SECTION 1.0 – SPF – INTRODUCTION TO THE SYSTEM PLANS FRAMEWORK

1.0 THE SYSTEM PLANS

The sections contained in this Exhibit form Hydro One's consolidated five-year system plans for the 2023 to 2027 planning period. The Transmission System Plan (TSP), Distribution System Plan (DSP), and General System Plan (GSP) collectively comprise the System Plans.

On March 16, 2018, the Ontario Energy Board (OEB) issued a letter setting out its expectations regarding future distribution applications for electricity rates and transmission revenue requirement applications by Hydro One. The letter directed Hydro One to file a transmission revenue requirement application for a four-year period from 2019 to 2022, to facilitate the filing of a joint transmission and distribution application for the planning period.

The System Plans have been prepared in accordance with the Chapter 2 Filing Requirements for Electricity Distribution Rate Applications (June 24, 2021), the Chapter 2 Filing Requirements for Electricity Transmission Applications (February 11, 2016) and the Chapter 5 Filing Requirements for Consolidated Distribution System Plans (June 24, 2021), 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.

The System Plans are organized into four chapters, as follows:

[Chapter 1] – The SPF, which is a summary of the overall planning process and drivers for Hydro One Networks, reflecting common practices, inputs and considerations reflected in each of the TSP, DSP, and GSP. The contents of Chapter 1 are as follows:

SPF Chapters – Section, Content
Section 1.0, Introduction to the System Plans Framework
Section 1.1, System Plans Framework Overview
Section 1.2, Coordination Through Regional Planning
Section 1.3, Procurement Process for Third-Party Benchmarking Reports and System Studies
Section 1.4, Productivity Framework
Section 1.5, Performance Measurement and Outcomes
Section 1.6, Customer Engagement
Section 1.7, Investment Planning Process
Section 1.8, Climate Change

[Chapters 2 – 4] – These chapters provide the TSP, DSP, and GSP, respectively. Each chapter provides an overview of Hydro One'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 subsections that detail the specific asset management and life-cycle optimization strategies for each system plan, which determine the portfolio of investments required to achieve the specific outcomes in each of the System Plans. These chapters detail Hydro One's capital expenditure plans for the 2023-2027 planning period, including factors such as asset information, benchmarking, productivity, performance management, and other capital planning drivers and considerations, including customer needs and preferences.

The culmination of these factors and inputs are the capital expenditure plans, which are the product of the investment planning process and asset management strategies described in SPF Section 1.7. 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 $3M for TSP, and over $1M for DSP. The GSP includes ISDs where the Transmission-allocated portion exceeds $3M or Distribution-allocated portion exceeds $1M during any year within the planning period.[1]

[1] Determined pursuant to Section 2.1.1 of the OEB's *Filing Requirements for Electricity Transmission Applications*, dated February 11, 2016, and Section 2.0.8 of the *Filing Requirements for Electricity Distribution Rate Applications*, dated June 24, 2021.

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SECTION 1.1 – SPF – SYSTEM PLANS FRAMEWORK OVERVIEW

1.1.1 INTRODUCTION

This is Hydro One Networks Inc.'s (Hydro One) first joint five-year Transmission, Distribution, and General Plant System Plan filing. Together, the System Plans cover a planning horizon from 2023 to 2027. Hydro One has prepared the System Plans in accordance with Section 2.4 of the Chapter 2 Filing Requirements, with further guidance from Chapter 5 of the Filing Requirements.

The System Plans are responsive to the OEB's direction, received March 16, 2018, to apply for rates for the Transmission and Distribution business segments in a single application. Although there are common elements to the System Plans, such as common shared services, general plant and corporate functions, the majority of the plans reflects the unique and distinct nature of the transmission and distribution businesses through the TSP and DSP.

Consistent with the Filing Requirements, the System Plans provide consolidated documentation concerning Hydro One's asset management process and capital expenditure plans for its transmission and distribution systems, and common support infrastructure, using a standardized approach and structure. The System Plans also provide related information about the steps Hydro One has taken to coordinate its planning with third parties, identify and take into account customer needs and preferences, as well as measure performance to support continuous improvement.

The System Plans provide comprehensive and detailed explanations of Hydro One's capital investment plans for its transmission and distribution systems in respect of the five-year planning period from 2023 to 2027.

The System Plans demonstrate how Hydro One has aligned its investment planning processes and intended outcomes with the principles and expectations articulated by the OEB in the RRF[1], namely by focusing on identified customer needs and preferences; continuous improvement in productivity, reliability and cost performance; public policy responsiveness; and financial performance.

To prepare the System Plans, Hydro One engaged its direct transmission and distribution customers, as well as the general population, and employees from across the company. Through this effort, Hydro One has carefully considered and set out its proposed investment plans over the course of the test years, with a view to ensuring its investment plans are appropriate in their focus, scope and pacing, having regard to the needs and preferences of customers, the systems, and the Company.

1.1.2 FORMAT OF THE SYSTEM PLANS

Consistent with the Filing Requirements, Hydro One's System Plans are organized into four chapters, as follows.

[Chapter 1] – The SPF, which is a summary of the overall planning process and drivers for Hydro One Networks, reflecting planning practices that are common to the System Plans, inputs and considerations reflected in each of the TSP, DSP, and GSP.

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

[1] OEB, Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.

Each of Chapters 2 – 4 contain subsections which detail the specific asset management and life-cycle optimization strategies for each segment, which determines the appropriate portfolio of investments having regard to the specific outcomes that Hydro One seeks to achieve. These chapters detail Hydro One's capital expenditure plans for the 2023-2027 planning period, including factors such as asset information, benchmarking, productivity, performance management, and other capital planning drivers and considerations, including customer needs and preferences.

The culmination of these factors and inputs are the capital expenditure plans, which are the product of the investment planning process and asset management strategies described in SPF Section 1.7. 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 \$3M for TSP, and over \$1M for DSP. The GSP includes ISDs where the Transmission-allocated portion exceeds \$3M or Distribution-allocated portion exceeds \$1M during any year within the planning period.[2]

Unless otherwise specified, the asset information contained in the System Plans is as of December 31, 2020.

[2] Determined pursuant to Section 2.1.1 of the OEB's *Filing Requirements for Electricity Transmission Applications*, dated February 11, 2016, and Section 2.0.8 of the *Filing Requirements for Electricity Distribution Rate Applications*, dated June 24, 2021.

1.1.3 RESPONSIVENESS TO OEB DECISIONS

Exhibit A-02-04 identifies the OEB's related areas of feedback and describes at a high level how Hydro One has responded to that feedback in preparing the present application. Each of these aspects is elaborated upon throughout the System Plans.

1.1.4 HYDRO ONE'S SYSTEM

Hydro One's transmission and distribution systems play a vital role in Ontario's electricity system and the customers they serve. Additional information related to the specific components of each of the transmission and distribution systems is included in TSP Section 2.2 and DSP Section 3.2 respectively.

1.1.4.1 SCOPE OF THE TRANSMISSION SYSTEM AND SERVICE AREA

The 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. A complete listing of all transmission system components is provided in TSP Sections 2.1 and 2.2. In addition to providing connections to its customer base, Hydro One's transmission system is connected with and enables the operation of all other licensed transmission systems in Ontario, including those owned and operated by Canadian Niagara Power Inc., Five Nations Energy Inc., Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP), NRP Limited Partnership, and B2M Limited Partnership. Hydro One's transmission system interconnects with transmission systems in five neighbouring jurisdictions in Canada and the United States (Manitoba, Quebec, Minnesota, Michigan and New York) and enables electricity transactions with those jurisdictions through interconnections.

Given the scope of Hydro One's transmission system and the scale of the territory that it serves, Hydro One's transmission system is deemed to be critical infrastructure for the Province of Ontario. The role of Hydro One's transmission system within the province is consistent with the definition of "critical infrastructure" that has been adopted by the Province for purposes of the

Ontario Critical Infrastructure Assurance Program, which considers such infrastructure to include "interdependent, interactive, interconnected networks of institutions, services, systems and processes that meet vital human needs, sustain the economy, protect public safety and security, and maintain continuity of and confidence in government".[3]

It is because of this critical role in Ontario's electricity system that 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 transmission system is essential to the service quality of Ontario electricity customers. Further information on the transmission system is included in TSP Section 2.1.

1.1.4.2 THE DISTRIBUTION SYSTEM

Hydro One operates and maintains power system assets associated with 992 distributing and regulating stations, which are critical to the reliable transformation and delivery of power received from the transmission system to distribution customers across the province. The distribution system employs more than 123,000 km of distribution circuits, spanning a vast area of the province with varying customer densities and regional needs such as forestry, weather patterns, and load growth. Hydro One manages distribution assets supplying electricity to customers across the province of Ontario. The distribution system delivers electricity at voltages below 50 kV from Ontario's transmission and generation systems to Local Distribution Companies, Large Distribution Accounts, Commercial & Industrial customers and nearly 1.4 million Residential and Small Business customers.

Hydro One's distribution system spans the province of Ontario, operating at a variety of voltages below 50 kV. Major distribution stations and lines components include station transformers and

[3] See https://www.emergencymanagementontario.ca/english/emcommunity/ProvincialPrograms/ci/ci.html
[4] Ontario's 2010 Long-Term Energy Plan: Building Our Clean Energy Future, p. 41.

reclosers, poles, line transformers, and conductors. A complete listing of all stations and lines components is provided in DSP Section 3.2 with additional information DSP Section 3.1.

1.1.4.3 SCOPE OF THE GENERAL PLANT SYSTEM PLAN

In addition to transmission and distribution lines and stations, Hydro One's business requires a fleet of general plant assets (including real estate and facilities, transport and work equipment, as well as information technology), which do not directly form part of the transmission and distribution systems but are critical to their function and reliability. These are assets that support the safe and reliable operation of both the transmission and distribution systems, but are not allocated entirely to either. These common assets are set out in the GSP.

The components of the GSP enable the power delivery functions of Hydro One, providing centralized operations enablement functions. These common centralized functions are supported by common facilities, transport and work equipment and information and operations technology, which are the basis of the GSP. Focus areas include Operations and Service Centres located throughout the province, which serve Hydro One's transmission and distribution businesses, provide base locations for field crews and the materials, tools and equipment they rely upon to provide maintenance and restoration services in a safe, timely, effective and efficient manner. Further, the GSP includes technology and communications sustainment and enhancements, which facilitate process reengineering, improves situational awareness in the field, and enables business efficiency. Additional information on the scope of the GSP is included in GSP Section 4.1.

1.1.5 SUMMARY OF THE SYSTEM PLANNING PROCESS

Hydro One follows a three-phase, risk-based process to identify, prioritize and optimize investments set out in the TSP, DSP, and GSP (Figure 1). The three phases of the system planning process are: (i) Strategy and Context, (ii) Asset Management, and (iii) Investment Planning.

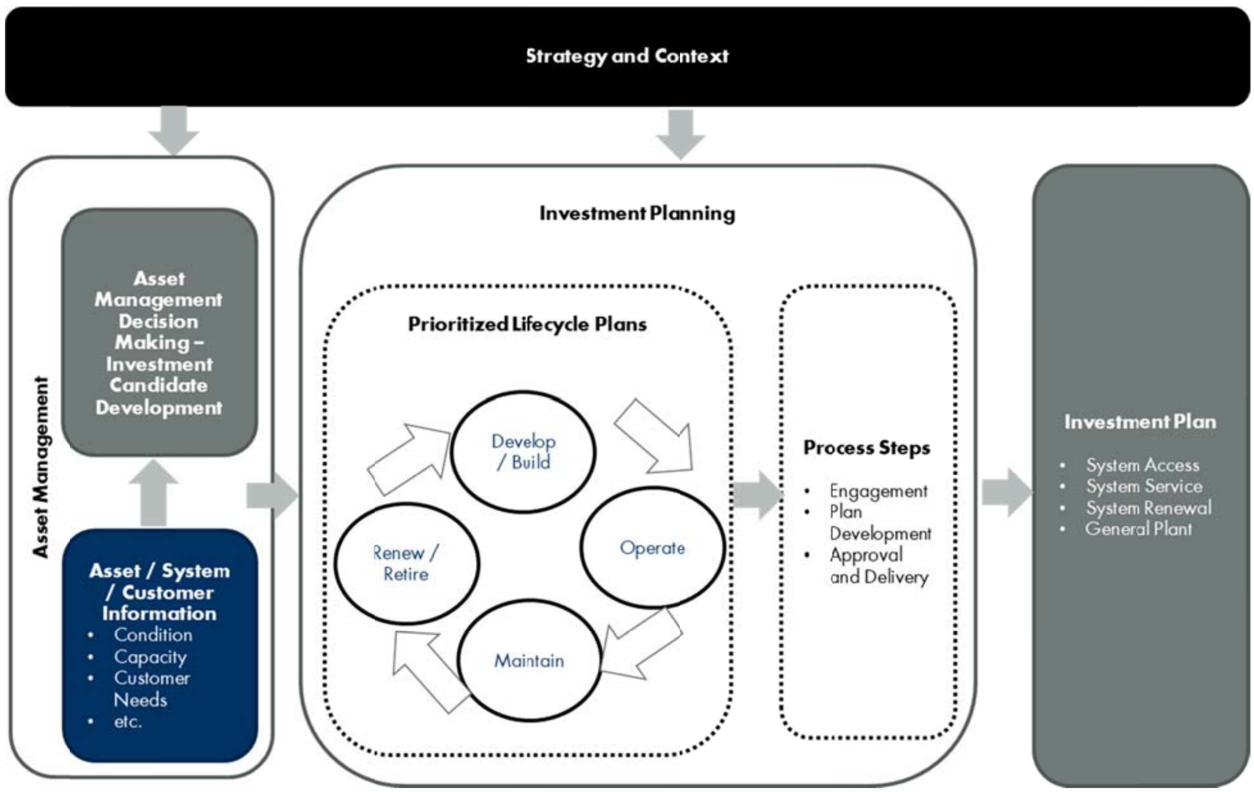

Figure 1: System Planning Process Diagram

In the Strategy and Context phase, Hydro One identifies long-term system needs within the context of Hydro One's corporate strategy, asset condition, customer needs and preferences, and customer and system load profiles. During the Asset Management phase, Hydro One assesses the current state of its assets, evaluates specific asset condition and system requirements and formulates potential options and develops a list of candidate investments. Based on the candidate investments developed in the Asset Management phase, Hydro One identifies, prioritizes and optimizes investments in the Investment Planning phase. Risk taxonomies guide the assessment of candidate investments based on safety, reliability and environmental consequences.

The System Planning Process is described in detail in SPF Section 1.7.

1.1.5.1 STRATEGIC OBJECTIVES

The investment planning process that has informed the System Plans was guided by a list of strategic priorities, as outlined in Figure 2.

Figure 2: Hydro One's Strategic Priorities

These strategic priorities and objectives, together with the guidance provided by the OEB's policy framework, in particular, customer engagement, helped inform the investment plans that are included in the System Plans. Moreover, there is close alignment between the Company's priorities and objectives and the themes and outcomes that the OEB has articulated through its policy framework, discussed below.

1.1.5.2 POLICY FRAMEWORK

In the System Plans, Hydro One alignments with the policy framework established by the OEB through the RRF and related guidance. In particular, Hydro One has developed outcomes-based plans that provide value to its customers by being responsive to their identified needs and preferences, addressing system needs and specific system access requirements, driving productivity improvements, and promoting innovation and continuous improvement.

Through this approach, Hydro One is confident that it has achieved an appropriate balance between the imperatives of meeting its compliance requirements, providing prudent stewardship over its system assets, responsibly managing health and safety risks, responding to customer needs and preferences, and achieving sustainable financial performance.

The key outcomes that Hydro One seeks to achieve through implementation of the system planning process as set out in the System Plans are provided in Table 1.

Table 1 - Hydro One's RRF Performance Outcome Objectives

Renewed Regulatory Framework Performance Outcomes		**Plan Outcomes**
Customer Focus	Customer Satisfaction	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Deliver industry-leading customer service, in response to identified customer preferences
Operational Effectiveness	Cost Control	• Focus on continuous improvement to enhance efficiency, productivity, and reliability
	Safety	• Achieve top-tier safety performance and eliminate serious injuries
	Employee Engagement	• Achieve and maintain employee engagement
Public Policy Responsiveness	Public Policy Responsiveness	• Deliver on obligations mandated by government through legislation and regulatory requirements
	Environment	• Lower Hydro One's environmental footprint through greenhouse gas reduction
Financial Performance	Financial Performance	• Responsible investment in rate base assets to ensure the safety and reliability of the grid • Manageable and stable rate impacts over the course of the planning period

1.1.5.3 CUSTOMER ENGAGEMENT

In preparing the System Plans, Hydro One engaged an independent third party research and consultation firm, Innovative Research Group (IRG), to develop and conduct a comprehensive, two-phase customer engagement study in order to identify customer needs and preferences (SPF Section 1.6, Attachment 1).

The customer engagement study began in 2019, at the earliest stage of the System Planning Process which ultimately led to the development of the System Plans presented in this application. Through the customer engagement study Hydro One obtained information to inform the development of the Company's investment and business plans as part of Phase 1, and subsequently followed-up with customers in Phase 2 to collect feedback on draft plans and alternate investment scenarios, which led to finalizing the investments proposed in the System Plans.

This customer engagement study is the most comprehensive in Hydro One's history. For the first time, investment planning and customer engagement processes were integrated over two phases and customer feedback was provided as an initial input into System Planning. Three alternate investment scenarios were prepared taking into account initial feedback, and were later presented to customers to test which scenario best reflected their needs and preferences. This approach allowed Hydro One to develop final investment plans for 2023-27 that are truly responsive to customers' needs and preferences.

Through Phase 1 of the customer engagement study, IRG surveyed a representative group of Hydro One's Distribution and Transmission customers through focus group sessions, phone surveys, in-depth interviews and an online survey using a workbook that asked customers about their general needs and outcome preferences, and for feedback on trade-offs they were willing to make between rate increases, levels of investment and service outcomes.

As part of Phase 2 of the customer engagement study, customers were given an opportunity to provide feedback on Hydro One's draft investment plans, including on specific investment trade-offs included in the plans.

For various investment decisions, customers were provided the option to choose between a draft plan, a somewhat "accelerated pace" of investment relative to the draft plan, or a somewhat "slower pace" of investment relative to the draft plan. Each trade-off option reflected a different risk level. For example, Hydro One may be able to defer some investments by delaying the replacement of equipment, but with more risk of failure, power outages and higher costs in the future.

The two-phase approach of the customer engagement study ensured appropriate incorporation of customer needs and preferences into the development and finalization of the investment plans, improving alignment between individual candidate investments and the outcomes of the customer engagement activities.

Besides the customer engagement study, additional customer feedback from other forms of engagement was also taken into account in, and helped inform, the investment planning process. By way of example, this includes feedback from large customers through the Account Executive Program. Through the incorporation of feedback received through a range of customer engagement activities, Hydro One has been able to develop and finalize System Plans that balance customer needs and preferences, including rate impacts, as well as operational and compliance needs.

SPF Section 1.6 provides detailed information on the customer engagement activities and how they informed the System Plans.

1.1.5.4 ASSET MANAGEMENT

Hydro One through its Asset Management process monitors its system assets, identifies needs, and determines the appropriate timing for executing maintenance work and capital investments throughout the asset lifecycle. In carrying out this responsibility, Hydro One strives to ensure that it delivers, and can continue to deliver over the long-term, a level of service that is responsive to customer needs and preferences, as well as operational needs, while managing risks and mitigating rate impacts.

During the Asset Management process, Hydro One undertakes extensive and detailed condition based technical reviews of its assets to ensure continued safe and reliable operations. Where deteriorated condition and operational risks are identified, potential interventions are identified to address system needs and the continued safe, reliable operation of the system. At this stage, cost-effective opportunities to maintain, refurbish or renew existing infrastructure are considered, where applicable, through lifecycle planning. Further, integrated planning considers opportunities to address system needs through both conventional and non-conventional (non-wires) alternatives, either as part of distribution system planning or integrated regional resource planning on the transmission system. Where capital investments are appropriate, Hydro One identifies a set of investment candidates. Investment candidates are put forth for further consideration during the Investment Planning process, which is discussed in the next section. The relationship between capital investments and operations and maintenance expenditures is described in the TSP Section 2.8 and the DSP Section 3.8.

Hydro One's Asset Management process starts with a thorough and systematic review of its asset investment needs, driven by asset condition and system requirements. The needs assessment identifies and evaluates individual asset condition that drives the development of candidate investments and includes the collection of data which enables risk scoring to support prioritization and optimization of work undertaken later in the Investment Planning Process. The needs assessment considers (i) asset needs, including but not limited to condition, (ii) customer needs and preferences, (iii) system needs (including those identified through participation in regional planning), and (iv) other external influences such as industry best practices, benchmarking performance, and other studies, as described in TSP Section 2.3 and DSP Section 3.3. The needs assessment also identifies potential hazards, vulnerabilities, threats or other risk sources that could present obstacles to achieving Hydro One's business objectives.

