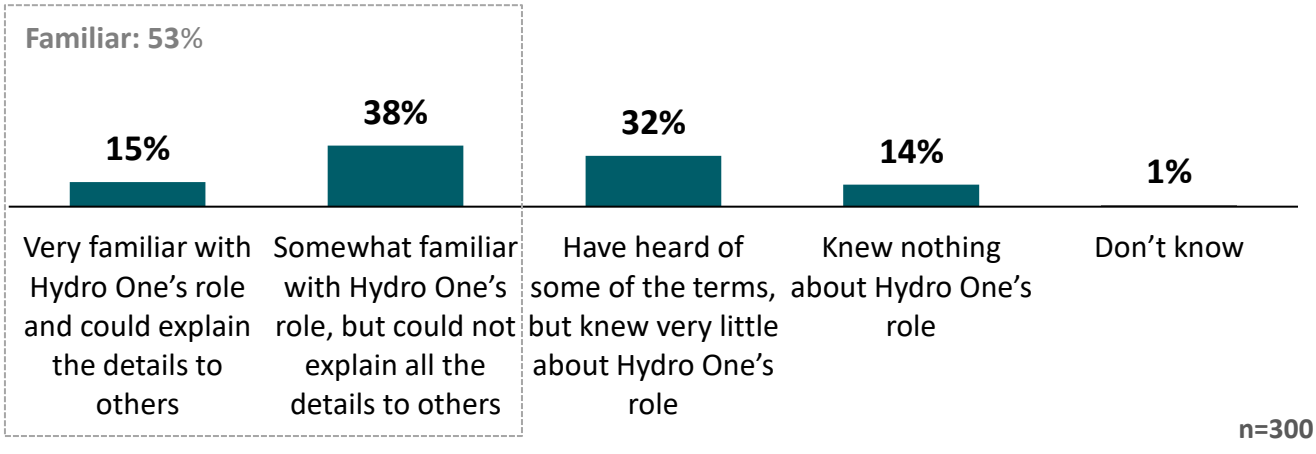
Hydro One does not generate electricity or set electricity prices.

Familiarity & Experience

Hydro One's role in Ontario's electricity system

Other LDC Small Business

Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



	Region				Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Very familiar	12%	20%	15%	13%	21%	7%
Somewhat familiar	40%	35%	38%	41%	37%	40%
Knew very little	31%	32%	33%	30%	30%	35%
Knew nothing	14%	13%	13%	17%	11%	18%
Don't know	3%	--	1%	--	2%	--
Familiar (Very + Somewhat)	**52%**	**55%**	**52%**	**53%**	**58%**	**47%**

INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Other LDC Small Business

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

As of **July 1, 2025**, for a typical Ontario small business customer, about 11% of the bill, or $36.50, goes to Hydro One per month to pay for the transmission of electricity from generation stations to your local electricity distributor.

The rest of your bill payment goes to your local electricity distributor power generation companies, taxes, and regulatory agencies.

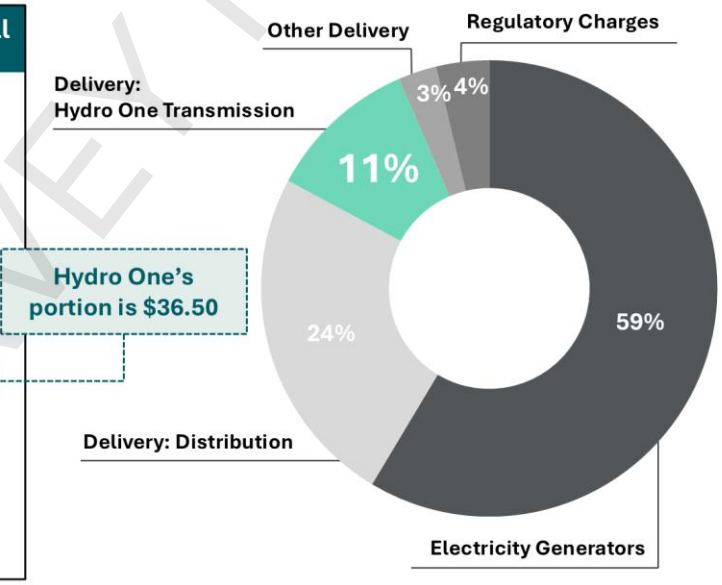
Sample Small Business Monthly Bill
(based on consumption of 2,000 kWh as of July 1, 2025)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 18.2 c/kWh	60.04
Mid-Peak (mid price) @ 12.2 c/kWh	43.92
Off-Peak (lowest price) @ 8.7 c/kWh	95.76
Delivery	128.41
Regulatory Charges	12.78
Total Electricity Charges	$340.91
HST	44.32
Ontario Electricity Rebate	(-$44.66)
Total Amount	$340.57

Hydro One's portion is $36.50



The pie chart above is based on a total bill of $340.91 excluding the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 2,000kWh per month; however, your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

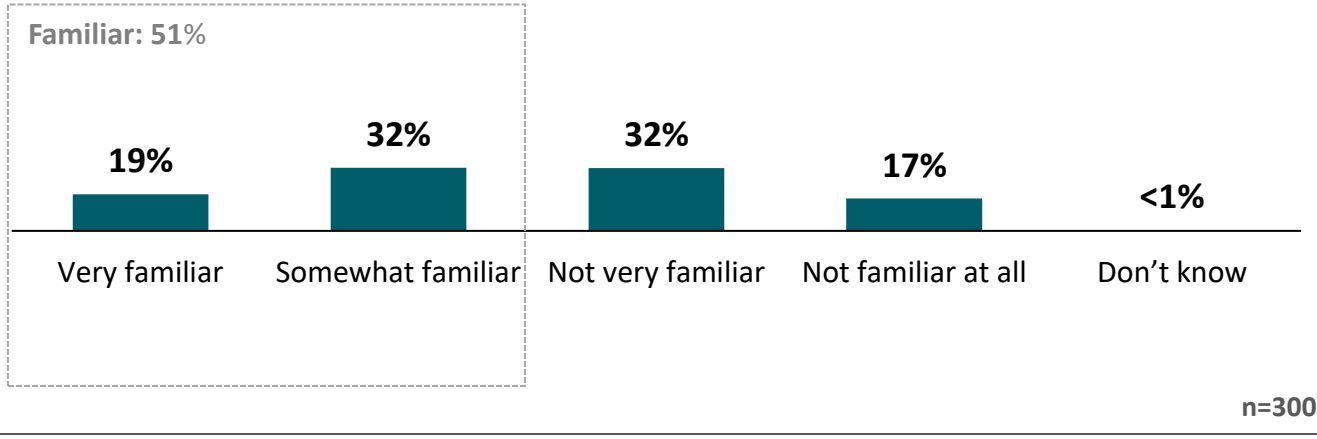
SURVEY PAGE

Familiarity & Experience

Bill familiarity

Other LDC Small Business

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Hydro One?



	Region				Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Very familiar	20%	20%	20%	15%	23%	13%
Somewhat familiar	30%	39%	33%	25%	36%	27%
Not very familiar	30%	30%	30%	41%	27%	39%
Not familiar at all	19%	12%	17%	20%	13%	22%
Don't know	2%	--	--	--	1%	--
Familiar (Very + Somewhat)	**49%**	**58%**	**53%**	**39%**	**59%**	**39%**

INNOVATIVE RESEARCH GROUP

Summary of Investment Plan

How Hydro One plans

Other LDC
Small Business

Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity transmission services. This feedback was used to inform planners in developing the draft investment plan.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.

SURVEY PAGE

Summary of Investment Plan

Challenges impacting Hydro One's plans

Other LDC Small Business

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

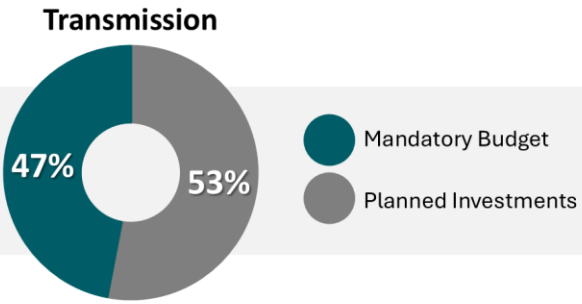
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Other LDC Small Business

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

Hydro One's draft plans cover both the **transmission system** serving most Ontarians and the **distribution system** serving their approximately 1.5 million customers.

Some of the highlights of Hydro One's draft plans include:

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest transmitter and distributor of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plans include:

Shared Transmission and Distribution Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

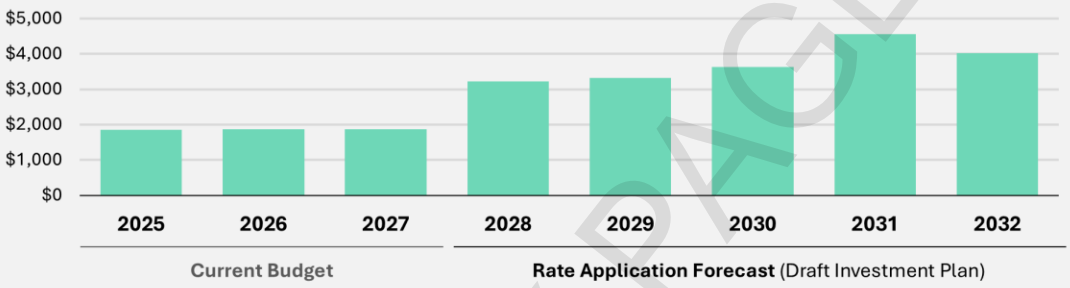
Other LDC
Small Business

Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)

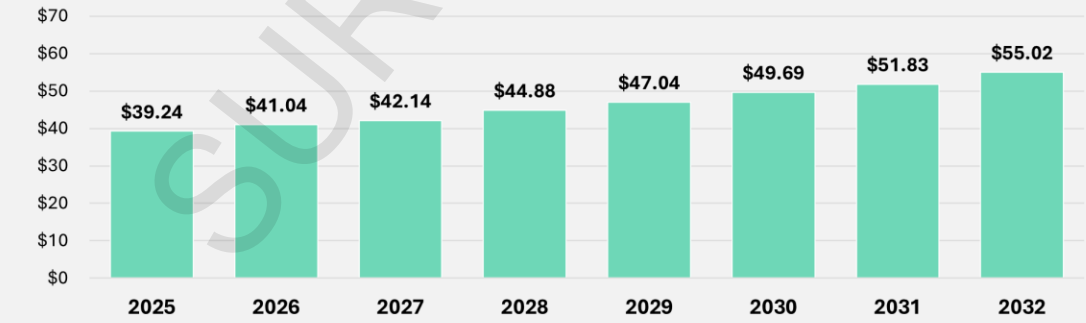


The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical Ontario **small business customer**, the **transmission** portion of their **monthly bill** is estimated to increase from $42.14 in 2027 to $55.02 by the end of 2032 – an increase of **$12.88** on the monthly bill. This represents an average increase of **$2.58** on the monthly bill each year.

Transmission Portion of Monthly Bill



Note:
- The transmission portion of the monthly bill and associated estimated bill impacts are based on a typical Hydro One small business customer for illustrative purposes.
- Hydro One's rates until December 31, 2027, were approved by the OEB in an earlier application.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

SURVEY PAGE

Summary of Investment Plan

How to make choices

Other LDC Small Business

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft transmission investment plan, plus **4 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost for you.



SURVEY PAGE

Summary of Investment Plan

Hydro One's transmission system

Other LDC
Small Business

Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

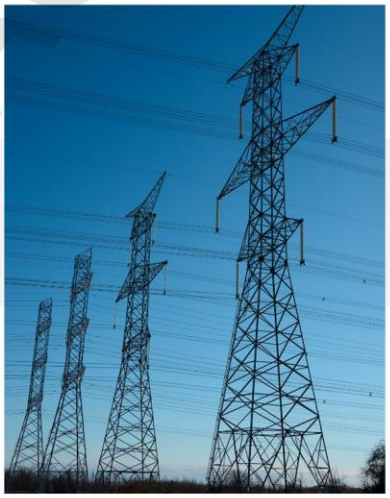
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

Other LDC
Small Business

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Average Monthly Transmission Bill Impact	$1.31 less by 2032 (average of $0.26 less each year)	**Included in Draft Plan**	$1.31 more by 2032 (average of $0.26 more each year)

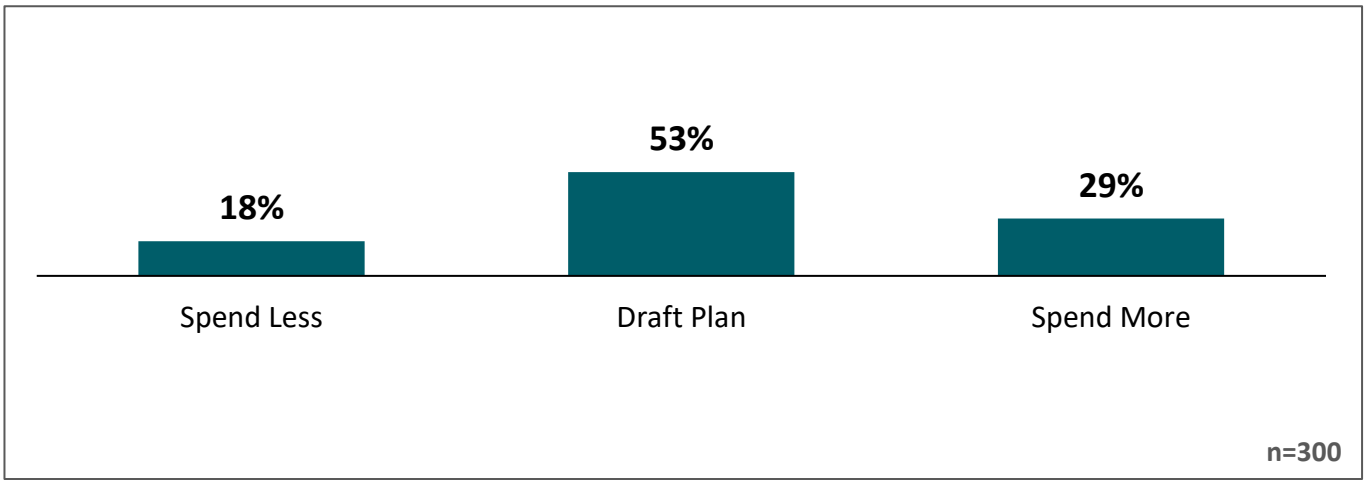
SURVEY PAPER

Investment Trade-Offs

Keeping pace with transmission renewal

Other LDC Small Business

Q Which of the following options do you prefer?



	Region				Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Spend Less	14%	18%	19%	19%	20%	14%
Draft Plan	57%	53%	52%	51%	57%	47%
Spend More	30%	29%	29%	30%	22%	39%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Keeping pace with transmission renewal

Other LDC
Small Business

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	2.5%
Focus on preventative maintenance	1.1%
Invest now to prepare for future/prevent future increases	0.9%
Against increases/costs are too expensive	0.8%
Willing to pay more for improved reliability	0.5%
Maintain current service levels/prioritize areas of higher need	0.5%
Distrust in the engagement/rate increases are inevitable	0.5%
Find efficiencies/alternative funding/customers shouldn't pay	0.3%
Infrastructure needs to be upgraded	0.2%
Other	1.8%
No comment/None/Don’t know	91.0%

Note: Only responses >0.1% shown

Investment Trade-Offs

Stewardship of the transmission system

Other LDC Small Business

Hydro One Customer Engagement Survey

Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Average Monthly Transmission Bill Impact	$1.05 less by 2032 (average of $0.21 less each year)	**Included in Draft Plan**	$1.05 more by 2032 (average of $0.21 more each year)

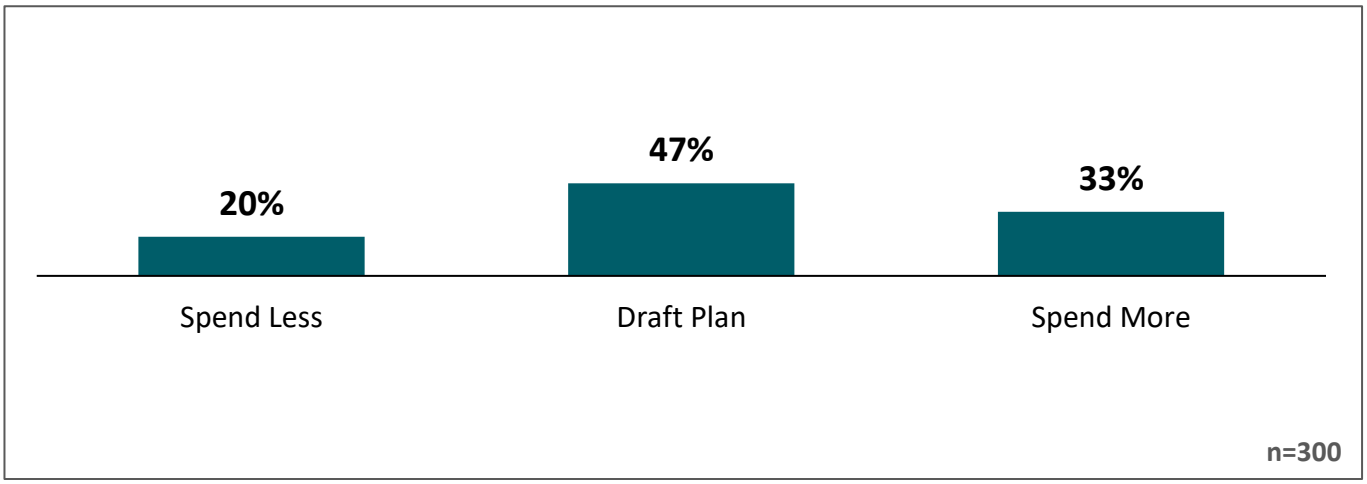
SURVEY PACE

Investment Trade-Offs

Stewardship of the transmission system

Other LDC Small Business

Q Which of the following options do you prefer?



	Region				Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Spend Less	17%	17%	28%	16%	25%	13%
Draft Plan	48%	49%	40%	55%	49%	44%
Spend More	35%	34%	32%	29%	26%	42%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Stewardship of the transmission system

Other LDC
Small Business

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	1.8%
Improve line maintenance/vegetation management	1.7%
Find efficiencies/alternative funding/customers shouldn't pay	1.1%
Willing to pay more for improved reliability	0.9%
Against increases/costs are too expensive	0.8%
Distrust in the engagement/rate increases are inevitable	0.5%
Infrastructure needs to be upgraded	0.3%
Improve reliability/reduce outages	0.2%
No comment/None/Don’t know	92.6%

Note: Only responses >0.1% shown

Investment Trade-Offs
Maintaining buildings and facilities

Other LDC
Small Business

Hydro One Customer Engagement Survey
Maintaining buildings and facilities

hydro one

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One distribution customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Average Monthly Transmission Bill Impact	$0.05 less by 2032 (average of $0.01 less each year)	**Included in Draft Plan**	$0.16 more by 2032 (average of $0.03 more each year)

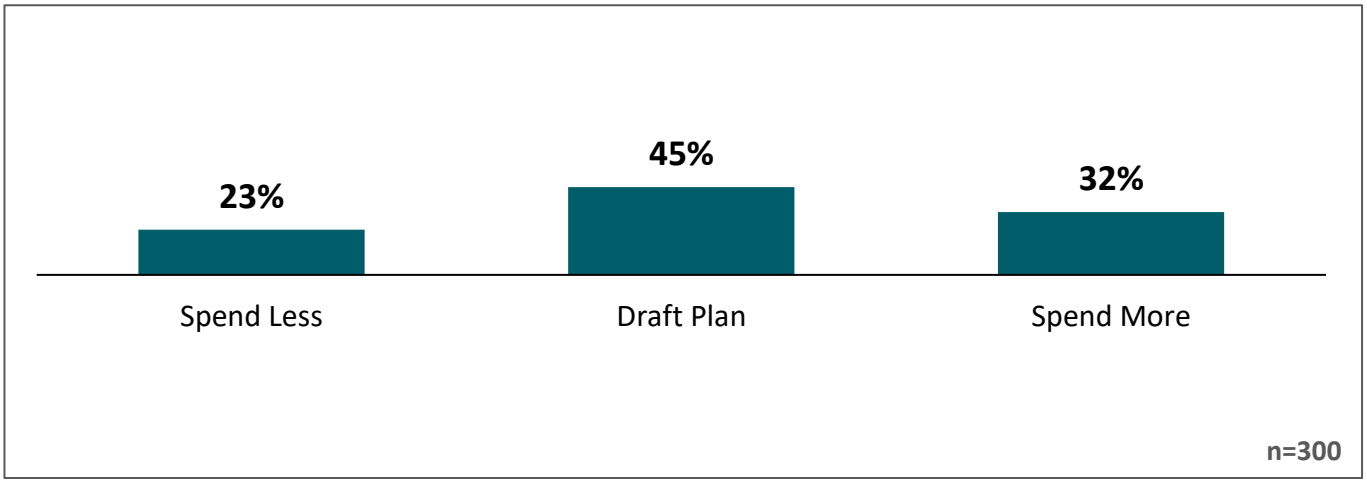
SURVEY PACE

Investment Trade-Offs

Maintaining buildings and facilities

Other LDC Small Business

Q Which of the following options do you prefer?



	Region				Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Spend Less	16%	24%	26%	24%	28%	16%
Draft Plan	51%	47%	37%	46%	49%	39%
Spend More	33%	29%	37%	29%	23%	45%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Maintaining buildings and facilities

Other LDC Small Business

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	3.2%
Against increases/costs are too expensive	1.4%
Financial strain on vulnerable customers (seniors, fixed income)	0.5%
Find efficiencies/alternative funding/customers shouldn't pay	0.4%
Other	0.7%
No comment/None/Don’t know	93.7%

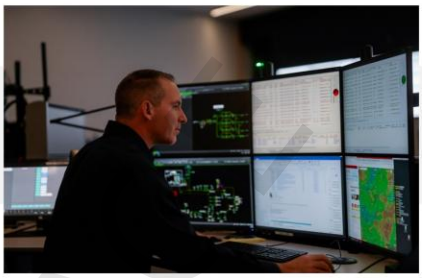
Note: Only responses >0.1% shown

Investment Trade-Offs
Information technology

Other LDC Small Business

Hydro One Customer Engagement Survey
Information technology

Hydro One



Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.

When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Average Monthly Transmission Bill Impact	$0.34 less by 2032 (average of $0.07 less each year)	**Included in Draft Plan**

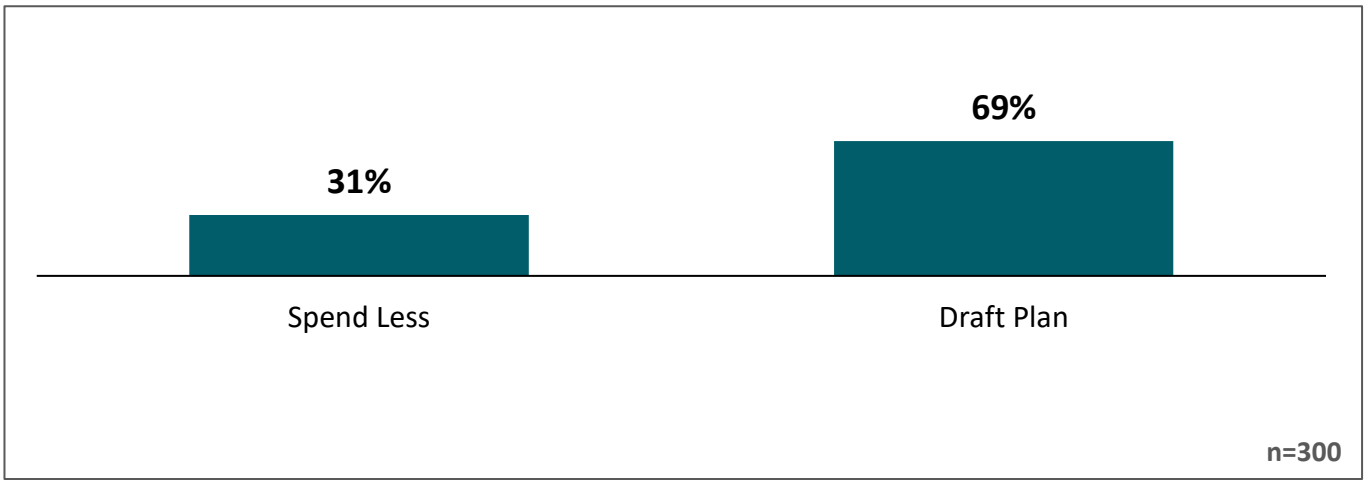
SURVEY PAPER

Investment Trade-Offs

Information technology

Other LDC Small Business

Q Which of the following options do you prefer?



		Region			Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Spend Less	32%	27%	35%	31%	38%	21%
Draft Plan	68%	73%	65%	69%	62%	79%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs
Information technology

Other LDC Small Business

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/increase is reasonable	2.0%
Concerns with AI/limitations	0.8%
Infrastructure needs to be upgraded	0.8%
Against increases/costs are too expensive	0.8%
Concerns with cyber attacks/prioritize cyber security	0.5%
Distrust in the engagement/rate increases are inevitable	0.2%
Other	0.4%
No comment/None/Don't know	94.5%

Note: Only responses >0.1% shown

SURVEY PAGE

Hydro One Customer Engagement Survey
What is the impact of my choices?

Throughout this survey, you have been asked about 4 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on the monthly bill will be recalculated.