Individual asset needs are determined based on asset condition data and engineering analysis, including factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations, to ensure capital expenditures target the most appropriate mix of assets.

These steps inform the development of a set of potential candidate investments, which are subsequently subject to an internal review. Through this review process, Hydro One ensures that identified customer needs and preferences have been considered and used to inform the development of investment plans and specific candidate investments.

The result of this process is a portfolio of specific candidate investments which proceed into the Investment Planning phase of the System Planning Process as summarized in the following section.

1.1.5.5 INVESTMENT PLANNING PROCESS

The investment planning process prioritizes specific investments to align with intended outcomes based on corporate priorities and strategic objectives, regulatory requirements, investment risks and identified constraints. This process provides a consistent understanding of risks to enable Hydro One to cost effectively deliver the highest value investments and service for its customers. This process allows the consistent assessment and prioritization of candidate investments based on the level of risk mitigated and the cost and value delivered toward achieving business objectives. The process is a structured three-stage process designed to allow Hydro One to deliver on its corporate strategic objectives, and RRF outcomes consistent with the needs and preferences of customers.

Hydro One’s Capital Expenditure Plans, presented through the TSP, DSP and GSP, itemize the specific investments that have received executive approval for implementation through the Capital Planning Process.

1.1.5.6 TRANSMISSION, DISTRIBUTION AND COMMON CAPITAL EXPENDITURE PLANS

A significant portion of transmission, distribution and common assets have deteriorated to the point where they pose a risk to achieving business objectives for safety, reliability, environment and the customer. For example, the proportion of transmission circuit breakers and overhead conductors in poor condition has deteriorated from 9% to 11%, and 12% to 13% respectively since the prior transmission rate application. Additionally, there are approximately 77,000 distribution wood poles or 5% of the overall fleet that are in poor condition. As a result, over the planning period, Hydro One plans to invest in the renewal of the system, to maintain and improve reliability performance, address customer needs and preferences, and mitigate asset and operational risks.

Although a prospective plan, extending out over a seven year period has been developed, Hydro One emphasizes the importance of the role of flexibility in executing the plan. Efforts will be made to operate within an OEB-approved capital envelope, however external drivers may result in the mix of investments evolving; for example:

- Costs in System Access are largely driven by external requests from customers and third parties, including the government. If Hydro One receives additional customer or third party requests and costs in this category increase, they may need to be funded through redirection from other OEB-cost categories, or exceeding the proposed envelopes.
- Costs in System Service are largely driven by provincial planning processes, including bulk transmission planning and integrated regional plans to provide access and additional capacity for new customer connections and to implement regional development plans that are jointly developed with customers, transmitters, distributors and the Independent Electricity System Operator (“IESO”) to accommodate regional growth. Depending on the output of the provincial planning processes, including ongoing Regional Planning and bulk system level studies, costs in this category could increase.

Summaries of the TSP, DSP, and GSP are provided below.[5]

Table 2 - 2023 – 2027 Transmission Capital Spending Forecast

	Forecasting Period ($M)				
Category	**2023**	**2024**	**2025**	**2026**	**2027**
System Access	79.4	70.9	59.8	36.5	50.1
System Renewal	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0
System Service	90.9	101.6	85.8	93.1	90.1
General Plant	146.8	124.0	114.2	115.9	105.0
Progressive Productivity Placeholder	(61.0)	(61.0)	(61.0)	(61.0)	(61.0)
Total	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**
System OM&A[6]	**420.5**	*	*	*	*

Table 3 - 2023 – 2027 Distribution Capital Spending Forecast

	Forecasting Period ($M)				
Category	**2023**	**2024**	**2025**	**2026**	**2027**
System Access	239.6	240.6	227.0	212.6	204.3
System Renewal	373.1	410.3	494.2	491.5	497.8
System Service	196.5	169.7	229.6	192.0	205.9
General Plant	195.9	207.4	170.1	175.5	162.9
Total	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**
System OM&A[7]	**597.5**	*	*	*	*

[5] Values include the General Plant portion attributable to each. Includes Norfolk, Haldimand, Woodstock.
[6] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the escalation factor identified in Exhibit A-04-01.
[7] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the escalation factor identified in Exhibit A-04-01.

Table 4 - 2023 – 2027 General Plant Capital Spending Forecast

	Forecasting Period ($M)				
Category	**2023**	**2024**	**2025**	**2026**	**2027**
Fleet	76.4	78.0	78.9	80.0	82.6
Facilities & Real Estate	91.4	92.1	61.7	58.1	50.5
Information Solutions	119.9	118.1	113.6	122.1	106.1
System Operations	27.4	18.5	8.2	8.0	6.5
Other	27.5	24.6	22.0	23.2	22.3
General Plant Total	**342.7**	**331.4**	**284.3**	**291.4**	**268.0**
General Plant – Transmission Allocation[8]	146.8	124.0	114.2	115.9	105.0
General Plant – Distribution Allocation	195.9	207.4	170.1	175.5	162.9

[8] Allocation between Transmission and Distribution is based on Black and Veatch's Allocation Study presented in E-04-08.

SECTION 1.2 – SPF – COORDINATION THROUGH REGIONAL PLANNING

Planning infrastructure with key stakeholders in a regional context promotes transparency and the cost-effective development of electricity infrastructure in Ontario. This is one of the key 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, in 2013, the OEB convened a stakeholder working group - Planning Process Working Group (PPWG) - to prepare a Report to the OEB (PPWG Report) that set out the details for 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 in order to improve its efficiency and effectiveness (EB-2020-0176).

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 to lead the development of the Needs Assessments (NA) and Regional Infrastructure Plans (RIP) in those regions. Hydro One Distribution, as a local distribution company (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.

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

1.2.1 REGIONAL PLANNING PROCESS

1.2.1.1 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 a planning trigger. Potential triggers may include but not limited to regularly scheduled Needs Screening by the transmitter, a scheduled review specified in an existing Regional Infrastructure Plan, a Government directive, or a significant change to the TSC or standard, or an emergent need brought forward by the transmitter, distributors, customers, or IESO that must be addressed before the next scheduled review. It is intended that regional planning is to be undertaken for each of the planning regions identified in the PPWG Report every five years starting from the introduction of the process in 2013; though the process may be more frequent 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 (NA);
ii. Scoping Assessment;
iii. Integrated Regional Resource Plan (IRRP); and
iv. Regional Infrastructure Plan (RIP).

I. 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 "Study Team"[1]). As part of the Needs Assessment, the Study Team collects information about major high voltage equipment replacement candidates based on condition, analyzes and identifies emerging needs in the region by utilizing load forecast, CDM and DER penetration forecasts, and assesses alternatives to address the identified needs. The objective of the assessment is to ensure that the needs over the mid to long term are met in the most economical and efficient manner.

At the end of the Needs Assessment, a decision is made by the Study Team 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

[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.

transmitter. The Study Team 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.

II. SCOPING ASSESSMENT

If during the Needs Assessment, the Study Team 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.

III. INTEGRATED REGIONAL RESOURCE PLAN

If the Scoping Assessment concludes that an IRRP is required, a Study Team, 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.

IV. 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's IRRP process and RIP process.

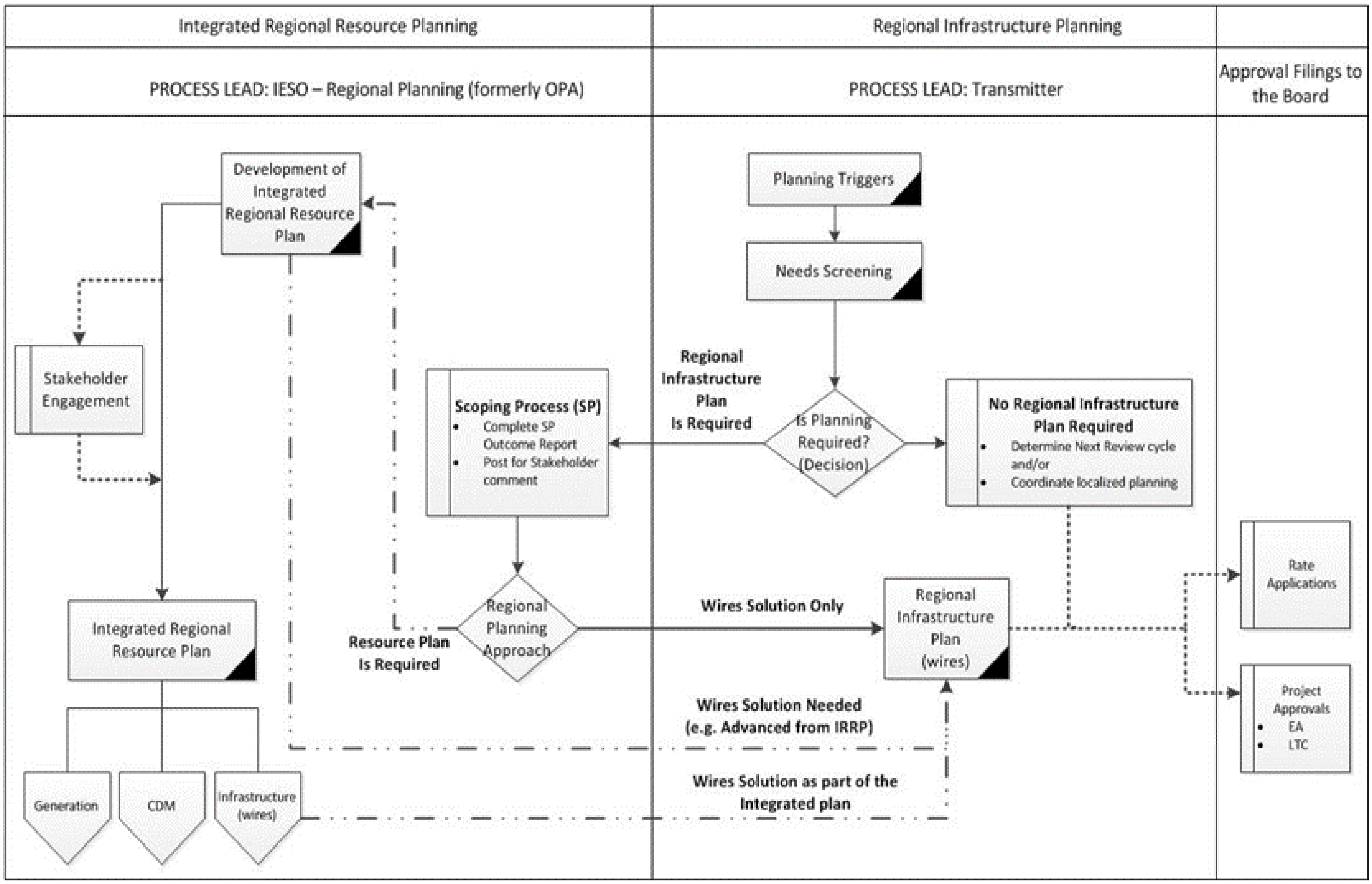

Figure 1: Regional Planning Process

1.2.1.2 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 is the lead transmitter in all regions, except the East Lake Superior[2] and North of Moosonee[3]. Hydro One Distribution is an LDC participating in 20 regions of the 21 regions.

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[2] Hydro One Sault Saint Marie, an affiliate of Hydro One Networks.
[3] 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
Metro Toronto	South Georgian Bay/Muskoka	Niagara
Kitchener-Waterloo-Cambridge-Guelph	Northwest Ontario	Chatham/Lambton/Sarnia
GTA West	London Area	North of Moosonee

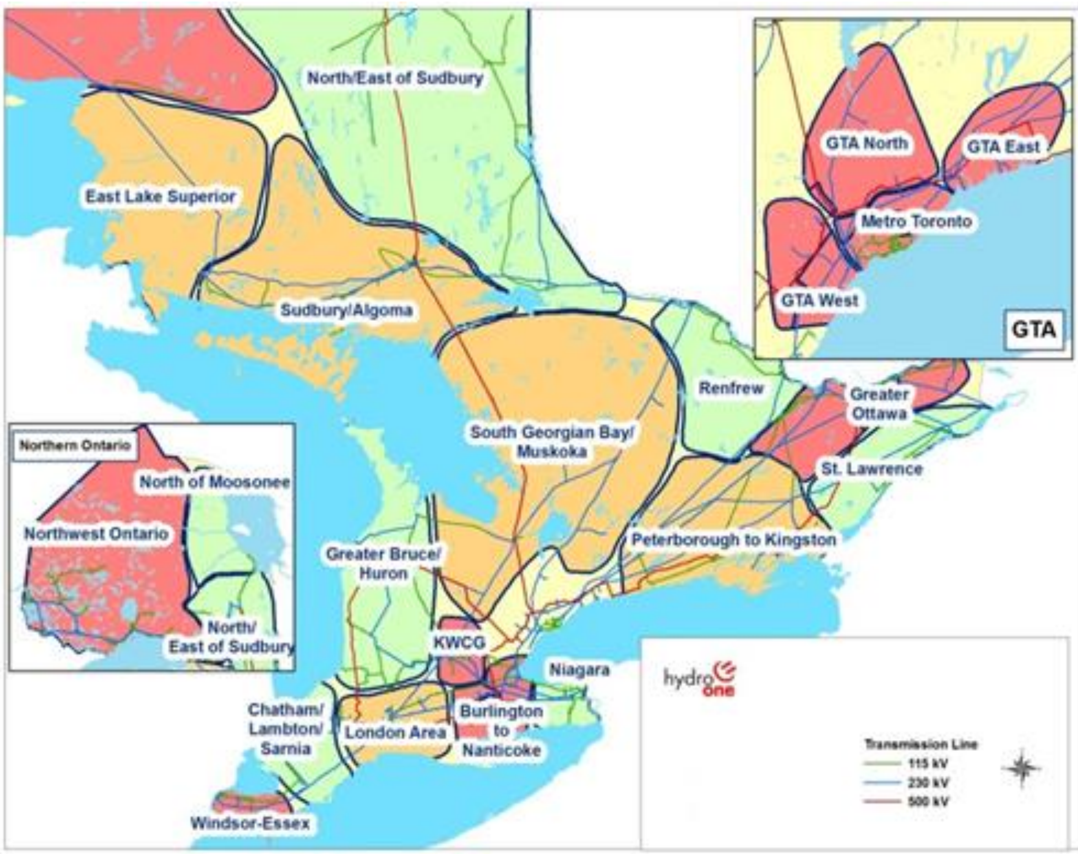

Figure 2: Regional Planning Regions

1.2.1.3 STATUS OF REGIONAL PLANNING ACTIVITIES

Regional planning is an inherently iterative process. Pursuant to the TSC, the Needs Assessment is undertaken at least 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 transmitter believes may trigger the need for investment in transmission facilities, distribution facilities or both in a region.

The first cycle of regional planning activities took place between 2013 and 2017 and have been successfully completed for all 21 regions. Currently, the second round of regional planning activities is underway. Table 2 below provides a summary status of second cycle regional planning for each region and sub-region showing the planning phases that are underway or have been completed. A letter from the IESO on the overall regional planning status is included in Attachment 1.

Table 2 - Regional Planning Status Summary

Region	Sub-region	1st Cycle (2013-2017)				2nd Cycle (2017→)			
		NA	SA	IRRP	RIP	NA	SA	IRRP	RIP
Burlington to Nanticoke	Brant	May, 2014	Sep, 2014	Apr, 2015	Feb, 2017	May, 2017	Aug, 2017	Feb, 2019	Oct, 2019
	Bronte			Jun, 2016					
	Greater Hamilton			*NR*[4]					
	Caledonia-Norfolk		*NR*	*NR*					
Toronto Area	Central	Jun, 2014	*Note*[5]	Apr, 2015	Jan, 2016	Oct, 2017	Feb, 2018	Aug, 2019	Mar, 2020
	Northern		*NR*	*NR*					
Windsor-Essex		*Note*		Apr, 2015	Dec, 2015	Oct, 2017	Mar, 2018	Sep, 2019	Mar, 2020
GTA North	York	Jun, 2014	*Note*	Apr, 2015	Feb, 2016	Mar, 2018	Aug, 2018	Feb, 2020	Oct, 2020
	Western		*NR*	*NR*					
Greater Ottawa	Ottawa	Jul, 2014	Nov, 2014	Apr, 2015	Dec, 2015	Jun, 2018	Sep, 2018	Mar, 2020	Dec, 2021
	Outer Ottawa		*NR*	*NR*					
Kitchener-Waterloo-Cambridge-Guelph		*Note*		Apr, 2015	Dec, 2015	Dec, 2018	Apr, 2019	Q2, 2021	
GTA West	Northwestern	May, 2014	Sep, 2014	Apr, 2015	Jan, 2016	May, 2019	Aug, 2019	Q2, 2021	
	Southern			*NR*					
Greater Bruce/Huron		May, 2016	*NR*	*NR*	Aug, 2017	May, 2019	Sep, 2019	Q2, 2021	
East Lake Superior		Dec, 2014	*NR*	*NR*	Dec, 2014	Jun, 2019	Oct, 2019	Q2, 2021	
GTA East	Pickering - Ajax - Whitby	Aug, 2014	Dec, 2014	Jun, 2016	Jan, 2017	Aug, 2019	*NR*	*NR*	Feb, 2020
	Oshawa - Clarington			*NR*					
Peterborough to Kingston		Feb, 2015	*NR*	*NR*	Jul, 2016	Feb, 2020	May, 2020	Q4, 2021	
South Georgian Bay/Muskoka	Barrie/Innisfil	Mar, 2015	Jun, 2015	Dec, 2015	Aug, 2017	Apr, 2020	Q4, 2020	Q2, 2022	
	Parry Sound/Muskoka			Dec, 2015				Q2, 2022	
London Area	Greater London	Apr, 2015	Aug, 2015	Jan, 2017	Aug, 2017	May, 2020	*NR*	*NR*	
	Alymer-			*NR*					
	Strathroy			*NR*					

[4] NR: Not Required
[5] Note: The planning activity in the region was already in progress prior to the commencement of the regional planning process; hence the NA/SA was deemed to be already completed by the Study Team.

Region	Sub-region	1st Cycle (2013-2017)				2nd Cycle (2017→)			
		NA	SA	IRRP	RIP	NA	SA	IRRP	RIP
	Woodstock			*NR*					
	St. Thomas			*NR*					
Sudbury/Algoma		Mar, 2015	*NR*	*NR*	Jun, 2016	Jun, 2020	*NR*	*NR*	
Northwest Ontario	North of Dryden	*Note*	Jan, 2015	Jan, 2015	Jun, 2017	Jul, 2020	Jan, 2021	Q2 2022	
	Greenstone - Marathon			Jun, 2016					
	Thunder Bay			Dec, 2016					
	West of Thunder Bay			Jul, 2016					
Chatham/Lambton/Sarnia		Jun, 2016	*NR*	*NR*	Aug, 2017	Expected to commence 2nd cycle in 2021			
Niagara		Apr, 2016	*NR*	*NR*	Mar, 2017 2017				
North/East of Sudbury		Apr, 2016	*NR*	*NR*	Apr, 2017				
Renfrew		Mar, 2016	*NR*	*NR*	Jul, 2016				
St. Lawrence		Apr, 2016	*NR*	*NR*	Jul, 2016				
North of Moosonee		Hydro One Transmission is not the lead transmitter in this region.							

1.2.1.4 ONGOING INITIATIVES TO REVIEW REGIONAL PLANNING PROCESS

In December 2020, the OEB initiated a consultation process to undertake a review of the regional planning process that applies to Ontario's electricity sector. The primary purpose of this review is to improve the efficiency and effectiveness of the current regional planning process. As a first step in this consultation, the OEB has re-established its RPPAG to assist the OEB in its review. The review will include consideration of certain recommendations from the high level regional planning process review completed by the IESO some time ago. The work of the RPPAG will therefore include further assessment of the IESO's recommendations.

1.2.2 HYDRO ONE TRANSMISSION

1.2.2.1 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 the Needs Assessment and RIP phases of the process. 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; completes and publishes 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 solution to address the identified needs. In particular, Hydro One Transmission undertakes the following activities:

1. <u>Data gathering:</u> Hydro One Transmission collects information, such as, but not limited to historical load data, future load forecast, 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 approach is used in coordination with the IESO and local LDCs taking into consideration CDM, DERs, and emerging technologies like electrical vehicles. Up to ten years of historical data based on asset condition is collected and analyzed 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 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. <u>Pre-meeting Conference Calls/Webinars:</u> In advance of each phase of the regional planning, local LDCs and the IESO are notified of upcoming regional planning activities and provided with an overview of the process. 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 Study Team 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 occurs on a regular basis to discuss various planning matters such as: assessment methodology, right sizing opportunity for deteriorated assets that require replacement, customer needs, and regional needs and timing before recommending a preferred plan
4. Feedback from LDCs: Hydro One Transmission regularly sends formal communications to LDCs to seek feedback on prioritization and scheduling of regional planning for the regions, as well as seeking suggestions for enhancements in the second cycle of regional planning.

Throughout the Scope Assessment and IRRP phases, Hydro One Transmission along with the other Study Team members seek further input from other stakeholders, such as local municipalities, Indigenous communities, business groups, citizen groups, consumers and environmental and conservation groups. If any further community input and broader engagement is required, the Study Team forms a Local Advisory Committee (LAC) made up of representatives from public and various interest groups. The LAC is an advisory body and a forum for communities to provide their input and stay informed about regional planning activities within their region. As an advisory body, the LAC members represent communities and bring forward their interests within the study area and provide insight into their values and perspectives. Currently, the LACs have been formed to engage communities in the regional planning process:

- Three in the Northwest Ontario region to represent three of the sub-regions: Greenstone-Marathon, City of Thunder Bay, and West of Thunder Bay;
- Two in the South Georgian Bay / Muskoka region to represent the two sub-regions: Parry Sound / Muskoka, and Barrie / Innisfil;

- One in the GTA North region to represent the York sub-region; and
- Four to represent the following four regions: GTA East, Greater Ottawa, Metro Toronto, and Windsor-Essex.

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, 2020 Status Report, was filed on November 1, 2020[6].
- Pursuant to section 2.4.2 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 1.
- 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 2020 Status Report, Hydro One Transmission identifies the LDCs to whom it has provided Planning Status Letters since October 2018. In addition to those LDCs, Hydro One Transmission has recently provided Planning Status Letters to Halton Hills Hydro Inc., North Bay Hydro Distribution Ltd., Oshawa PUC Networks Inc., Waterloo North Hydro Inc. and Hydro One Distribution.

1.2.2.1.1 REGIONAL PLANNING PROCESS IMPROVEMENTS

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 identify areas for improvement. Hydro One Transmission sought feedback from various stakeholders

[6] Regional Planning Annual Status Report to the OEB 2020.

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.

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.

Assets Condition Inputs

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. Most recently, Hydro One Transmission has 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 compiles, develops and provides the information for equipment that is identified to be replaced or refurbished based on asset condition. Once it is determined that replacing the deteriorated equipment is the most appropriate approach, the Study Team assesses, discusses planning alternatives and recommends the preferred approach, which may include:

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.

The above described improvements have been successfully implemented into the second cycle of the regional planning process and is further documented in both the Needs Assessment and RIP reports for each region, thereby enhancing the quality of the planning deliverables.

1.2.2.2 SUMMARY OF HYDRO ONE TRANSMISSION NEEDS AND ASSOCIATED INVESTMENTS

This section provides further details regarding capital investment recommendations scheduled for each of the regions and sub-regions over the 2023 to 2027 period for which Hydro One Transmission is the lead transmitter. In total, this application includes over 80 projects totalling approximately $2.0B in net capital expenditures. The overview of the investments arising from the recommendations of the Study Team that form part of Hydro One Transmission's capital plans over the 2023 to 2027 period are presented below by each region. Further details on these investments are presented in TSP Section 2.11 as well as the corresponding RIP reports that are appended to this section at Attachments 2-20**.**

BURLINGTON TO NANTICOKE

The Burlington to Nanticoke region is comprised of four sub-regions: Brant, Bronte, Greater Hamilton, and Caledonia-Norfolk. The participants in the region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Alectra Utilities Inc. (formerly Horizon Utilities Corp.)
- Brantford Power Inc.
- Burlington Hydro Electric Inc.
- Energy + Inc.
- Hydro One Networks Inc. (Distribution)
- Oakville Hydro Electricity Distribution Inc.

The RIP report for this region is found in Attachment 2. The RIP report reaffirms the needs identified in the first cycle RIP as well as identifies additional needs for the system renewal investments over the 2023 to 2027 period as follows:

- Beach TS: Auto-Transformer (T1/T7/T8) Replacement and DESN Switchgear (T-SR-01);
- Burlington TS: T12 Autotransformer and LV Switchgear (T-SR-03);
- Birmingham TS: MV Metalclad Switchgear Refurbishment (T-SR-03);
- Caledonia TS: T1 and Component Replacement (T-SR-03);
- Dundas TS #2: Two New Feeder Positions;
- Jarvis TS: T3, T4 & Component Replacement;
- Lake TS: T1/T2 Transformers and LV Switchyard Refurbishment (T-SR-03);
- Newton TS: Station Refurbishment (T-SR-03);
- Nebo TS: T3/T4 Transformers and Component Replacements (T-SR-03);
- Norfolk TS: Install Capacitor Bank;
- 115kV B7/B8 Transmission Line: Refurbish line sections from Burlington TS to Nelson Junction.

GREATER OTTAWA

The Greater Ottawa Region is comprised of two sub-regions: Ottawa Area and Outer Ottawa. The participants in the region’s Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro Ottawa Limited
- Ottawa River Power Corporation
- Hydro 2000 Inc.
- Renfrew Hydro Inc.

The second cycle Regional Infrastructure Plan report for this region was published in December 2020 and is found at Attachment 3. The RIP has identified the need for the following investments over the 2023 to 2027 period:

- Arnprior TS: Transformer (T1/T2) Replacement (T-SR-03);
- Longueuil TS: Transformer (T3/T4) Replacement (T-SR-03);
- Slater TS: Transformer (T1/T2/T3) Replacement (T-SR-03);
- Lincoln Heights TS: Transformer (T1/T2) Replacement (T-SR-03);
- Riverdale TS: Replacement of 115kV Breakers (T-SR-03);
- Albion TS: Transformer (T1/T2) Replacement (T-SR-03);
- Russell TS: Transformer (T1/T2) Replacement (T-SR-03);
- Bilberry Creek TS: Transformer (T1/T2) Replacement (T-SR-03);
- Nepean TS: Transformer (T3/T4) Replacement (T-SR-03);
- Merivale TS: Autotransformer (T22) and HV Breaker Replacement (T-SR-01);
- Merivale TS: Addition of Autotransformer and Station Expansion (T-SS-05); and
- Merivale TS to Hawthorne TS – 230kV Conductor Upgrade (T-SS-03).

GTA EAST

The GTA East Region is comprised of two sub-regions: Pickering-Ajax-Whitby and Oshawa-Clarington. The participants in this region’s Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO

- Hydro One Networks Inc. (Distribution)
- Oshawa PUC Networks Inc.
- Elexicon Energy Inc.

The latest RIP for this region was completed in February 2020 and is found at Attachment 4. This RIP advances the work from the Needs Assessment and identifies the following investments over the 2023-2027 period:

- Cherrywood TS: LV DESN Switchyard Refurbishment (T-SR-03); and
- Cherrywood TS: ABCB Breaker Replacement (T-SR-02).

GTA NORTH

The GTA North Region is comprised of two sub-regions: York and Western. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Utilities Co. (formerly Enersource Hydro Mississauga Inc., Hydro One Brampton Networks Inc. and PowerStream Inc.)
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited (THESL)

The second cycle RIP for this region was issued in October 2020 and is found at Attachment 5. The RIP has identified the need for the following investments over the 2023 to 2027 period:

- Connection of a new load station in Northern York Region (T-SA-09); and
- Woodbridge TS: Transformer (T5) Replacement (T-SR-03).

GTA WEST

The GTA West Region is comprised of two sub-regions: Northwestern and Southern. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- 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.

In response to the RIP recommendations found at Attachment 6, the TSP includes the following investments over the 2023 to 2027 period:

- Connection of a new load station “Halton TS #2” (T-SA-03);
- Milton SS: Component Replacement (T-SR-01);
- Bramalea TS: T3/T4 Transformer and Component Replacement (T-SR-03);
- Erindale TS: PCT and Component Replacement (T-SR-03);
- Halton TS: PCT and Component Replacement (T-SR-03);
- Palermo TS: T3 / T4 Supply Transformer (T-SR-03); and
- Reconductor 230kV H29/H30 Transmission Line (T-SA-08).

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 Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)

- IESO
- Energy+ Inc.
- Centre Wellington Hydro Ltd.
- Guelph Hydro Electric System 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.

The RIP has been included at Attachment 7 and the second cycle NA report[7] for this region was published in December 2018. The NA report has identified the need for the following investments over the 2023 to 2024 period:

- Campbell TS: PCT and Component Replacement (T-SR-03);
- Cedar TS: Transformer (T7/T8) Replacement (T-SR-03); and
- Preston TS: Transformer (T3/T4) Replacement (T-SR-03).

METRO TORONTO

The Metro Toronto Region is comprised of two sub-regions: Central Downtown and Northern. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Inc. (formerly Enersource Hydro Mississauga Inc. and PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- THESL

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[7] 2nd Cycle Needs Assessment Report – KWGC

- Elexicon Energy Inc.

The second cycle RIP, found at Attachment 8, identified the need for the following additional investments over the 2023 to 2027 period:

- Bermondsey TS: Transformer (T3/T4) Replacement (T-SR-03);
- John TS: Station Reinvestment (T-SR-03);
- Leslie TS: Transformer (T1) Replacement (T-SR-03);
- 115kV C5E/C7E Underground Cables: Refurbish cable sections from Esplanade TS to Terauley TS (T-SR-18);
- 115kV H1L/H3L/H6LC/H8LC Transmission Lines: Refurbish line sections from Leaside Junction to Bloor St. Junction;
- 115kV L9C/L12C Transmission Lines: Refurbish line sections from Leaside TS to Balfour Junction; and
- 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).

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. The participants in this region’s Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Hydro One Networks Inc. (Distribution)
- Synergy North
- Sioux Lookout Hydro Inc.

The RIP has been included at Attachment 9 and the second cycle NA report was published in July 2020.[8] The reports have reaffirmed the needs identified in the first cycle of RIP plus identified several needs over the 2023 to 2027 period. In response to the RIP recommendations, the TSP contemplates the following investment over the 2023 to 2027 period:

- Marathon TS: Component Replacement (T-SR-01),
- Fort Frances TS – Transformer Replacement (T-SR-01),
- Kenora TS – Component Replacement (T-SR-01),
- Lakehead TS – Component Replacement (T-SR-01),
- Mackenzie TS – Component Replacement (T-SR-01).
- Port Arthur TS #1 – PCT & Component Replacement (T-SR-03),
- Rabbit Lake SS – Component Replacement (T-SR-01),
- Whitedog Falls SS – Component Replacement (Part of T-SR-01),
- 115kV A4L Circuit – Beardmore Jct x Longlac TS Refurbishment (T-SR-13); and
- 115kV E1C Circuit – Ear Falls TS x Slate Falls DS Refurbishment; Etruscan Jct x Crow River DS Refurbishment (T-SR-13).

WINDSOR-ESSEX

The Windsor-Essex Region is in the southern-most part of Ontario, extending from Chatham southwest to Windsor. The participants in this region's Study Team include representatives from the following organizations:

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

[8] 2nd Cycle Needs Assessment Report – Northwest Ontario

The second cycle RIP report was published in March 2020 and has been included at Attachment 10. The RIP reaffirms the needs identified in the first cycle RIP and has identified the need for the following investments over the 2023 to 2027 period:

- Keith TS: Autotransformer (T11/T12) Replacement (T-SR-01);
- Lauzon TS: Transformer (T5, T6, T7 and T8) and Component Replacement (T-SR-03); and
- Supply Capacity need to Kingsville – Leamington area:
  - Build new switching station at Leamington Junction (Lakeshore TS),
  - Build Leamington Area Transformer Stations – South Middle Road DESN1 and DESN2 (referred to as "Leamington Area Station #4") in T-SA-10; and
  - Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS (Station costs reflected in T-SS-07, transmission line costs have been excluded, see Exhibit A-03-01 for further information) .

LONDON AREA

The London Area Region is comprised of five sub-regions: Greater London, Aylmer- Tillsonburg, Strathroy, Woodstock, and St. Thomas. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Entegrus Powerlines Inc.
- Erie Thames Powerlines Corporation
- Hydro One Networks Inc. (Distribution)
- London Hydro Inc.
- Tillsonburg Hydro Inc.

The RIP has been included at Attachment 11 and the second cycle NA report was published in May 2020.[9] The reports have identified the need for the following investments over the 2023 to 2027 period:

- Wonderland TS: Station Refurbishment (T-SR-03);
- Buchanan TS: T2, T3 and Component Replacement (T-SR-01) ;
- Clarke TS: DESN transformer replacement (T-SR-03); and
- Clarke TS: PCT & Switchyard 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 Study Team include representatives from the following organizations:

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

The RIP has been included at Attachment 12 and the second cycle NA report was published in May 2020.[10] The reports have identified the need for the following investments over the 2023 to 2027 period:

- Port Hope TS: Transformer Replacement (T-SR-03); and

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[9] 2nd Cycle Needs Assessment Report – London Area
[10] 2nd Cycle Needs Assessment Report – Peterborough to Kingston

- Havelock TS: Transformer Replacement (T-SR-03);

SOUTH GEORGIAN BAY/MUSKOKA

The South Georgian Bay/Muskoka Region is comprised of two sub-regions: Barrie/Innisfil and Parry Sound/Muskoka. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Alectra Utilities
- 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.
- Orillia Power Distribution Corp. (Recently acquired by Hydro One Distribution)
- Wasaga Distribution Inc.

The RIP has been included at Attachment 13 and the second cycle NA report was published in April 2020.[11] The reports have identified the need for the following investments over the 2023 to 2027 period:

- Orangeville TS: Transformer (T1/T2) Replacement (T-SR-03);
- Parry Sound TS: Transformer Replacement (T-SR-03);
- Sections of M6E/M7E circuits line refurbishment (T-SR-13);
- Sections of E8V/E9V circuits line refurbishment (T-SR-13); and
- Sections of D1M/D2M circuit's line refurbishments (T-SR-13).

[11] 2nd Cycle Needs Assessment Report – South Georgian Bay/Muskoka

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 Study Team include representatives from the following organizations:

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

The second cycle of Regional Planning Infrastructure was completed in December 2020 and the report is provided at Attachment 14. The RIP determined that identified needs in the region can be addressed directly by Hydro One along with relevant LDCs, and therefore Scoping Assessment and/or IRRP are not required. The following needs were identified by the Study Team in the second cycle Needs Assessment:

- Martindale TS: T25 & T26 Transformer Replacement (T-SR-03);
- Elliot Lake TS: Component Replacement (T-SR-03);
- Algoma TS: Component Replacement (T-SR-01); and
- 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 Study Team include representatives from the following organizations:

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

The RIP for this region was completed in August 2017 and is provided at Attachment 15. The RIP identified that the needs for this region were strictly local in nature and no transmission infrastructure investment is required. Local plans have been implemented by Hydro One to address a capacity issue at Kent TS. In addition to the local needs, the RIP also identified several system renewal investments for the region. In response to the recommendations made in the RIP report, theTSP contemplates the following investments over the 2023 to 2027 period:

- St. Andrews TS: Transformer (T3/T4) Replacement and DESN Refurbishment (T-SR-03);
- Sarnia Scott TS: Transformer (T5) and component Replacement (T-SR-01); and
- Lambton TS: T7/T8, T5/T6, DESN Replacement (T-SR-03).

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 Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Entegrus Powerlines Inc.
- Erie Thames Powerlines Corporation
- Festival Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Wellington North Power Inc.
- Westario Power Inc.

The RIP has been included at Attachment 16 and the second cycle NA report for this region was completed in May 2019.[12] The reports have identified the need for the following investments over the 2023 to 2027 period:

- Seaforth TS – Transformer T1/T2/T5/T6 and component replacement (T-SR-01);

[12] 2nd Cycle Needs Assessment Report – Greater Bruce/Huron

In addition to above investments, the second cycle of the NA recommends that the issue of overloading on circuit L7S be studied as part of further regional coordination.

NIAGARA

The Niagara Region comprises twelve municipalities in the southern end of the Golden Horseshoe. The participants in this region's Study Team include representatives from the following organizations:

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

The RIP for this region was completed in March 2017 and is provided at Attachment 17. The RIP identified that the needs for this region were strictly local in nature. Local plans have been implemented by Hydro One to address thermal overloading of the 115kV circuit (Q4N) by upgrading the conductor on a section of Q4N from Beck 1 SS to Portal Junction. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2023 to 2027 planning period.

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 Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)

- IESO
- Hearst Power Distribution Company Ltd.
- Hydro One Networks Inc. (Distribution)
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.

The RIP for this region was completed in April 2017 and is provided at Attachment 18. The RIP identified that the needs for this region were strictly local in nature. Local plans were developed by Hydro One and the impacted LDCs in the area to address Timmins TS/Kirkland Lake TS voltage regulation issues. At this time, no further regional planning transmission infrastructure investments are contemplated over the 2023 to 2027 planning period.

RENFREW

The Renfrew Region includes all of Renfrew County. The participants in this region's Study Team include representatives from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- IESO
- Hydro One Networks Inc. (Distribution)
- Ottawa River Power Corporation
- Renfrew Hydro Inc.

The RIP for the region was completed in July 2016 and is provided at Attachment 19. The RIP identified that there were no capacity, system reliability or operating needs that required investments over the planning horizon. As such, the TSP does not contemplate any transmission infrastructure investments for this region over the 2023 to 2027 period resulting from the regional planning process.

ST. LAWRENCE

The St. Lawrence Region covers the southeastern part of Ontario bordering the St. Lawrence River. The participants in this region's Study Team include representatives from the following organizations:

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

The RIP for this region was completed in July 2016 and is provided at Attachment 20. The RIP identified that there were no capacity, system reliability or operating needs that required investments over the planning horizon. As such, the TSP does not contemplate any transmission infrastructure investment for this region over the 2023 to 2027 period resulting from the regional planning process.

EAST LAKE SUPERIOR

Hydro One Sault Saint Marie (Hydro One SSM) 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.

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.

1.2.3 REGIONAL PLANNING CONSULTATIONS – HYDRO ONE DISTRIBUTION

1.2.3.1 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 Study Team 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.

As further described in section 1.2.2.1 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 as well as the resulting cost allocation – if applicable – to Hydro One Distribution. A copy of the Regional Planning Status Letter is provided at Attachment 21.

1.2.3.2 SUMMARY OF HYDRO ONE DISTRIBUTION NEEDS AND ASSOCIATED INVESTMENTS

By nature, regional planning is primarily focused on the capacity and infrastructure needs of a broader area, and therefore does not specifically identify investments to address needs that are embedded within the distribution system. However, by way of participating in the regional planning process, Hydro One Distribution benefits as an LDC, as it is an opportunity to confirm forecasts and trends on the distribution system. The investments listed below are those that were identified as part of regional planning and coincide with the 2023-2027 rate filing test years. Since these investments were specifically identified within a Regional Planning context, they require coordination between Hydro One Transmission and Distribution. Investments with needs that do not extend beyond the distribution system are listed exclusively within the DSP, and are not listed as part of this Regional Planning exhibit.

SOUTH MIDDLE ROAD TS DESN #1 FEEDER DEVELOPMENT, ISD D-SS-01

- This investment is associated with the line work performed by Hydro One Distribution to construct new feeders at South Middle Road TS DESN#1. These feeders will enable the utilization of additional capacity resulting from the construction of South Middle Road TS DESN #1. The distribution scope of work will be in-serviced beginning in 2022, but will extend into 2023 (inside the 2023-2027 rate filing period).

SOUTH MIDDLE ROAD TS DESN #2 FEEDER DEVELOPMENT, ISD D-SS-01

- This investment is associated with the line work performed by Hydro One Distribution to construct new feeders at South Middle Road TS DESN#2. These feeders will enable the utilization of additional capacity resulting from the construction of South Middle Road TS DESN #2. The development of these feeders will begin in 2022, with construction expected to be completed in 2025

ATTACHMENTS:

Attachment 1 – IESO Regional Planning Progress Update Letter to Hydro One Transmission

Attachment 2 – RIP Report: Burlington to Nanticoke

Attachment 3 – RIP Report: Greater Ottawa

Attachment 4 – RIP Report: GTA East

Attachment 5 – RIP Report: GTA North

Attachment 6 – RIP Report: GTA West

Attachment 7 – RIP Report: KWCG

Attachment 8 – RIP Report: Metro Toronto

Attachment 9 – RIP Report: Northwest Ontario

Attachment 10 – RIP Report: Windsor-Essex

Attachment 11 – RIP Report: London Area

Attachment 12 – RIP Report: Peterborough to Kingston

Attachment 13 – RIP Report: South Georgian Bay / Muskoka

Attachment 14 – RIP Report: Sudbury / Algoma

Attachment 15 – RIP Report: Chatham / Lambton / Sarnia

Attachment 16 – RIP Report: Greater Bruce / Huron

Attachment 17 – RIP Report: Niagara

Attachment 18 – RIP Report: North/East of Sudbury

Attachment 19 – RIP Report: Renfrew

Attachment 20 – RIP Report: St. Lawrence

Attachment 21 – Hydro One Transmission Regional Planning Status Letter to Hydro One Distribution.