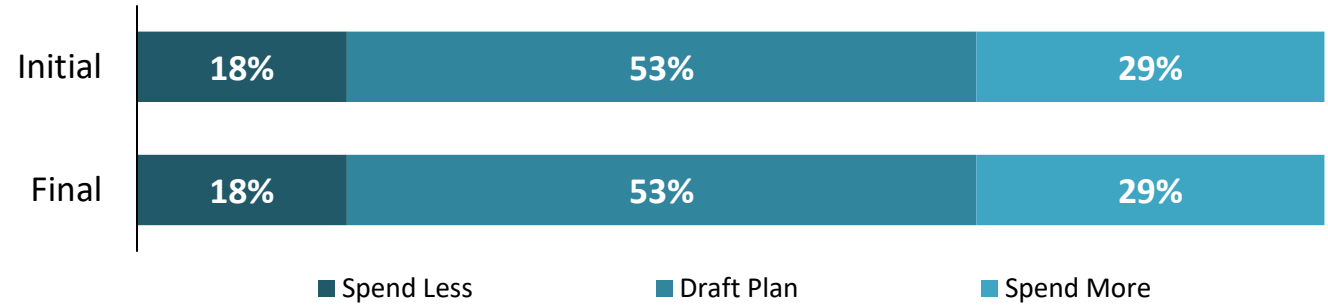
The bill impacts associated with each choice represent the average estimated increase on the transmission portion of the monthly bill from 2027 to 2032, followed by the average estimated increase on the transmission portion of the monthly bill each year. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Investment Trade-Offs

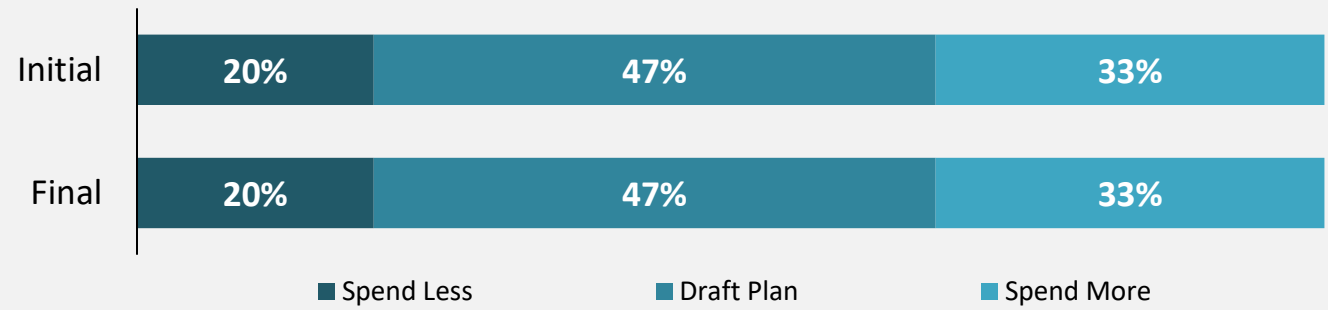
Finalizing Choices

Other LDC Small Business

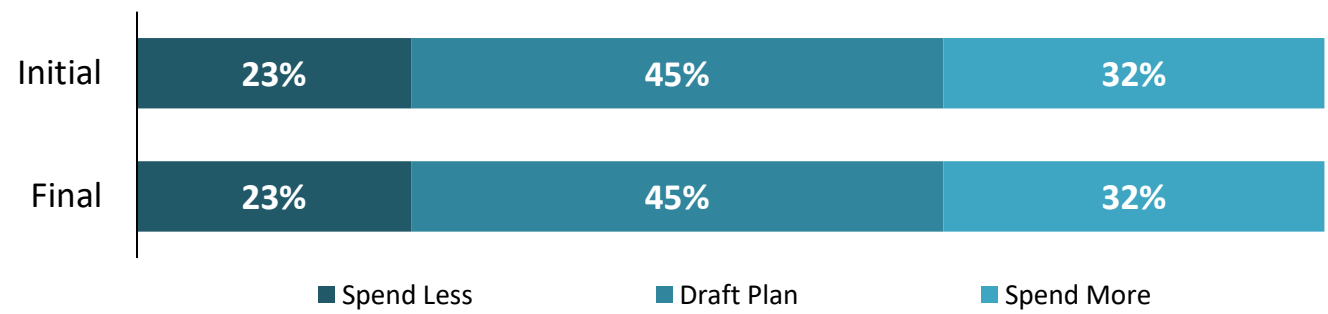
Keeping pace with transmission renewal



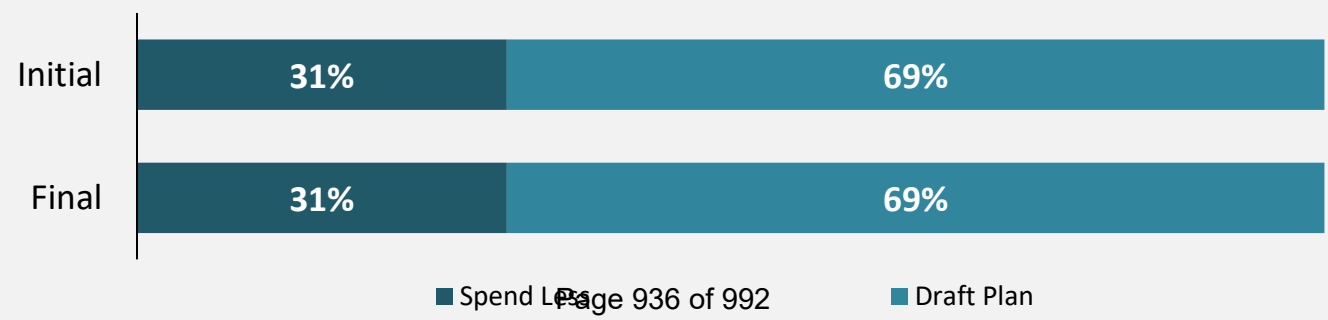
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



Investment Trade-Offs

Overall evaluation of the draft plan

Other LDC
Small Business

SURVEY PAGE

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plan. While the plan may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plan.

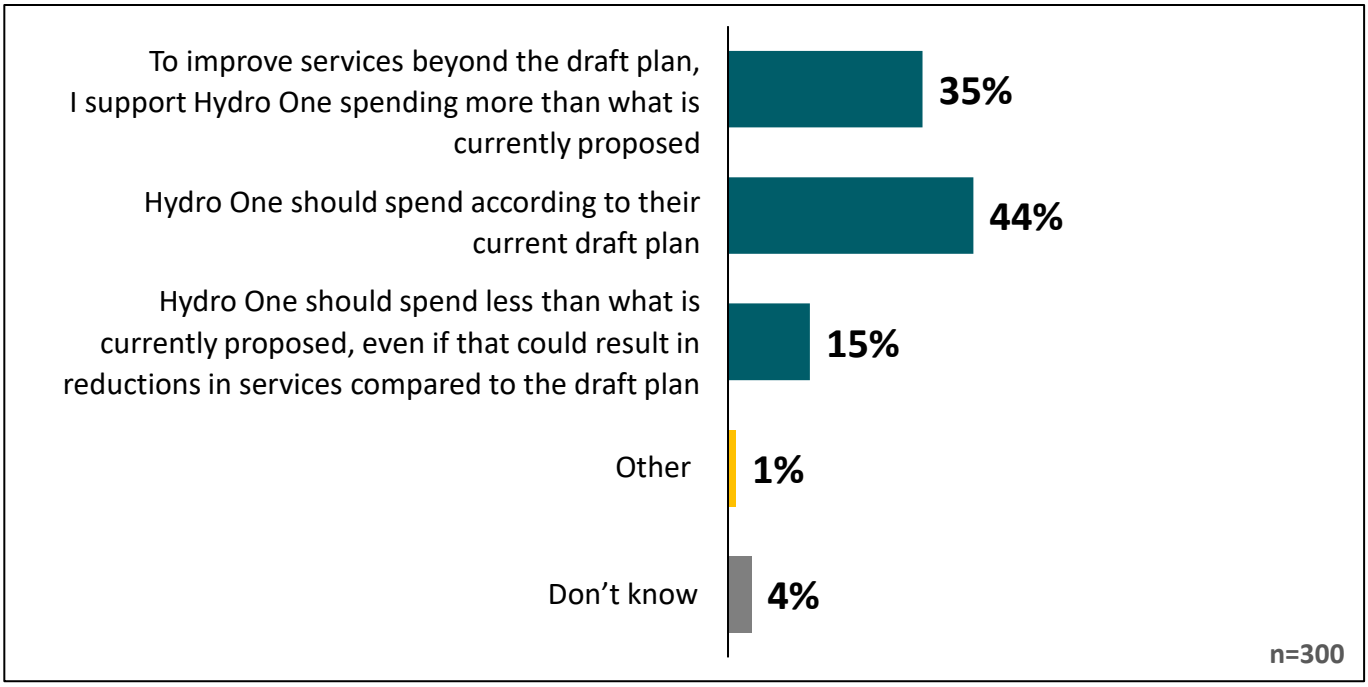
It is estimated that a typical Ontario **small business customer** would see the **transmission** portion of their **monthly bill** increase from $42.14 in 2027 to $55.02 by the end of 2032 – an increase of **$12.88** on the monthly bill. This represents an average increase of **$2.58** on the monthly bill each year.

Investment Trade-Offs

Overall evaluation of the draft plan

Other LDC Small Business

Q Considering what you have learned about Hydro One's 2028–2032 draft plan, which of the following best represents your point of view?



	Region				Bill Impact	
	Toronto	Rest of GTA	South/West	North/East	Major Impact	No Major Impact
Spend More	29%	35%	35%	42%	30%	43%
Draft Plan	50%	43%	42%	44%	51%	35%
Spend Less	14%	15%	18%	11%	15%	14%
Other	2%	2%	2%	--	1%	2%
Don't know	6%	5%	3%	3%	3%	6%

Investment Trade-Offs

Final comments on the draft plan

Other LDC Small Business

Q Do you have any final comments regarding Hydro One's draft plan for 2028–2032 and the proposed rate increase? (Optional)

Responses	%
Lower rates/rates are too high	3.9%
Support the increase/investments are necessary	2.3%
Invest now to prepare for future/prevent future increases	1.4%
Find efficiencies/alternative funding/customers shouldn't pay	0.9%
Transparency on internal operations	0.5%
Positive comment about Hydro One/service	0.4%
Be transparent/communicate about rate increases/investments	0.4%
Concerns around cost of living/inflation	0.4%
Improve reliability/reduce outages	0.4%
Need more information/educate customers	0.2%
Other	0.8%
No comment/None/Don't know	88.3%

Note: Only responses >0.1% shown

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Other LDC Small Business Customers

Survey Diagnostics

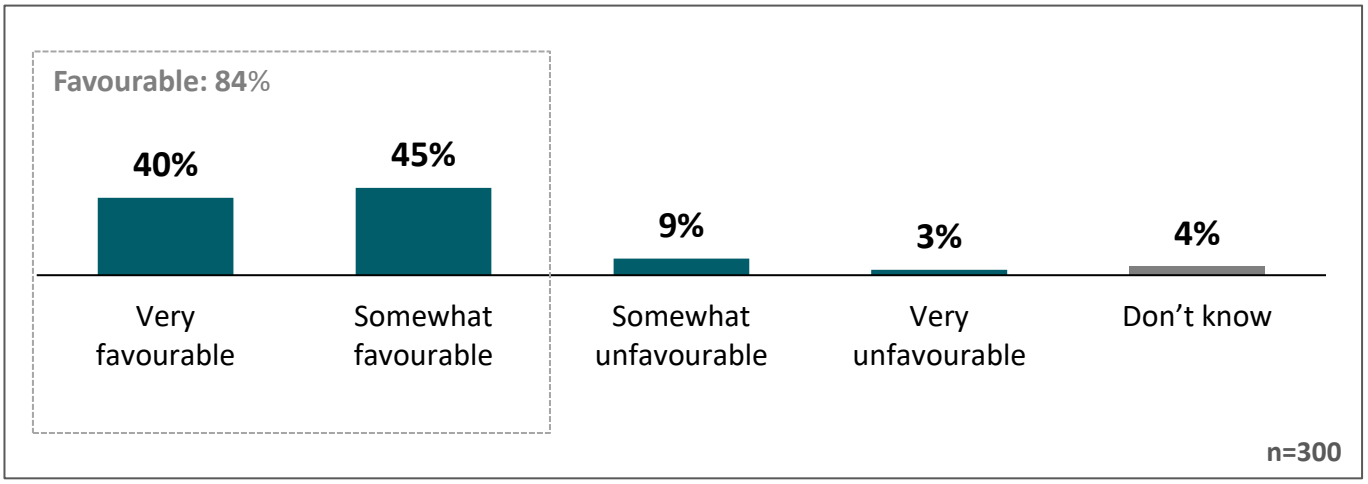


Survey Diagnostics

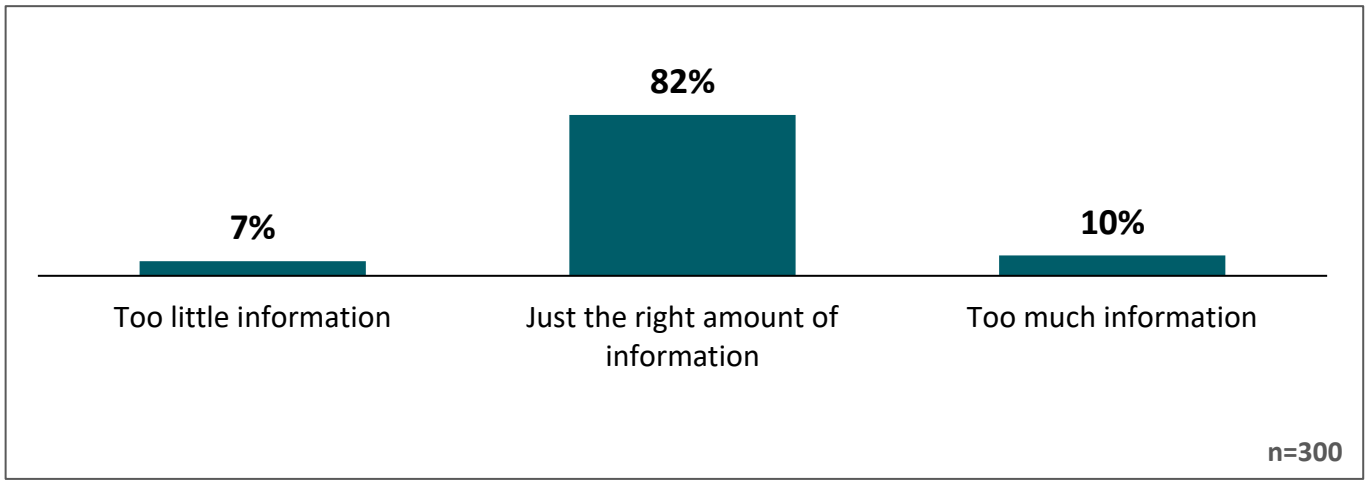
Favourability and amount of information

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



Survey Diagnostics
Other information not included

Other LDC
Small Business

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
Transparency on internal operations	2.3%
Survey/engagement experience feedback - positive	2.2%
Customer demographic comparison/region specific information	1.2%
More information/communication about rate increases	1.1%
Better explanation/transparency on bills	0.8%
Reducing customer costs/affordability measures	0.8%
Survey/engagement experience feedback - negative	0.7%
Positive comment about Hydro One/service	0.6%
How Hydro One's costs compare to other companies/jurisdictions	0.5%
Helping seniors/fixed-income individuals	0.4%
Information on energy sold to US/other countries/out of province	0.3%
Impact of EVs/AI/new technology	0.2%
More detailed information on the investments/infrastructure	0.1%
Other	1.2%
No comment/None/Don’t know	87.6%

Note: Only responses >0.1% shown

Survey Diagnostics
Outstanding questions

Other LDC
Small Business

Q Is there anything that you would still like answered? (Optional)

Responses	%
Survey/engagement experience feedback - positive	1.4%
Plans to reduce/lower customer costs	0.7%
Focus on renewable, nuclear & energy storage solutions	0.6%
How Hydro One's costs compare to other companies/jurisdictions	0.5%
Different types of customers and their rates	0.5%
Transparency on internal operations	0.5%
Positive comment about Hydro One/service	0.4%
Better explanation/transparency on bills	0.4%
Be transparent/communicate about rate increases	0.4%
Survey/engagement experience feedback - negative	0.4%
Government involvement/subsidies	0.2%
Other	0.5%
No comment/None/Don’t know	93.5%

Note: Only responses >0.1% shown

INNOVATIVE RESEARCH GROUP

Large Transmission Account Customers

Online Survey Results

Section 9



Online Survey
Methodology

Field Dates

The **Large Transmission Customer Online Survey** was sent to all Hydro One large transmission account customers with an available email address. Customers had an opportunity to complete the survey between **November 14th and December 22nd, 2025.**

Each customer received a unique URL that could be linked back to their region and customer type (End-User, Generator, or LDC). Survey pages that differed by customer type are identified as end-user/LDC or generator versions throughout this report.

In total, the large transmission customer survey was sent to **197** customers from *customerexperience@hydroone.com*. A total of four reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Large Transmission Accounts Online Survey Completes

A total of **73** (unweighted) Hydro One large transmission account customers completed the online survey.

Sample Weighting

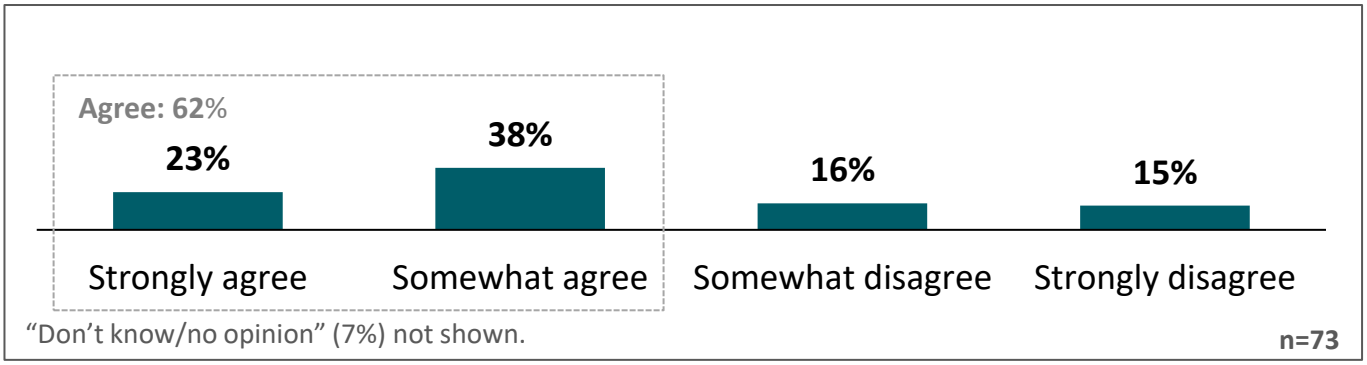
The large transmission account online survey sample was not weighted.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n sizes.*

Environmental Controls

To what extent do you agree or disagree with the following statements?

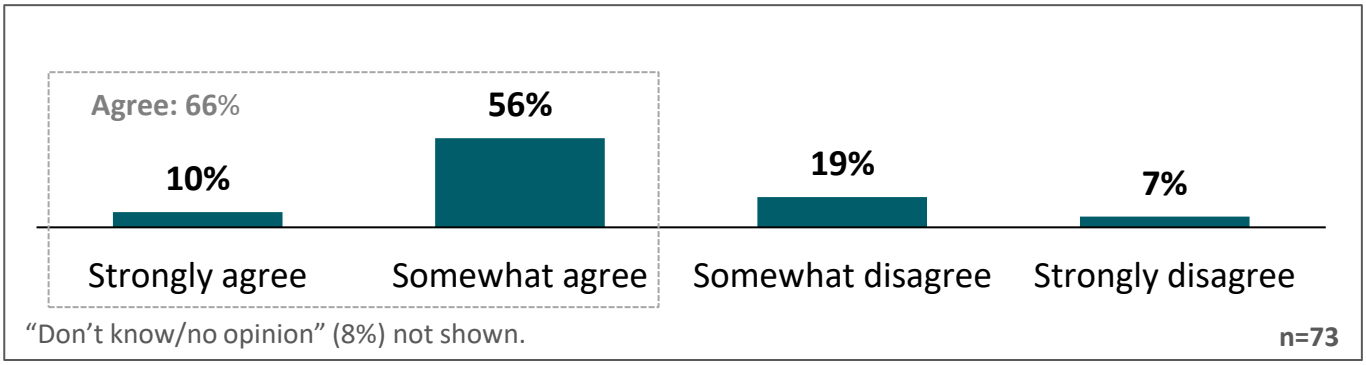
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (7%) not shown.

n=73

Q Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



"Don't know/no opinion" (8%) not shown.

n=73

End-Users/LDCs Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive and the rates you pay.

- **Hydro One is looking for your feedback on their draft investment plan** for the years 2028 to 2032 to ensure they make spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 10-15 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a transmission-connected customer.

Note: *The estimates throughout this survey are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.*

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

Generators Version

Hydro One Customer Engagement Survey

Welcome to Hydro One's customer engagement survey!

As Hydro One plans for the future, they need your input on choices that will impact the services you receive.

- **Hydro One is looking for your feedback on their draft investment plan** for the years 2028 to 2032 to ensure they make spending decisions that matter to customers.
- **You don't need to be an electricity expert to complete this survey.** It focuses on basic choices and provides the background information you need to answer the questions.
- The survey will take approximately 10-15 minutes to complete. If you need to pause and return later to finish the survey, your progress will be saved. If you are reading this on a mobile device, you may want to consider switching to a tablet or laptop so that it is easier for you to read.



While you may have multiple accounts with **Hydro One**, for this survey, we want you to think about your overall experience as a transmission-connected generator.

Note: *The estimates throughout this survey are for illustrative purposes only.*

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Hydro One to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Hydro One in any identifiable way.

SURVEY PAGE

Hydro One Customer Engagement Survey
What is this survey about?



Hydro One is funded by the rates paid by their customers. Every five years, Hydro One is required to file an application with the Ontario Energy Board (OEB), the energy regulator in Ontario, to set rates. Hydro One's next rate application will cover the years 2028-2032.

In this process, Hydro One's rate application will be examined in detail and Hydro One must demonstrate that customer needs and priorities were factored into their investment planning process.

Today, Hydro One wants your feedback on their draft investment plan, including specific investment choices where they need customer input. This feedback, along with other input, will be used to help Hydro One's planners refine and finalize the draft investment plan.

Next year, Hydro One will present their proposed plan and input provided by customers to the OEB.

SURVEY PAGE

Hydro One Customer Engagement Survey

What is Hydro One's role in Ontario's electricity system?

Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

Hydro One's transmission system takes electricity from generation stations and transports it via high-voltage transmission lines to local communities across the province.

In many communities, **Hydro One** is also responsible for the local distribution system, which delivers electricity to homes, seasonal properties, or organizations through a network of wires, poles and other equipment.



Hydro One does not generate electricity or set electricity prices.

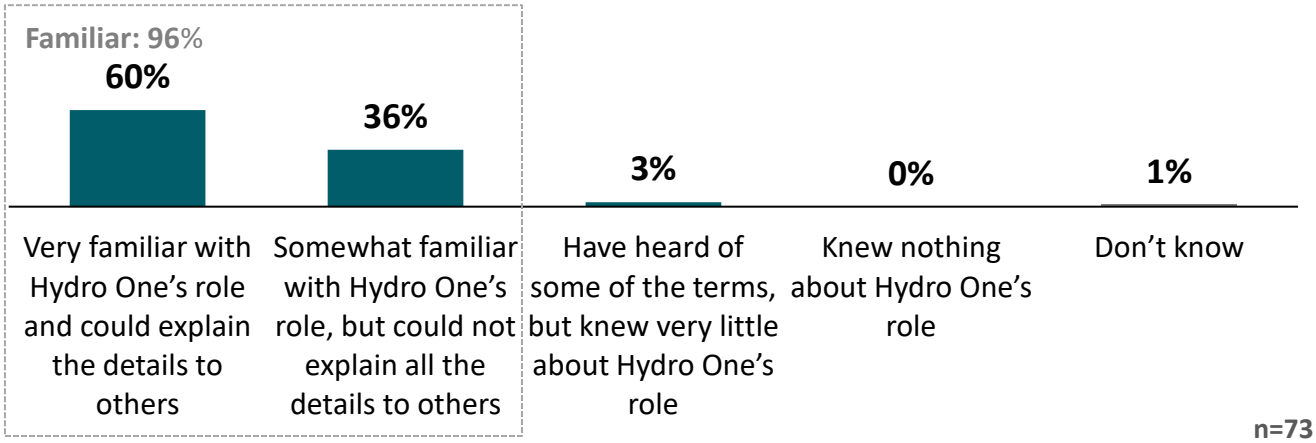
Hydro One builds and maintains power lines, towers and poles, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

SURVEY PAGE

Familiarity & Experience

Hydro One's role in Ontario's electricity system

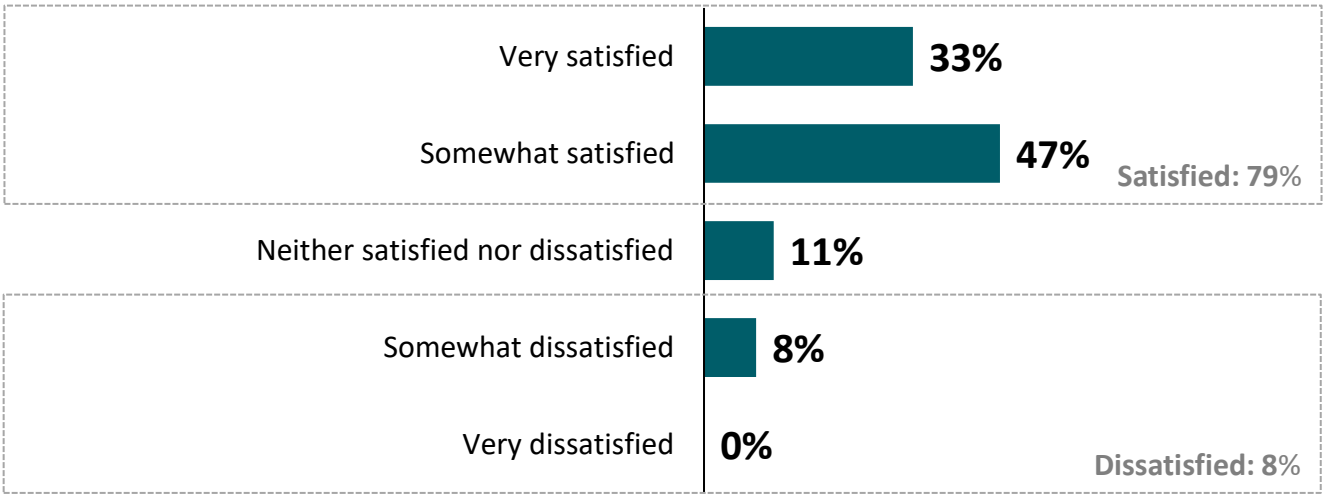
Q Before this survey, how familiar were you with Hydro One's role in Ontario's electricity system?



Familiarity & Experience

Overall satisfaction with Hydro One's service

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Hydro One?



"*Don't know*" (1%) not shown.