March 18, 2021

Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
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www.ieso.ca

VIA EMAIL

Mr. Ajay Garg
Senior Manager, Transmission Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2P5

Dear Mr. Garg:

Re: Independent Electricity System Operator
Regional Planning Progress Update

The Independent Electricity System Operator (IESO) has been notified by Hydro One Networks Inc. (Hydro One Transmission) of its upcoming 2023-2027 rate application to the Ontario Energy Board (OEB) and has been requested to provide Hydro One Transmission with a status update for those regions where regional planning is underway, but a Regional Infrastructure Plan (RIP) has not yet been completed. This request includes regional planning areas undergoing either a Needs Assessment (NA), Scoping Assessment (SA) or an Integrated Regional Resource Planning (IRRP).

Hydro One Transmission's request is based on the requirement of Section 2.4.2 of the OEB's Chapter 2 Filing Requirements for Electricity Transmission Applications which states:

> *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 Independent Electricity System Operator ("IESO"), identifying the status of the regional planning process, and the potential impacts on the applicant's investment plans.*

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

The first cycle of regional planning for all 21 regions was completed in Q3 2017 and the second cycle of regional planning is underway. The table below provides the status of the regional plans where Hydro One Transmission is a lead Transmitter.

Region	Sub-region	2nd Cycle			
		NA *	SA	IRRP	RIP *
Burlington to Nanticoke	Brant Bronte Greater Hamilton Caledonia-Norfolk	May, 2017	Aug, 2017	Feb, 2019 (Addendum estimated completion 2022)	Oct, 2019
Metro Toronto	Central Downtown Northern	Oct, 2017	Feb, 2018	Aug, 2019 (Addendum estimated completion Q2 2021)	Mar, 2020
Windsor-Essex		Oct, 2017	Mar, 2018	Sep, 2019	Mar, 2020
GTA North	York Western	Mar, 2018	Aug, 2018	Feb, 2020	Oct, 2020
Greater Ottawa	Ottawa Outer Ottawa	Jun, 2018	Sep, 2018	Mar, 2020 (Addendum estimated completion Q2 2021)	Dec, 2020
Kitchener-Waterloo-Cambridge-Guelph		Dec, 2018	May, 2019	Q1 2021	TBD
GTA West	Northwestern Southern	May, 2019	Aug, 2019	Q2 2021	TBD
Greater Bruce/Huron		May, 2019	Sep, 2019	Q2 2021	TBD
East Lake Superior (Affiliate of Hydro One Networks Inc.)		Jun, 2019	Oct, 2019	Apr, 2021	TBD
GTA East	Pickering-Ajax-Whitby Oshawa-Clarington	Aug, 2019	*Not Required*	*Not Required*	Feb, 2020
Peterborough to Kingston		Feb, 2020	May, 2020	Q4 2021	TBD
South Georgian Bay/Muskoka	Barrie/Innisfil	Apr, 2020	Nov, 2020	Q2 2022	TBD
	Parry Sound/Muskoka			Q2 2022	
London Area	Greater London Alymer-Tillsonburg Strathroy Woodstock St. Thomas	May, 2020	*Not Required*	*Not Required*	TBD
Sudbury/Algoma		Jun, 2020	*Not Required*	*Not Required*	TBD
Northwest Ontario	North of Dryden Greenstone-Marathon Thunder Bay West of Thunder Bay	Jul, 2020	Jan, 2021	Q2 2022	TBD
Chatham/Lambton/Sarnia		Estimated Commencement 2nd cycle in 2021			
Niagara					
North/East of Sudbury					
Renfrew					
St. Lawrence					
		* Hydro One products		Green cells = work underway	

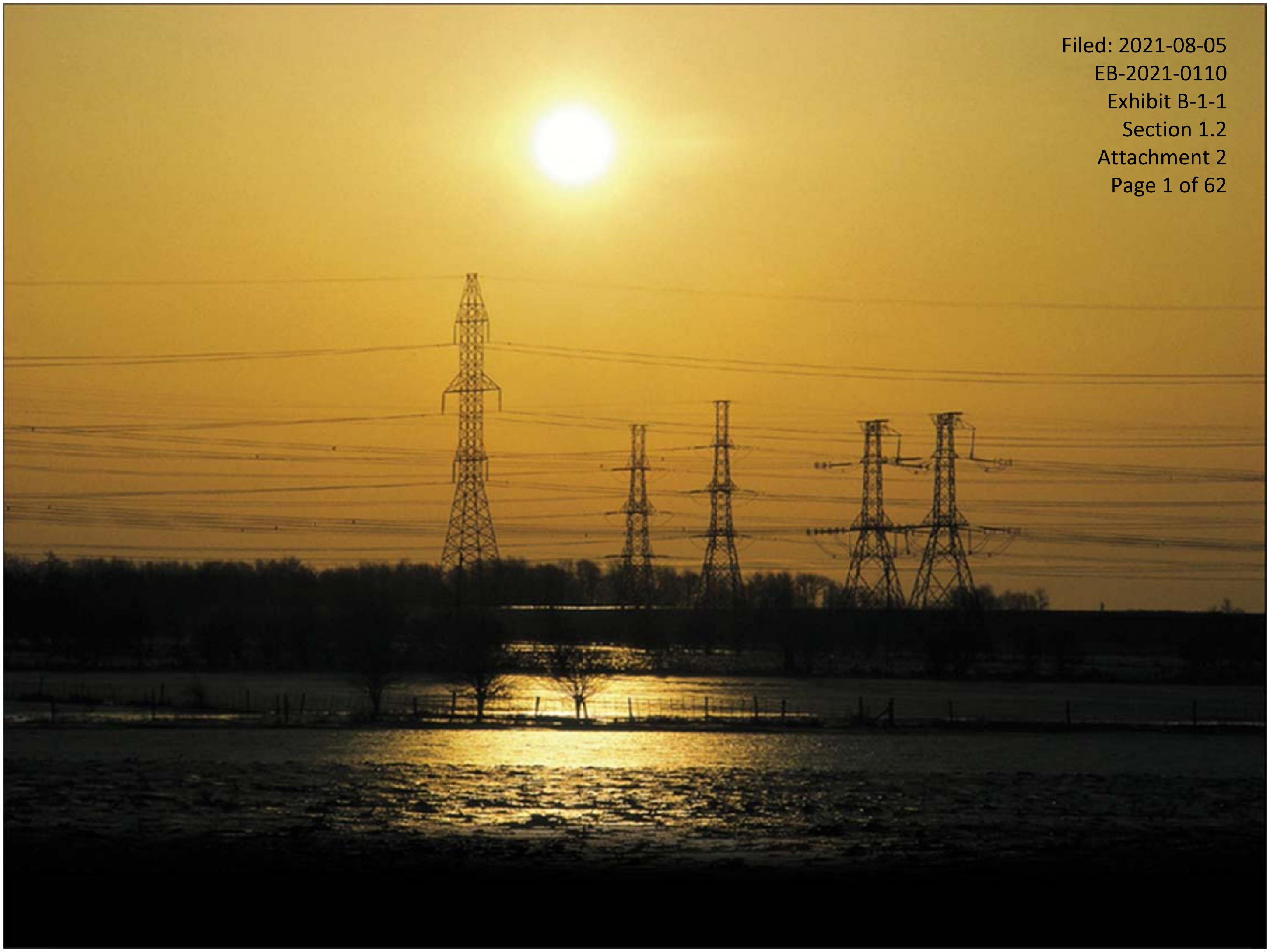
Ongoing IRRPs, as well as ongoing addendum studies, may lead to changes in recommendations by the Regional Planning Study teams. Where possible, the IESO has worked with Hydro One to reflect the most up-to-date information in their investment plans.

If you have any questions about the IESO's comments please contact me directly at 416-957-3594 or Devon.Huber@ieso.ca.

Yours truly,

Devon Huber
Senior Manager, Regulatory Affairs

cc: Ahmed Maria, Director, Transmission Planning, IESO



Burlington to Nanticoke

REGIONAL INFRASTRUCTURE PLAN

October 08, 2019

hydro one

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Prepared and supported by:

Company
Brantford Power Inc.
Burlington Hydro Inc.
Energy + Inc.
Alectra Utilities Corporation (former Horizon Utilities Inc.)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Oakville Hydro
Hydro One Networks Inc. (Lead Transmitter)

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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 (2019-2029) 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.

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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 BURLINGTON TO NANTICOKE REGION.

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

- Alectra Utilities Corporation (former Horizon Utilities Inc.)
- Brantford Power Inc.
- Burlington Hydro Inc.
- Energy + Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Oakville Hydro

The first regional planning cycle for the Burlington to Nanticoke Region was completed in February 2017 with the publication of the RIP report. Due to several sustainment needs arising during the final phase of the 1st cycle regional planning, the Study Team and the RIP recommended to trigger 2nd regional planning cycle.

This RIP is the final phase of the 2nd regional planning cycle and follows the completion of the Integrated Regional Resource Plans ("IRRP") for Hamilton sub-region in February 2019 and the 2nd Cycle Burlington to Nanticoke Region's Needs Assessment ("NA") in May 2017. This RIP provides a consolidated summary of the needs and recommended plans for the Burlington to Nanticoke Region in the near-term (up to 5 years) and the mid-term (5 to 10 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRP, also identifies additional needs related to load growth and end-of-life facilities in the Burlington to Nanticoke Region.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment report for this cycle and the Hamilton Sub-region IRRP; 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:

1- Bronte TS: 115 kV B7/B8 Transmission line capacity
2- Beach TS: Replace EOL T3/T4 transformers
3- Horning TS: Refurbish EOL transformers T1/T2 & switchgears
4- Mohawk TS: Replace EOL T1/T2 transformers
5- Brant Switching Station: 115 kV B12BL/ B13BL Transmission line capacity
6- Bronte TS (T5/T6 DESN): Refurbish EOL transformers T5/T6 & switchgears
7- Cumberland TS: Power Factor Correction

The major infrastructure investments recommended by the Study Team in the near and mid -term planning horizon are provided below in Table 1 and 2 respectively, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1: Near-Term Needs in Burlington to Nanticoke Region

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate ($M)
1	115 kV B7/B8: EOL line section from Burlington TS to Nelson Jct.	Refurbish the EOL B7/B8 line section	2020	2
2	115 kV B3/B4: EOL line section from Horning Mountain Jct. to Glanford Jct.	Refurbish the EOL B3/B4 line section conductor	2020	22
3	Elgin TS: EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	2021	81
4	Newton TS: EOL transformers	Replace EOL transformers	2021	22
5	Kenilworth TS: EOL transformer & switchgear	Reconfigure from 2 DESNs to single DESN and replace EOL equipment	2021	36
6	Dundas TS: Load transfer	Add two new feeders at Dundas TS #2	2021	2
7	Gage TS: EOL transformers & switchgear	Reduce from 3 DESNs to 2 DESNs and replace EOL equipment	2021	55
8	Kenilworth TS: Power factor correction	LDC is developing distribution option	2022	1
9	Norfolk area supply capacity	Norfolk TS: Install capacitor bank	2022	3

Table 2: Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Recommended Plan of action	Planned I/S Date	Budgetary Estimate ($M)
1	Birmingham TS: EOL transformer and metalclad switchgears	Replace EOL equipment	2025	29
2	Mid-Term EOL transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4)	Monitor and review in next planning cycle	2025-29	69
3	Mid-Term EOL switchgear at Norfolk TS and Burlington TS[1]	Monitor and review in next planning cycle	2026	57
4	EOL cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4[2]	To further assess the options in this RIP by the Study Team and addendum issued to Hamilton IRRP and RIP	2026	28
5	Norfolk area supply capacity	To further assess the options in this RIP by the Study Team in advance of next planning cycle and addendum issued to RIP	2026	80
6	Beach TS: EOL 230 kV auto-transformers[3] and DESN transformers	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2027	71
7	Lake TS: EOL transformers and switchgears	Monitor and review in next planning cycle	2027	45
8	Burlington TS: EOL 230 kV auto-transformer [3]	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2030	14

[1] Further condition assessment did not confirm the earlier need of refurbishing Brantford switchgear
[2] To be finalized after the completion of Hamilton IRRP Addendum by the IESO
[3] To be finalized after the completion of Middleport Bulk Study by the IESO

The Study Team recommends that:

- Hydro One to continue with the implementation of major infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- Hydro One to continue with the implementation of infrastructure investment at Birmingham TS for replacement of EOL transformers and switchgears;
- The EOL 230 kV autotransformer options at Beach TS and Burlington TS will be assessed through the IESO Middleport Bulk Study in coordination with Hydro One to develop a final recommended plan;
- The EOL 115 kV Hamilton area cables options are included in this RIP. It will be further assessed by the Study Team to develop a recommended plan to be included as an addendum to the Hamilton IRRP and this RIP;
- The options to reinforce supply to the Norfolk area are included in this RIP and will be further assessed by the Study Team in advance of the next planning cycle to develop a recommended plan and an addendum be made to the RIP; and
- All the other identified needs/options in the mid and 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 BURLINGTON TO NANTICOKE REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Burlington o Nanticoke RIP Study Team. . In addition to Hydro One representatives, other members of the RIP Study Team included representative from Brantford Power Inc. ("Brantford Power"), Burlington Hydro Inc. ("Burlington Hydro"), Energy + Inc. ("Energy +"), Alectra Utilities Corporation (former Horizon Utilities Inc. "Alectra Utilities"), Hydro One Distribution, the Independent Electricity System Operator ("IESO") and Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

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. Electrical supply to the region is provided from twenty-nine 230 kV and 115 kV step-down transformer stations. The sum of 2018 non-coincident summer station peak load of the Region was about 2381 MW. The boundaries of the Region are shown in Figure 1-1 below.

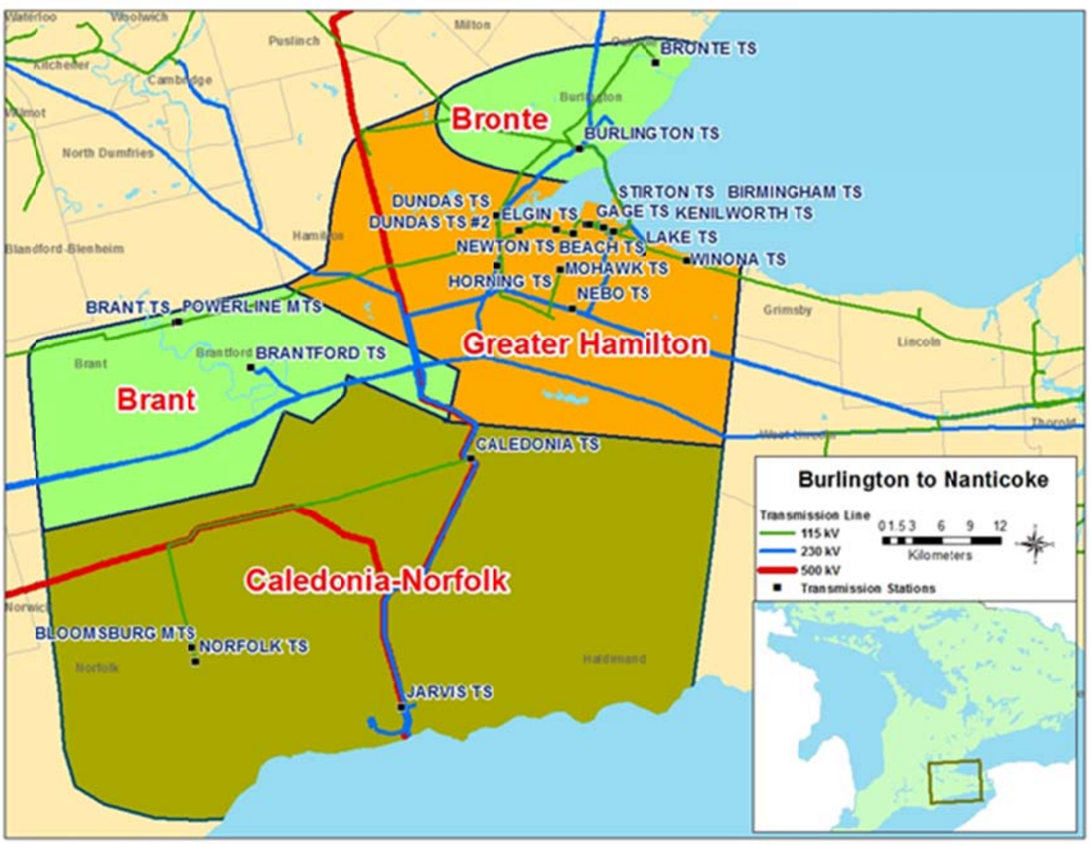

Figure 1-1 Burlington to Nanticoke Region

1.1 Objective and Scope

The 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;
- 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 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 summary of the wires plan developed during LP (Local Planning), SA (Scoping Assessment), and/or as identified in IRRP phase.
- Discussion of any other major transmission infrastructure investment plans over the near to mid-term planning horizon(0-10 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information.

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 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[4] ("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

[4] Also referred to as Needs Screening

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 Hamilton IRRP was identified in the Scoping Assessment phase of the Burlington to Nanticoke Region's second regional planning cycle and was completed in February 2019.

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.

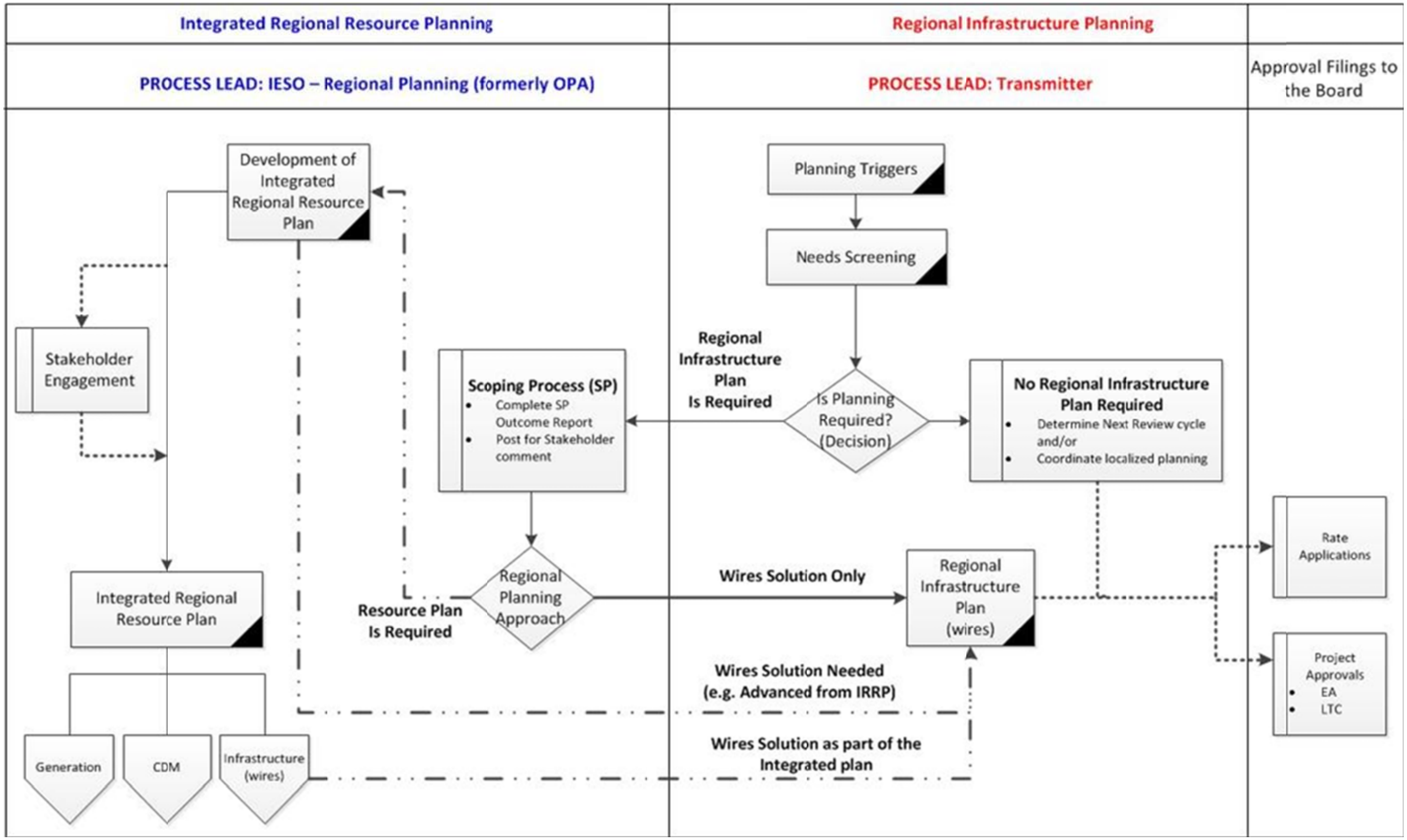

Figure 2-1 Regional Planning Process Flowchart

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.

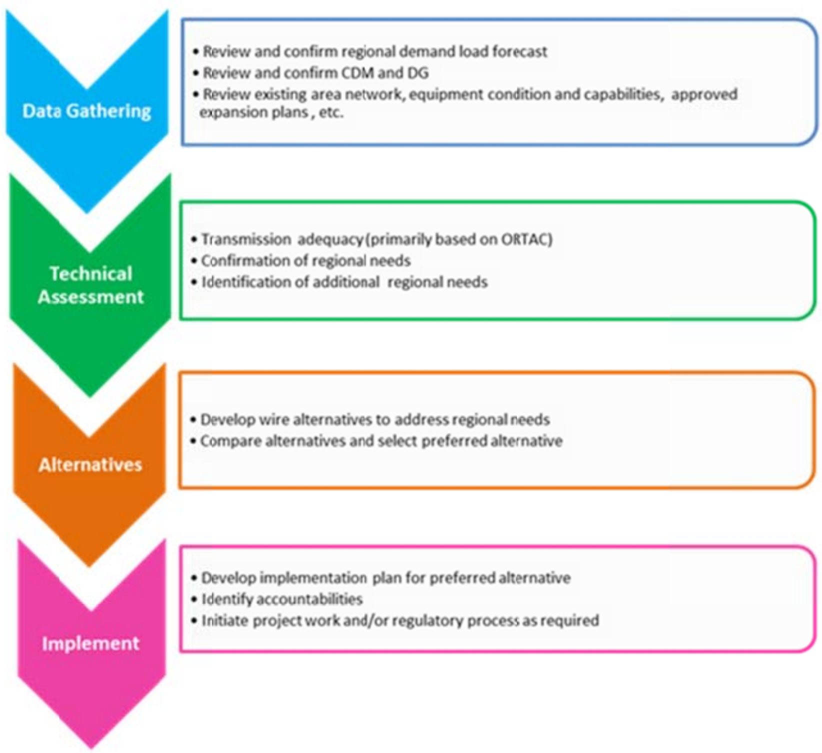

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE BURLINGTON TO NANTICOKE REGION COVERS THE CITY OF BRANTFORD, MUNICIPALITY OF HAMILTON, COUNTIES OF BRANT, HALDIMAND AND NORFOLK. SOME OF THE ELECTRICAL INFRASTRUCTURE IN THE REGION IS ONE OF THE OLDEST INSTALLATIONS IN THE PROVINCE. 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.

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 1-1 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 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.

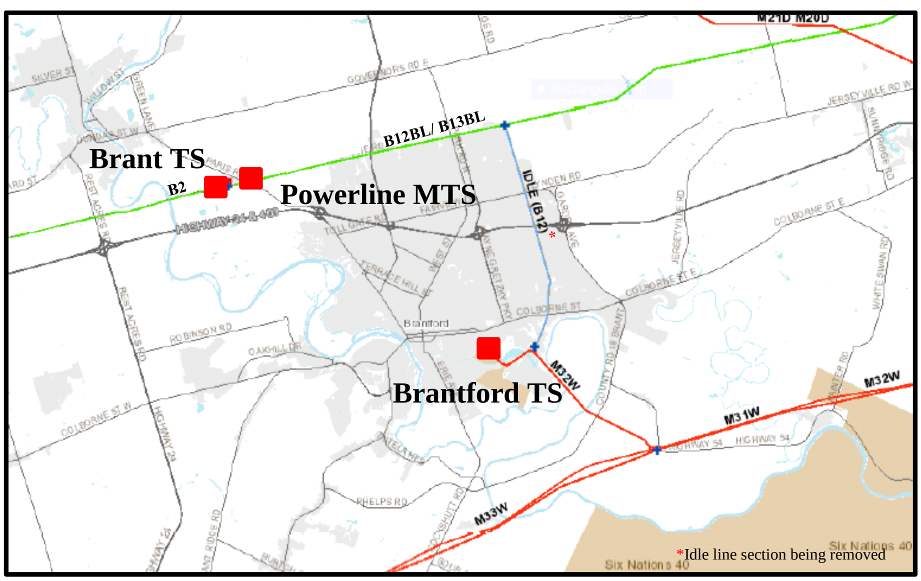

Figure 3-1 Brant sub-region

The total 2018 non-coincident peak demand of the three stations was 289 MW. Energy + Inc. and Brantford Power Inc. are the main LDCs that serve 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. Electricity supply to the sub-region is provided by:
  - Bronte TS supplied by 115 kV double circuit line B7/B8.
  - Burlington TS supplied by 230 kV double circuit line Q23BM/ Q25BM.
  - Cumberland TS supplied from 230 kV double circuit transmission line B40C/B41C.

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

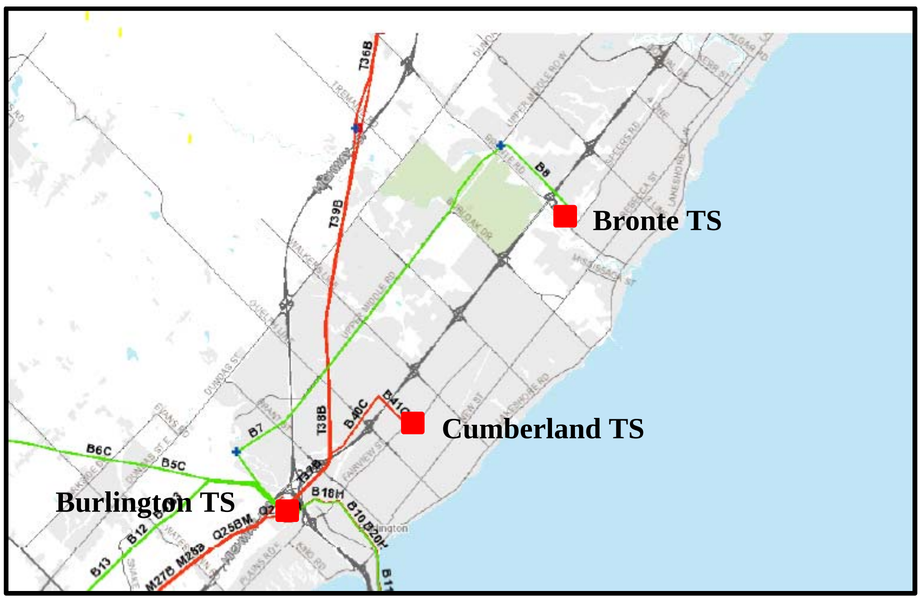

Figure 3-2 Bronte sub-region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial and industrial customers. The total 2018 non-coincident peak station demand of the three stations was 401 MW.

- The Greater Hamilton sub-region encompasses the City of Hamilton that includes Townships of Flamborough and Glanbrook and towns of Dundas and Stoney Creek. Some of the electrical infrastructure in the sub-region was built over 50 years ago and is one of the oldest installations in the province. Electricity supply to the sub-region is grouped 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 115 kV area which includes Dundas TS, Dundas #2, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer owned 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.

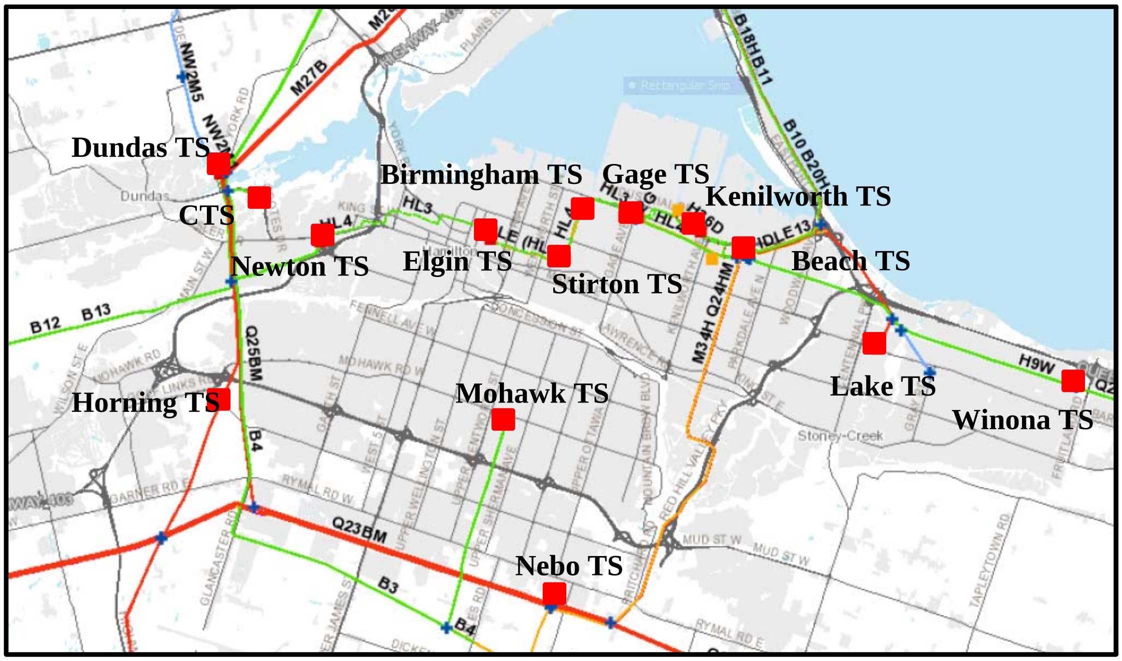

Figure 3-3 Greater Hamilton sub-region

The total 2018 non-coincident peak demand of the Greater Hamilton sub-region was 1371 MW. The area is served by Alectra Utilities, Hydro One Distribution and CTSs comprises 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 and a CTS supplied from the 230 kV double circuit line N21J/N22J.
- One CTS supplied from the 230 kV single circuit N20K.
- Bloomsburg DS and Norfolk TS 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 2018 non-coincident peak demand of this sub-region was 320 MW.

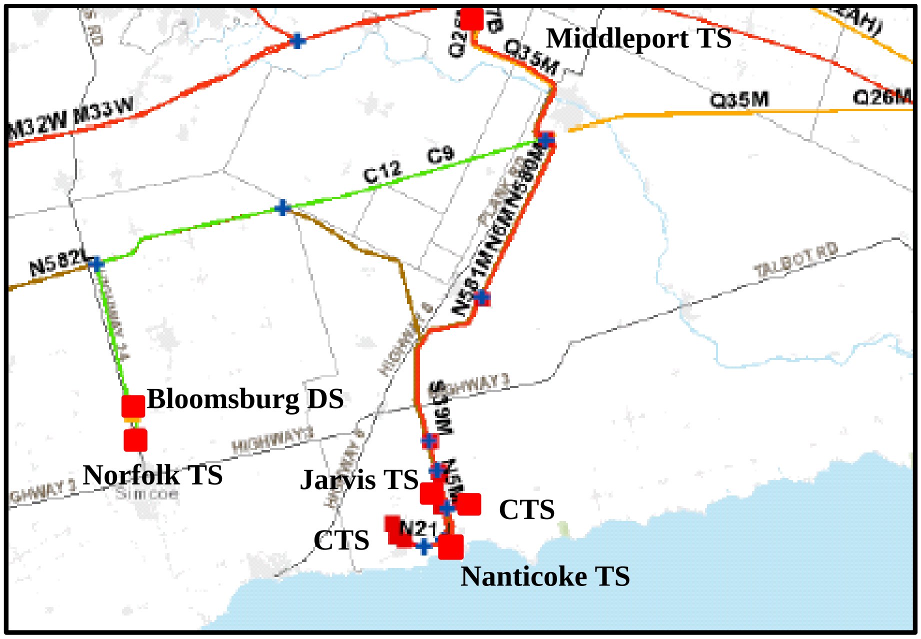

Figure 3-4 Caledonia Norfolk sub-region

Electrical single line diagrams for the Burlington to Nanticoke region's 500 kV/ 230 kV facilities and 115 kV facilities are shown below in Figure 3-5 and Figure 3-6.

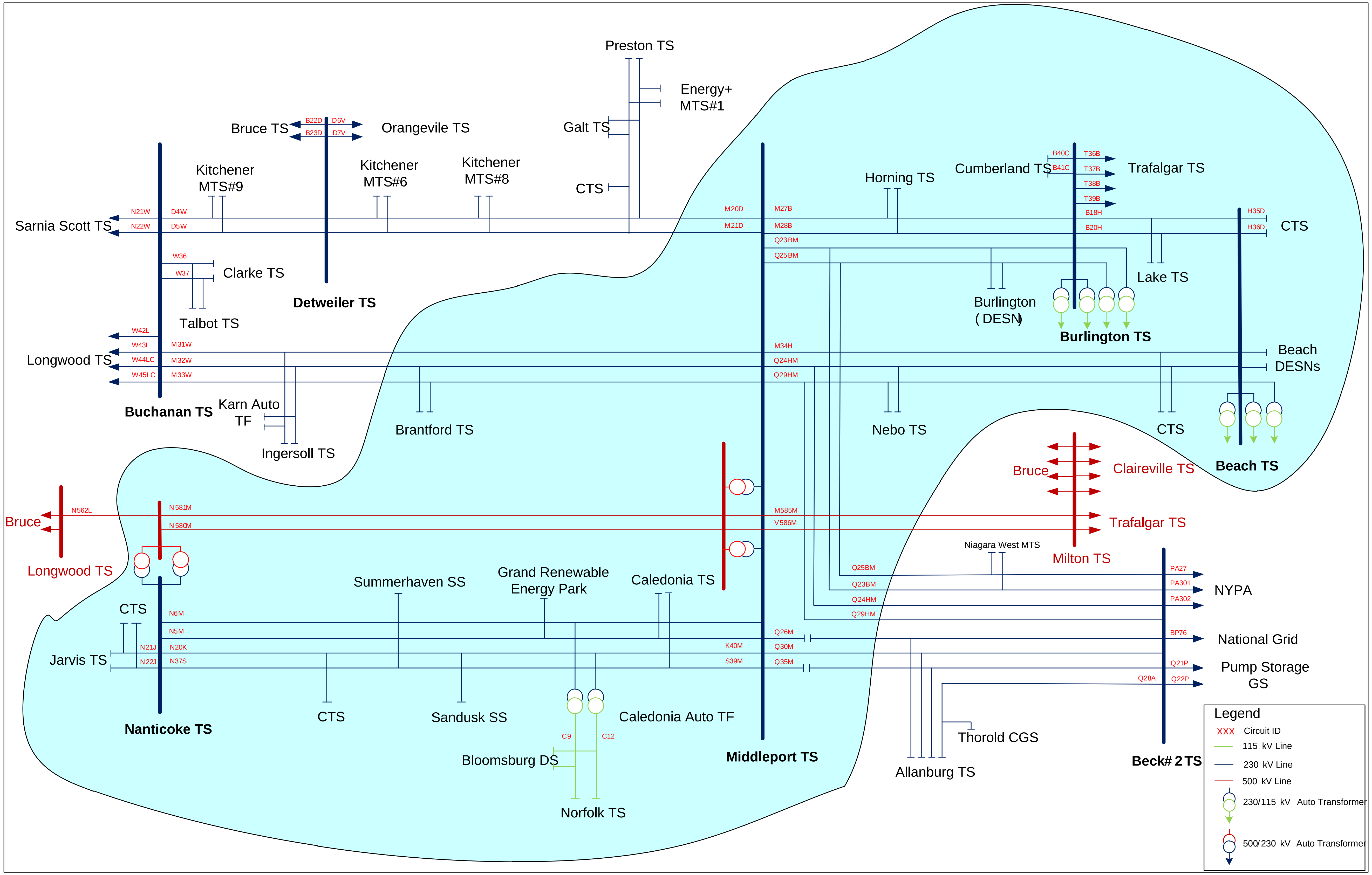

Figure 3-5 Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

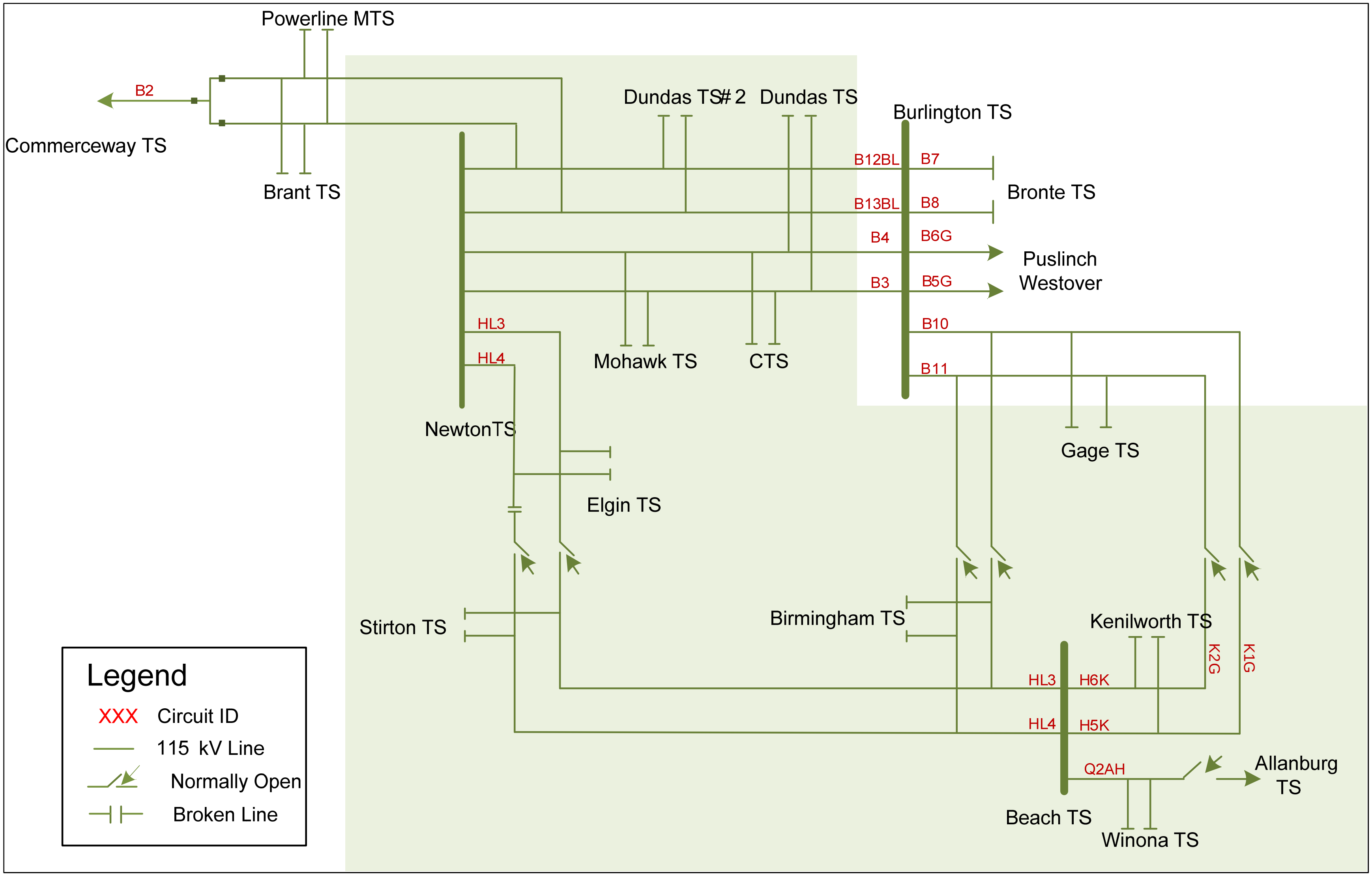

Figure 3-6 115 kV Network Supplied by Burlington TS and Beach TS

4. TRANSMISSION FACILITIES 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 BURLINGTON TO NANTICOKE REGION.

A brief listing of some of the major projects completed over the last ten years are as follows:

- Burlington TS (2009) - replaced 230/115 kV autotransformer T6 following failure.
- Second 115 kV supply to Norfolk TS and Bloomsburg DS (2009) – Built 12 km of new 115 kV circuit to provide second supply to Norfolk TS and Bloomsburg DS.
- Jarvis TS (2011) and Caledonia TS (2012) – installed LV reactors to reduce short circuit levels below the TSC limits and to allow increased generation connection capability at these stations.
- Nebo TS (2013) – replaced 230/ 27.6 kV transformers (T1/T2) with larger size standard units and added six new breaker positions to meet customer needs.
- 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.
- Transformer replacement at stations: Norfolk TS (2009), Birmingham TS (2010), Cumberland TS (2012), Brantford TS (2013), Kenilworth TS (2014), Dundas TS (2015), Brant TS (2016), Beach TS (2018) and Mohawk TS (2018).
- B7/B8 115 kV Transmission line capacity (2018) – addressed supply capacity constraint to Bronte TS through distribution load transfers (Ongoing)
- Horning TS (2018) – replaced 230/ 13.8 kV transformers (T1/T2) & LV switchgears
- Bronte TS (2019) – replaced 115/ 27.6 kV transformers (T5/T6) & associated LV switchgears
- 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.