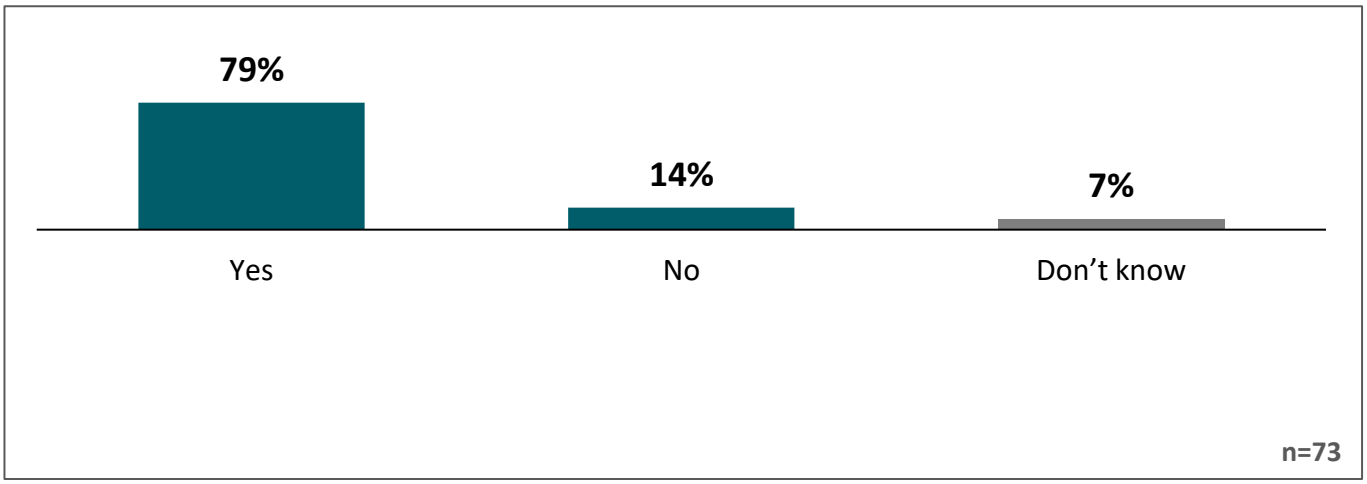
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Familiarity & Experience

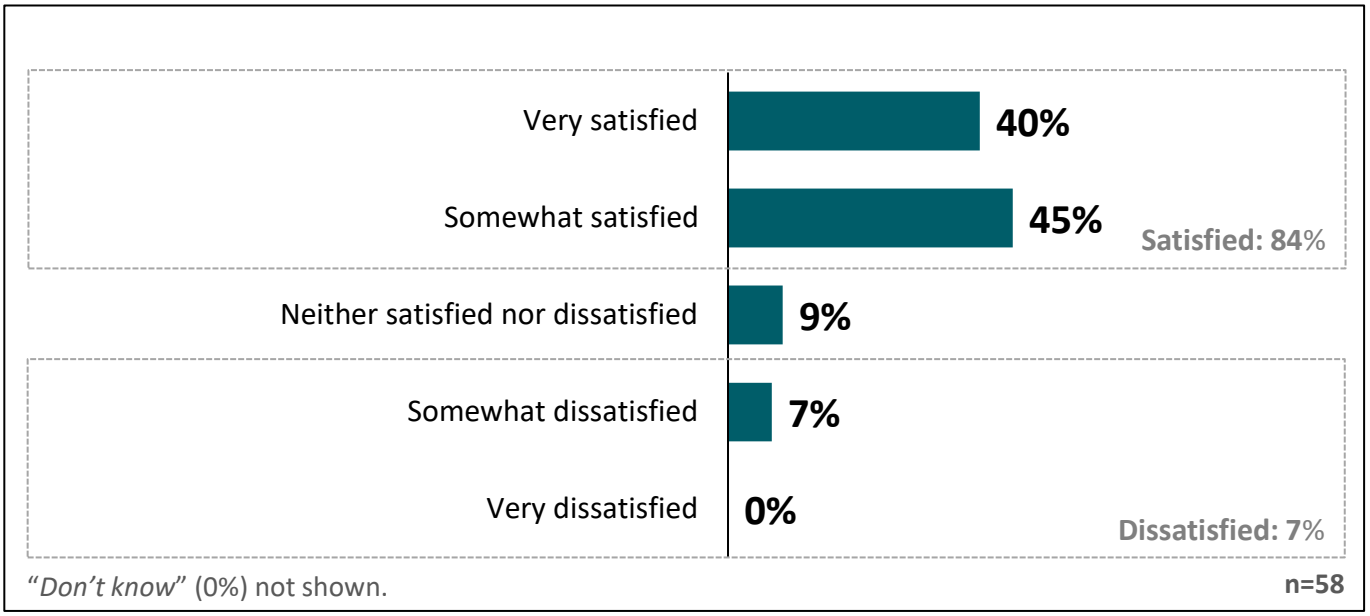
Planned power outage experience

Large Transmission

Q In the past year, has your organization experienced any planned power outages (or loss of supply) with Hydro One?



Q Generally, how satisfied or dissatisfied were you with the way your organization's planned power outages were managed by Hydro One? *[Asked of those who have experienced a planned outage in the past year]*



INNOVATIVE RESEARCH GROUP

Familiarity & Experience

Portion of the electricity bill that goes to Hydro One

Large Transmission

End-Users/LDCs Version

SURVEY PAGE

Hydro One Customer Engagement Survey

How much of my electricity bill goes to Hydro One?

Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.

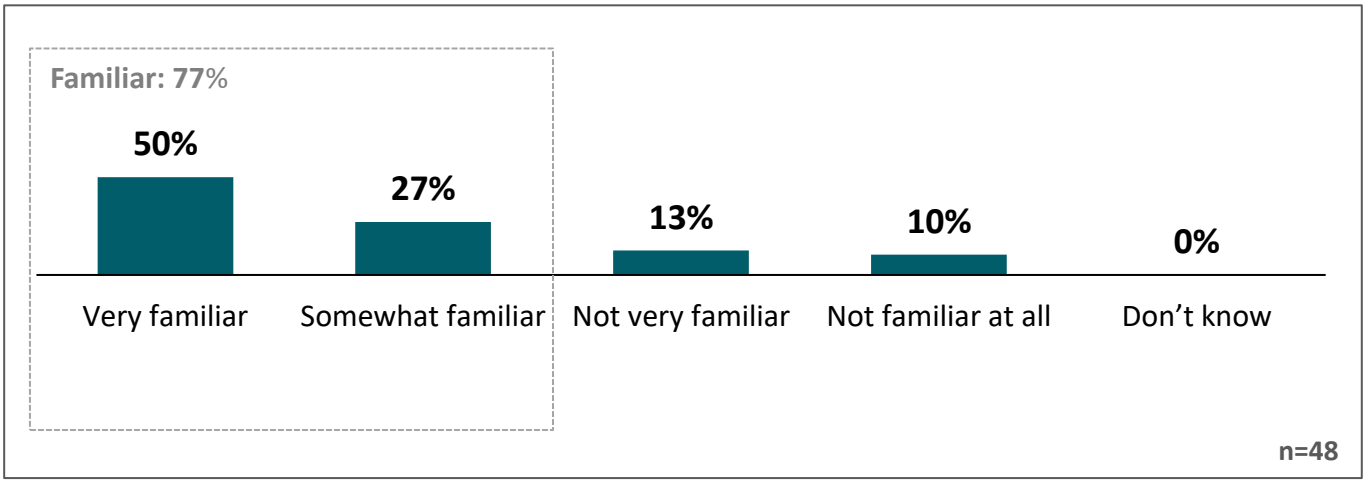
Hydro One is responsible for most of the transmission charges on your organization's monthly bill. For an average transmission-connected customer, transmission charges represent about **12.6%** of the total electricity bill. This share may vary for your organization, depending on your organization's load profile.

The rest of your bill payment goes to power generation companies, taxes, and regulatory agencies.

Familiarity & Experience

Bill familiarity

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One? *[Asked only of End-Users and Local Distribution Companies]*



Hydro One Customer Engagement Survey

How does Hydro One plan?

Every five years, Hydro One develops comprehensive plans that outline both short-term and long-term system needs. These plans are the combination of thousands of inputs from technical experts and customers.

The three key areas that inform Hydro One's plans are:

- **Customer feedback** collected through both ongoing interactions and specific engagements, such as this.
- Information and input from **internal engineering and technical experts**, who closely monitor the pressures on the system and develop solutions to address these challenges.
- Hydro One's **mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters.

What has Hydro One heard from customers so far?

In 2024, Hydro One collected feedback from thousands of customers across Ontario on their needs and priorities for electricity transmission services. This feedback was used to inform planners in developing the draft investment plan.

In this initial feedback, most customers expressed a desire for Hydro One to:

1. Prioritize **reasonable rates** and **reliable service**.
2. Make investments to **improve or maintain current levels of reliability**.

SURVEY PAGE

Hydro One Customer Engagement Survey

What challenges are impacting Hydro One's plans?

Hydro One is facing challenges that require more resources, new solutions, or growing costs to manage.

Some of these challenges, like the pace of addressing aging and deteriorating infrastructure are within Hydro One's control. Others, like the frequency of severe weather, are not.

When developing their plans, Hydro One must consider **external pressures**, including:

Increasing demand for electricity

According to the Independent Electricity System Operator (IESO), electricity demand in Ontario is forecasted to increase by 75% by 2050.

In fact, since 2021, growth in the province has far exceeded expectations and customer requests for new connections have grown considerably: **demand for new connections to Hydro One's distribution system has outpaced projections** by, on average, 21% per year.

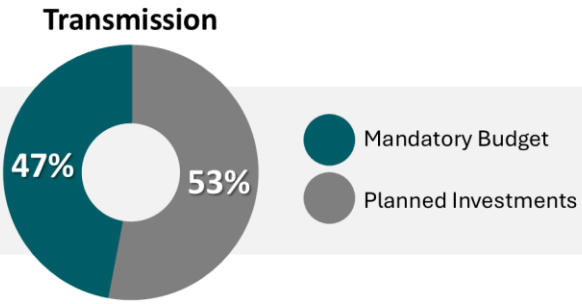
Rising cost pressures

Businesses across Ontario are **experiencing significant cost pressures** from factors including tariffs and inflation. Hydro One has been working to offset some of these cost pressures by finding savings and internal efficiencies. In 2024, Hydro One realized approximately $150 million in savings.

How does this impact how Hydro One plans?

Despite increasing demand for electricity, external rising cost pressures, and more frequent severe weather, Hydro One has been working to manage spending within their original budget that was approved by the OEB in 2022. This means that Hydro One has had to delay some planned work to accommodate unexpected higher growth and rising costs.

For the 2028-2032 period, **about half of Hydro One's draft capital budget is committed to work that is necessary to meet mandatory requirements**, including meeting safety, legal, and regulatory requirements, accommodating increased demand for electricity and supporting provincial economic growth.



SURVEY PAGE

Summary of Investment Plan

Objectives Hydro One is focused on

Hydro One Customer Engagement Survey

What objectives is Hydro One focused on?

Today, Hydro One has developed draft investment plans that focus on achieving objectives that balance customer feedback, economic growth in Ontario, engineering and technical analysis, and current and emerging pressures on the system.

Hydro One's draft plans cover both the **transmission system** serving most Ontarians and the **distribution system** serving approximately 1.5 million customers.

Some of the highlights of Hydro One's draft plans include:

Transmission Objectives



1. **Maintaining the overall health** of the transmission system by limiting the risk of equipment failure.
2. **Getting the most out of the system** by reinforcing and extending the life of equipment and limiting the impacts of severe weather.
3. **Keep pace with Ontario's economic development**, including meeting demand for new and expanded industry in the province

One of the benefits of being both the largest transmitter and distributor of electricity in Ontario is the ability to invest in technology systems, buildings, and facilities that benefit both systems.

Some of these shared objectives of Hydro One's draft plans include:

Shared Transmission and Distribution Objectives



1. **Limiting the risk of potential damage to equipment** by addressing the most at-risk building components and making sites more resilient to severe weather.
2. **Maintaining the company's existing technology systems**, improving operational efficiency and resilience to cybersecurity threats, and **modernizing the system** to provide enhanced services to customers.

SURVEY PAGE

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Large Transmission

End-Users/LDCs Version

SURVEY PAGE

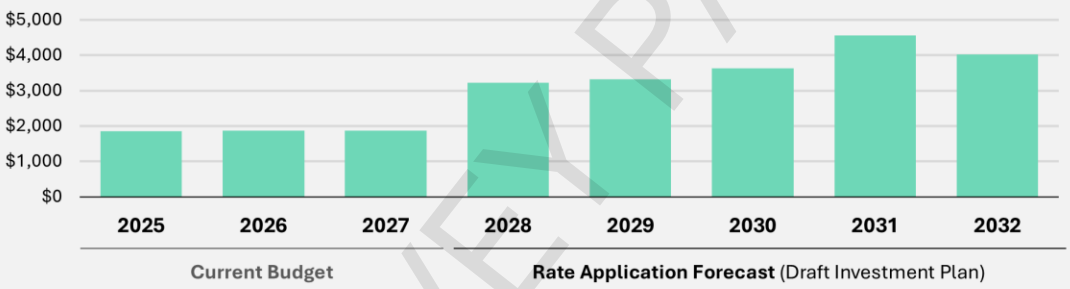
Hydro One Customer Engagement Survey

How much will Hydro One's draft transmission plan cost?

hydro one

For the **transmission system**, investment costs are shared by more than 5 million electricity rate payers in Ontario.

Transmission Budget: Current and Forecasted ($ millions)



The draft transmission investment plan would result in an average annual funding requirement of **$3.8 billion** for **transmission** for 2028-2032.

How will this plan impact the transmission portion of customer bills?

For a typical **transmission-connected customer**, transmission charges are estimated to increase by an average of **5.5%** each year for the period 2028 – 2032. As a result, the **total monthly bill** is estimated to increase by an average of **0.69%** each year for the period 2028 – 2032.

Note:

- The estimated increase in transmission charges and total monthly bill, and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

Cost of Hydro One's draft transmission plan

Large Transmission

Generators Version

SURVEY PAGE

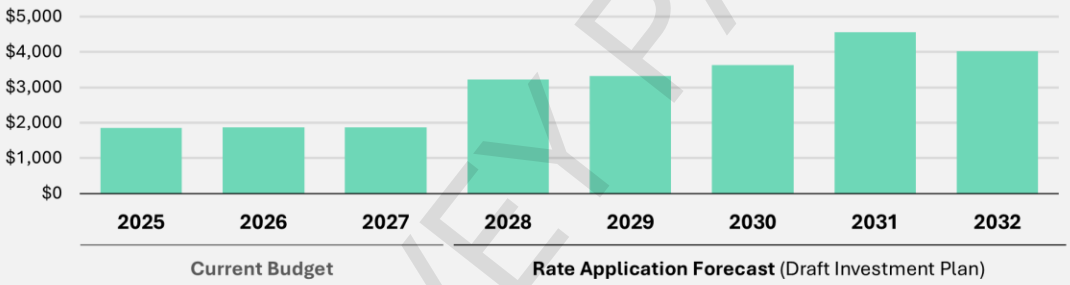
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How will this plan impact the transmission portion of customer bills?

For a typical **transmission-connected generator**, transmission charges are estimated to increase by an average of **5.5%** each year for the period 2028 – 2032.

Note:
- Transmission charges are applied to your net load use.
- This estimated increase in transmission charges and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors.

Summary of Investment Plan

How to make choices

Large Transmission

End-Users/LDCs Version

Hydro One Customer Engagement Survey

What choices does Hydro One want my input on?

The remainder of this survey asks for your input on the total cost of the draft investment plan, plus **4 key choices** within the plan that Hydro One is looking for your guidance on.

- Each choice has a summary of the options that Hydro One is considering. In many cases, that includes options that would see Hydro One ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Hydro One has estimated what impact it would have on customer bills **compared to the draft plan**. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on the key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost.



SURVEY PAGE

Summary of Investment Plan

How to make choices

Large Transmission

Generators Version

SURVEY PAGE

Hydro One Customer Engagement Survey

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hydro one

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Hydro One Customer Engagement Survey

What is the transmission system and who does it serve?

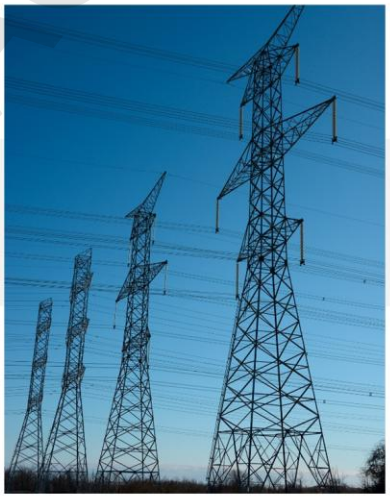
Let's talk about the provincial transmission system. The transmission system is the highway for Ontario's electricity, bringing power from generation stations to your community.

Hydro One's transmission system serves most electricity customers in Ontario, including distribution companies across the province.

Outages on Hydro One's transmission system have significant impacts on communities and Ontario's economy. As such, the transmission system is designed to minimize both the frequency and duration of outages.

For example, most of Ontario's population centres are served by multiple transmission lines so that if one fails, there is always a backup to keep power flowing.

Since 2019, the typical Ontarian connected to Hydro One's transmission system has experienced, on average, **1 outage per year** related to the transmission system.



In a 2024 survey, a majority of customers said that they want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid.

SURVEY PAGE

Investment Trade-Offs

Keeping pace with transmission renewal

Large Transmission

End-Users/LDCs Version

SURVEY PREVIEW

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

Portions of Hydro One's transmission system were built in the 1930s, 40s, and 50s.

Hydro One has identified several types of equipment that are at increased risk of failure due to age and condition and would have widespread impacts if they were to fail.

Transmission station equipment ensures electricity can safely travel from power plants to communities. Hydro One has identified close to 200 out of 700 transmission transformers and 400 out of 4,700 circuit breakers in poor condition that are at increased risk of failure. While an equipment failure may not result in an immediate outage, it leaves the system more vulnerable with limited backup.



Underground transmission cables serve many high-density areas. Hydro One has identified that 20 km of their network of around 270 km of cables are at increased risk of failure. Because of the complex nature of these cables, if they were to fail, the outage impacts would be widespread and time-consuming and costly to repair.

Hydro One's **current draft plan** is focused on managing the risk of equipment failure and supporting growth across the province by:

- **Replacing major transmission station equipment:** In their current draft plan, Hydro One plans to replace 70 of the nearly 200 transformers and 230 of the 400 breakers identified as being in poor condition in order to reduce the risk of failure and costly repairs.
- **Replacing high-impact underground transmission cables:** Replacing all 20 km of the underground cables that Hydro One has identified as being at increased risk of failure could take up to 10 years to complete. In their current draft plan, Hydro One is proposing to begin the replacement of all 20km of these underground cables, with 12km being replaced by 2032.

Eventually, all poor condition or deteriorating equipment will need to be addressed; however, Hydro One would like your feedback on the pace of replacement. Doing less of these types of investments in the near term could lead to more equipment failure and higher emergency repair costs in the future. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure	Maintain the current risk of equipment failure	Lower risk of equipment failure
	Main Differences Between Plans		
Replacing transformers and breakers	55 transformers & 195 breakers	70 transformers & 230 breakers	85 transformers & 265 breakers
Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Total Monthly Bill Impact	Average of 0.06% less each year	**Included in Draft Plan**	Average of 0.06% more each year

Investment Trade-Offs

Keeping pace with transmission renewal

Large Transmission

Generators Version

SURVEY PREVIEW

Hydro One Customer Engagement Survey

Keeping pace with transmission renewal

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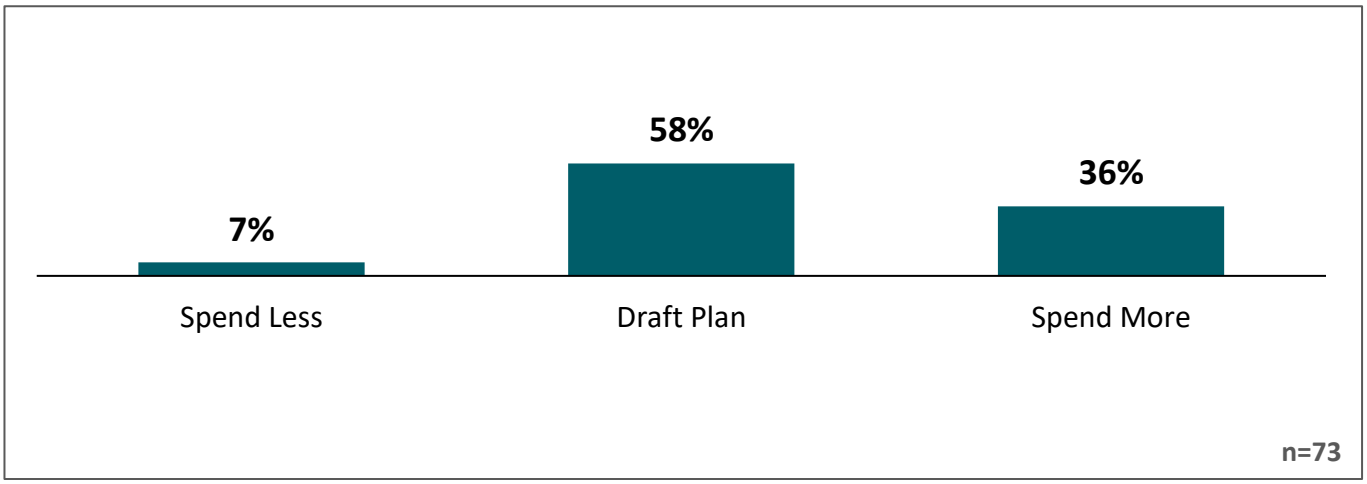
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Replacing underground cables	Begin replacing 20km of underground cables	Begin replacing 20km of underground cables, completing 12km by 2032	Replace 20km of underground cables by 2032
Impact on Transmission Charges	Average of 0.5% less each year	**Included in Draft Plan**	Average of 0.5% more each year

Investment Trade-Offs

Keeping pace with transmission renewal

Large Transmission

Q Which of the following options do you prefer?



INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Keeping pace with transmission renewal

Large Transmission

Q Additional Feedback (Optional)

Verbatim comments (89% No comment)
"As an industrial customer with a current life of mine to [REDACTED], we want to ensure the lowest risk of failure to ensure smooth operations."
"Hydro One should not wait to repair/replace its infrastructure. A comprehensive Preventative Maintenance program would have easily identified the condition of these assets and allowed for planned replacement. For example, a 1930's transformer could have been replaced in 1970 or 1980 and then again in 2020 rather than wait for failure."
"I'd like Hydro One to spend more efficiently. I think there should be less spending on innovative ideas that don't always pan out. We need to spend on prudent technology and most importantly, spend efficiently. Right now, Hydro One costs to build transmission infrastructure is too high."
"Is there a more cost-effective and quicker method to replace the 20km of cables nearing end-of-life. 20km is a relatively short run for transmission. Possibly outsource the work to a more cost-effective contractor and not Hydro One construction crews. Are these underground cables in a large urban centre? For example, if these cables are within the GTA, should those costs not be specifically applied to distribution utilities to pass on to local rate payers? Lead time for transformers and most HV equipment is around 18-36 months once contracts are signed. Seeing as 2026 is a month away and there are budget/approval/engineering/procurement processes to follow, is it reasonable to expect this work to begin in 2028?"
"Less interest in replacing underground cable. The primary driver for underground is aesthetic for city residents. Views for city residents is not a reasonable priority for costly investment. Spend more on the transformers and breakers. Less on the underground lines."
"The options presented do not correlate to outage frequency, so it is challenging to understand the impacts. Also, the 'spend less and spend more' ranges appear to be quite minimal in impact, which is reducing the effectiveness of making a choice."
"While I support an increased pace for the replacement of aging infrastructure, these plans should also include increases in station capacity. i.e. all aging station transformers should be proactively upsized as part of this capital plan to accommodate the IESO's forecasted 75% increase in demand."
"Would like to see more focus on reinvestment in Eastern Ontario."

Investment Trade-Offs

Stewardship of the transmission system

Large Transmission

End-Users/LDCs Version

Hydro One Customer Engagement Survey

Stewardship of the transmission system

Proactive maintenance and system monitoring are among the ways that Hydro One can ensure that equipment lasts as long as possible.

In their **current draft plan**, Hydro One is proposing a series of investments to get the most out of the existing system by:

- **Replacing at-risk transmission lines:** Hydro One has identified that 11% of their approximately 28,000 km of transmission lines are at increased risk of failure due to a combination of age and condition. As these lines are replaced, they are built to modern standards that are more resilient to severe weather.
- **Reinforcing wood poles and extending the life of steel towers:** Hydro One has identified that over 23,000 of their nearly 90,000 wood poles and steel transmission towers are at the end of their expected service life. In the current draft plan, Hydro One is proposing reinforcing or extending the life of many of these structures.
- **Increasing the rate of clearing overgrown trees and brush:** Contact with vegetation accounts for a significant portion of transmission outages and increasing the rate of clearing trees and brush can help reduce the risk of outages.



Additionally, Hydro One is proposing investments in new satellite technology that can help better monitor trees and brush encroaching on infrastructure, further helping reduce the risk of outages.

These investments would be complementary to the ongoing renewal of aging or poor condition equipment, as discussed earlier.