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5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Burlington to Nanticoke Region is growing at a slow rate of about 1% annually. However the loads at Norfolk TS and Bloomsburg DS mark a significant growth over the study period due to the high penetration of greenhouse loads and developments in Brant and Hamilton sub-regions.

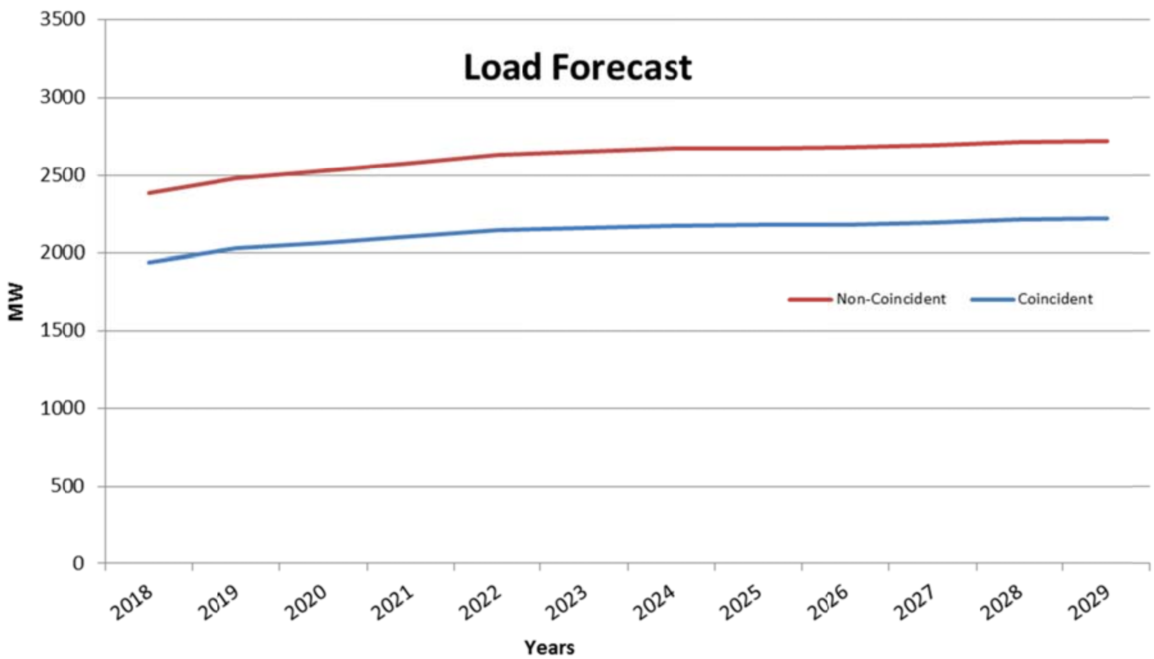

Figure 5-1 Burlington to Nanticoke Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Burlington to Nanticoke Region peak summer non-coincident load forecast. The non-coincident and coincident load forecasts were prepared based on the 2018 extreme weather corrected loads. The non-coincident forecast represents the sum of the individual station's peak load and is used to determine the need for stations and the coincident load forecast was used to determine line capacity needs. Regional non-coincident and coincident load forecasts for the Burlington to Nanticoke Region are given in Appendix D.

The RIP load forecast was developed as follows:

- Load forecast for all stations was developed using the summer 2018 actual peak load adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The net station loads account for CDM measures and connected DG in the region.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All planned facilities listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- 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).

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE BURLINGTON TO NANTICOKE REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle three regional assessments have been conducted for the Burlington to Nanticoke Region. These studies are:

1) NA Report - Burlington to Nanticoke Region, May 15 , 2017
2) SA Report – Burlington to Nanticoke Region, August 25, 2017
3) IRRP Report – Hamilton sub-region, February 25, 2019

The NA and IRRP reports identified a number of needs to meet the forecast load demands and asset approaching EOL. A review of the loading on the transmission lines and stations in the Burlington to Nanticoke Region was also carried out as part of the assessment using the latest regional load forecast provided 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.

6.1 500 and 230 kV Transmission Facilities

The 500 kV and most of the 230 kV transmission circuits in the Burlington to Nanticoke Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of Ontario’s transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. In addition there are three 230 kV double circuit lines H35D/ H36D, B40C/ B41C and N21J/ N22J that supply only local loads. The circuits supplying local loads in the region are as follows (refer to Figure 3-5):

Terminal Stations	**Circuits**	**Connected Supply Stations**
Middleport TS to Burlington TS	M27B/ M28B	Horning TS
Middleport TS to Beck #2 TS to Burlington TS	Q23BM/ Q25BM /Q24HM/ Q29HM	Burlington (DESN) TS, Nebo TS and a CTS
Middleport TS to Buchanan TS	M32W/ M33W	Brantford TS
Middleport TS to Nanticoke TS	N5M/ S39M/ N20K	Caledonia TS and a CTS
Burlington TS to Beach TS	B18H/ B20H	Lake TS
Nanticoke TS to Jarvis TS	N21J/ N22J	Jarvis TS and a CTS
Beach TS to a CTS	H35D/ H36D	CTS
Burlington TS to Cumberland	B40C/ B41C	Cumberland TS

6.2 230/115 kV Transformation Facilities

Almost half of the Region's load is supplied from the 115 kV transmission systems. The primary source of 115 kV supply is from three 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS.

Table 6-1 summarizes the loading levels for all three 230 /115 kV auto transformers in the Burlington to Nanticoke region.

Table 6-1 Adequacy of 230/115 kV Autotransformer Facilities

Facilities	MVA Load Meeting Capability	2018 MVA Loading	Need Date
Burlington TS 230/115 kV autotransformers	912	560	-[1]
Beach TS 230/115 kV autotransformers	582	268	-[1]
Caledonia TS 230/115 kV autotransformer	187	104	-[1]

[1] Adequate over the study period (2019- 2029)

The autotransformers in the Burlington to Nanticoke region are of adequate capacity over the study period (2019-2029). The installation of the 230/115 kV autotransformers at Cedar TS in 2017 have reduced the loading on the Burlington autotransformers. The recently in-service 115 kV switching at Brant TS will further reduce loading on the Burlington TS autotransformers.

The loading on the Burlington TS 230/115 kV autotransformers, for the simultaneous loss of two autotransformers, is therefore expected to remain within the short term rating of the two remaining in-service autotransformers at Burlington TS. No further action is required.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities can be divided in three main sections: Please see Figure 3-5 and 3-6 for the single line diagrams.

1. Burlington 115 kV – has twelve 115 kV circuits B3/B4, B5/B6, B7/B8, B10/B11, B12BL/B13BL and HL3/ HL4. The supply capacity of Burlington 115 kV lines is adequate over the study period (2019-2029). The HL3/ HL4 115 kV double circuit cable consist of two sections:
   i. HL3/ HL4 Newton TS to Elgin TS
   ii. HL3/ HL4 Elgin TS to Stirton TS (HL4 is idle)

These cables provide normal and backup supply to Elgin TS. The supply capacity of 115 kV HL3/ HL4 cables is adequate over the study period (2019-2029).

2. Beach 115 kV– has five 115 kV circuits H5K/ H6K, HL3/ HL4 and Q2AH out of Beach TS serving the area. In addition there are two115kV circuits K1G and K2G connecting Kenilworth TS to Gage TS. These circuits are normally open and provide backup supply.

   The supply capacity of Beach 115 kV cables and lines is adequate over the study period (2019-2029).

3. Norfolk Caledonia – has two 115 kV circuits C9 and C12 supplying Norfolk TS and Bloomsburg DS. The need of additional supply capacity for C9/C12 double circuit line was identified during the earlier phases of the regional planning cycle.

   The updated load forecast and further assessment as part of this RIP shows that the combined load of Norfolk TS and Bloomsburg DS exceeds the 87 MW supply capacity of C9/ C12 line. This need is further discussed in this RIP (Section 7).

   The loading on the limiting 115 kV circuits is summarized below in Table 6-2.

Table 6-2 Limiting Sections of 115 kV Circuits

Line Section	Overloaded Circuit	Reference Section	Capacity (MW)	Contingency	2018 Loading (MW)	Need Date
Caledonia TS to Norfolk TS	C9/ C12	Section 7.9	87	C9/ C12	94*	2019

*Local coincident peak. Excess loads being transferred to Jarvis TS

The adequacy of 115 kV lines capacity was assessed using 2018 Summer Peak base case updated with 2029 loading.

The list of all the 230 kV and 115 kV circuits is given in Appendix A.

6.4 Step-Down Transformation Facilities

There are a total of 29 step-down transmission connected transformer stations in the Burlington to Nanticoke Region. The stations have been grouped based on the geographical area and supply configuration. The station loading in each area and the associated station capacity is provided in Table 6-3 below. The complete list of all the stations in the Burlington to Nanticoke region and their supply circuits is given in Appendix B.

Table 6-3 Adequacy of Step-Down Transformer Stations

sub-region	Capacity (MW)	2018 Loading (MW)	Need Date
Brant sub-region	403	289	-(2)
Bronte sub-region	540	401	-(2)
Greater Hamilton sub-region (1)	2017	1092	-(2)
Caledonia Norfolk sub-region (1)	344	203	-(3)

(1) Excludes Customer Transformer Stations (CTS)
(2) Adequate over the study period (2019-2029)
(3) Near term and mid to long term needs, for details refer to section 7.

Dundas TS has two DESN units T1/T2 and T5/T6. The T1/T2 DESN at Dundas TS is loaded over its supply capacity due to unbalanced loading between the two Dundas TS DESNs. The total supply capacity of both the Dundas TS DESNs is sufficient over the study period. The loading between the two Dundas TS DESNs is required to be balanced.

Nebo TS 13.8 kV T3/T4 DESN was also identified as marginally over loaded during an earlier phase of the regional planning cycle. Further assessment as part of this RIP based on updated forecast confirms that the loads on the Nebo TS T3/T4 DESN will remain around its supply capacity during the study period. No further action is required.

Bloomsburg DS is currently forecasted to reach its limit by 2022 but Norfolk TS has adequate station supply capacity over the study period. However, the supply circuit C9/C12 is constrained and a mid-term to long term solution will be required.

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.

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.

It is expected that all loads can be restored within 8 hours in the Burlington to Nanticoke Region over the study period. None of the transmission circuits in the Burlington to Nanticoke region will be supplying total loads in excess of 250 MW. The following double circuit lines in the Burlington to Nanticoke Region are expected to supply the loads in excess of 150 MW at peak times:

- B3/ B4
- B12BL/ B13BL
- H35D/ H36D

- M32W/ M33W
- Q23BM/ Q25BM

These circuits are located in urban and semi urban areas and are well accessible in the events of emergencies. Therefore based on the past performance and reliability data, the restoration criteria are met and the Study Team recommends that no further action is required at this time.

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7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE, SCOPING ASSESSMENT AND THE HAMILTON SUB-REGION 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 plan. The long term needs will be assessed in the next planning cycle.

The near-term (2019-2024) electrical infrastructure needs in the Burlington to Nanticoke Region are summarized below in Table 7-1.

Table 7-1 Identified Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
1	Cumberland TS: Power factor correction	7.1	2019
2	115 kV B7/B8: EOL line section from Burlington TS to Nelson Jct.	7.2	2020
3	115 kV B3/B4: EOL line section from Horning Mountain Jct. to Glanford Jct.	7.3	2020
4	Elgin TS: EOL transformers & switchgears	7.4	2021
5	Newton TS: EOL transformers	7.5	2021
6	Kenilworth TS: EOL transformer & switchgear	7.6	2021
7	Dundas TS: Load transfers	7.7	2021
8	Gage TS: EOL transformers & switchgear	7.8	2021
9	Kenilworth TS: Power factor correction	7.9	2022
10	Norfolk area supply capacity	7.10	2023

Note: Further condition assessment did not confirm the earlier identified need of refurbishing Brantford switchgear.

The mid- and long-term (beyond 2025) electrical infrastructure needs in the Burlington to Nanticoke Region are summarized below in Table 7-2. Where available, a preliminary plan to address that need is provided in the corresponding sub-section.

Table 7-2 Identified Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
1	Birmingham TS: EOL transformer and metalclad switchgears	7.11	2025
2	Mid-Term EOL transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4)	7.12	2025-29
3	Mid-Term EOL switchgears at Norfolk TS and Burlington TS	7.13	2026
4	EOL cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4	7.14	2026
5	Norfolk area supply capacity: Install new 230 kV double circuit lines and a new DESN	7.10	2026
6	Beach TS: EOL 230 kV auto-transformers and DESN transformers	7.15	2027
7	Lake TS: EOL transformers and switchgear	7.16	2027
8	Burlington TS: EOL 230 kV auto-transformer	7.17	2030

The needs identified in the Burlington to Nanticoke Region in the above Tables 7-1 and 7-2 are further discussed below.

7.1 Cumberland TS: Power Factor Correction

7.1.1 Description

The Cumberland TS supplies about 120 MW of loads in the city of Burlington. The historical loading data of Cumberland TS indicated that under peak load conditions the power factor at Cumberland TS is lagging slightly below the ORTAC requirement of 0.9.

7.1.2 Recommended Plan and Current Status

The Needs Assessment report identified this need and Study Team recommended Burlington Hydro to work with their load customers supplied by Cumberland TS and install capacitor banks on distribution system required to meet the minimum power factor requirement of 0.9.

A Burlington Hydro customer supplied by Cumberland TS has recently installed capacitor banks within its facilities to improve the power factor. This is expected to address the power factor need at Cumberland TS. However, the Study Team recommends that Hydro One and Burlington Hydro continue monitoring the power factor at this station.

7.2 115 kV Circuits B7/B8: End of Life Section (Burlington TS to Nelson Junction)

7.2.1 Description

The 115 kV double circuit line B7/B8 line supplies about 140 MW of Burlington and Oakville area loads through Bronte TS. The line section from Burlington TS to Nelson junction (about 2.3 km) was built in 1920's. Hydro One has identified that the conductor on this line section from Burlington TS to Nelson junction has reached end of useful life.

7.2.2 Alternatives and Recommended Plan

The following alternatives were considered to address 115 kV B7/B8 end of life line section from Burlington TS to Nelson junction:

- <u>Maintain status quo</u>: This alternative was considered and rejected as it does not address the EOL issue, risk of failures resulting in poor supply reliability and would result in increased maintenance expenses.
- <u>Refurbishment of EOL line section</u>: Refurbish 2.3 km of EOL line conductor section of B7/B8 line section.

The Study Team recommendation is to refurbish the 115 kV B7/ B8 line section from Burlington TS to Nelson junction supplying Bronte TS using similar ACSR conductor. The refurbishment work is expected by Hydro One to be completed by 2020 at an estimated cost of approximately $2 million.

7.3 115 kV Circuits B3/B4: End of Life Section (Horning Mountain Jct. to Glanford Jct.)

7.3.1 Description

The 115 kV B3/B4 line supplies Hamilton sub-region loads including Dundas TS (T1/T2 DESN) and Mohawk TS. The 11 km long from Horning Mountain Jct. to Glanford Jct. section of this line has a solid copper conductor which is approximately 100 years old and at end of useful life.

7.3.2 Alternatives and Recommended Plan

The following alternatives were considered to address the above need:

- <u>Continue to maintain the assets (status quo)</u>: This alternative was considered and rejected as it does not address the frequent failure, increased maintenance expenses and poor supply reliability.
- <u>Refurbishment of EOL line section</u>: Refurbish this line section and replacing EOL copper conductor with 605 kcmil ACSR conductor on this line tap section.

The Study Team recommends Hydro One to continue refurbishment of this line section and replace copper conductor with 605 kcmil ACSR from Horning Mountain Jct. to Glanford Jct. supplying Mohawk TS. This work is currently expected to be completed in 2020 at an estimated cost of $21 million.

7.4 Elgin TS: End of Life Transformers and Switchgears

7.4.1 Description

Elgin TS consists of two DESNs (T1/T2 and T3/T4) built in 1960's supplying loads in the city of Hamilton through three switchgears. The 2018 peak load at Elgin TS was approximately 98 MW.

The T1/T2 transformers are 75 MVA units while the T3/T4 units are non-standard 33 MVA units. All existing four transformers (T1, T2, T3, and T4) and three switchgears at Elgin TS have been identified by Hydro One as approaching end of their useful life. This need was identified in the Needs Assessment phase.

7.4.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Elgin TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining four transformers and the associated three switchgears. This option is extremely costly and cannot be justified with load forecast not showing any growth at this station.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Elgin TS. This alternative was considered but is not feasible due to limited load transfer capacity with neighboring stations and higher costs associated with load transfers.
- Reconfiguration and downsize the station from two DESNs to one DESN station: In this option, the station will be reconfigured and downsized from the existing four transformers to two transformers.

The Study Team recommends Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. Under this plan, T1/T2 and T3/T4 DESNs will be replaced by a single T5/T6 DESN with two 100 MVA standard units and four new switchgears. This will maintain adequate supply capacity to the loads. This plan is expected to cost $81 million with an expected in service of 2021.

7.5 Newton TS: End of Life Transformers

7.5.1 Description

Newton TS is a 115 / 13.8 kV DESN station built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. The current load at Newton TS is approximately 52 MW, and is expected to stay at this level over the study period.

The T1/T2 transformers are 67 MVA nonstandard units, supplying loads through 13.8 kV switchgears. Both these transformers have been identified as EOL requiring replacement. Recently the transformer T2 has failed and is being replaced on an emergency basis and transformer T1 is also showing signs of deterioration.

7.5.2 Alternatives and Recommended Plan

The following alternatives are considered in the light of recent developments with regards to end of life asset at Newton TS:

- 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 Newton TS. This alternative was considered but is not feasible due to stations' geographic location separating it from the neighboring 13.8 kV distribution system.
- Replacement of the assets: Replace existing 67 MVA Newton TS companion transformer T1 with 75 MVA units built to current standards.

The Study Team recommends to replace existing 67 MVA Newton TS transformer T1 with 75 MVA unit similar to T2 built to current standards to ensure reliability of supply for the customers in the area. This replacement work at Newton TS is currently planned to be completed by 2021.

7.6 Kenilworth TS: End of Life Transformer and Switchgear

7.6.1 Description

The two DESNs at Kenilworth TS are over 60 years old, supplying 52 MW load in the city of Hamilton. The T1/T4 DESN transformers are non-standard 67 MVA units. The transformer T2 of second DESN is rated at 100 MVA while T3 is a non-standard 120 MVA unit.

The original T2 transformer failed in 2014 and was replaced with a standard 100 MVA unit. The remaining three transformers (T1, T3, and T4) and one of the two in service switchgears at Kenilworth TS have been identified as approaching end of their useful life.

7.6.2 Alternatives and Recommended Plan

The following alternatives were considered to address end of life issue at Kenilworth TS:

- 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 reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: This alternative would require maintaining four transformers and the associated three switchgears which is not justifiable based on the load forecast.

- Station/load consolidation: Moving loads to neighboring station(s) and retiring Kenilworth TS. This alternative was considered but is not feasible due to: a) unique electrical characteristics and requirements of industrial costumer load in the area, and b) higher costs associated with reconfigurations and transfer of customer loads.
- Reconfiguration of the station reducing to two supply transformers and two switchgears: This option will reconfigure and adequately downsize the station. In this configuration, station will be reduced from four transformers to only two transformers supplying two switchgears.

The Study Team recommends Hydro One proceed with the last option above and reconfigure the station, reducing it to a single DESN with two transformers and two switchgears. The recently replaced transformer and one of the existing metalclad switchgear will be utilized while one transformer and switchgear will be replaced. The new transformer T3 will be a standard unit similar to T2 that was replaced in 2014. This refurbishment project is currently expected to be completed by the year 2021 at an estimated cost of $35.8 million.

7.7 Dundas TS: Load Transfer

7.7.1 Description

Dundas TS (T1/T2) and Dundas TS #2 (T5/T6) are supplying a total peak load of 150 MW in the city of Hamilton. The total supply capacity of both stations is 188 MW which is sufficient over the study period.

The loading at Dundas TS will be capped at its supply capacity of 99 MW and any additional loads will be supplied from Dundas TS #2. Hydro One distribution currently supplied from the Dundas TS is planning to transfer any excess load to Dundas TS #2.

7.7.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address customer's needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the DESN's load balancing and customer's needs.
- Transfer customer load to Dundas TS #2: Move off loads in excess to the supply capacity of Dundas TS to Dundas TS #2. To facilitate this, two new feeder positions are required at Dundas TS #2. These new breaker positions will be also used to meet future load growths. This option will require reconfiguring of distribution assets by the LDCs.

The Study Team recommends the option to transfer excess load from Dundas TS to Dundas TS #2 by the LDCs utilizing two additional breaker positions at an estimated cost of $2 million, by 2021. It is estimated that LDCs will have to invest approximately $9 million in distribution infrastructure to fully implement this plan.

7.8 Gage TS: End of Life Transformers and Switchgear

7.8.1 Descriptions

Gage TS has three DESNs (T3/T4, T5/T6, and T8/T9) predominantly supplying large industrial customer loads in Hamilton. T3/T4 and T5/T6 DESNs were built in the 1940's with each transformer rated at 63 MVA LTR, while T8/T9 DESN was built in 1960's with each transformer rated at 137 MVA LTR.

These transformers are non-standard units meeting unique high short circuit requirements of the customers. The transformers T3, T4, T5, and T6, as well as T8/T9 DESN switchgear at Gage TS have been identified at their EOL. The refurbishment of these assets has been previously deferred to better understand customer load requirements. Transformer T5 and breakers in the T5/T6 DESN have experienced recurring problems.

The load at Gage TS has reduced over the years to approximately 50 MW, and is currently expected to stay at around this level over the study period. The existing station capacity (of the three DESNs) is about 240 MW. Although there seems to be over-capacity at Gage TS, unique short-circuit and connection requirements of industrial loads at this station limits the feasibility of some of the alternatives/solutions.

7.8.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Gage TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining six transformers and the associated three switchgears. This option is extremely costly and cannot be justified since the load has significantly reduced at this station.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Gage TS. This alternative is not feasible due to: a) unique costumer load requirements (i.e., high short circuit currents are required to operate customer's large arc furnaces and large motors without significant impact to power quality), and b) higher costs associated with reconfigurations of LV cables and transfer of customer loads to other stations.
- Reconfiguration of the station and downsize the station from three DESN to two DESN station: In this option, the station will be reconfigured and downsized from the existing six transformers to four transformers.

The Study Team recommends that Hydro One proceed with the reconfiguration of the station, reducing it from 3 DESNs to 2 DESNs. This plan also provides future flexibility to eliminate the T8/T9 DESN when it approaches EOL. Under this plan, T3/T4 and T5/T6 DESNs will be replaced by a single T10/T11 DESN with two 100 MVA standard units. It also includes replacement of switchgear currently supplied from the T5/T6 transformers.

The refurbishment of Gage TS is expected to be completed in 2021 at an estimated cost of $55 million.

7.9 Kenilworth TS: Power Factor Correction

7.9.1 Description

There are two supply stations inside Kenilworth TS T1/T4 and T2/T3 supplying about 52 MW of loads in the city of Hamilton. The historical loading data of Kenilworth TS indicated that under peak load conditions the power factor at Kenilworth TS is lagging below the ORTAC requirement of 0.9.

7.9.2 Alternatives and Recommended Plan

The following alternatives were considered to address the power factor need at Kenilworth TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the need to meet the ORTAC power factor requirement.
- Improve power factor on distribution system: Install capacitor bank/s and/or work with load customers supplied by Kenilworth TS.

This need was identified during the last Regional Planning cycle and the Study Team recommended Alectra Utilities to install capacitor bank and/or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9.

The installation of capacitor bank will be initiated after completion of refurbishment of Kenilworth TS in 2021 at an estimated cost of $1 million in 2022.

7.10 Norfolk Area Supply Capacity

7.10.1 Description

Norfolk area is currently supplied by two 115 / 27.6 kV DESNs, Norfolk TS and Bloomsburg DS through 115 kV double circuit supply (C9/C12) from Caledonia TS. Both Norfolk TS and Bloomsburg DS have two identical 115 / 27.6 kV transformers of 83 MVA and 42 MVA respectively and are less than 20 years old. The area supply capacity is limited to 87 MW by voltage decline limit in the event of loss of one the two (C9 or C12) supply circuits. The 2018 total peak load of Norfolk area was 94 MW, approximately 7 MW over the supply capacity.

This area has recently seen a significant interest from greenhouse developers and the loads are expected to grow significantly over the study period as identified during this RIP by the study team.

By the year 2021-22, the net load growth of around 20 MW is envisaged and will require supplementing the 115 kV supply system. Over the study period, the net load growth of about 55 MW is forecasted which would be above the thermal limit of 139 MVA for the existing 115 kV transmission line.

7.10.2 Alternatives and Recommended Plan

The following alternatives are considered to address the future supply needs of Norfolk area:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's needs in the area.
- Near Term Options/Solutions:
    - Install capacitor banks: Install capacitor banks at Norfolk TS to improve voltage profile increasing supply capacity of area to accommodate approximately 10 MW of expected load increases in the near term
    - Transfer loads from Norfolk area to nearby stations using existing feeders: There is limited load transfer capacity available between the Norfolk area stations and Jarvis TS. New feeder inter-ties may need to be built to transfer around 5 MW of load from Norfolk area to Jarvis TS.
- Mid- to Long Term Options/Solution:
    - Converting C9/ C12 115 kV circuits to 230 kV: Upgrading 115 kV C9/C12 circuits to 230 kV will impart additional transmission capacity beyond the current capacity of 87 MW. However, this option will have line capacity limitation along with implementation challenges.
    - New 230 kV double circuit line about 20-25 km long and a new 230/ 27.6 kV DESN: A new station in Norfolk area supplied by a new 230 kV double circuit line by either tapping two 230 kV circuits in the Middleport TS to Nanticoke TS or Middleport TS to Buchanan TS corridor.

The Study Team recommends that in the near term a) Hydro One install new additional capacitor bank at Norfolk TS in 2022 and b) LDCs build feeder inter-ties to transfer load between the Norfolk area stations and Jarvis TS. Hydro One transmission will plan capacitor bank to be connected in 2022 at an estimated cost of $3 million.

The Study Team recommends further assessment be carried out by the IESO and Hydro One to review that mid to long term options identified above and develop a recommended plan to address the capacity needs for the Norfolk Area in advance of the next planning cycle. Following the assessment, an addendum will be included to the IRRP and RIP reports in 2020.

7.11 Birmingham TS: End of Life Transformer and Switchgears

7.11.1 Description

Birmingham TS is located in the city of Hamilton having two DESN units T1/T2 and T3/T4 of 75 MVA each. Both the DESNs at Birmingham TS can supply a total load of about 185 MVA (LTR). The Birmingham TS currently supplies a large industrial customer with unique connection requirements. The load at Birmingham TS is forecasted at about 90 MW over the study period.

At this time one 115 / 13.8 kV transformer and three 13.8 kV LV metalclad switchgears are at EOL and have been identified by Hydro One for refurbishment.

7.11.2 Alternatives and Recommended Plan

The following alternatives are considered to address Birmingham TS end of life asset 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 Birmingham TS. This alternative was considered but is not feasible due to customer's unique needs.
- Replacement of the assets: Replace existing T1 EOL transformer with similar unit and three metalclad switchgears to current standards.

The Study Team recommends to replace the end of life 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 and. Currently, Hydro One expects to complete this replacement by 2025.

7.12 Mid-Term End of Life Transformer Replacements

7.12.1 Description

Hydro One has identified the following transformers reaching end-of-life in the 2025 – 2029 timeframe:

1. Nebo TS (T3/T4)
2. Caledonia TS (T1)
3. Jarvis TS (T3/T4)

7.12.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above end of life asset 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 these stations. This alternative was considered but is not feasible as there were no nearby stations that can accommodate their loads.
- Replacement of the assets: Replace existing transformers with similar units built to current standards.

The option for these needs is like-for-like replacement of transformers. However, as these needs are far in future, the Study Team recommends reviewing these needs again in the next regional planning cycle.

7.13 Mid-Term End of Life LV Switchgear Replacement

7.13.1 Description

Hydro One has identified that the LV switchgears at a number of stations are reaching end-of-life in the 2025 – 2029 timeframe and need to be replaced. These stations are:

1. Norfolk TS
2. Burlington TS

7.13.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above end of life asset 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.
- Replacement of the assets: Replace existing switchgear with one's built to current standards.

The option for these needs is like-for-like replacement of switchgear. However, as these needs are far in future, the Study Team recommends reviewing these needs in the next regional planning cycle.

7.14 End of Life Cables in Hamilton Sub-region: HL3/HL4, K1G/K2G, H5K/H6K

7.14.1 Description

The Hamilton sub-region has following four (4) pairs of 115 kV underground cable circuits that are around 50 years old and approaching end of life over the next 10 years. These cables primarily supply industrial, residential and commercial loads in the City of Hamilton. These cables are also used as alternate supply during outages and emergency conditions.

i. 115 kV K1G/K2G Cable (Kenilworth TS to Gage TS)
ii. 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)
iii. 115 kV HL3/HL4 Cable (Newton TS to Elgin TS)
iv. 115 kV H5K/H6K Cable (Beach TS to Kenilworth TS)

The replacement and/or reconfiguration of these high voltage underground cables was identified in the previous cycle because it will be complicated and expensive and therefore requires assessment of alternative/s at the earliest possible as mentioned in the last regional planning.

i. 115 kV K1G/K2G Cables (Kenilworth TS to Gage TS)

These cables are 1.8 km long, of 1973 vintage connecting Gage TS and Kenilworth TS. Each of these cables is rated to supply 180 MW of loads and are used for providing backup supply to Gage TS (from Beach TS) and to Kenilworth TS (from Burlington TS) during outages and emergencies. These cables do not carry load under normal operating configuration.

Alternatives/Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers.
- Building a new 1.8 km overhead 115 kV double circuit corridor between Kenilworth TS and Gage TS: This option will be the least expensive but the existing route passes along the narrow road allowances and through private properties. Building new overhead line section may not be feasible due difficulty in meeting required clearances and obtaining easement rights.
- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. Although it may not be the least cost option, it is the only practical alternative.

ii. 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)

These cables are 1.9 km long, of 1968 vintage connecting Elgin TS to Stirton TS. One of the two cables (HL4) was damaged in 1998 and since then it has been out-of-service. The HL3 cable is rated at 170 MW and is used for providing backup supply to Elgin TS (from Beach TS) and to Stirton TS (from Burlington TS) during outages and emergencies. HL3 cable does not carry load under normal operating configuration.

Alternatives/Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers. Unavailability of this HL3 circuit at the time of need will be catastrophic.
- Building a new 1.9 km overhead long 115 kV double circuit line between Stirton TS and Elgin TS: This option will be the least expensive but the existing route passes through densely populated areas with narrow road allowances. Therefore building new overhead line section is not feasible.
- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. This is the only practical alternative but the replacement of these cables will be challenging as it passes through a densely populated areas with a number of other utilities crossing or sharing the same corridor. Further project specific assessment and details will have to be undertaken prior to initiating the project including consultation with other stakeholders, such as, municipality and other utilities on the same ROW.

iii. 115 kV HL3/HL4 Cables (Newton TS to Elgin TS)

These cables are 4.6 km long, of 1975 vintage connecting Newton TS and Elgin TS. Each of these cables is rated to supply 176 MW of loads and used for providing primary supply to Elgin TS (from Burlington TS). These cables supply about 100 MW of load at Elgin TS. For the loss of a single HL3/HL4 cable, the companion cable is sufficient to supply Elgin TS loads forecasted over the study period.

Alternatives /Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers.
- Building a new 4.6 km overhead 115 kV double circuit line between Newton TS and Elgin TS: This option will be the least expensive but the existing route passes through densely populated areas with narrow road allowances. This option will require section-92 application, acquiring easement rights and may still be not be feasible due to difficulty in meeting required clearances.
- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. This is the only practical alternative but the replacement of these cables will be challenging as it passes through a densely populated areas with a number of other utilities crossing or sharing the same corridor. Further project specific assessment and details will be undertaken prior to initiating the project including consultation with other stakeholders, such as, municipality and other utilities on the same ROW.

iv. 115 kV H5K/H6K Cables (Beach TS to Kenilworth TS)

These cables are 1.5 km long, of 1973 vintage connecting Beach TS and Kenilworth TS. Each of these cables is rated to supply 180 MW of loads and used for providing primary supply to Kenilworth TS (from Beach TS). These cables supply about 50 MW of load at Kenilworth TS. For the loss of a single H5K/H6K cable, the companion cable is sufficient to supply Kenilworth TS loads forecasted over the study period.

Kenilworth TS has a backup supply from Burlington TS through 115 kV K1G/ K2G cables between Kenilworth TS and Gage TS.

Alternatives /Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers.
- Building a new 1.5 km overhead 115 kV double circuit corridor between Kenilworth TS and Beach TS: This option will be the least expensive but the existing route passes along the narrow road allowances and through private properties. Building new overhead line section may not be feasible due difficulty in meeting required clearances and obtaining easement rights.

- <u>"Like-for-Like" replacement of the assets:</u> This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. Although it may not be the least cost option, it may be the only practical alternative.

7.14.2 Recommendation

The Study Team recommends that the above options to replace these 115 kV cables in the Hamilton Area be further assessed by Hydro One and the IESO to develop a recommended plan. After the completion of this assessment, an addendum to Hamilton Area IRRP and RIP will be incorporated in 2020.

7.15 Beach TS: End of Life 230 kV Autotransformers and DESN Transformers

7.15.1 Description

Beach TS is a major switching and transformer station in East Hamilton. Station facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T1/T7/T8), a 115 kV switchyard and two T3/T4 and T5/T6 230/13.8 kV DESNs.

Hydro One has determined that all the three T1/T7/T8 autotransformers and the T5/T6 DESN transformers are expected to reach end of life by 2027 and may need to be replaced.

7.15.2 Recommended Plan

The Study Team recommends that the replacement of autotransformers to be assessed as part of the Middleport area bulk transmission planning study by the IESO in coordination with Hydro One. Since the Beach TS autotransformers are expected to require replacement in 2027, the bulk study should be planned at the earliest.

7.16 Lake TS: End of Life Transformers and Switchgears

7.16.1 Description

Lake TS is located in the city of Hamilton having two DESN units. T1/T2 DESN is a 230/27.6 kV and T3/T4 230/13.8 kV of 83 MVA and 75 MVA transformers respectively. Both the DESNs at Lake TS can supply a total load of about 230 MVA (LTR). The load at Lake TS is forecasted at about 105 MW.

At this time the T1/T2 230 / 27.6 kV transformers and both 13.8 kV and 27.6 kV LV switchgears are at their EOL and have been identified by Hydro One expected to require refurbishment in 2027.

7.16.2 Alternatives and Recommended Plan

The following alternatives are considered to address Lake TS end of life asset issue:

- 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.
- Replacement of the assets: Replace existing EOL transformers with similarly sized units and to meet current standards.

The Study Team is recommending that this need can be further assessed in the next regional planning cycle.

7.17 Burlington TS: End of Life 230 kV Autotransformer

7.17.1 Description

Burlington TS is a major switching and transformer station in Burlington. Station facilities include a 230 kV switchyard, four 230/115 kV autotransformers (T4/T6/T9/T12), 115 kV switchyard and a 230/27.6 kV DESN.

Hydro One has determined that autotransformer T12 is expected to reach end of life by 2030 and will need to be replaced.

7.17.2 Recommended Plan

The Study Team recommends that Burlington TS autotransformer replacement options and plan be studied as part of the Middleport area bulk transmission planning study by the IESO in coordination with Hydro One to develop a recommended plan.

7.18 Other Considerations

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 battery storage systems to reduce cost and for improved reliability of electricity supply.

There may be situations where behind the meter battery storage cannot be connected due to current connection requirements and constraints. The LDCs in Ontario and Hydro One, outside the regional planning forum, have undertaken the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

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 reviewing the updated regional community energy plans in the next Regional Planning cycle.

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8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE BURLINGTON TO NANTICOKE REGION.

The major infrastructure investments recommended by the Study Team for the Burlington to Nanticoke region over the near and mid -term are provided in below Table 8-1 and 8-2 respectively, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1 Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	115 kV B7/B8: EOL line section from Burlington TS to Nelson Jct.	Refurbish the EOL B7/B8 line section	2020	2
2	115 kV B3/B4: EOL line section from Horning Mountain Jct. to Glanford Jct.	Refurbish the EOL B3/B4 line section conductor	2020	22
3	Elgin TS: EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	2021	81
4	Newton TS: EOL transformers	Replace EOL transformers	2021	22
5	Kenilworth TS: EOL transformer & switchgear	Reconfigure from 2 DESNs to single DESN and replace EOL equipment	2021	36
6	Dundas TS: Load transfer	Add two new feeders at Dundas TS #2	2021	2
7	Gage TS: EOL transformers & switchgear	Reduce from 3 DESNs to 2 DESNs and replace EOL equipment	2021	55
8	Kenilworth TS: Power factor correction	LDC is developing distribution option	2022	1
9	Norfolk area supply capacity	Norfolk TS: Install capacitor bank	2022	3

Table 8-2 Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Planned I/S Date	Budgetar y Estimate ($M)
1	Birmingham TS EOL transformer and metalclad switchgears	Replace EOL equipment	2025	29
2	Mid-Term EOL transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4)	Monitor and review in next planning cycle	2025-29	69
3	Mid-Term EOL switchgear at Norfolk TS and Burlington TS[5]	Monitor and review in next planning cycle	2026	57
4	EOL cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4[6]	To further assess the options in this RIP by the Study Team and addendum issued to Hamilton IRRP and RIP	2026	28
5	Norfolk area supply capacity	To further assess the options in this RIP by the Study Team in advance of next planning cycle and addendum issued to RIP	2026	80
6	Beach TS: EOL 230 kV auto-transformers[7] and DESN transformers	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2027	71
7	Lake TS: EOL transformers and switchgears	Monitor and review in next planning cycle	2027	45
8	Burlington TS: EOL 230 kV auto-transformer [8]	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2030	14

Further details, alternatives, and recommended plans for the above needs are provided in Section 7.

[5] Further condition assessment did not confirm the earlier need of refurbishing Brantford switchgear.
[6] To be finalized through Hamilton IRRP Addendum by the IESO
[7] To be finalized through Middleport Bulk Study by the IESO

The Study Team recommends:

- Hydro One to continue with the implementation of major infrastructure investments listed in Table 8-1;
- Hydro One to continue with the implementation of infrastructure investments at Birmingham TS for replacement of EOL transformers and switchgears;
- The EOL 230 kV autotransformer options at Beach TS and Burlington TS will be assessed through the IESO Middleport Bulk Study in coordination with Hydro One to develop a final recommended plan;
- The EOL 115 kV Hamilton area cables options are included in this RIP. It will be further assessed by the Study Team to develop a recommended plan to be included as an addendum to the Hamilton IRRP and this RIP;
- The options to reinforce supply to the Norfolk area are included in this RIP and will be further assessed by the Study Team in advance of the next planning cycle to develop a recommended plan and an addendum be made to the RIP; and
- All the other identified needs/options in the mid and long-term will be further reviewed by the Study Team in the next regional planning cycle as discussed in Section 7.