These investments are designed to reduce the risk of major equipment failures, outages, and emergency repair costs over time. Delaying or scaling back these investments will reduce short-term costs but may increase the likelihood of unplanned outages and result in more costly reactive repairs. While doing more could further reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Higher risk of equipment failure and impacts of severe weather compared to the draft plan	Lower the current risk of equipment failure and impacts of severe weather	Further lower risk of equipment failure and impacts of severe weather compared to the draft plan
	Main Differences Between Plans		
Replacing at-risk transmission lines	Replace 1,000 km of at-risk lines	Replace 1,400 km of at-risk lines	Replace 1,800 km of at-risk lines
Reinforcing wood poles and extending the life of steel towers	2,500 wood poles and 1,500 steel towers	6,000 wood poles and 2,750 steel towers	9,500 wood poles and 4,000 steel towers
Clearing overgrown trees and brush	Clear 16% (3,100 km) of overgrown vegetation each year	Clear 17% (3,400 km) of overgrown vegetation each year	Clear 18% (3,700 km) of overgrown vegetation each year
Total Monthly Bill Impact	Average of 0.05% less each year	Included in Draft Plan	Average of 0.05% more each year

SURVEY PAGE

Investment Trade-Offs

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Large Transmission

Generators Version

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Impact on Transmission Charges	Average of 0.4% less each year	Included in Draft Plan	Average of 0.4% more each year

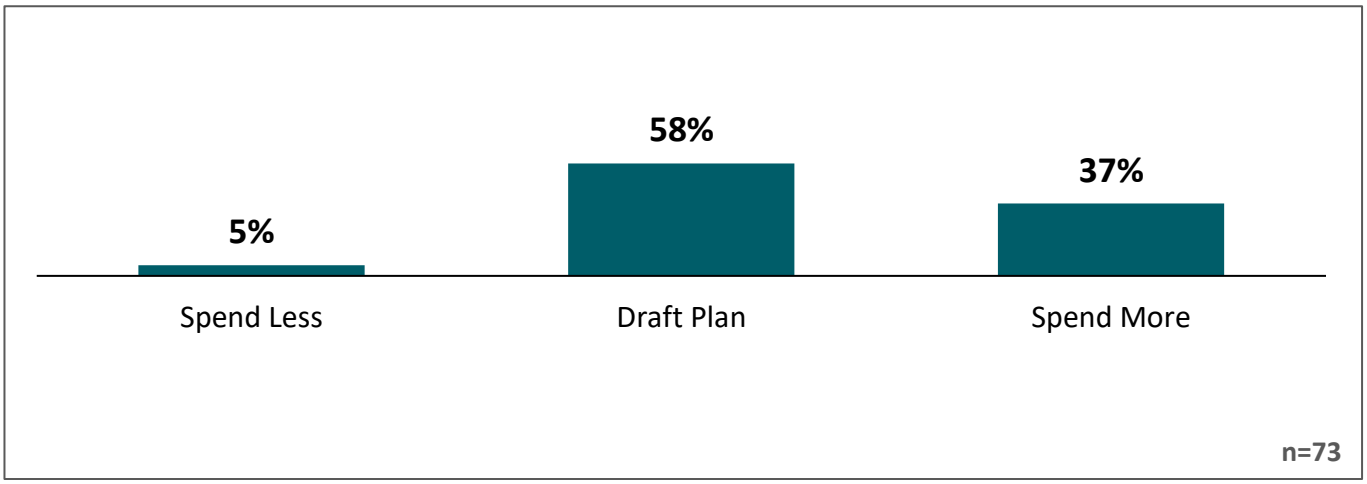
SURVEY PAGE

Investment Trade-Offs

Stewardship of the transmission system

Large Transmission

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INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Stewardship of the transmission system

Large Transmission

Q Additional Feedback (Optional)

Verbatim comments (89% No comment)
"Once again, I'd like Hydro One to spend more efficiently. I think the picture that this survey paints does not include all the options that are there. We can spend less and not have 1000 km lines at risk."
"Reducing outages and emergency repairs has a payback that is worth the investment."
"System reliability should be the overriding priority for Hydro One."
"The lines being updated to be more 'resilient to weather' should also be upgraded to provide more capacity to the province."
"Using modern assessment technology like satellite and Ai can improve efficiency. Has there been a cost benefit analysis to compare this satellite assessment vegetation management against current personnel physical inspections? Thinking the larger personnel costs are uncontrolled OT for vegetation crews and call-outs. Are efficiencies being sought on the OpEx side too? Is it more cost effective and faster to outsource this non-critical vegetation management work to local contractors using modern vegetation management practices."
"Vegetation clearing plan is unclear, given that HONI has laid off significant portions of the forestry team. Is vegetation clearing then actually increased over the original plan since it is now behind due to the reduction over the past year?"
"Why is Hydro One waiting for assets to be at the end of useful life before replacing? That is akin to replacing on failure, which usually costs much more than planned. Stop operating to failure."
"Would like to see old 115kV transmission towers and stations upgraded to 230kV in Eastern Ontario."

Investment Trade-Offs

Maintaining buildings and facilities

Large Transmission

End-Users/LDCs Version

Hydro One Customer Engagement Survey

Maintaining buildings and facilities

There are certain parts of Hydro One's draft plans that benefit both the transmission and local distribution systems. While the transmission portion of those investments is paid by most Ontarians, the distribution portion is paid by Hydro One distribution customers only.

Hydro One operates and maintains approximately 1,500 facilities across Ontario.

In addition to housing Hydro One's nearly 10,000 employees, these facilities store specialized fleet equipment including bucket trucks and helicopters, protect sensitive equipment, serve as central dispatch for crews, act as training and development campuses, and allow experts to remotely monitor and operate the grid.

Each year, Hydro One classifies their building components into one of three categories – ***high risk***, ***medium risk*** or ***low risk***. This considers both the likelihood of failure and how critical the component is. For instance, a roof that is beyond its useful life and houses critical equipment would be deemed ***high risk***. Whereas older office equipment may be classified as ***low risk***.

In 2025, 25% of Hydro One's building components were assessed as either high or medium-risk.

In their **current draft plan**, Hydro One is focused on:

- **Addressing at-risk building components**: In their current draft plan, Hydro One plans to address 50% of high to medium-risk building components, prioritizing those that are most critical.
- **Making at-risk sites more resilient to severe weather**: In their draft plan, Hydro One plans to invest in reducing flooding risks at 2 of out 12 at-risk sites. For example, in 2024, severe rain flooded a transmission station, resulting in outages for nearly 170,000 customers.



Flooding at a Hydro One transmission station in 2024

- **Repairing or retrofitting field offices**: Many facilities that serve as dispatch for Hydro One crews were built more than 50 years ago. Since then, standards for accessibility have changed considerably. In their draft plan, Hydro One plans to invest in 70 of their 115 facilities that no longer meet modern standards.

Doing less of these types of investments now could increase the number of reactive repairs to facilities, as well as increase the risk of more frequent outages caused by severe weather and longer crew dispatch times. While doing more could reduce risk, it would impact customer bills.

Which of the following options do you prefer?

	Spend Less	Draft Plan	Spend More
	Lower risk of critical asset failures, but address fewer aging field facilities than the draft plan	Lower risk of critical asset failures and make progress on addressing aging field facilities	Further lower risk of asset failures and address more aging field facilities than the draft plan
	Main Differences Between Plans		
Addressing at-risk building components	Same as draft plan	50% of at-risk building components	57% of at-risk building components
Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Total Monthly Bill Impact	Average of 0.003% less each year	Included in Draft Plan	Average of 0.01% more each year

SURVEY PAGE

Investment Trade-Offs
Maintaining buildings and facilities

Large Transmission

Generators Version

Hydro One Customer Engagement Survey
Maintaining buildings and facilities

hydro one

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Making at-risk sites more resilient	Same as draft plan	2 at-risk sites	8 at-risk sites
Repairing or retrofitting facilities	50 facilities	70 facilities	90 facilities
Impact on Transmission Charges	Average of 0.02% less each year	Included in Draft Plan	Average of 0.06% more each year

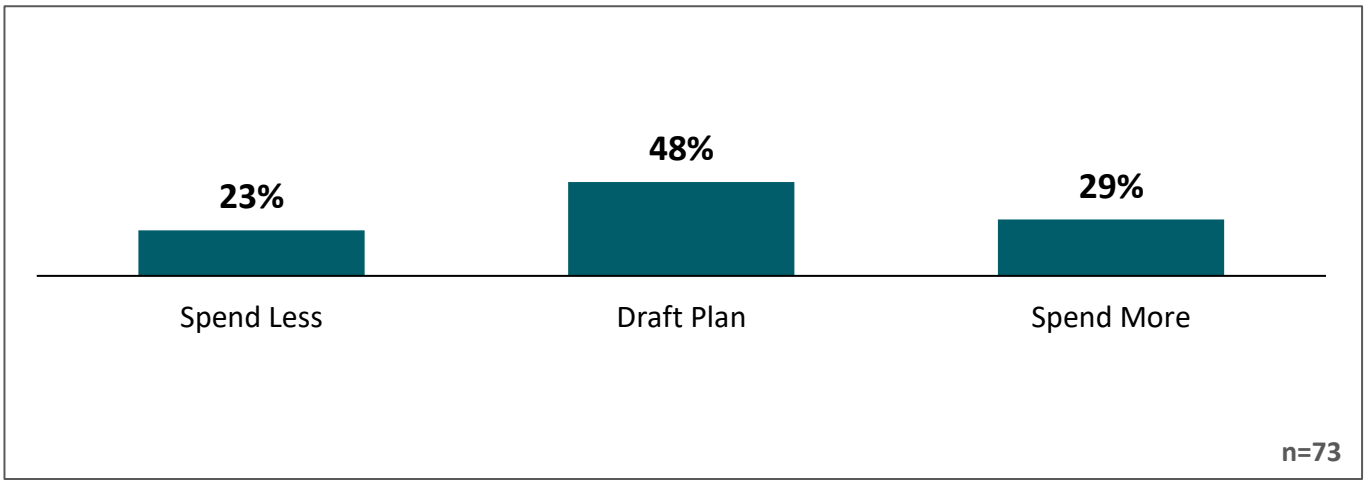
SURVEY PAGE

Investment Trade-Offs

Maintaining buildings and facilities

Large Transmission

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

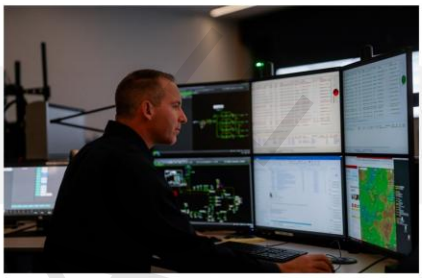
Verbatim comments (96% No comment)
"Consider more innovation on facilities vs investing in these if possible. Focus on things that will impact restoration or cause outages."
"Large urban centres need to bear some of this responsibility for flooded facilities. Urban sprawl in the GTA coupled with global warming (increasing torrential rains) have created the conditions that lead to poor run-off management. Has Hydro One considered pulling back as urban centres grow? Pass on the equipment and risk to distribution utilities to manage, place accountability and costs where they should fall. Can also move away from brick & mortar substation buildings (shutter those) in the older stations and towards modern steel buildings on concrete pilings."
"Spend more efficiently. Same as the previous 2 comments. There is a significant opportunity to do more with less spending."

INNOVATIVE RESEARCH GROUP

End-Users/LDCs Version

Hydro One Customer Engagement Survey
Information technology

Hydro One's daily operations require technology systems for all aspects of their business, including billing, operating the grid, responding to outages, planning projects, and communicating with customers.



When deciding the right level of information technology (I.T.) investment, Hydro One must balance various factors, including the cost of new or updated systems, the risks related to current systems, and the benefits that new technologies could bring to the company and customers.

Hydro One's current draft plan is focused on:

- **Maintaining the current state of technology systems**: Like with poles and wires, technology systems need to be maintained so that crews can restore power and customers can access key services like their online account and the outage restoration map.
- **Enhancing customer service**: I.T. investments and advanced data can help Hydro One offer better services to customers, improve estimated restoration times during outages and notify customers when service will be back online.
- **Improving Hydro One's operational efficiency**: Investments in technology systems can help Hydro One dispatch crews and perform their work more effectively.
- **Protecting the grid from both cyber and physical security threats**: Investments in new technologies can provide more robust protection against external threats, enhancing the resilience of critical system infrastructure.

While a significant portion of Hydro One's I.T. budget is allocated to meet safety, legal, and regulatory requirements, Hydro One could defer investments focused on enhancing customer service, improving efficiency, and expanding capabilities beyond 2032.

Deferring these types of investments would delay these benefits and potentially limit Hydro One's ability to accommodate newer technologies in the future.

Which of the following options do you prefer?

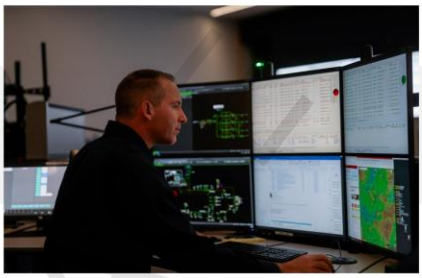
	Spend Less	Draft Plan
	Maintain the current state of technology systems but make fewer investments to enhance service and efficiencies	Maintain the current state of technology systems while modernizing capabilities to enhance service and efficiencies
	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Total Monthly Bill Impact	Average of 0.02% less each year	**Included in Draft Plan**

SURVEY PAPER

Generators Version

Hydro One Customer Engagement Survey
Information technology

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	Main Differences Between Plans	
Customer service	Limit or delay investments in systems focused on enhancing customer service	Invest in systems focused on enhancing customer service
Operational efficiency	Limit or delay investments in systems focused on improving operational efficiency	Invest in systems focused on improving operational efficiency
Impact on Transmission Charges	Average of 0.1% less each year	**Included in Draft Plan**

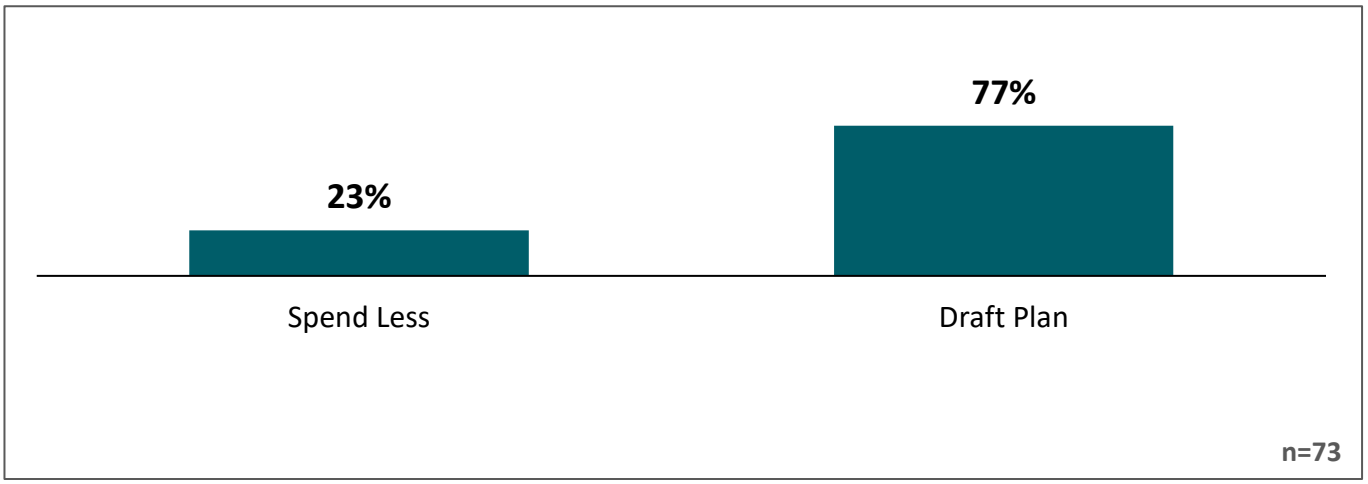
SURVEY PAPER

Investment Trade-Offs

Information technology

Large Transmission

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Verbatim comments (95% No comment)
"Commented here for the last 4 questions…Investment needs to increase where possible. The infrastructure is critical for any or all electrification changes that are happening now or coming in the near future. This network should not be dated, but ready for additional load and new technology. Seems like we are already behind."
"Cybersecurity of grids is obviously paramount in today's threat environment. Current systems can likely benefit in certain areas from AI, like incident/outage compiling and reviews to improve processes. But customer interactions should continue to allow for people-people options."
"Let's have Hydro One try and do more with less. Please spend more efficiently."
"More investment should go to Operational Efficiency, I care more about outages ending faster, I do not care about knowing how long they will last."

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Investment Trade-Offs

Finalizing Choices

Large Transmission

End-Users/LDCs Version

Hydro One Customer Engagement Survey

What is the impact of my choices?

Throughout this survey, you have been asked about 4 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total bill impact of all your answers. You can change your responses if you desire, and the estimated impact on your bill will be recalculated.

The bill impacts associated with each choice represent the average increase on your total monthly bill each year for the period 2028 – 2032. The impacts under the "spend less" or "spend more" options are relative to the bill impact of the draft plan.

Generators Version

Hydro One Customer Engagement Survey

What is the impact of my choices?

Throughout this survey, you have been asked about 4 key choices. Below is a summary of your choices.

At the bottom of this page, you will find the total impact of all your answers. You can change your responses if you desire, and the estimated impact on transmission charges will be recalculated.

The impacts associated with each choice represent the average increase in transmission charges each year for the period 2028 – 2032. The impacts under the "spend less" or "spend more" options are relative to the impact of the draft plan.

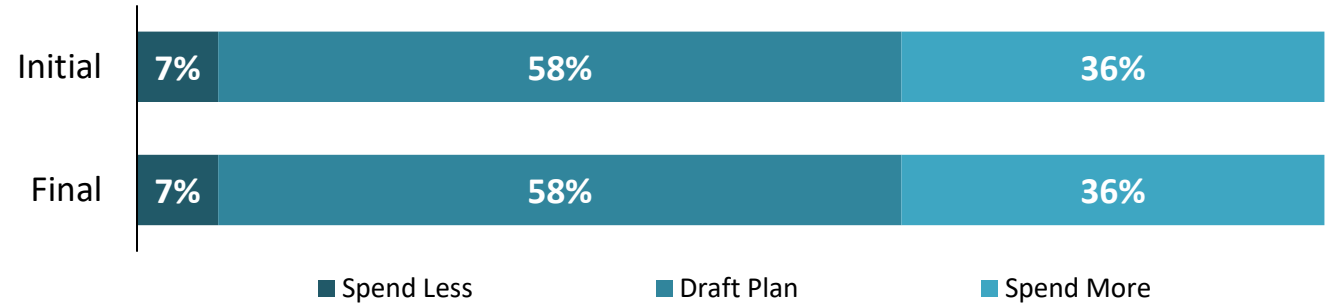
SURVEY PAGE

Investment Trade-Offs

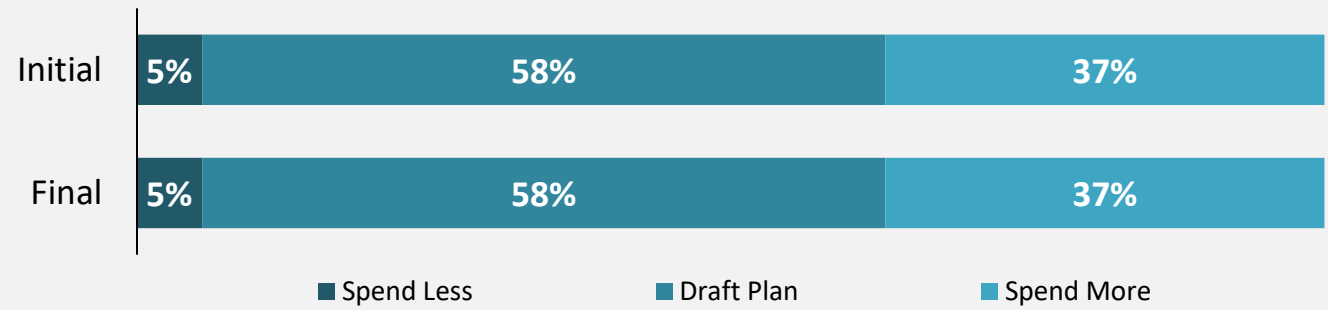
Finalizing Choices

Large Transmission

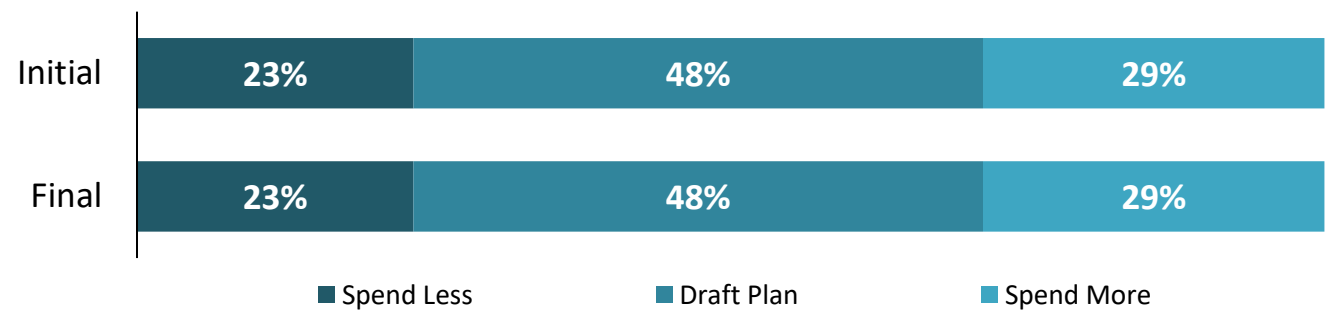
Keeping pace with transmission renewal



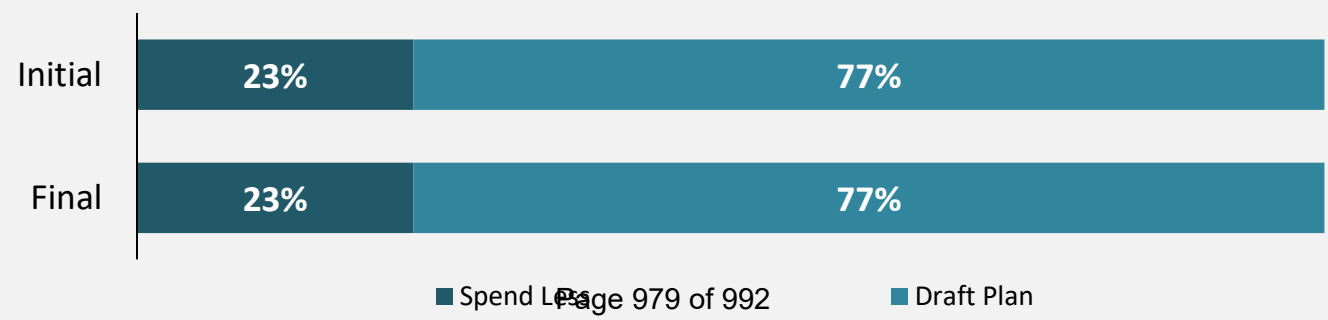
Stewardship of the transmission system



Maintaining buildings and facilities



Information technology



Investment Trade-Offs

Overall evaluation of the draft plan

End-Users/LDCs Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plan. While the plan may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plan.

For a typical **transmission-connected customer**, transmission charges are estimated to increase by an average of **5.5%** each year for the period 2028 – 2032. As a result, the **total monthly bill** is estimated to increase by an average of **0.69%** each year for the period 2028 – 2032.

Generators Version

Hydro One Customer Engagement Survey

Evaluating Hydro One's 2028-2032 draft plan

Hydro One has calculated an overall cost for their draft plan. While the plan may change based on feedback from the earlier questions in this survey, Hydro One would like to know how you feel about the overall draft plan.

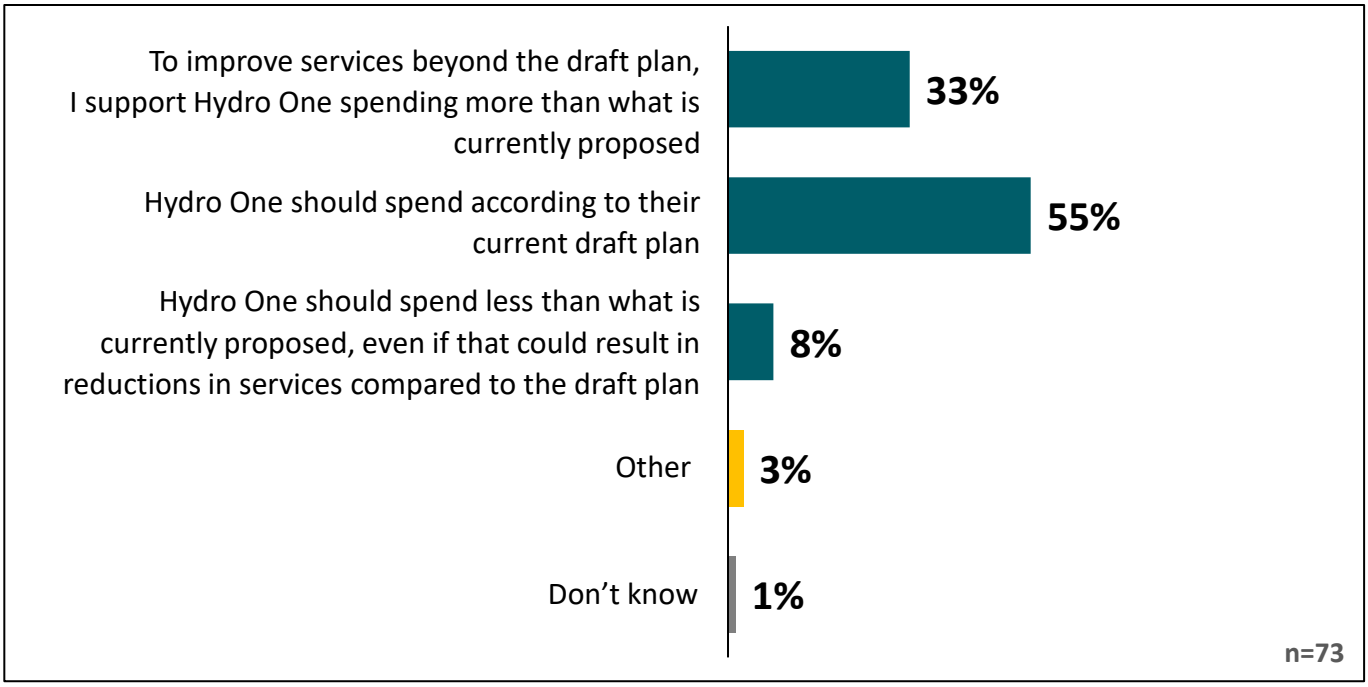
For a typical **transmission-connected generator**, transmission charges are estimated to increase by an average of **5.5%** each year for the period 2028 – 2032.

Investment Trade-Offs

Overall evaluation of the draft plan

Large Transmission

Q Considering what you have learned about Hydro One's 2028–2032 draft plan, which of the following best represents your point of view?



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Investment Trade-Offs

Final comments on the draft plan

Large Transmission

Q Do you have any final comments regarding Hydro One's draft plan for 2028–2032 and the proposed rate increase? (Optional)

Verbatim comments (81% No comment)
"As a large industrial customer, our Mine depends on a reliable transmission and distribution system to maintain safe, continuous operations. Our current Life-of-Mine extends to [REDACTED], and Hydro One's investment plans for 2028–2032 will directly affect our ability to operate. Support improved reliability and resilience in Northwest Ontario along with operational readiness and communication."
"Being a large user and an Industrial facility reliable distribution is critical to operations."
"Due to the increasing probability of worsening weather events in the future and increased system load demands, the power system reliability should be the primary focus of Hydro One to ensure continuity of service with the provincial power grid."
"Hydro One should accept and facilitate other transmitters in Ontario."
"I estimate that the choices offered only provided a total reduction opportunity of about 10% on the transmission portion of the bill. Total Bill data is not helpful, and there will be a 5% Tx increase regardless of the Customer input."
"I think the increase from the draft plan is marginal and will help lower costs in the future where I expect costs will be more expensive than in the current period plan."
"In light of aging electrical infrastructure and significant projected increases in the demand for electricity, I believe that this is a critical time for HONI to invest heavily in electrical infrastructure throughout Ontario, and I fully support the proposed investments. The proposed investments will help to strengthen Ontario's economy, which is a key investment into our future and the future of our children."
"Increase stability of the [REDACTED] transmission line. This year, on [REDACTED], the [REDACTED] line had a fault between [REDACTED]. The outcome was that our G2 generator burned down, and we are still trying to get it fixed. We have a big loss of income because of this. A [REDACTED] fault occurred on the line [REDACTED]."
"More investment in reducing outages and their duration. Less investment in customer service - the best customer service is better reliability."
"Please consider spending more efficiently in the plan. Hydro One is very important to our province, but the costs to build transmission infrastructure are significantly more expensive than alternative options."

Investment Trade-Offs

Final comments on the draft plan continued

Large Transmission

Q Do you have any final comments regarding Hydro One's draft plan for 2028–2032 and the proposed rate increase? (Optional)

Verbatim comments (81% No comment)
"Please reinvest in Eastern Ontario Transmission System as it is vital to the economic development of the region."
"Support the investments in the transmission grid to ensure adequate capacity and reliability. Hydro One should focus on completing work on time and within budget. Focus should be on customer-centric practices, which don't require capital investment but improvements in customer service practices."
"There was a period of recent time where Hydro One barely spent on CapEx. The consumer is unlikely to be able to continue to carry the burden of 5.5% compounding cost increases, even with the provincial government subsidizing electricity rates. There should be a minimum electrical efficiency standard for any new equipment/loads connecting to the grid. Data centers should not be given large discounts and should provide more of their own electricity needs by incorporating generation. Would also like to see Hydro One compounding of OpEx costs be reduced proportionally to compounding CapEx cost increases."
"We support an increase in spending at [REDACTED] because there is an acute shortage of investment relating to Hydro One-owned assets, which reside in [REDACTED] service territory in the Town of [REDACTED], Ontario. Of particular concern are a number of deteriorated wood poles along [REDACTED] St in the Town, which carry a 44kV circuit that have not been addressed by Hydro One for many years. There is a high degree of concern on our part that these assets will fail catastrophically. Increasing investment is imperative to safeguard public safety."

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Large Transmission Account Customers

Survey Diagnostics

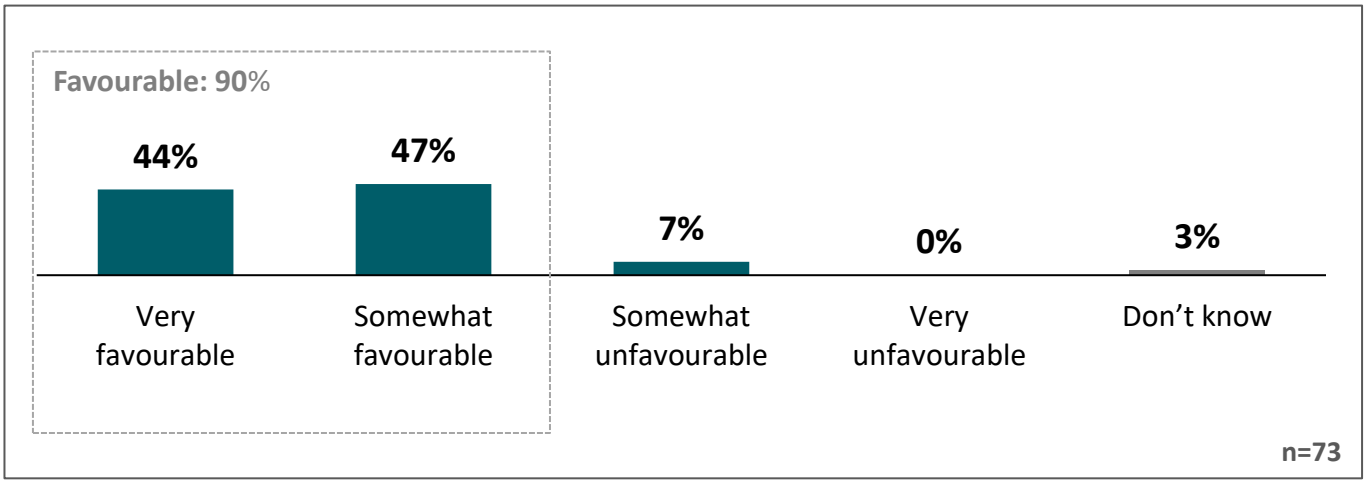


Survey Diagnostics

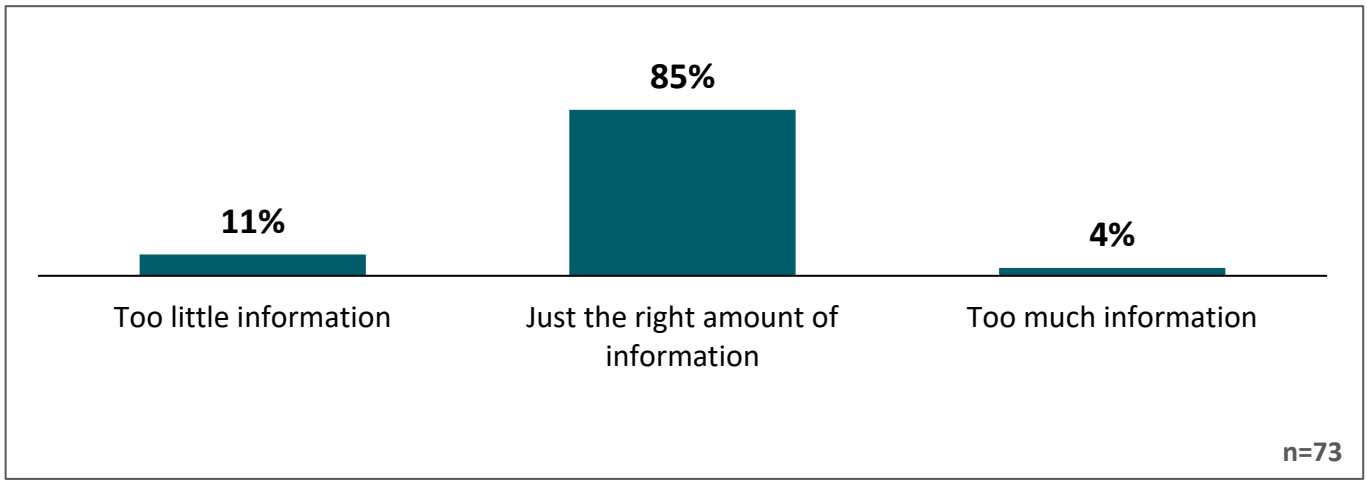
Favourability and amount of information

These last few questions are about the customer engagement that you just completed. In order to do better in the future, Hydro One wants to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Hydro One provided too much information, not enough, or just the right amount?



Survey Diagnostics
Other information not included

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Verbatim comments (70% No comment)
"1) Greater detail on how these investments will drive savings or lower rates in the future. 2) What would be the plan and impact to customers if Hydro One were forced to: a) hold rates steady, b) increase rates annually by no more than the rate of inflation? 3) A description of what customer group/industry/sector/geographic region is driving the investment and how much is being allocated to each. 4) If I support your 5.5% increase each year for 5 years, how will this affect my community?"
"As a resident of Northern Ontario, I would like to have seen which parts of Ontario that HONI's investments are earmarked for. I would understand how much of the proposed increased fund investments to the benefit of Northern Ontarians."
"Budget shows chunks of money that make up the operating expenses. I would like to understand what that is composed when rate payers are being asked to increase, how is the increase in that chunk relative to the reason for the need additional for the parts discussed in this survey?"
"Content/questions related to expansion or new infrastructure spending. If electricity demand is expected to double by 2050, how is Hydro One addressing infrastructure needs in spending?"
"Did not address the cost and performance of customer connections."
"I wish there was focus for individual areas. I am representing [REDACTED] company in [REDACTED] Ontario. The key item for my company is the old bell cables and replacing the infrastructure with fiberoptic or new bell cables. The old bell cables drop out often and the IESO response is to drop the transmission line [REDACTED]. Local companies are looking for Hydro One and IESO to take the lead on this."
"I would have liked the investment options to have a wider spectrum. The differences in more or less investment were essentially trivial."
"I would like to receive specific information regarding Sector 1 L7S circuit changes/ upgrades/ maintenance."
"In order to agree to spend on the draft plan and not less, it would have been beneficial to see what type of additional services would be provided. The high level education did not give me the comfort to agree to spend to draft plan."
"It would be helpful to know to what extent the mandatory increases arise from the increase in load projected by the Province."

Survey Diagnostics

Other information not included continued

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Verbatim comments (70% No comment)
"It would have been beneficial to provide additional details on specific station work or infrastructure upgrades/replacements that could affect me as a customer. I know its difficult to provide the entire program however having some insights into what Hydro One is planning may have altered our responses."
"It would have been helpful to understand reliability impacts of deferring investments."
"More information about trade-offs. For example, how does increased investment in renewal impact future reliability? What targets does Hydro One set for Transmission reliability and power quality? Also, there was a reference to growth based on the IESO forecasts, but there were no options for capacity improvements on the Transmission system. Perhaps these expansions were part of the mandatory/obligated investments. We would have supported higher investments in transmission capacity projects. Also, is Hydro One investing in integrating battery storage and other distributed energy resources? Alternatives to traditional transmission projects would have been helpful."
"More specific information on Distribution expenditures."
"OpEx planning, plenty of focus on CapEx. But when it comes to customer costs both are equally important."
"Perhaps having access to regional information in terms of investments/future plans. Having the information accessible, but not embedded, would be a nice feature."
"Region specific information for Eastern Ontario."
"The theme of my response is spending more efficiently. I would love to understand how Hydro One is driving efficiency."
"Where does the bulk of the Tx rate increase come from? Are major infrastructure spends like 230kv lines and transmission to Northern Ontario part of the budget spend increase?"
"Your account executives are overloaded with too much work and can't provide a good level of support. You need more account executives to support your costumers properly. The current level of support is not acceptable."

Survey Diagnostics
Outstanding questions

Q Is there anything that you would still like answered? (Optional)

Verbatim comments (86% No comment)
"Again, is there more information on Distribution expenditures. Important upgrades to Hydro One distribution infrastructure, such as for those assets that reside along [REDACTED] St in the Town of [REDACTED], are sorely needed to safeguard public safety."
"As an industrial customer, the survey should focus a little on Hydro One and IESO interactions as well."
"Has Hydro One completed all the work proposed in their last plan? If so, was it completed on schedule and within budget? Historical performance provides context for the adequacy of plans."
"If the annual increase is 5.5%, then why is the monthly increase also not 5.5%. This area is confusing. Also, the total percent increase does not equal the sum of the increases from each area, and the reason for this is not made clear."
"See above."
"Totally unrelated to this report, but for planned power outages the .csv report that gets sent out has a lot of extraneous information. If that could be limited to just the outages that impact our facility that would be great!"
"What are the major investments for Eastern Ontario?"
"When will the cover process be streamlined to ensure critical generation assets can re-connect to the system in a timely manner? As outages become harder to obtain or change, months of planning/review of may not be feasible."
"When you have a fault on the transmission [REDACTED] line, and it damages the customer's generator, is there a way you can help with damages done to our equipment?"
"Yes - How hydro one is driving efficiency and enabling the Ontario economy?"

Voluntary Stream Results



Voluntary Stream Results

Summary of Results

Those without an available email address on file had the opportunity to participate in the customer engagement through an open-access survey link. Verified customers (those who supplied their account number and the first three characters of a postal code associated with one of their accounts) were routed into the "representative" stream.

Customers who chose not to verify their account information or were unable to do so could still participate by self-selecting the appropriate survey version (residential, including seasonal, First Nations On-Reserve residential, or small business) and were included in the "voluntary", unverified stream. Feedback provided through the voluntary stream is summarized below.

Customer Type	Hydro One Distribution & Transmission Customers		Hydro One Transmission-Only Customers	
	Residential n=218	Small Business n=3	Other LDC* Residential n=269	Other LDC* Small Business n=3
Distribution Investment Trade-Offs				
Overall System Reliability				
Spend More	37%	1/3		
Draft Plan	38%	2/3		
Spend Less	25%	--		
Managing the Impacts of Severe Weather				
Spend More	38%	1/3		
Draft Plan	38%	2/3		
Spend Less	35%	--		
Targeted Reliability Improvements				
Spend More	31%	1/3		
Draft Plan	35%	2/3		
Spend Less	33%	--		

*Local distribution company | Note: Tables may not total 100% due to rounding.
Counts are shown rather than percentages for samples less than 30.

Voluntary Stream Results

Summary of Results

Customer Type	Hydro One Distribution & Transmission Customers		Hydro One Transmission-Only Customers	
	Residential n=218	Small Business n=3	Other LDC* Residential n=269	Other LDC* Small Business n=3
Transmission Investment Trade-Offs				
Keeping Pace with Transmission Renewal				
Spend More	31%	2/3	51%	--
Draft Plan	45%	1/3	35%	--
Spend Less	24%	--	14%	3/3
Stewardship of the Transmission System				
Spend More	36%	--	43%	--
Draft Plan	40%	3/3	43%	--
Spend Less	24%	--	14%	3/3
Shared Investment Trade-Offs				
Maintaining Buildings and Facilities				
Spend More	31%	1/3	46%	--
Draft Plan	44%	2/3	35%	--
Spend Less	25%	--	19%	3/3
Information Technology				
Draft Plan	67%	1/3	78%	--
Spend Less	33%	2/3	22%	3/3
Evaluating Hydro One's 2027-2032 Draft Plans**				
Spend More	31%	1/3	49%	--
Draft Plan	37%	2/3	30%	--
Spend Less	21%	--	10%	2/3
Other	9%	--	7%	1/3

*Local distribution company | Note: Tables may not total 100% due to rounding.
**"don't know" not shown.
Counts are shown rather than percentages for samples less than 30.

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Hydro One. The conclusions drawn and opinions expressed are those of the authors.

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SECTION 1.6 – ATTACHMENT 2 – ADDRESSING NEEDS AND PREFERENCES OF INDIGENOUS COMMUNITIES

1.0 INTRODUCTION

SPF Section 1.6 addresses customer engagement activities involving Indigenous Peoples, including First Nations communities and Métis individuals, including through the application-specific IRG Study and other ongoing engagement. The sections below address Hydro One's Indigenous Relations Policy and summarize steps taken to address the needs and preferences of Indigenous communities and customers, including procurement opportunities.

2.0 INDIGENOUS RELATIONS POLICY

Hydro One's Indigenous Relations Policy, updated in 2023, sets out the Company's commitment to building partnerships with Indigenous people and communities. The policy delineates Hydro One's commitment to, among other things, increase procurement opportunities for Indigenous businesses, increase Indigenous representation in Hydro One's workforce, consult on projects that may impact Aboriginal and Treaty rights, ensure Hydro One employees have the training to advance relationships and understanding with Indigenous communities, and advance positive and lasting socio-economic outcomes with Indigenous communities through partnership. Please refer to the appendix of this attachment for the Indigenous Relations Policy.

3.0 ADDRESSING THE NEEDS AND PREFERENCES OF INDIGENOUS COMMUNITIES AND CUSTOMERS

Hydro One is taking various steps which are responsive to and assist in addressing the needs and preferences of Indigenous customers and communities as they expressed through customer engagement activities. These include the steps summarized below.

Reliability. As described in SPF Section 1.6, First Nations customers, surveyed as part of the IRG Study, prioritized reliability outcomes and supported investments that would

improve reliability. Interviews with First Nations communities identified reliability and power quality as a priority. Métis Nation of Ontario representatives also identified reliability as a priority for rural and remote areas.

Distribution reliability to First Nations communities is described in DSP Section 3.11, D-SS-04, Attachment 1. Hydro One is expanding the grid-scale and residential Battery Energy Storage System (BESS) program to improve distribution reliability for First Nations communities and some residential customers currently experiencing poor reliability (DSP Section 3.11, D-SS-04). In addition, Hydro One is embarking on several province-wide distribution reliability and resilience-improvement initiatives such as installation of switches to sectionalize and automate system restoration post outage where feasible (DSP Section 3.11, D-SS-05), accelerating replacement of poor condition poles (DSP Section 3.11, D-SR-07), and expanding expenditure on vegetation management programs as outlined in Exhibit E-03-02, Section 2.4.1.

Hydro One's proposed transmission investments will also respond to reliability concerns through targeted system renewal and reinforcement work. Planned activities include refurbishing aging transmission lines and stations, reinforcing the transmission system in northern Ontario with new transmission lines, and continuing line maintenance inspections and vegetation management. These investments and activities will improve delivery point performance and enhance the reliability of supply to First Nations communities and remote areas. Transmission reliability to First Nations communities and the associated reliability improvement initiatives are further described in TSP Section 2.4 Attachment 1.

Over the 2028-2032 period, Hydro One's Indigenous Partnership and Business Development (IPBD) Group will continue to support the Transmission and Distribution businesses by relaying community concerns and goals that will support in implementing reliability improvement initiatives.

System Access. Hydro One will provide customers, including Indigenous customers and communities, with timely access to the network through customer connections and paced

regional expansions. Hydro One will enable approximately 18,600 new connections and upgrade services for approximately 7,700 existing load customers annually. Further details are included in DSP Section 3.1[1] and DSP Section 3.11 D-SA-02.

Procurement Opportunities. Hydro One supports the Indigenous Relations Policy through its procurement opportunities for qualified Indigenous businesses. This is intended to develop and expand the number and capacity of Indigenous suppliers who can provide goods and services to Hydro One. Hydro One procures materials and services through a framework of policies and procedures that are intended to deliver productivity and allow the company to achieve greater value in its sourcing.

Hydro One's Indigenous Procurement Policy has steadily increased procurement opportunities for qualified Indigenous businesses from 1.62% ($16.5M) in 2016 to 7.1% ($215.9M) of spend under management in 2025. In 2021, Hydro One set a new target of 5% of spend under management for procurement opportunities for qualified Indigenous businesses by 2026. For 2025, Hydro One exceeded 5% and has achieved this goal.

The measures Hydro One continues to implement to increase access to procurement opportunities and ensure that Indigenous communities will access meaningful benefits from Hydro One's activities, and that new relationships will be established and strengthened, include the following.

- Hydro One's Indigenous Procurement Procedure is designed to increase opportunities for Indigenous businesses to supply Hydro One with services and materials through a variety of sourcing processes such as competitive bids and direct awards.
- Hydro One has implemented criteria related to Indigenous participation requirements included in all Requests for Proposal (RFP) documents regarding the use of an Indigenous businesses and sub-contractor(s) to complete the goods and services requirements, local Indigenous participation commitment, and active Indigenous diversity programs, policies and/or initiatives.

[1] DSP Section 3.1, System Access, page 41 – 43 and System Service, page 47 – 50

- Hydro One hosts meetings with Indigenous suppliers and communities to share information about Hydro One's procurement process, learn about products and services local Indigenous communities and businesses can provide, and share upcoming procurement opportunities with them.
- In 2022, Hydro One launched a "Retain & Grow" program to improve internal cultural alignment around Indigenous procurement, and to build upon existing relationships with Indigenous suppliers through: connection-based mentoring and networking; performance evaluations and feedback; and tracking and monitoring of collaboration. This program has since evolved to support high-performing Indigenous suppliers into leading suppliers for Hydro One, while also providing Hydro One stakeholders with an important opportunity to learn more about the Indigenous communities and Peoples they serve.
- In 2024, Hydro One held an Indigenous Supplier Business Fair to provide a platform for Indigenous businesses to showcase their products and services. The Company also hosted the second Engineering, Procurement and Construction Safety Summit to foster conversations with our contractors, including Indigenous contractors, on collaboration and safety.

Indigenous businesses currently supply a diverse and growing range of materials and services to Hydro One. Examples include emergency storm response, engineering services, facility maintenance, security services and general contracting.

Procurement targets will be set for each year of the application period, and Hydro One's IPBD team will continue to work with Supply Chain to set clear expectations with external vendors to support increased Indigenous procurement. Hydro One has also continued to refine its contract process for Indigenous businesses. For further information on Hydro One's procurement management, refer to Exhibit E-05-01, and for details of Hydro One's spend under management, refer to Exhibit C-09-04, Section 2.0.

Employment. Hydro One is advancing its commitment to Indigenous employment by strengthening its long-term talent pipeline through targeted recruitment events,

scholarships and early-talent programs, as well as partnering with Indigenous communities in project delivery efforts.

Communications. Hydro One's IPBD team is reviewing the Indigenous Relations Policy, and implementing standardized engagement tools, templates and processes to strengthen consistency and transparency in engagement approaches. The IPBD team also works with the Distribution Lines and Forestry teams to ensure timely communication with Indigenous communities where routine or emergency maintenance work is planned or underway, with IPBD providing additional support if concerns arise. Hydro One will continue the focus on relationship building and supporting timely, consistent engagement with Indigenous communities across operations over the 2028-2032 period.

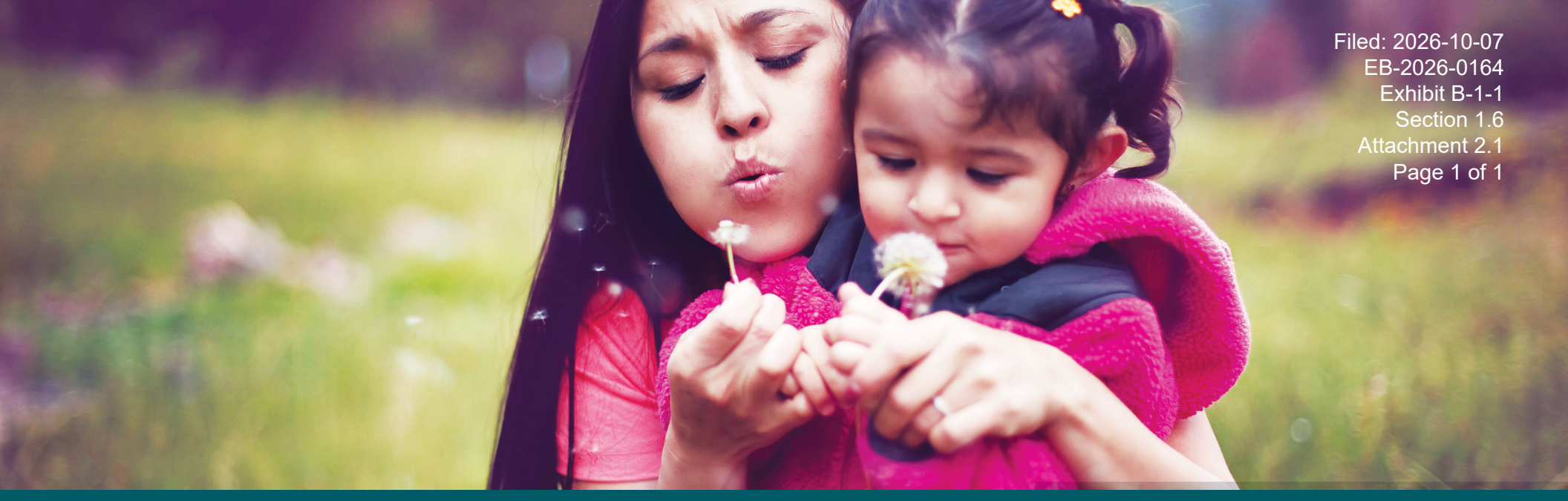
Affordability. If the proposed 2028 – 2032 investment plan is approved, the monthly bill for a typical Hydro One year-round medium density residential will increase by an average of $1.14 each year for transmission and decrease by an average of $0.10 each year for distribution, from 2028 to 2032.

Hydro One does not have authority to apply the First Nations Delivery Credit beyond what is specified in the legislation. However, Hydro One supports affordability for customers by providing information and assistance on available financial and energy-efficiency programs. Depending on eligibility, these include the Low-Income Energy Assistance Program, the Ontario Electricity Support Program, payment arrangements and the First Nations Conservation Program.

4.0 CONCLUSION

Hydro One is continuing to focus on ensuring it is meeting the aspirations, goals, interests and needs of First Nations communities and Métis organizations, partners, customers and employees. Feedback received from First Nations communities, Métis organizations, and customers have resulted in Hydro One introducing measures that will help address a number of the concerns raised, though Hydro One recognizes that more work needs to be done. Hydro One will continue to engage and work with First Nations communities and

Métis organizations as it develops and executes programs intended to provide improved service and customer care, and Hydro One will continue to build and maintain positive partnerships with First Nations communities and Métis organizations across Ontario.



Hydro One
Indigenous Relations Policy

Key Beliefs

At Hydro One:

- We acknowledge that Indigenous communities have historically borne impacts of development without benefiting from it.
- We acknowledge that Indigenous communities have real issues and grievances arising from past and current development.
- We commit to a journey of Reconciliation that is guided by this context and by the unique Indigenous communities we work with during engagement and for the life cycle of our assets.
- We understand that our success is dependent on demonstrating leadership in Indigenous Relations and embracing partnerships with Indigenous communities.

Our Guiding Principles and UNDRIP

- We approach Indigenous communities with **transparency** and **respect**.
- We meet Indigenous communities **where they are** in their governance, capacity and priorities, as participants in industry and environmental practice, and as the **original stewards** of the lands that make up Ontario and Canada.
- We respect the **cultures, traditions and rights** unique to each Indigenous community.
- We recognize the **obligations** industry has in **Reconciliation** with Indigenous people, to address meaningful and measurable change in cultural understanding and economic outcomes.
- We understand that Hydro One succeeds when Indigenous communities succeed and that all Hydro One employees benefit from a greater understanding of Indigenous issues, opportunities and knowledge.

UNDRIP

We understand that our relationships and interactions with Indigenous communities in Canada require a paradigm shift. Guided by the evolving legal obligations and opportunities for consultation and engagement, we embrace the United Nations Declaration on the Rights of Indigenous Peoples as it supports human rights, language, education and governance for Indigenous people. It is a critical lens on our relationship with Indigenous communities. We are committed to supporting UNDRIP.

It remains our goal to achieve the agreement and support, articulated in UNDRIP as “Free Prior and Informed Consent”, of Indigenous peoples. We will use FPIC as a goal and a guide in every engagement. We understand that UNDRIP and FPIC are an important lens to view our relationship with Indigenous people, along with the evolving law, practices, and the guidance of Indigenous communities in Ontario.

Our focus is on meaningful reconciliation under Call to Action #92, which includes increasing and retaining our Indigenous employee base, offering equity investment opportunities to Indigenous communities when we build new capital Transmission projects, challenging ourselves to set aggressive procurement targets for Indigenous businesses and focusing on the input and guidance of Indigenous communities as we develop and implement our strategic goals.

David Lebeter
President and CEO
Hydro One Ltd.

February 2023

The Hydro One Indigenous Relations Policy reflects our Vision and Guiding Principles. Our engagement, advocacy and strategic direction are set by the Indigenous Relations Policy and led in collaboration with the Indigenous communities (First Nations, Inuit and Métis Nation) we work with every day.

Our Vision

A better and brighter future for all.

Our Goals

- We will be the partner of choice for Indigenous communities
- We will attract, retain and learn from Indigenous employees as their employer of choice
- We will advance meaningful economic Reconciliation as partners with Ontario Indigenous communities

hydro One

SECTION 1.7 – SPF – INVESTMENT PLANNING PROCESS

1.7.1 OVERVIEW

This section describes Hydro One's integrated planning framework known as the 'system planning process' which supports the development of Hydro One's investment plan underpinning this Application. The output of these interrelated processes is a detailed, multi-year investment plan comprised of investments described in the Transmission System Plan (TSP), Distribution System Plan (DSP), and General Plant System Plan (GSP) (together the System Plans) and the company's OM&A requirements.

1.7.1.1 THE INVESTMENT PLANNING PROCESS

Planning teams from across Hydro One develop the investment plan through a risk-based process, which develops and assesses candidate investments based on safety, reliability and environmental risk, mandated requirements, and consideration of customer input, management insight, and the company's strategic priorities and objectives. The process allows Hydro One to address asset needs and operational risks, meet mandated obligations, as well as respond to customer needs and preferences.

Hydro One follows a three-phase, risk-based process to identify, prioritize and optimize investments set out in the TSP, DSP and GSP. As presented in Figure 1 and summarized below, the three phases of the system planning process are: i) Corporate Strategy and Context, ii) Asset Management, and iii) Investment Planning.

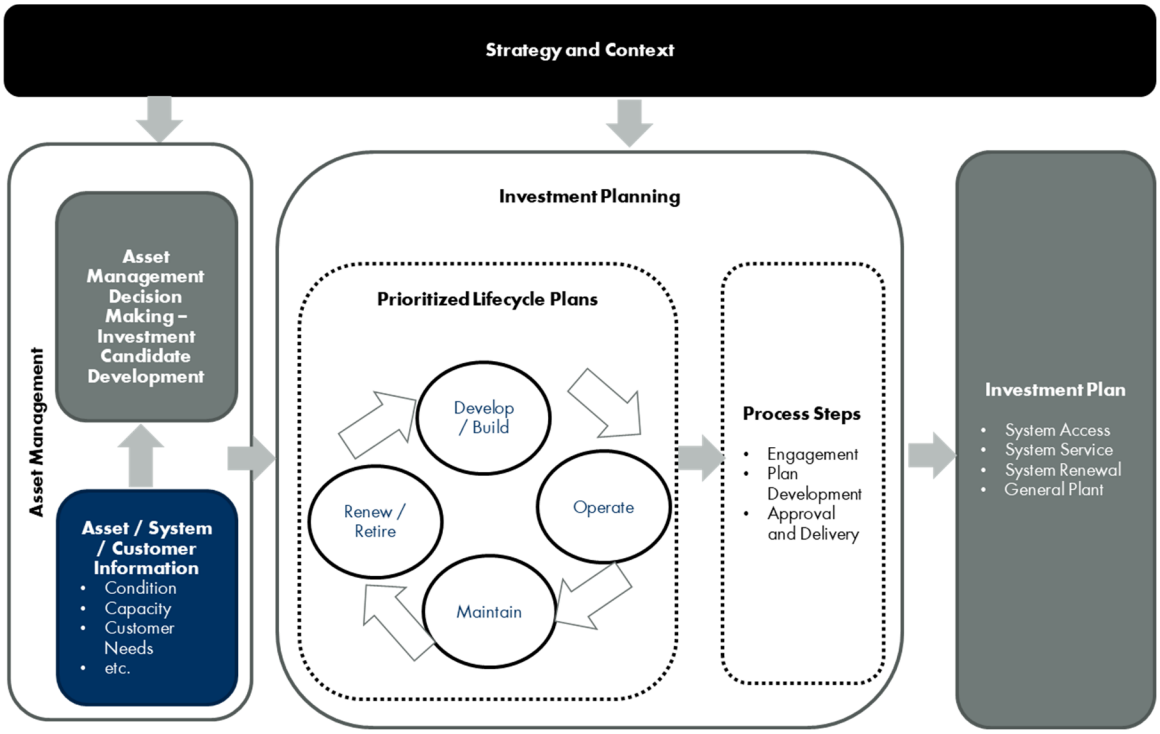


Figure 1: System Planning Process Diagram

Strategy and Context: Hydro One identifies long-term system needs within the context of customer needs, asset condition, system performance, and system capability. In addition, Hydro One's Strategic Priorities, alignment with the OEB's RRF outcomes and the results of the customer engagement process described in SPF Section 1.6 are considered.

Asset Management: Hydro One employs a lifecycle management approach that balances asset performance, costs and associated risks during the asset service life. During the asset management process, Hydro One assesses the current state of its assets, evaluates the needs of the system and customers, and develops a list of potential candidate investments. Further information on the Asset Management approach that Hydro One has employed when preparing the System Plans is provided in Section 1.7.4 below.

Investment Planning: Based on the candidate investments, Hydro One uses its investment planning process to identify, prioritize and optimize investment decisions considering customer needs, system and asset risks. Risk taxonomies guide the assessment of candidate investments, based on safety, reliability and environmental risks. These assessments underpin the prioritization and optimization of the candidate investments to produce a draft portfolio of investments. This approach allows Hydro One to manage costs, address asset and system operational risks, address customer needs and preferences and mitigate customer rate impacts.

1.7.1.2 APPROACH TO TRANSMISSION AND DISTRIBUTION SEGMENTS

Hydro One prioritizes transmission and distribution system investments separately, consistent with separate OEB approvals and separate revenue requirements. Common corporate costs and general plant investments are allocated based on the shared asset allocation study provided in E-04-08.

The discrete drivers that inform the System Plans vary across the Transmission (including HOSSM) and Distribution lines of business. For example, a significant portion of the distribution investment plan is responsive to external factors including new customer connections, joint use and relocations, and storm response. Conversely, transmission investments are typically large, complex, multi-year projects that require extensive coordination with customers, generators, and the IESO to execute.

Hydro One prioritizes transmission and distribution investments based on a range of factors. Many lifecycle-driven investments are classified as System Renewal and prioritized on the basis of risk. Mandated investments driven by external sources such as the IESO, local area and regional supply plans, and customer requests are classified as System Service and System Access. These investments are required to comply with the terms of Hydro One’s Transmission and Distribution licences and are prioritized in a manner consistent with the requirements driving the investments.

1.7.1.3 THE DEVELOPMENT OF THE 2028-2032 SYSTEM PLANS

The system planning process for the 2028-2032 investment plan started in early 2025, following the completion of Phase I of Customer Engagement. Lines of Business developed preliminary plans which were responsive to the needs of the system and customer needs and preferences identified in Phase I of customer engagement. Hydro One developed the draft investment plan and two other investment scenarios – a spend less plan (Scenario 1) and a spend more plan (Scenario 3) – and the resulting bill impacts, which were presented for customer feedback during Phase II of Customer Engagement in the late fall of 2025.

In early 2026, Hydro One received the results of Phase II of Customer Engagement. This feedback, together with consideration of ongoing IESO Bulk Planning studies, updated system and asset data, and updated cost and execution considerations, helped refine the investment plan for this Application.

1.7.1.4 TIMELINE TO DEVELOP THE 2028 - 2032 SYSTEM PLANS

Figure 2 sets out the major milestones to develop the 2028-2032 System Plans.

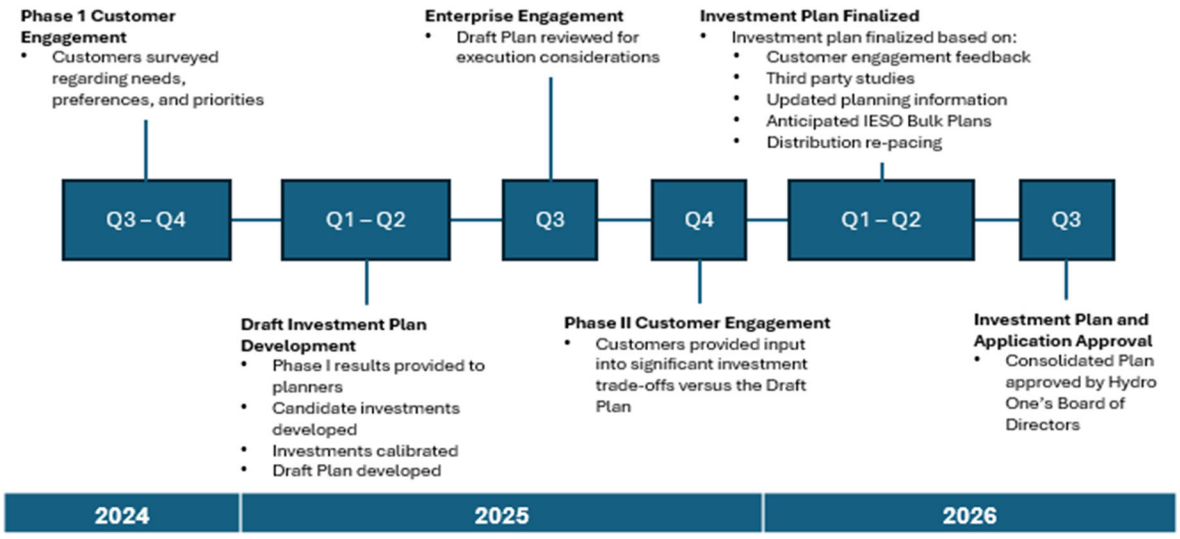


Figure 2: 2028-2032 System Plan Development Timeline

The sections that follow discuss each phase of the system planning process shown in Figure 1 further above.

1.7.2 STRATEGY AND CONTEXT

1.7.2.1 HYDRO ONE'S STRATEGIC PRIORITIES

Hydro One's planning process begins with a consideration of Hydro One's Strategic Priorities, the OEB's Renewed Regulatory Framework (RRF) outcomes, and customer engagement results. These factors establish the focus of the System Plans by identifying areas that are valued by the Company's diverse stakeholders, customers and regulators. Hydro One's Strategic Priorities are presented in Figure 3 below.

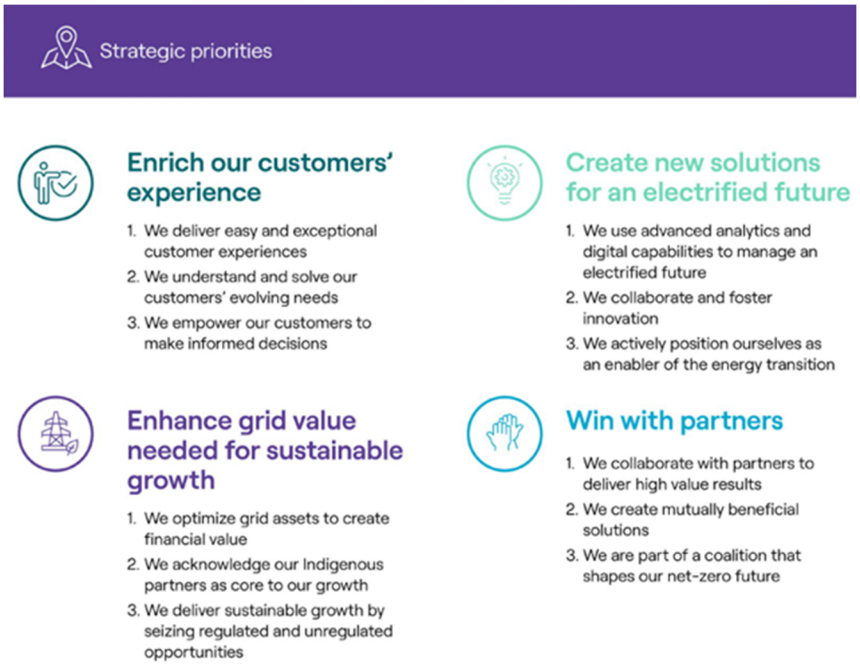


Figure 3: Hydro One's Strategic Priorities

1.7.2.2 THE OEB'S RENEWED REGULATORY FRAMEWORK

Hydro One's System Plans are guided by the four outcomes identified in the OEB's RRF:

- **Customer Focus** – services are provided in a manner that responds to identified needs and customer preferences;

- **Operational Effectiveness** – continuous improvement in productivity and cost performance is achieved; and distributors and transmitters deliver on system reliability and quality objectives;
- **Public Policy Responsiveness** – distributors and transmitters deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- **Financial Performance** – Financial viability is maintained; and savings from operational effectiveness initiatives are sustainable.

In managing assets that are critical to customers and Ontario's economy, Hydro One is committed to meeting the RRF outcomes and has integrated them into its Investment Planning process. Table 1 below demonstrates how the System Plan outcomes are aligned with the RRF outcomes.

Table 1 - Hydro One's RRF Performance Outcome Objectives

RRF Outcomes	System Plan Outcomes
Customer Focus	• Improve current levels of customer satisfaction • Deliver exceptional experiences and empower customers
Operational Effectiveness	• Achieve top-tier safety performance and eliminate serious injuries
	• Focus on continuous improvement to enhance efficiency, productivity, and reliability
	• Achieve and maintain employee engagement
	• Deliver on operational commitments to renew, expand, and enhance the grid • Maintain Transmission reliability and improve Distribution reliability
Public Policy Responsiveness	• Deliver on obligations mandated by government through legislation and regulatory requirements
	• Lower Hydro One's environmental footprint through greenhouse gas reduction
Financial Performance	• Responsible investment in rate base assets to ensure the safety and reliability of the grid • Reasonable and stable rate impacts over the course of the planning period

1.7.2.3 CUSTOMER ENGAGEMENT

The investment planning process is also informed by customer engagement. Hydro One's customer engagement initiatives are designed to:

- increase Hydro One's understanding of customer needs and preferences;
- enhance Hydro One's ability to provide services that meet these needs;
- produce outcomes that are valued by customers; and
- improve overall customer satisfaction.

Hydro One relied upon customer engagement in developing the 2028-2032 System Plans, discussed further in TSP Section 2.7, DSP Section 3.7, and GSP Section 4.7. To identify customer needs and preferences, Hydro One engaged an independent third-party research firm, Innovative Research Group (IRG), to design and conduct a comprehensive, two-phased, customer engagement study, further discussed in SPF Section 1.6. This engagement allowed Hydro One to both shape and refine its investments based on customer input and implement explicit trade-offs between spending levels and outcomes, further discussed in section 1.7.5.6.2 below.

1.7.2.4 ECONOMIC PLANNING ASSUMPTIONS

Hydro One has used the Ontario Consumer Price Index for the inflation assumption in the investment planning process.

1.7.2.5 ASSET MANAGEMENT PROCESS

Hydro One's asset management goal is to monitor system assets and determine the appropriate timing of asset maintenance and capital investments throughout the asset lifecycle. This approach allows Hydro One to manage risks and to support Hydro One's Strategic Priorities, customer and operational needs, and RRF outcomes, while managing total cost and customer rate impacts. The asset management process is a key component of the investment planning process.

Hydro One monitors and assesses the current state of the system and its assets on an ongoing basis. The development of candidate investments is underpinned by a needs

assessment considering (i) asset condition, (ii) customer needs and preferences, (iii) power system and operational needs (including regional and bulk planning considerations), and (iv) other external influences. Each of these components is discussed in the sections that follow.

1.7.2.6 ASSET CONDITION NEEDS

Hydro One planners perform an asset needs assessment to identify candidate investments and collect the data necessary to assess risks and facilitate the subsequent calibration process. A systematic assessment of asset-specific investment needs is an essential input into investment planning. The investment candidates are further scored and prioritized through the investment planning process to achieve the optimal balance of risk and benefits.

The asset needs assessment process is structured to determine individual asset needs. The process relies on asset data, including condition, utilization, performance, obsolescence and other factors, and focusses on major equipment groups in transmission (such as transformers, conductors, breakers, and protection and control systems) and distribution (such as station transformers and poles) that directly affect system reliability. This process ensures a consistent view of asset information. As part of the preliminary needs assessment, asset condition and other factors are assessed against current and future requirements to identify investment candidates.

Asset condition, criticality, utilization and performance are key factors that help identify asset risks that require further screening and confirmation:

- **Condition** – The degradation of asset condition over time increases the probability of failure, which presents a risk to the system. Asset condition is determined using different criteria for different assets. For example, the condition of a transmission or distribution station transformer is confirmed by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is assessed by a visual inspection, a sounding test, and if required, a boring test. While condition evaluation methods to evaluate condition vary, all assets of a given type are

evaluated through objective criteria. Assets that have a high condition risk are candidates for refurbishment or replacement.

- **Criticality** – Assets whose failure would result in an interruption to a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller impact on the system load. Asset criticality is used to prioritize the refurbishment or replacement of assets whose condition, performance, utilization, or economic risk has already resulted in the asset being considered a candidate for refurbishment or replacement.
- **Utilization** - The deterioration of some assets is highly dependent on their loading and number of loading cycles. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate faster than those that are lightly loaded. Similarly, circuit breakers utilized for capacitor and reactor switching which are subject to significant operations experience accelerated mechanical and electrical wear-out. Therefore, the asset utilization risk for transformers and circuit breakers considers their relative deterioration based on loading and operational history.
- **Performance** - Past performance can be a good indicator of expected future performance. Therefore, assets with a high-performance risk can be considered candidates for refurbishment or replacement.

Hydro One considers additional factors including load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence including vendor support, and health and safety considerations to help ensure that capital expenditures target an appropriate mix of assets. While age is not the primary driver for any specific investment, demographics provide insight into long-term fleet level needs.

On-site assessments with field personnel are conducted to validate and confirm asset conditions, based on site-specific considerations. For high-value assets such as transformers, subject matter experts perform a thorough assessment of asset condition and consider and advise on issues such as equipment obsolescence, manufacturer support, and “repair vs. replace” evaluations. Detailed asset assessment and field review,

inspection, and validation are tools that ensure the identified needs reflect the condition of the assets in the field.

Through asset lifecycle strategies, developed for major system components, Hydro One considers refurbishment as an alternative to replacement when technically feasible. Considerations differ among assets with further information provided in TSP Section 2.2, DSP Section 3.2 and GSP Section 4.2 - Asset Information and Lifecycle Strategies.

Investments largely underpinned by asset condition data from ongoing asset assessments are found within the System Renewal category in TSP Section 2.12, DSP Section 3.11 and GSP Section 4.11.

1.7.2.7 CUSTOMER NEEDS

Understanding customer needs is critical to Hydro One's business and investment planning. Ongoing customer processes help the Company proactively identify customer needs. The needs of new, large customers are often identified through direct customer connection requests, needs assessments and customer consultations conducted as part of the Regional Planning process. The needs of existing customers are identified through continuous monitoring of the power system and engagement with major customers (such as transmission connected local distribution companies, transmission connected industrials, and large distribution accounts).

In addition to broad customer preferences on priorities and trade-offs gathered through Hydro One's two-phase customer engagement (see SPF Section 1.6), specific customer needs in terms of connection to the system, as well as broader local, regional, and bulk growth requirements have directly driven various investments within the System Access and System Service category in TSP Section 2.12 and DSP Section 3.11.

1.7.2.8 POWER SYSTEM NEEDS

Power System needs relate to work that is necessary to maintain and operate the transmission and distribution system to reliably and securely deliver power to customers

and meet current and forecast requirements resulting from new load customers, generation facilities and other distributed energy resources. System needs include:

- Providing adequate capacity to reliably deliver electricity to the local areas connected to Hydro One's system.
- Addressing local area reliability performance, including pockets of distribution customers who may experience poor reliability.
- Implementing mitigation measures to minimize high-impact events to ensure the safe, secure and reliable operation of Hydro One's transmission system in accordance with the IESO's Market Rules, the OEB's Transmission System Code, and other mandatory industry standards such as those established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC);
- Implementing IESO Bulk System planning needs and regional transmission facility needs identified as part of the Regional Planning process;
- Local distribution upgrades and enhancements to relieve system capacity constraints and meet forecast load growth, consistent with the requirements of the Distribution System Code; and
- Protecting critical infrastructure from physical and cyber threats.

Under the electricity sector structure in Ontario, the need for new transmission system facilities or system enhancements may be identified by Hydro One Transmission, the IESO, the Government of Ontario, or customers. The regional planning process identifies distribution-level investments necessary to address regional needs more effectively, instead of other transmission or resource options. Needs are identified and assessed by Hydro One in conjunction with customers, the IESO and LDCs under the regional planning process (outlined in SPF Section 1.2) or by the IESO as part of the planning for the bulk electric system for ensuring supply to more than one distributor (discussed in TSP Section 2.6).

Investments resulting from IESO Bulk System planning and Regional Planning have directly driven various investments within the System Service category in TSP Section 2.12 and DSP Section 3.11, as well as some investments in GSP Section 4.11.

1.7.2.9 EXTERNAL AND OTHER INFLUENCES

Hydro One uses information on industry best practices, trends and benchmarking to evaluate its performance against peer utilities. These studies and comparisons generate insight regarding Hydro One's operations relative to benchmark comparators, which can guide continuous improvement efforts and inform investment decision-making. A description of the studies related to the System Plans is included in SPF Section 1.3, and further discussed in TSP Section 2.3, DSP Section 3.3 and GSP Section 4.3.

In addition, Hydro One's investment plan has been influenced by new regulatory requirements including the OEB's Vulnerability Assessment and System Hardening requirements and Non-Wires Solutions requirements; these two requirements have informed various investments found in DSP Section 3.11 and Exhibit E-03-02.

1.7.2.10 INVESTMENT CANDIDATE DEVELOPMENT

After evaluating the current state of the system, Hydro One considers reasonable opportunities to group and bundle related needs, based on logical, functional and geographic groups. For example, if multiple assets are identified for intervention on a common circuit or feeder, these needs may be grouped together to form an integrated investment. Through this process, diverse individual needs are brought together to form potential projects or programs that may be brought forward as candidate investments.

These groupings of potential candidate investments are then scoped and defined based on identified asset needs, customer feedback, coordination with system needs, and other inputs. The outputs of these assessments are potential investments which are considered further during the Investment Planning process and are evaluated on the risk factors described below.

The current state assessment establishes the necessary fact base to assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the Investment Planning process described in section 0 below. Risks related to asset condition, performance and utilization inform the probability score, and risks relating to asset criticality directly inform the consequence score.

1.7.3 POWER SYSTEMS INVESTMENT PLANNING

The following section describes the investment planning process for the Transmission and Distribution systems. General Plant such as Fleet, Facilities and Real Estate, Information Systems and System Operations utilize a similar approach to assess risk and develop candidate investments (see GSP Section 4.7).

1.7.3.1 CANDIDATE LIFECYCLE RISK ASSESSMENT

Following investment candidate identification, potential investments are assessed and calibrated. This stage involves the following activities (each of which is described further below):

- assessing the risk mitigation impact of investment candidates.
- assessing the impact of investment candidates on desired outcomes; and
- calibrating risk assessments to enable consistent assessments across investments.

Risk assessment considers both the probability and the consequence of an event. Risks relating to asset condition, performance and utilization directly inform the probability score. Risks relating to asset criticality directly inform the consequence score. The assessments reflect a current evaluation of existing baseline operational risks without investment and the residual risks remaining following an investment.

The risk assessment process is conducted in the following six steps:

1. **Understand the primary purpose of the candidate investment**: Identify the primary objective of the investment and the risks addressed (safety, reliability, environmental).

2. **Define worst reasonable direct impact (WRDI)**: Identify the worst reasonable direct impact of not making the investment, based on credible scenarios experienced by Hydro One and other utilities.[1]
3. **Determine the consequence of the baseline risk**: Establish the consequence of the WRDI in the event the investment is not completed, using the risk taxonomies.
4. **Determine the probability of the baseline event**: If no investment occurs, evaluate the consequence and probability of the WRDI occurring using the risk-based framework.
5. **Determine the residual consequence and probability**: Determine the consequence and probability of the WRDI occurring even if the investment is made.
6. **Calculate the final mitigated risk score**: Determine the final mitigated risk score based on the difference in baseline and residual risk score for each of the three risk areas (safety, reliability, and environment).

The risk assessment process relies primarily on three risk ratings that have been developed to classify safety, reliability and environmental risks.[2] Each risk rating features clear definitions and consistent assessments, which permits a proper comparison between candidate investments. These risk ratings exclude extreme events such as natural disasters or health pandemics.

[1] The WRDI reflects an outcome avoided if the investment is made with a remaining residual risk of an impact that strikes a balance on the continuum of residual risk between an investment to avoid the average outcome with a higher residual risk and an investment to avoid the worst conceivable risk with no or negligible risk. This is consistent with the objective of risk assessment which is to avoid a reasonable level of risk, while permitting a reasonable and manageable level of residual risk to remain part of the operational focus of Hydro One. In doing this, Hydro One's risk assessment process takes into account total risk. The WRDI is determined by defining a scenario and a reasonable undesired outcome that could occur as a direct result of not making the investment (e.g., failure event that is the most reasonable, additional cost/risk of repair during emergency compared to regular operation). Determination of a "reasonable" outcome is based on an assessment of expectation based on: (i) historical events, (ii) unique characteristics of the proposed investment, and (iii) confidence in the outcome occurring. Determination of a "direct" outcome is based on an assessment of whether the event/damage is an immediate result of the failure itself, or whether it is a secondary/coincidental result.

[2] Reliability consequences can be classified in terms of unsupplied energy to current or forecast loads, load impacted and minutes of interruption duration. Environmental consequences can be classified in terms of overall impact to the environment, oil spill severity and greenhouse gas emissions. Safety consequences can be classified in terms of harm to employees or the public.

Hydro One assesses proposed candidate investments on the consequences and probability of the safety, reliability and environmental risks that they are designed to mitigate. These risk classifications were developed in an iterative and collaborative process based on: (i) historical data from Hydro One and other utilities, (ii) economic impact studies (e.g., insurance tables), (iii) management insights, and (iv) customer feedback (e.g., outage frequency was added to the probability framework to incorporate specific feedback from customers). Each risk classification has seven levels of consequence upon which each investment is assessed. The seven consequence levels are quantified to the same scale for each of the three risk classifications. The assessments are calibrated across all classifications. For example, a score of "6" in the reliability consequence scale is equivalent and comparable in severity to a score of "6" in safety and environmental classifications. Figure 4 to Figure 7 below illustrate the three risk taxonomies.

Taxonomy to evaluate consequences related to one failure event

Score	Impact on workforce : employee and contractor[1]	OR	Impact on public
7	▪ Multiple fatalities of employees		▪ Multiple public fatalities
6	▪ Fatality to 1 employee		▪ Fatality to a single member of public
5	▪ Permanent health consequence that precludes injured party from regular day-to-day activity (e.g., paralysis)		▪ Permanent health consequence that precludes or hinders injured party from regular day-to-day activity
4	▪ Permanent health consequence that hinders the injured party from regular day-to-day activity / doing their job (e.g., loss of hand)		▪ Permanent health consequence that does not prevent injured party from most regular day to day activity ▪ Injury to member of public requiring extended medical treatment with more than 8 weeks recovery time
3	▪ Permanent health consequence that does not prevent injured party from most regular day to day activity, e.g. doing their job (loss of finger) ▪ Injury requiring medical treatment resulting in 8+ weeks absence or temporary modified work for the employee		▪ Injury or illness to member of public requiring medical treatment with less than 8 weeks recovery time ▪ No permanent health consequences
2	▪ Injury requiring medical treatment resulting in less than 8 week absence and no modified work for the employee ▪ No permanent health consequences		▪ Minor injury to member of public requiring First Aid with quick and complete recovery in less than 1 week; No permanent health consequences
1	▪ Minor injury requiring First Aid resulting in less than a week absence and no modified work for the employee ▪ Quick and complete recovery without permanent health consequences		▪ No impact on public

Figure 4: Safety Consequence Framework

Taxonomy to evaluate consequences related to one failure event

Score	Impact on customers	OR	Load impacted	OR	Unsupplied energy	OR	Outage Duration
7	Impacts an entire metropolitan area, including multiple customers **and** 2+ priority customers		>500 MW		>1 200 MWh		> 7 days
6	(Impacts on at least 3 customers **and** one priority customer) **or** Impact on 2+ priority customers		200-500 MW		500 -1 200 MWh		1-7 days
5	Impacts on at least 3 customers **or** including multiple critical locations **or** one priority customer		75-200 MW		200 – 500 MWh		10-24 hours
4	Impacts on at least 2 customers **or** including a single critical location		25-75 MW		25 – 200 MWh		1-10 hours
3	Impacts one customer resulting in a small area outage with no disruption of service to critical locations (e.g., water plant)		<25MW		<25 MWh		<1 hour
2	No power interruption		None		None		None
1	No power interruption and no supply through redundancy		None		None		None

Figure 5: Transmission Reliability Consequence Framework

Scored per event

Score	Impact on customers	OR	Average load impacted	OR	Unsupplied energy	OR	Customer Minutes Interruption
7	>50,000 customers[1] Or >30 LDAs[2]		>60 MW		> 180 MWh		> 7M CMI
6	20,000 – 50,000 customers Or 10 – 30 LDAs		25 – 60 MW		70 – 180 MWh		3M – 7M CMI
5	7,000 – 20,000 customers Or 4 – 10 LDAs		10 – 25 MW		30 – 70 MWh		1M – 3M CMI
4	2,500 – 7,000 customers Or 2 - 4 LDAs		3 –10MW		10 – 30 MWh		350K – 1M CMI
3	500 – 2,500 customers Or 1 LDA		1 – 3 MW		2 – 10 MWh		70K – 350k CMI
2	100 – 500 customers		200kW – 1 MW		500 kWh – 2 MWh		20K – 70k CMI
1	< 100 customers		< 200 kW		<500 kWh		< 20K CMI

Figure 6: Distribution Reliability Consequence Framework

Taxonomy to evaluate consequences related to one failure event

Score	Description[1]	Examples[2]
7	▪ **Catastrophic / irreversible changes to the environment** such as entire loss of habitat, plant, and/or animal populations/ species at risk in the impacted area; will never completely recover ▪ Chronic threat to human health; National media coverage, viral social media coverage/criminal charges/ major fines/charges	Catastrophic/negligent release of PCB oil to sensitive environmental area requiring significant remediation, engineering, and/or long-term monitoring
6	▪ **Significant change to the environment** – substantial loss of habit, plant and/or animal populations / species at risk in the impacted area; requires multiple years to recover completely; Chronic risk to human health; ▪ Widespread provincial media coverage; significant fines/charges/order to comply	Very large off-site soil and/or groundwater contamination due to historical practices; significant release of PCB oil to a sensitive environmental area requiring significant remediation, engineering and/or long-term planning; catastrophic SF6 release
5	▪ **Notable change to environment** – visible loss of habitat, plant and/or animal populations / species at risk in impacted area; requires 1-2 years to recover completely ▪ Definite acute risk to human health ▪ Provincial media coverage; fines/order to comply	Large off-site soil and/or groundwater contamination due historical practices; notable PCB oil to sensitive environmental area requiring significant remediation, engineering and/or long term planning; some SF6 release
4	▪ **Measurable change to environment** – moderate loss of plant and/or animal populations/species at risk in impacted area; damage to environmentally sensitive sites/special interest sites; requires months/year to recover completely ▪ Potential for acute risk to human health ▪ Widespread local media coverage; limited fines/order to comply	Moderate on/off-site soil and/or groundwater contamination due to historical practices; measurable PCB oil, mineral oil, hydraulic oil or other hazardous liquid spill to an environmentally sensitive area requiring moderate remediation, engineering, and/or long-term planning
3	▪ **Limited change to environment** – limited loss of habitat, plant and/or animal populations/species at risk; requires weeks/months to completely recover ▪ Potential for limited risk to human health ▪ Local media coverage; inspection/ comment from regulator/order to comply but no charges/fines	PCB regulatory infraction/fine; minor on/off-site contamination from historical practices; large spill/fire of PCB oil, mineral oil, hydraulic oil or other hazardous liquid requiring remediation, engineering, and/or long-term monitoring
2	▪ **Limited change to environment/ requires day(s) to recover completely** ▪ No plant and/or animal species impacted ▪ No acute risk to human health ▪ No media coverage; minor regulatory fine or order	Large spill/fire of PCB oil or mineral oil requiring cleanup; other large volume liquid spills requiring cleanup (i.e., hydraulic oil, coolant); SAR infraction/fine; invasive species infraction/fine
1	▪ **Limited change to environment/ recovers immediately after remedial action** ▪ No media coverage; no regulatory fine or order	Typical pole-top/ padmount transformer spill of PCB oil or mineral oil requiring cleanup; other liquid spills requiring clean up (i.e., hydraulic oil, coolant) Minor liquid spills (mineral oil, hydraulic coil, coolant); minor environmental incidents (e.g., wood pole treatment seepage)

Figure 7: Environmental Consequence Framework

The probability scoring (set out below in Figure 8 below) assesses the likelihood of an event happening each year or during a specified period and the worst reasonable direct impact defined for the associated consequence.

Taxonomy to evaluate the probability of a failure event

Score	Frequency	OR	Expected time to event	OR	Prob. of event occurring in the next yr.	OR	Prob. of event occurring in the next 5 yr.	Example phrases you might hear during scoring
7	4+ per year		<3 months		100%		100%	This has happened 10 times every year for the last 5 years
6	1-4 times per year		3-12 months		100%		100%	Based on run time, the equipment life is over for 2 years, it will fail in the next year
5	1 every 1-3 years		1-3 years		33-100%		85-100%	We have to trench every 2 years, disturbing the habitat
4	1 every 3-10 years		3-10 years		10-33%		40-85%	We see this event about once a year on the whole system, which has 8 of these assets
3	1 every 10-25 years		10-25 years		4-10%		20-40%	This event happens on the system sometimes, and it's much more likely to happen here
2	1 every 25-100 years		25-100 years		1-4%		5-20%	This would happen on an APD (abnormal peak day), a 1/90 year event
1	Less than 1 every 100 years		>100 years		0-1%		0-5%	This has never happened, would be unexpected and an outlier

Figure 8: Probability Framework

The risk assessment process emphasizes fact-based and quantitative decision-making to the extent possible relying on historical data and experience for the purpose of making

and justifying a particular assessment decision. The risk assessment is a key component to the Prioritization process, with further reviews occurring through the Challenge process, including consideration of the total risk exposure.

1.7.3.1.1 FLAGGING

Hydro One utilizes a "flagging" process to account for special considerations and to ensure stakeholder perspectives are included in the evaluation of investments. Except for mandatory considerations, flags are not used to determine investment priority.

Investment considerations that cannot be quantified using the risk framework described above are captured by using qualitative flags to allow consideration of potential benefits of an investment beyond risk mitigation. In most cases, flags are used to identify mandatory investment requirements according to specific categories, described below. Non-mandatory flags are used to identify other considerations.

1.7.3.1.2 MANDATORY INVESTMENTS

Mandatory flags are applied to investments that are non-discretionary, as risk-based scoring cannot capture all relevant considerations. These mandatory investments address requirements and obligations that must be met, and a "do nothing" alternative would not satisfy the underlying requirement. The process is intended to reduce the number of proposed investments that are considered mandatory and foster a more effective discussion of what should be completed.

The following outlines what constitutes a mandatory/non-discretionary investment for the purpose of investment planning:

- Immediate risk to reliability, environment or safety
- Immediate / Short-term Compliance – Mandated obligation to a regulatory agency or regulatory requirement, including mandatory reliability standards or requirements established by standards authorities such as NERC, NPCC, the IESO, or the OEB
- Third party requests/direction – Transmission or distribution work, where explicitly requested, recommended or directed, by a governmental authority, to be

performed by Hydro One and/or in relation to Hydro One's transmission or distribution system, as applicable, and/or with a risk of non-compliance with transmission and distribution licences and other regulatory obligations.

  - This includes work required to connect new load, connect generation, address equipment loading or voltage/short circuit stresses when rated capacities are exceeded, or complete transmission work that Hydro One is required by its licence to develop and seek approvals for as well as investments recommended in IESO bulk system or regional planning reports and studies or a provincial government-approved plan, required to achieve provincial government objectives prescribed in directives or regulations, including but not limited to where such investment is the subject of an IESO hand-off letter or similar, Ministerial Directive or Order in Council declaring such investment to be a priority transmission project.

- Contractual – Contractual commitments with third parties for services such as IT support, or facility leases.
- In-Flight – Project already under construction.

Based on the foregoing, these investments are considered mandatory and are prioritized ahead of discretionary investments:

- All Transmission and Distribution System Access investments;
- All Transmission System Service investments; and
- Some Distribution System Service, Transmission and Distribution System Renewal, and General Plant investments that meet one or more of the mandatory criteria described above.

Other investments are considered discretionary/non-mandatory or not time-critical and are prioritized relative to one another through the process steps that follow.

1.7.3.2 CALIBRATION

Hydro One has implemented enterprise-wide calibration sessions to ensure that scoring is comparable across different types of investments. Once candidate investments have been scored and flagged, the scores are reviewed in calibration sessions. The calibration sessions bring planners and management from across the organization together to

compare approaches, assumptions and quality of data used in scoring investments. The sessions ensure that the scoring process is done consistently. After the session, investment owners have an opportunity to revise their scores based on feedback received.

1.7.3.3 PRIORITIZATION AND OPTIMIZATION

The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments, which provides consistency across the organization. The conversion is completed using a risk matrix, as presented in Figure 9 below, and total risk mitigated is calculated by summing the risk score for each taxonomy (i.e., safety, reliability, environmental). To more effectively differentiate between the risk levels of investments with similar consequences and probability scores, Hydro One uses a logarithmic scale to assign risk scoring points.

Risk score (risk unit)

Consequence								
	7	900	4,200	12,000	36,000	100,000	400,000	1,000,000
	6	430	1,900	5,000	17,000	50,000	200,000	500,000
	5	170	800	2,100	7,000	20,000	80,000	200,000
	4	60	280	800	2,400	7,000	28,000	70,000
	3	20	80	230	700	2,200	8,000	20,000
	2	4	20	50	150	460	1,700	4,200
	1	1	3	10	30	90	350	800
		1	2	3	4	5	6	7
		Probability						

Figure 9: Risk Matrix

Based on the risk scores and cost estimates associated with each investment, candidate investments are ranked according to risk mitigation achieved per dollar or the risk-spend efficiency.

1.7.3.4 CHALLENGE SESSIONS

Challenge sessions are facilitated discussions to (i) review an integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g., strategic or productivity investments), (iii) assess and debate investments on the margin of the funding decision, and (iv) make trade-off decisions based on facts.

Challenge sessions are designed to provide a fact-based and structured approach to define the funded investments portfolio, with the focus on ensuring that the most valuable work is included in the plan. The discussions allow for the merits of an investment to be considered from both risk and non-risk perspectives. Challenge sessions are attended by various levels and types of stakeholders, which provide for execution feasibility and strategic alignment considerations.

Initial challenge sessions are held to identify investments that should be funded considering factors related to risk mitigation, productivity and non-risk parameters. The output is a funded investment portfolio, which is subsequently reviewed by portfolio owners and members of the executing lines of business. Additional and final challenge sessions are then held to confirm final trade-offs.

1.7.3.4.1 TRADE-OFF DECISIONS

As part of the challenge sessions, trade-off decisions assess which investments should be promoted or demoted based on the following levers:

- Risk: Is Hydro One comfortable with the remaining risk? Are there unfunded investments which mitigate large risks? The focus on total and absolute risk exposure provides a cross check that all critical and major risks are being addressed as part of the plan to augment prioritization based on risk-spend efficiency.
- Flags (non-risk parameters): Are there non-risk factors which need to be considered?
- The consideration of both ‘risk spend efficiency’ (i.e. risk mitigated per dollar) and mitigated risk supports the making of prudent and data-driven trade-off decisions.

1.7.3.5 ENGAGEMENT

Following the development of the draft portfolio of investments, the draft plan is subject to two types of engagement. Internally, an enterprise engagement process is undertaken to incorporate further execution considerations. In the case of investments to be included in regulatory applications, the Draft Plan is included in the second phase of customer engagement to solicit customer feedback on specific investment decisions. The results of both engagement activities are considered in the development of the final plan.

1.7.3.5.1 ENTERPRISE ENGAGEMENT

The enterprise engagement process is held to ensure that the investment plan is properly reviewed by the executing lines of business. The goal is to create an executable and up-to-date investment plan. This process incorporates operational and execution considerations such as resourcing, material availability and outage feasibility. Candidate investments are updated with the latest cost forecasts, schedule, and scope. Enterprise review also identifies investment definition milestone stages to monitor the investment and identify challenges early in the process.

Adjustments may be made to reflect emerging execution or asset management risks based on discussions during enterprise engagement sessions.

1.7.3.5.2 CUSTOMER ENGAGEMENT

To identify customer needs and preferences in preparation for its 2028 – 2032 investment planning process and this Application, Hydro One engaged Innovative Research Group (IRG) to develop and conduct a customer engagement study – see SPF Section 1.6. IRG employed a two-phased approach which allowed Hydro One to develop and finalize investment plans that are informed by customer input and have been refined based on specific investment trade-offs to achieve outcomes valued by customers

Phase I of the IRG Study focused on customers' general needs and outcome preferences for the electricity system. Customers expressed high levels of satisfaction with the electricity service they receive and identified reasonable rates and reliable electricity as

the top priorities across all customer segments. C&I, LDA, and other LDC Residential customers also indicated meeting growing electricity demand as a top priority.

While reasonable and affordable rates are generally of importance to customers, customers indicated that they generally value and are willing to pay for investments that maintain or improve performance on reliability, resiliency, enabling economic growth and system visibility where costs for these benefits are within the directional bill impacts provided.

In Phase II of the IRG Study, three investment scenarios were presented to customers, representing trade-offs that Hydro One has within its investment plan. These scenarios considered the customer feedback collected in Phase I:

- **Scenario 1: Spend Less / Slower Pace –** prioritizes lower cost/managing rate impacts, by deferring investments to a future rate period, and thus resulting in higher system risk
- **Scenario 2: Draft Plan –** balances needs of system, assets, customer preferences and rates, allowing Hydro One to keep pace with and/or improve assets condition and performance while managing costs
- **Scenario 3: Spend More / Accelerated Pace –** responds to the needs of the system and assets, and delivers the outcomes prioritized by customers, allowing Hydro One to invest more; costs under this plan are higher but long-term risk is lower because of accelerated investment

Phase II gave customers an opportunity to provide feedback on Hydro One's investment scenarios, including specific investment trade-offs. In respect of distribution, transmission and shared services, customers were presented with investment trade-offs relating to the following areas and objectives:

- Distribution: (i) overall system reliability; (ii) managing the impacts of severe weather; and (iii) targeted reliability;
- Transmission: (i) keeping pace with transmission renewal; and (ii) stewardship of transmission system; and

- Shared Services: (i) maintaining buildings and facilities; and (ii) information technology.

In respect of the above areas, customers were generally given options to choose between spending at the level of the draft plan, higher than the plan, or lower than the plan, with associated impacts on outcomes.

As stated in the IRG Overview Report (see SPF Section 1.6): "Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans."[3] Depending on customer type, between 68% to 88% of customers support spending at or above the level of investment included in the plans.[4] Similar levels of support were observed for categories of investments in the transmission and distribution systems, as well as shared services.[5]

Phase II demonstrated that customers are willing to accept rate increases in exchange for prudent investments in the distribution and transmission systems. Some differences exist between customer segments regarding the specific level of investment, and corresponding bill impact, they prefer.

Hydro One's planners used the Phase I and II customer feedback, summarized in the tables below to revise and finalize the proposed investment plans. For further details on Phase I customer feedback, Phase II trade-offs and customer feedback, see SPF Section 1.6.

[3] IRG Overview Report p. 2.
[4] IRG Overview Report p. 13.
[5] IRG Overview Report p. 14-17.

Table 2 - Distribution Outcomes Supported by Customer Feedback

Segment	Outcome	Customer Input
Distribution 	**Phase I**	
	Connections and Growth Requirements for timely access and grid service Proactive investment to enable anticipated growth and accommodate new connections and service upgrades in a timely manner	A near majority of customers support proactive investments to enable anticipated growth and accommodate new connections.
	Phase I and II	
	Overall System Reliability Investments in overall system reliability included repairing or replacing overhead line defects, maintaining, repairing, or replacing major stations' equipment, and replacing or repairing underground cables.	A majority of customers want Hydro One to make investments to: • Improve or maintain current levels of reliability related to the distribution grid. • Make the system more resilient to severe weather, with a plurality wanting proactive investment. • Target reliability improvements for customers with significantly poorer reliability. Across all customer types, a majority or near majority of customers selected Hydro One's draft plan level of spending as it relates to distribution investments in overall system reliability, managing severe weather, and targeted reliability improvements
	Manage the Impacts of Severe Weather Investments in managing the impacts of severe weather included relocating or reinforcing vulnerable power lines, clearing of overhead trees and brush, and installing automated "intelligent" switches.	
	Targeted Reliability Investments in targeted reliability improvements included community-scale batteries and smaller individual customer batteries.	

Table 3 - Transmission Outcomes Supported by Customer Feedback

Segment	Outcome	Customer Input
Transmission 	**Phase I**	
	Connections and Growth Provide timely access and grid service	Meet mandated requirements for system access and system service.
	Phase I and II	
	Keeping Pace with Transmission Renewal Investments in keeping pace with transmission renewal included replacing major transmission station equipment and replacing high-impact underground transmission cables.	A majority of customers want Hydro One to make investments to either increase or maintain current levels of reliability related to the transmission grid. Across all customer types, a majority or near majority of customers selected Hydro One's draft plan level of spending as it relates to transmission investments in keeping pace with transmission renewal, and stewardship of the transmission system.
	Transmission System Stewardship Investments to replace overhead conductors and wood poles and extending the life of steel towers and clearing overgrowth trees and brush.	

Table 4 - Shared Services Outcomes Supported by Customer Feedback

Segment	Outcome	Customer Input
Shared	**Phase I and II**	
	Maintaining Buildings and Facilities Investments in maintaining buildings and facilities included addressing at-risk building components, making at-risk sites more resilient to severe weather, and repairing or retrofitting field offices.	A majority of customers want Hydro One to make investments to • Maintain buildings and facilities and increase resiliency to severe weather. • Proactively utilize technology to accommodate customer requests and improve system visibility. Across all customer types, a majority or near majority of customers selected the draft plan level of spending as it relates to shared investments in maintaining buildings and facilities, and information technology.
	Information Technology Investments in information technology included maintaining the current state of technology systems, enhancing customer service, improving operational efficiency, and protecting the grid from both cyber and physical security threats.	

This two-phased approach allowed Hydro One to ensure the final plans for 2028-2032 are responsive to customer needs and preferences. Phase II customer feedback confirmed support for Hydro One's Draft Plan, which formed the basis of the System Plans in this Application, with adjustments in select areas described in section 1.7.5.6 below. The tables below present a summary of customer feedback and how it shows up in the System Plans.

Table 5 - Reflection of Customer Feedback into the DSP

Segment	Option	Customer Feedback	How it shows up in the plan
Distribution 	**Connections and Growth**	Requirements for timely access and grid service Proactive investment to enable anticipated growth and accommodate new connections and service upgrades in a timely manner	• Provide customers with timely access to the network through customer connection (D-SA-01) • Build out the network to enable growth (D-SS-01)
	Overall System Reliability	Improve day-to-day reliability by 2032 through a balanced program addressing overhead line defects, station transformers, underground cables, and targeted pole refurbishments.	• Replace poor condition station transformers (D-SR-04) • Replace and rejuvenate underground cable (D-SR-15). • Address priority line defects (E-03-02)
	Manage the Impacts of Severe Weather	Reduce outage risk and shorten restoration times through targeted line hardening, increased vegetation clearing, and expanded deployment of automated switches.	• Selectively strengthen vulnerable pole clusters with higher-class poles (D-SR-07) • Selectively underground vulnerable, high-consequence overhead line sections (D-SR-14) • Rebuild distribution line sections and relocate off-road assets to roadside (D-SR-10) • Modernize feeders with remote operable switches and communicating fault circuit indicators (CFCIs) (D-SS-05) • Increased vegetation management (E-03-02)
	Targeted Reliability	Improve reliability for over 10,000 customers through a balanced deployment of community-scale and individual customer batteries.	• Selectively strengthen vulnerable pole clusters with higher-class poles (D-SR-07) • Selectively underground vulnerable, high-consequence overhead line sections (D-SR-14) • Rebuild distribution line sections and relocate off-road assets to roadside (D-SR-10) • Modernize feeders with remote operable switches and communicating fault circuit indicators (CFCIs) (D-SS-05) • Increased vegetation management (E-03-02)

Table 6 - Reflection of Customer Feedback in the TSP

Segment	Option	Customer Feedback	How it shows up in the plan
Transmission 	**Connections and Growth**	Requirements for timely access and grid service	• Provide customers timely access to the network through customer connections and paced regional expansions (T-SA, T-SS)
	Transmission Renewal	Maintain the current level of transmission station and cable health by replacing the highest-risk assets and managing failure risk over time.	• Address transformers and breakers at network stations and connection stations (T-SR-01, 02, 03). • Invest in replacement of underground cables (T-SR-16)
	Transmission Stewardship	Lowers the risk of equipment failure and severe weather through balanced investment in line renewal, structural asset stewardship, vegetation management, and system monitoring.	• Renew poor condition overhead lines (T-SR-13). • Replace and refurbish wood poles (T-SR-04) and steel towers (T-SR-05). • Carry out proactive vegetation management (E-02-02).

Table 7 - Reflection of Customer Feedback in the GSP

Segment	Option	Customer Feedback	How it shows up in the plan
Shared	**Maintaining Buildings and Facilities**	Maintains buildings and facilities by addressing some at-risk building components, increasing resiliency, and repairing or retrofitting facilities.	• Address at-risk building components (G-GP-03). • Increase resiliency for at-risk sites (G-GP-03). • Repairing or retrofitting facilities (G-GP-04).
	Information Technology	Improves systems focused on enhancing customer service and delivering operational efficiency.	• Improve systems focused on enhancing customer service (G-GP-07). • Improve systems focused on improving operational efficiency (G-GP-05, 06, 08, 16, 26).

1.7.3.6 INVESTMENT PLAN DEVELOPMENT

The final investments are developed, incorporating internal consultation and customer feedback. Those investments incorporate the following:

- **Feedback from Phase II of Customer Engagement** – when available, incorporate customer feedback and reprioritize investments based on cost-outcome considerations.
- **Input from third party and external studies** – incorporate select recommendations from benchmarking and other studies.
- **Updated costs, schedule, and scope** – reprioritizing based on updated cost, schedule maturity, and execution feasibility.

  Updated planning assumptions – incorporate updated planning assumptions associated with latest IESO bulk studies, and re-pacing of the distribution plan.

Additional considerations in the refinement to the investment plan include updated allocation of common assets between Transmission and Distribution, and updated load forecast based on latest IESO information.

1.7.3.7 INVESTMENT PLAN APPROVAL AND DELIVERY

The draft final Investment Plan is reviewed by all levels of the organization before leadership review and approval, firstly, at the executive level and then the Board of Directors level.

Once the plan is approved, the execution team takes ownership for delivery. The plan is reviewed throughout the execution phase as new information on asset condition and risks become available. If needed, resources may be redeployed based on changing operational and business conditions.

1.7.3.7.1 INDIVIDUAL INVESTMENT APPROVAL

Individual investments are reviewed and approved, consistent with the provisions of the corporate expenditure authority register. Once approval is granted, the individual investments move to the implementation and work execution phase, delivered through the strategies discussed in TSP Sections 2.11, DSP Section 3.10, and GSP Section 4.10 for capital and E-02-05 and E-03-05 for OM&A.

1.7.3.7.2 MONITORING, CONTROL AND PERFORMANCE REPORTING

Hydro One continues to monitor the performance of the approved Investment Plan by tracking year-to-date expenditures, accomplishments, and projected year-end expenditures as well as monitoring internal and regulatory scorecard performance as outlined in SPF Section 1.5, TSP Section 2.5, and DSP Section 3.5.

1.7.3.7.3 REPRIORITIZATION

While the System Plans are developed through extensive planning, analysis, and engagement, Hydro One must retain flexibility during implementation to respond to new information and changing circumstances. Plan adjustments may be required where customer-driven projects change, new customer requests emerge, cost estimates or execution assumptions are updated, approved projects or programs vary in pace or scope, policy and regulatory considerations evolve, or because of a regulator decision. In these circumstances, Hydro One may need to add previously unplanned investments,

accelerate or defer planned work, or reallocate resources within the portfolio to continue meeting its obligations efficiently and effectively.

Reprioritization applies the same planning, review, and approval principles described in this Exhibit to ensure that any adjustments to the System Plans are made consistent with Hydro One's risk-based investment planning framework, and in a manner that supports effective pacing of work across the plan period.

Reprioritization is assessed separately within the transmission and distribution portfolios, consistent with the separate planning, prioritization, and approval processes for each segment. General Plant investments are assessed on an integrated basis and resulting changes may affect both transmission and distribution segments. Where plan adjustments are required, Hydro One communicates the proposed changes to the relevant internal stakeholders for review and coordination.

SECTION 1.8 – SPF – MANAGING MARKET COST PRESSURES

1.8.1 INTRODUCTION

This section describes the persistent and materially higher inflation and cost pressures that have affected the utility sector since 2020.

Substantial inflation began to materialize during Hydro One's prior rate application (EB-2021-0110) causing Hydro One to update its Capital and OM&A envelopes for actual and forecasted inflation, which were reflected in the OEB-approved Capital and OM&A envelopes. However, higher and sustained industry inflation continued above Hydro One's inflation forecasts for the 2023-2027 period as substantiated by Handy-Whitman indices, which measure construction cost trends for utility functions, Statistics Canada's product price indices which reflect broad electrical equipment market pricing, and Hydro One's procurement experience purchasing electrical equipment and materials.

This section is organized as follows:

- **Industry-Wide Inflation Impacts:** Over the historical and bridge period, utility industry inflation trends have materially exceeded the levels reflected in both Hydro One's forecasts and in the OEB inflation factor used to adjust the company's rates over the historical and bridge period. This overall inflationary trend is described in Section 1.8.2.
- **Inflation Impacts on Critical Hydro One Equipment and Materials:** The cost of key equipment and materials necessary for Hydro One's investment plans has significantly exceeded even the generally heightened price inflation in the historical period. The prices of certain categories of critical equipment, like high-voltage circuit breakers, have increased by an average of 140% since 2020. These costs are described specifically in Section 1.8.3.
- **Hydro One's Management of Inflation:** Hydro One has actively managed these cost pressures in various ways, including i) leveraging its supply chain process, ii) challenging internal lines of business to deliver significant productivity and cost savings, and iii) prioritizing investments while deferring work as necessary to manage capital and OM&A expenditures within OEB-approved envelopes. These

cost management strategies and the results achieved are summarized in Section 1.8.4.

- **Impacts of Inflation on Hydro One's 2028-2032 Investment Plans:** As described in Section 1.8.5, the investment plans in this application reflect the material and sustained cost escalation that Hydro One and the broader utility sector has experienced over the historical period (until year-end 2025) and work that was deferred to manage towards OEB-approved capital and OM&A funding envelopes.

1.8.2 INDUSTRY-WIDE INFLATION IMPACTS

Since 2020, inflation in the utility sector has risen at a higher rate than the general economy.

Substantial inflation increases began to materialize during Hydro One's prior rate application (EB-2021-0110), causing Hydro One to update its Capital and OM&A envelopes to reflect actual inflation in 2021 (3.5%), forecast inflation in 2022 (4.5%), and forecast inflation in 2023 (3.3%).[1] An inflation assumption of 2.0% was used for the 2024 through 2027 capital forecast. These inflation assumptions were then reflected in the OEB-approved Capital and OM&A envelopes and are shown in Figure 1 below (Prior Application Assumption).

Higher and sustained inflation continued above the Prior Application Assumption in the current rate period, with significant increases in the cost of key electrical equipment and materials. Neither the Prior Application Assumption, nor the OEB inflation factors[2] have kept pace with the actual costs that Hydro One and other utilities have experienced during this period.

[1] EB-2021-0110, Exhibit O-01-02, p. 8-9, filed 2022-03-31.
[2] The OEB Inflation Factor is a weighted sum of the GDP-IPI (FDD) and the Average Weekly Earnings (AWE) for workers in Ontario, as reported by Statistics Canada. These factors lag by two years.

These trends are consistent with expert observations on utility costs during the historical period. In the 2025 Total Cost Benchmarking Survey issued by Pacific Energy Group (PEG) on behalf of the OEB, PEG similarly observed:

> unusually rapid inflation in the construction costs of US-based distributors in the years since the pandemic. For example, the Handy Whitman Indexes of Power Distribution Construction costs in the North Atlantic region of the United States have risen drastically in recent years. The summary index for distribution plant in July 2023 was 52% higher than it was in July of 2019 and the line transformers were 86% higher.[3] [emphasis added]

Handy-Whitman indices are widely used throughout the U.S. utility industry as a measure of construction cost trends for utility functions in different regions of the United States.[4] For Capital expenditures, Hydro One has shown the North Central region indices for Distribution (HW-Dx) and Transmission (HW-Tx) in Figure 1 below.[5] These indices follow the same pattern as Handy-Whitman's other indices across the United States as they are mostly based on similar prices for Distribution and Transmission inputs and are representative of Hydro One's market and costs. The North Central region is shown as it includes two out of three interconnections between Ontario and the United States (Michigan and Minnesota), while the North Atlantic region (referenced by PEG above) includes the other interconnection (New York).

Figure 1 shows the impact of inflation on a hypothetical $100 of capital expenditures starting in 2020 (the base year of cost estimates in Hydro One's prior rate application). Applying the Prior Application Assumption for inflation results in a modest increase to $116 (or 16% increase) by year-end 2025.

[3] Preamble to question B4 in the Construction Cost section of the PEG TCB Survey, issued May 6, 2025.
[4] Handy-Whitman data provided by S&P Global (formerly IHS Global Insight).
[5] Not adjusted to Canada: US exchange rates or tariffs.

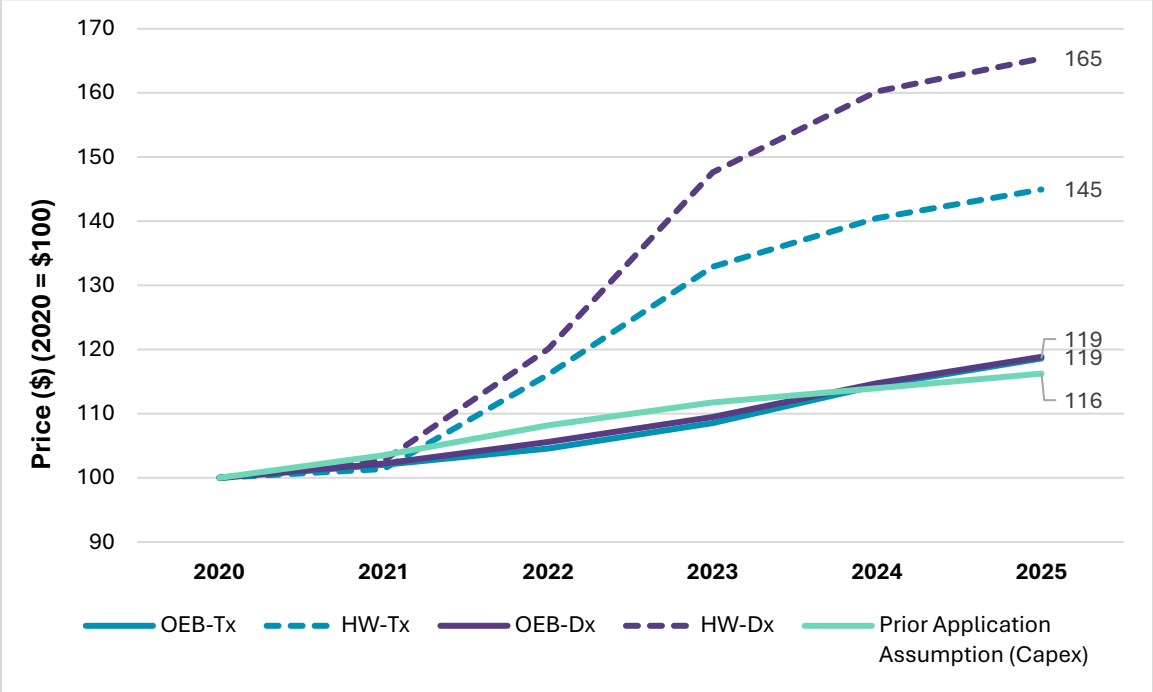


Figure 1: Capital-Related Inflation vs Hydro One's Prior Application Assumption

However, the inflation assumed in the prior application was lower than the published OEB inflation factor, and substantially lower than the Handy-Whitman indices (HW-Dx, HW-Tx). These latter indices most closely reflect the inflationary challenges that Hydro One has faced since 2020, and the degree to which utility-related inflation has exceeded the level reflected in rates over the historical period. While this difference is significant for Transmission, it is even greater in the Distribution context, in which $100 in 2020 has escalated as high as $165 by 2025 year-end, an increase of 65% in five years.

Similarly, Clearspring Energy Advisors, an independent energy consulting firm, observed that Handy-Whitman indices have grown significantly faster than the OEB's inflation factor over both the long term (by an average difference of 3.9% [Distribution] and 2.3% [Transmission] per year over the past two decades) and, even more sharply, since 2020 (by an average difference of 7% [Distribution] and 4.1% [Transmission] per year).[6] This widening capital inflation differential means that even if future annual asset-price inflation

[6] Exhibit A-04-01 Attachment 1, Clearspring Energy Advisors, Benchmarking, Productivity, and Incentive Regulation Parameter Study, p. 15 -16.

moderates, the elevated replacement cost of long-lived utility assets will continue to be higher than what the OEB's inflation (I) minus productivity (X) formula provides, is beyond the control of utilities, and will affect Hydro One's future capital forecasts.[6]

The significant and sustained inflation reflected in the Handy-Whitman indices is also evident in Statistics Canada's product price indices (PPIs) for broad categories of electrical equipment, including transformers, circuit breakers, and wire and cable equipment. From 2020 to 2025, these PPIs showed materially higher inflation increases ranging from 67% to 80%, compared to 19% for the OEB's Inflation factors and 16% for Hydro One's Prior Application Assumption, as shown in Figure 2.

While these PPIs confirm the elevated inflation in broader electrical equipment market indices, they do not reflect what the consumer pays. The PPIs exclude indirect taxes, such as sales taxes and tariffs, and all costs that occur between the time a good leaves the plant and the time the final user takes possession of the good. For these reasons, while the PPIs also show material increases, they are not directly comparable to Hydro One's specific equipment price increases summarized in Table 1, which shows the more acute final cost pressures affecting electrical equipment being procured.

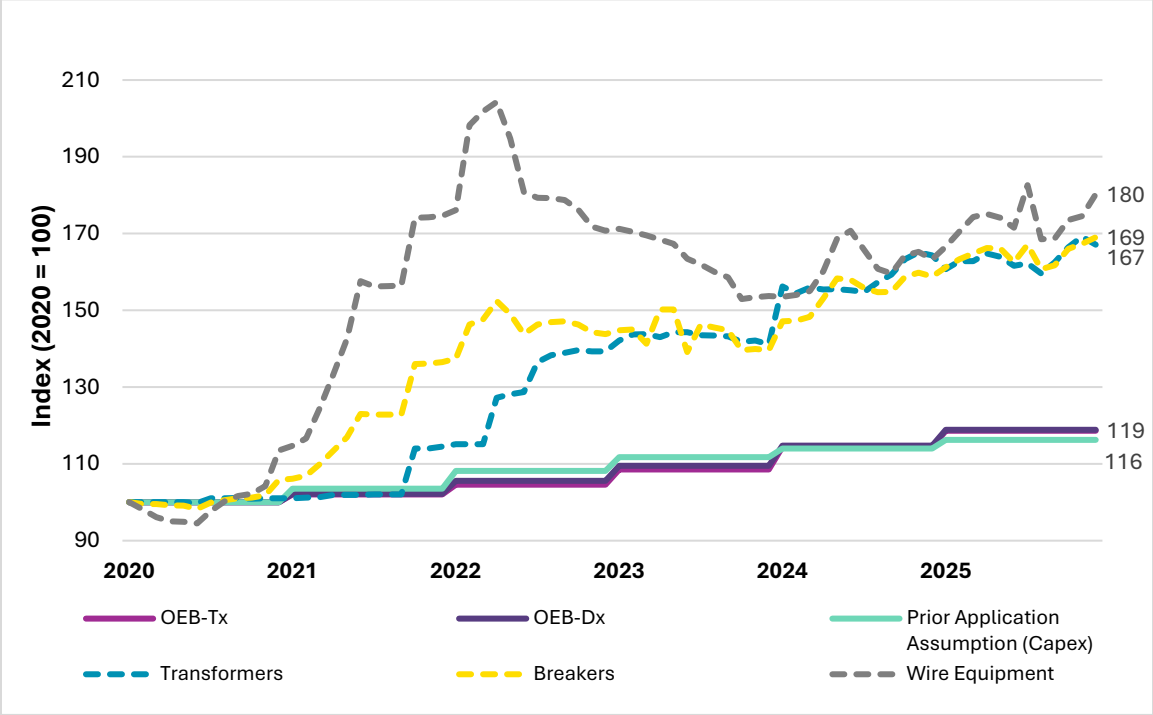


Figure 2 - Product Price Indices vs Hydro One's Prior Application Assumption

1.8.3 INFLATION IMPACTS ON CRITICAL HYDRO ONE EQUIPMENT AND MATERIALS

Since 2020, Hydro One has experienced material and sustained cost escalation across key equipment and materials required to deliver its transmission, distribution, and general plant work programs. These cost increases reflect broader utility-sector market conditions and are not isolated to a single procurement category. Rather, they are the result of various factors including supply-chain disruptions, constrained manufacturing capacity, rising commodity prices, tariffs, and increased demand for grid equipment.

The most significant pressure has been in equipment and materials such as power transformers, breakers and conductors that are highly exposed to global supply chains, and commodity inputs like steel, copper, and aluminum. Global supply chains have been strained by the rapid growth in demand for power equipment, as governments and utilities pursue system expansion to support load growth (including electrification and renewable generation), system renewal to replace aging power equipment, and grid modernization, as well as demand driven by customers seeking larger and more complex connections.

This demand has created a supply-demand imbalance for the equipment Hydro One regularly procures and has resulted in higher prices, longer lead times and shorter quote validity periods. These imbalances and pressures have been exacerbated by constrained manufacturer capacity, global conflicts that have altered supply chains and/or impacted freight costs, and the volatility of domestic and foreign tariffs being imposed on the commodities used to manufacture equipment and the finished equipment that Hydro One procures.

Since 2025, the trade environment between Canada and the United States has become increasingly volatile, with both countries implementing multiple rounds of tariffs and counter-tariffs targeting goods, commodities like steel, aluminum, copper and lumber, and products made from these commodities. These measures, ranging from 15% to 50%, depending on product classification, directly and indirectly affect utility supply chains because electrical equipment like transformers, conductors, circuit breakers, and transmission structures rely heavily on these commodity inputs sourced through complex global manufacturing networks. Direct exposure occurs on goods purchased from U.S. suppliers that are subject to Canadian import tariffs and indirect exposure is introduced through tariffs charged to suppliers. As tariff costs make their way through the supply chain, suppliers face higher material costs and increasingly seek to recover those costs through price increases, surcharges, escalation provisions and higher bid prices. Although Hydro One is actively managing this emerging issue, the evolving tariff environment creates new cost uncertainty that cannot be reliably predicted.

Wood Mackenzie, a leading research and consultancy business, has observed these supply chain and tariff impacts. Wood Mackenzie found: i) key transmission and distribution equipment types falling from a slight market surplus in 2020 to a significant shortage in 2025 (and expects this market shortage to continue throughout 2030), ii) increased demand for transformer and switchgear from electrification and load growth projects including data centers and commercial facilities that are intensifying pressure on

supply chains that are already operating at capacity, and iii) new tariffs are increasing market pricing.[7]

Similarly, Concentric Energy Advisors, a management consulting and economic advisory firm, referenced observations from the Canada Electricity Advisory Council that transmission transformers have seen a drastic increase in both procurement lead times and prices, that SaskPower faced a tripling of timelines for expected delivery of Neutral Grounding Transformers, a price increase of more than 50 percent and even higher costs for more complex units.[8]

Commodity inflation has been another driver of utility equipment cost increases. Key inputs for utility equipment, including steel, copper, aluminum, plastics, fuel, and chemicals, have experienced significant price increases since 2020. These commodity inputs represent a substantial portion of the manufacturing cost for transformers, circuit breakers, conductors, cables, vehicles, and other critical equipment. As these input costs increased, suppliers incorporated them into the cost of the equipment Hydro One purchases, either through update mechanisms in contracts or as legacy contracts expire and new contracts reflect current (higher) market pricing. Commodity inflation has also impacted fuel costs, increasing the cost to transport and deliver equipment and services.

While Hydro One sources some equipment such as distribution transformers from Canadian manufacturers to support the domestic industry and to help ensure supply reliability, domestic procurement does not insulate prices from global commodity markets and other market forces. Canadian manufacturers sell into global markets and depend on global commodity markets and international supply chains, meaning that global cost pressures inevitably flow into domestic pricing.

Beyond power equipment, Hydro One has also experienced material and sustained cost escalation in technology-related goods and services. These pressures include higher costs for enterprise software licensing, vendor support, managed services, cybersecurity

[7] Exhibit E-05-01 Attachment 2, Wood Mackenzie Supply Chain Practices Report, p. 23-25.
[8] Exhibit F-01-01 Attachment 1, Concentric Cost of Capital Study, p. 24.

capabilities, cloud services, advanced analytics, and other grid-enabling technologies. As reflected in Table 1, observed increases for information and operational technology ranged from approximately 9% to 90%.

These increases reflect broader market conditions affecting the technology sector, including increased cybersecurity requirements, higher baseline support costs, and a competitive labour market for specialized technology skills. Demand for expertise in cybersecurity, cloud services, advanced analytics, operational technology, and other grid-enabling capabilities has intensified across the utility sector and other infrastructure-critical industries, contributing to upward pressure on both external service costs and internal costs.

Within the broader portfolio of equipment, materials and services procured by Hydro One, Table 1 summarizes the observed cost increases for key equipment and materials, and services that are sourced to support Hydro One's work programs. The increase for each category is based on the average price increase of materials in the category weighted by actual annual expenditure. In some categories, increases since 2020 have reached as high as 140% on average.

Table 1 - Hydro One Equipment/Service Price Increases Since 2020

Material and Services Category	Average Increase	Application
Power Transformers	115%	These transformers are used across the Transmission and Distribution system
Distribution Transformers (<2.5 MVA)	40%	These transformers perform the final step-down to utilization voltages for end-use customers.
High Voltage Circuit Breakers	140%	These breakers are located in transmission stations and operate to isolate/deenergize transmission lines.
Conductor, Cables, and Wires	65%	Conductors, and submarine and underground cables transport electricity across the province.
Transmission and Distribution Poles	45%	Poles hold the conductors that transport electricity across the province. Generally, Hydro One uses wood poles however steel and composite poles may be used.
Vehicles	35%	Pickup trucks, and specialized line and service trucks are the backbone of the fleet and are essential for daily operations to move staff and equipment to job sites. These vehicles often require custom bodies, upfitting, and specialized components.
Information and Operational Technology	9% to 90%	This includes hardware and software such enterprise software licensing, vendor support, and managed services and are essential for daily operations

Since 2020, a portfolio of key materials routinely purchased by Hydro One representing $400M in annual spend has increased by approximately 75% to $700M a year by the end of 2025.[9] These sustained cost escalations, consistent with inflationary impacts observed across the utility industry, have been driven by a convergence of the factors described above, including supply chain disruptions, elevated energy costs, and the increase in commodity costs for critical inputs such as steel, copper, and aluminum.

[9] Hydro One annually procures over $1B in materials that flow through its procurement processes of which $700M or 70% of annual material procurement relate to routinely purchased materials. The balance of material procurement ($300M) is related to un-catalogued, engineered-to-order materials or low volume catalogued materials.

1.8.4 HYDRO ONE'S MANAGEMENT OF INFLATION

Overall, Hydro One's 2023-2027 experience demonstrates that cost pressures have been broad-based, material, and sustained. However, Hydro One has not been a passive recipient of these conditions.

As described below, Hydro One has taken proactive steps to manage cost pressures including i) leveraged its supply chain process, ii) challenged internal lines of business to deliver significant productivity savings and iii) prioritized investments important to our customers while managing Capital and OM&A expenditures towards the OEB-approved envelopes.

1.8.4.1 LEVERAGE SUPPLY CHAIN

Hydro One procures materials and services through a structured framework of policies and procedures designed to deliver productivity, maximize buying power, improve service levels and foster innovation while building supplier relationships necessary to control costs and maintain a secure supply chain.

Hydro One's large and growing work program – and the specialized, engineered-to-order, equipment needed to deliver it – requires sourcing strategies that deliver value, as well as capacity and continuity of supply. To that end, Hydro One utilizes multi-year contracts, indexed pricing, and multi-supplier strategies to provide sourcing resilience and flexibility, and to minimize pricing volatility and supply disruptions.

Hydro One's procurement management practices are described in further detail in Exhibit E-05-01 (Procurement Management). Hydro One's sourcing practices were evaluated by Wood Mackenzie, a leading research and consultancy business (see Exhibit E-05-01 Attachment 2, Wood Mackenzie Supply Chain Practices Report). Wood Mackenzie found:

- Hydro One demonstrates strong governance and disciplined sourcing practices under volatile market conditions;
- Indexed pricing mechanisms and a diversified supply base have aligned with best practices to effectively manage price increase requests;
- Procurement and engineering collaboration supports proactive planning and operational stability; and
- Sourcing plans are tightly aligned with capital investments and capacity needs.

In respect of recent trade tariffs discussed in section 1.8.3, Hydro One continues to proactively seek alternative sources for materials and equipment subject to direct tariffs, and to work with suppliers to mitigate their upstream tariff exposure: particularly where U.S. inputs can be replaced with viable Canadian alternatives, and requiring suppliers to demonstrate mitigation efforts before tariff-related increases are considered. Hydro One is also working with peer utilities across Canada to aggregate demand and encourage manufacturers to establish new domestic capacity, thereby reducing Canadian utilities to some tariff exposure.

Hydro One has also taken proactive steps to manage vendor-driven cost pressures while maintaining the service levels, operational reliability, and regulatory compliance required to support safe and reliable utility operations. For example, the Digital & Technology Services (DTS) function worked with vendors to optimize contract scopes by removing non-essential features or usage tiers, and renegotiated service levels, and consolidated overlapping services, thereby reducing technology-related costs. Applying this approach in respect of services provided by IT vendors resulted in forecasted savings as discussed in Exhibit E-04-04.

1.8.4.2 ACHIEVED PRODUCTIVITY SAVINGS

Hydro One's productivity program is a key corporate initiative which finds efficiencies within the annual OM&A and capital work programs. Hydro One targets annual productivity achievements with the goal of reducing costs while achieving the same output or accomplishing more work for a similar cost.

Notwithstanding the material and sustained cost pressures Hydro One has experienced, internal lines of business continue to challenge the status quo and explore improved ways of working by modernizing work practices to deliver efficiency and savings to partially offset external cost pressures. For example, Hydro One Transmission optimized crew sizing while maintaining productivity and safety, and Distribution increased wood pole refurbishments where possible instead of completing more costly full pole replacements. For more information, see SPF Section 1.4 (Productivity Framework).

1.8.4.3 INVESTMENT REPRIORITIZATION

Hydro One plans and prioritizes investments through the robust framework described in SPF Section 1.7, which supports risk-informed decisions across its transmission, distribution, and general plant work programs.

Over the 2023-2027 period, Hydro One experienced a material increase in non-discretionary work while also being impacted by significant and sustained cost escalation across key equipment and materials required to deliver its work programs. These pressures included higher System Access requirements to connect both distribution and transmission customers, growing System Renewal needs driven in part by severe storm events affecting the distribution network, and increased transmission System Service work associated with IESO Bulk System and Regional planning activities.

The combination of growing demand for non-discretionary work and escalating equipment and materials costs impacted the type and amount of work Hydro One could complete within the OEB-approved capital and OM&A funding envelopes.

In response, Hydro One optimized its work programs and allocated available funding to mandatory, customer-driven, and other high-priority investments while continuing to operate towards approved funding levels. This required the deferral of work where Hydro One had flexibility over timing/scheduling. Consistent with the prioritization processes described in SPF Section 1.7, Hydro One focused resources on the most critical assets and highest-value investments to mitigate potential impacts and maintain customer and system outcomes. For further information about the reprioritization of work in the 2023-

2027 period see TSP Section 2.9, DSP Section 3.9 and GSP Section 4.9 for capital and Exhibit E-02-01 (Transmission), E-03-01 (Distribution) and E-04-01 (Common) for OM&A.

1.8.5 IMPACTS OF INFLATION ON HYDRO ONE'S 2028-2032 INVESTMENT PLANS

The significant cost inflation that Hydro One and the broader utility sector experienced since 2020 has proven to be sustained, rather than temporary. Hydro One has continued to update project cost estimates to reflect market prices for materials and equipment, including power transformers, breakers, conductors, vehicles, and other critical inputs. These updated costs, which reflect the inflation of recent years until year-end 2025, now form the basis of the assumptions underlying Hydro One's 2028-2032 investment plans.

To manage towards OEB-approved capital and OM&A funding envelopes, Hydro One deferred certain investments during the 2023-2027 period where timing flexibility existed. While these deferrals were necessary, the underlying deferred work remains prudent and required. Accordingly, this work has been incorporated into the 2028-2032 plan and prioritized through the asset management process described in SPF Section 1.7.