9. REFERENCES

[1]. Independent Electricity System Operator, “Hamilton Area Integrated Regional Resource Plan”, 25 February 2019
http://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Hamilton/Hamilton-IRRP-FINAL-February2019.pdf?la=en

[2]. Hydro One, “Needs Assessment Report, Burlington to Nanticoke Region”, 15 May 2017
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/burlingtontonanticoke/Documents/Needs%20Assessment_Burlington%20to%20Nanticoke_May15_2017.pdf

[3]. Hydro One, “Regional Infrastructure Plan”, 07 February 2017
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/burlingtontonanticoke/Documents/RIP%20Report_Burlington%20to%20Nanticoke.pdf

APPENDIX A: TRANSMISSION LINES IN THE BURLINGTON TO NANTICOKE REGION

No.	Location	Circuit Designations	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 B: STATIONS IN THE BURLINGTON TO NANTICOKE REGION

No.	Station	Voltage (kV)	Supply Circuits
1	CTS	230	H35D, H36D
2	Beach TS	230	Beach TS 230 kV Bus (1)
3	Birmingham TS	115	HL3, HL4
4	Bloomsburg DS	115	C9, C12
5	Brant TS	115	B12BL, B13BL
6	Brantford TS	230	M32W, M33W
7	Bronte TS	115	B7, B8
8	Burlington TS DESN	230	Q23BM, Q25BM
9	Caledonia TS	230	N5M, S39M
10	Cumberland TS	230	B40C, B41C
11	CTS	230	Q24HM, Q29HM
12	Dundas TS	115	B3, B4
13	Dundas TS #2	115	B12BL, B13BL
14	Elgin TS	115	HL3, HL4
15	Gage TS	115	B10, B11
16	Horning TS	230	M27B, M28B
17	CTS	230	N20K
18	Jarvis TS	230	N21J, N22J
19	Kenilworth TS	115	H5K, H6K
20	Lake TS	230	B18H, B20H
21	CTS	115	B3, B4
22	Mohawk TS	115	B3, B4
23	Nebo TS	230	Q24HM, Q29HM
24	Newton TS	115	Newton TS 115 kV Bus (2)
25	Norfolk TS	115	C9, C12
26	Powerline MTS	115	B12BL, B13BL
27	Stirton TS	115	HL3, HL4
28	CTS	230	N21J, N22J
29	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: DISTRIBUTORS IN THE BURLINGTON TO NANTICOKE REGION

Distributor Name	Station Name	Connection Type
Energy + Inc.	Brant TS	Dx, Tx
	Brantford TS	Dx
Brantford Power Inc.	Brant TS	Tx
	Brantford TS	Tx
Brantford Power Inc. and Energy + Inc.	Powerline MTS	Tx
Burlington Hydro Inc.	Bronte TS	Tx
	Burlington TS	Tx
	Cumberland TS	Tx
Haldimand County Hydro Inc.	Caledonia TS	Dx, Tx
	Jarvis TS	Dx, Tx
Alectra Utilities Corporation	Beach TS	Tx
	Birmingham TS	Tx
	Dundas TS	Dx, Tx
	Dundas TS #2	Tx
	Elgin TS	Tx
	Gage TS	Tx
	Horning TS	Tx
	Kenilworth TS	Tx
	Lake TS	Dx, Tx
	Mohawk TS	Tx
	Nebo TS	Dx, Tx
	Newton TS	Tx
	Stirton TS	Tx
	Winona TS	Tx
Hydro One Networks Inc.	Brant TS	Tx
	Caledonia TS	Tx
	Dundas TS	Tx
	Dundas TS #2	Tx
	Jarvis TS	Tx
	Lake TS	Tx
	Nebo TS	Tx
	Norfolk TS	Dx, Tx
	Bloomsburg DS	Dx, Tx
Oakville Hydro Electricity Distribution Inc.	Bronte TS	Tx

APPENDIX D: REGIONAL LOAD FORECASTS (MW)

Table – 1 Burlington to Nanticoke Region - Non-Coincident Load Forecast (Extreme Weather Corrected)

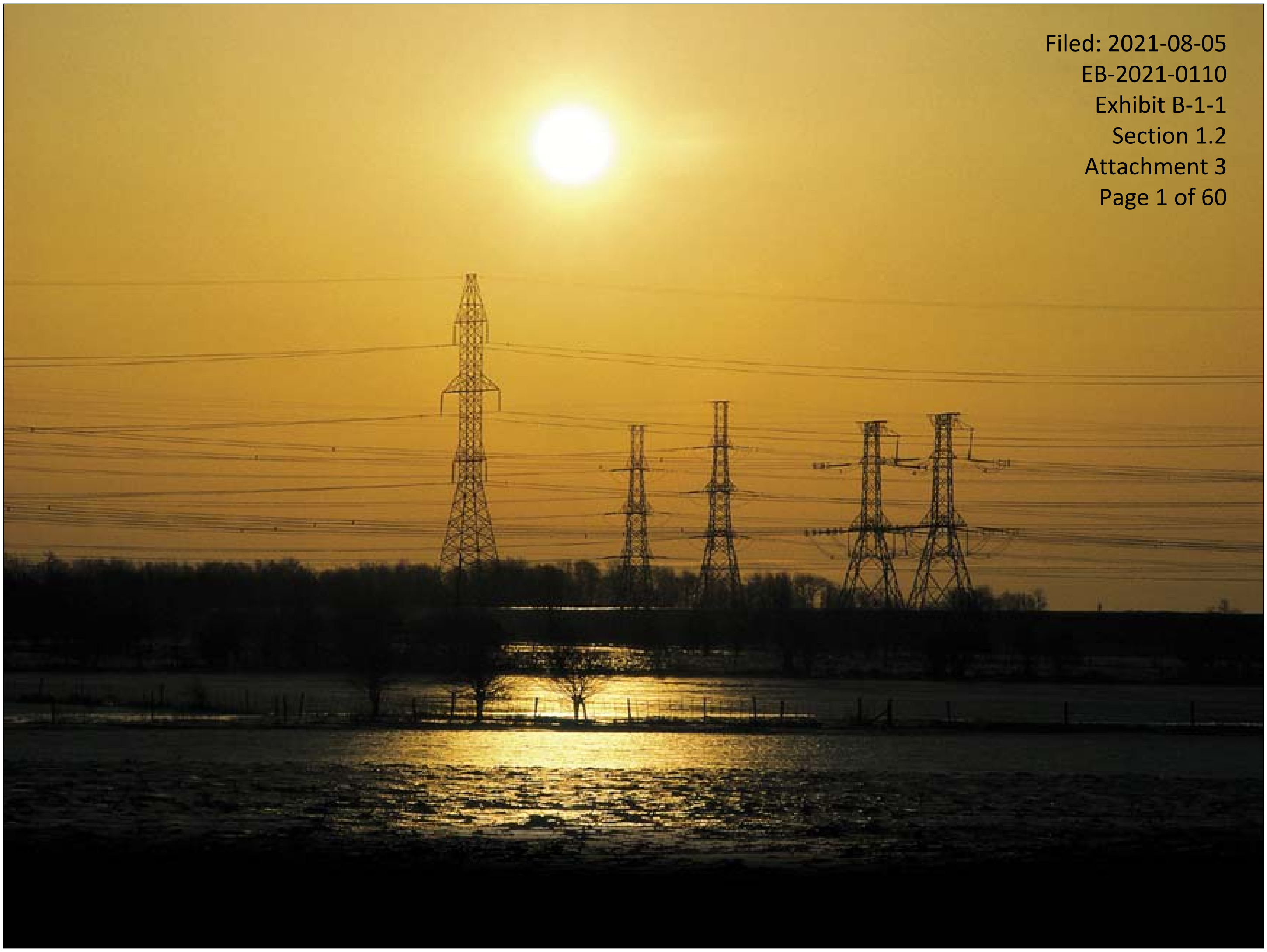
Area	Station	LTR	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brant 115 kV	Brant TS (T1 / T2)	101	70	75	81	81	82	83	84	85	86	86	87	88	89	93	94	95	96	98	99	100	101	102
	Powerline MTS (T1 / T2)	114	78	78	82	83	85	86	87	88	89	90	92	93	94	96	97	99	100	103	104	106	108	110
	Total		**148**	**153**	**164**	**165**	**167**	**169**	**171**	**173**	**175**	**177**	**179**	**181**	**183**	**189**	**191**	**194**	**197**	**200**	**203**	**206**	**209**	**212**
Brant 230 kV	Brantford TS (T3 / T4)	188	141	164	166	170	172	175	177	179	180	187	189	191	194	196	198	199	202	205	208	210	213	215
	Total		**141**	**164**	**166**	**170**	**172**	**175**	**177**	**179**	**180**	**187**	**189**	**191**	**194**	**196**	**198**	**199**	**202**	**205**	**208**	**210**	**213**	**215**
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	180	141	133	134	136	137	138	139	140	141	143	144	143	143	143	143	143	143	143	143	143	143	143
	Total		**141**	**133**	**134**	**136**	**137**	**138**	**139**	**140**	**141**	**143**	**144**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	141	154	154	154	153	153	153	152	152	151	151	151	151	150	150	150	150	150	150	150	150	150
	Cumberland TS (T3 / T4)	174	120	123	124	125	126	127	128	129	130	131	132	133	135	136	137	137	137	137	137	137	137	137
	Total		**260**	**277**	**278**	**279**	**279**	**280**	**280**	**281**	**282**	**282**	**283**	**284**	**285**	**287**	**287**	**286**	**287**	**287**	**287**	**287**	**287**	**287**
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	21	29	33	33	33	33	33	32	32	32	32	32	32	31	31	31	31	31	31	31	31	31
	Birmingham TS (T3 / T4)	91	59	60	63	63	62	62	62	61	61	61	61	60	60	60	59	59	59	59	59	59	58	58
	Dundas TS (T1 / T2)	99	100	106	111	112	113	114	114	115	116	116	117	118	119	119	120	121	122	131	132	133	134	135
	Dundas TS #2 (T5 / T6)	89	50	53	54	56	57	57	57	56	56	56	55	55	55	55	55	55	54	54	54	54	54	54
	Elgin TS (T1 / T2)	135	98	105	111	114	118	118	117	116	116	115	115	114	114	113	113	112	114	113	113	113	113	113
	Gage TS (T3 / T4)	57	21	21	21	21	21	21	20	20	20	20	20	20	20	20	20	20	20	20	19	19	19	19
	Gage TS (T5 / T6)	57	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	Gage TS (T8 / T9)	123	16	16	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14
	Kenilworth TS (T2 / T3)	127	52	52	52	52	52	51	51	51	50	50	50	50	50	49	49	49	49	49	48	48	48	48
	Mohawk TS (T1 / T2)	104	75	77	77	77	77	77	76	76	76	75	75	75	74	74	73	73	73	73	73	73	73	72
	Newton TS (T1 / T2)	78	52	53	54	60	62	62	62	61	61	61	60	60	60	60	60	59	59	59	59	59	59	59
	Stirton TS (T3 / T4)	112	44	46	48	50	53	53	52	52	52	52	51	51	51	51	51	50	50	50	50	50	50	50
	Winona TS (T1 / T2)	89	49	52	52	56	58	58	57	57	57	56	56	56	56	56	56	55	55	55	55	55	55	55
	Total CTS		24	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	Total		**675**	**706**	**729**	**747**	**761**	**759**	**756**	**753**	**750**	**747**	**745**	**743**	**742**	**741**	**738**	**736**	**737**	**746**	**746**	**745**	**745**	**745**
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	24	36	36	36	36	35	35	35	35	35	35	34	34	34	34	34	34	34	34	33	33	33
	Beach TS (T5 / T6)	96	57	64	65	65	66	65	67	66	66	66	65	65	65	65	64	64	64	64	64	64	64	63
	Horning TS (T3 / T4)	113	77	79	79	79	80	79	79	78	78	78	77	77	76	76	76	75	75	75	75	75	75	75
	Lake TS (T1 / T2)	94	50	51	51	58	58	57	57	57	56	56	56	56	55	56	55	55	55	55	55	55	55	54
	Lake TS (T3 / T4)	113	54	54	55	52	54	53	53	53	53	52	52	52	52	51	51	51	51	50	50	50	50	50
	Nebo TS (T1/T2)	178	127	127	135	140	144	148	151	154	157	160	166	168	170	172	174	176	179	181	184	186	188	191
	Nebo TS (T3 / T4)	51	52	53	53	53	53	53	53	52	52	52	52	51	51	51	51	51	51	51	51	50	50	50
	Total CTS		255	249	230	228	244	244	242	241	241	240	240	239	239	238	238	237	237	237	237	237	237	237
	Total		**695**	**714**	**703**	**711**	**735**	**736**	**737**	**737**	**738**	**739**	**742**	**742**	**742**	**743**	**743**	**743**	**744**	**747**	**749**	**750**	**753**	**754**
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	57	61	67	68	69	69	74	74	74	78	82	84	85	86	87	87	87	88	88	89	89	90
	Bloomsburg DS (T1/T2)	49	38	40	41	44	52	61	69	69	69	69	69	69	73	74	74	74	74	76	76	76	76	77
	Total		**95**	**101**	**108**	**112**	**120**	**130**	**143**	**143**	**143**	**147**	**151**	**153**	**158**	**160**	**161**	**161**	**162**	**164**	**165**	**165**	**166**	**166**
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	41	43	52	62	67	69	70	72	74	75	85	85	86	87	88	88	89	90	91	92	93	94
	Jarvis TS (T3/T4)	100	67	74	76	78	79	79	80	80	81	81	82	82	83	84	84	85	86	87	87	88	89	89
	Total CTS		117	115	116	118	117	117	117	116	116	116	115	115	115	115	114	114	114	114	114	114	114	114
	Total		**225**	**232**	**245**	**257**	**263**	**265**	**267**	**268**	**270**	**272**	**282**	**283**	**284**	**285**	**286**	**287**	**290**	**291**	**293**	**294**	**296**	**297**
Regional Total			2381	2480	2527	2577	2633	2652	2669	2673	2680	2694	2715	2720	2732	2744	2748	2751	2761	2782	2793	2801	2812	2820

Table – 2 Burlington to Nanticoke Region - Coincident Load Forecast (Extreme Weather Corrected)

Area	Station	LTR	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brant 115 kV	Brant TS (T1 / T2)	101	50	54	58	58	59	60	60	61	61	62	63	63	64	68	69	69	70	71	72	73	74	75
	Powerline MTS (T1 / T2)	114	64	64	67	68	69	70	71	72	73	74	75	76	77	79	80	81	82	84	86	87	89	90
	Total		**114**	**118**	**126**	**127**	**128**	**130**	**131**	**133**	**134**	**136**	**138**	**139**	**141**	**146**	**148**	**150**	**153**	**155**	**158**	**160**	**162**	**165**
Brant 230 kV	Brantford TS (T3 / T4)	188	132	153	155	159	161	164	166	167	169	176	177	179	182	184	186	187	190	192	195	197	199	202
	Total		**132**	**153**	**155**	**159**	**161**	**164**	**166**	**167**	**169**	**176**	**177**	**179**	**182**	**184**	**186**	**187**	**190**	**192**	**195**	**197**	**199**	**202**
Burlington and Oakville 115 Kv	Bronte TS (T2 / T5 / T6)	180	106	105	106	107	108	109	109	110	111	112	113	113	113	113	113	112	112	113	113	113	113	113
	Total		**106**	**105**	**106**	**107**	**108**	**109**	**109**	**110**	**111**	**112**	**113**	**113**	**113**	**113**	**113**	**112**	**112**	**113**	**113**	**113**	**113**	**113**
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	133	146	146	145	145	145	144	144	143	143	143	142	142	142	142	142	141	142	142	142	142	142
	Cumberland TS (T3 / T4)	174	106	109	110	111	111	112	113	114	115	116	117	118	119	121	121	121	121	121	121	121	122	122
	Total		**239**	**254**	**255**	**256**	**257**	**257**	**257**	**258**	**258**	**259**	**259**	**260**	**262**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	13	13	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14	14	14	14	14
	Birmingham TS (T3 / T4)	91	48	49	51	51	51	51	50	50	50	49	49	49	49	49	48	48	48	48	48	48	48	47
	Dundas TS (T1 / T2)	99	79	84	88	89	89	90	91	91	92	92	93	93	94	95	95	96	96	106	107	107	108	109
	Dundas TS #2 (T5 / T6)	89	43	46	48	49	50	50	49	49	49	49	48	48	48	48	48	48	48	48	48	48	47	47
	Elgin TS (T1 / T2)	135	77	82	87	89	93	93	92	91	91	91	90	90	89	89	89	88	90	90	89	89	89	89
	Gage TS (T3 / T4)	57	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Gage TS (T5 / T6)	57	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7
	Gage TS (T8 / T9)	123	13	13	13	13	13	13	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	Kenilworth TS (T2 / T3)	127	48	48	48	48	48	47	47	47	47	46	46	46	46	45	45	45	45	45	45	45	44	44
	Mohawk TS (T1 / T2)	104	61	62	62	63	63	62	62	62	61	61	61	60	60	60	60	59	59	59	59	59	59	59
	Newton TS (T1 / T2)	78	49	50	50	56	58	58	58	57	57	57	56	56	56	56	56	55	55	55	55	55	55	55
	Stirton TS (T3 / T4)	112	42	43	45	47	50	50	50	49	49	49	49	49	48	48	48	48	48	47	47	47	47	47
	Winona TS (T1 / T2)	89	47	50	51	55	56	56	55	55	55	55	54	54	54	54	54	54	53	53	53	53	53	53
	Total CTS	50	14	16	16	17	17	17	17	17	17	16	16	16	16	16	16	16	16	16	16	16	16	16
	Total		**549**	**569**	**587**	**603**	**615**	**613**	**611**	**608**	**607**	**604**	**603**	**601**	**600**	**599**	**597**	**596**	**596**	**605**	**605**	**605**	**605**	**604**
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	16	16	16	16	16	16	16	16	16	16	15	15	15	15	15	15	15	15	15	15	15	15
	Beach TS (T5 / T6)	96	53	59	60	60	61	61	62	62	61	61	61	61	60	60	60	60	59	59	59	59	59	59
	Horning TS (T3 / T4)	113	63	64	65	65	65	65	64	64	64	63	63	63	62	62	62	62	61	62	61	61	61	61
	Lake TS (T1 / T2)	94	50	51	51	58	58	58	58	57	57	57	56	56	56	56	56	56	55	55	55	55	55	55
	Lake TS (T3 / T4)	113	50	51	51	48	50	50	50	49	49	49	49	48	48	48	48	48	47	47	47	47	47	47
	Nebo TS (T1/T2)	178	120	120	126	132	136	139	142	145	148	151	156	158	160	162	164	166	168	170	173	175	177	179
	Nebo TS (T3 / T4)	51	38	39	39	39	39	39	39	38	38	38	38	38	37	37	37	37	37	37	37	37	37	37
	Total CTS	305	185	189	172	171	185	185	184	183	183	182	182	181	181	181	180	180	180	180	180	180	180	180
	Total		**574**	**589**	**581**	**589**	**610**	**612**	**613**	**614**	**615**	**616**	**620**	**620**	**621**	**622**	**622**	**622**	**623**	**626**	**628**	**629**	**631**	**633**
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	33	35	39	39	39	39	42	42	43	46	50	52	52	54	54	55	55	55	55	56	56	56
	Bloomsburg DS (T1/T2)	49	26	27	28	30	35	41	46	46	46	47	47	47	51	51	51	51	51	53	53	53	53	53
	Total		**58**	**62**	**66**	**69**	**74**	**80**	**89**	**89**	**89**	**93**	**97**	**98**	**103**	**105**	**105**	**106**	**106**	**108**	**108**	**109**	**109**	**109**
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	20	21	26	31	33	34	35	36	37	37	46	46	47	47	48	48	49	49	49	50	50	51
	Jarvis TS (T3/T4)	100	53	59	60	61	62	63	63	64	64	64	65	65	66	67	67	67	69	69	70	70	70	71
	Total CTS	225	92	97	97	99	98	98	98	98	97	97	97	97	96	96	96	96	96	96	96	96	96	96
	Total		**166**	**177**	**184**	**191**	**194**	**195**	**196**	**197**	**198**	**199**	**208**	**208**	**209**	**210**	**210**	**211**	**213**	**214**	**215**	**216**	**217**	**218**
Regional Total			**1937**	**2027**	**2060**	**2101**	**2147**	**2160**	**2173**	**2176**	**2182**	**2194**	**2214**	**2219**	**2229**	**2241**	**2245**	**2247**	**2256**	**2276**	**2285**	**2291**	**2300**	**2307**

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
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



Greater Ottawa

REGIONAL INFRASTRUCTURE PLAN

December 18, 2020

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Hydro Ottawa Limited
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Hydro Hawkesbury Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address 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 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 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 SUPPORT 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 DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER OTTAWA REGION.

The participants of the RIP Study Team included members from the following organizations:

- Hydro Ottawa Limited
- Hydro Hawkesbury Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)

This RIP provides a consolidated summary of the needs and recommended plans for both the Ottawa Area Sub-Region and Outer Ottawa Area Sub-Region that make up the Greater Ottawa Region over the next ten years.

The RIP is the final phase of the second cycle regional planning process of Greater Ottawa Region, which follows the completion of the Ottawa Sub-Region's Integrated Regional Resource Plan ("IRRP") in March 2020, the Greater Ottawa Region Scoping Assessment ("SA") in September 2018 and the Greater Ottawa Area Region's Needs Assessment ("NA") in June 2018.

The major infrastructure investments recommended by the Study Team, based on right sizing of equipment considering needs over the next ten years , are provided in the Table 1-1 below along with their planned in-service date.

Table 1-1. Recommended Plans in Greater Ottawa over the Next 10 Years.

No	Need	Recommended action plan	Expected I/S
1	Lincoln Heights TS: End of life of transformers T1/T2.	Replace end of life equipment.	2023
2	Longueuil TS: End of life of transformers T3/T4.	Replace end of life equipment.	2024
3	Riverdale TS: End of life of 115 kV breakers.	Replace end of life equipment.	2024
4	Transformation Capacity in South East Ottawa.	Hydro Ottawa to proceed with building transformer station.	2025
5	Albion TS: End of life of transformers T1/T2 and circuit breakers.	Replace end of life equipment.	2026
6	Russell TS: End of life of transformers T1/T2.	Replace end of life equipment.	2026
7	Overbrook TS: Station capacity.	Determine limitation of LV cables.	2021
		Upgrade cables or implement load transfers.	2026
8	Hawkesbury MTS: Capacity upgrade.	Hydro Hawkesbury to proceed with upgrade.	2026
9	Bilberry Creek TS: End of life of transformers T1/T2 and LV circuit breakers. Addition of two new LV circuit breakers for Hydro Ottawa.*	Install two new LV circuit breakers.	2024
		Replace end of life equipment.	2028
10	Merivale TS: Autotransformation capacity and end of life of T22, 230 kV breakers, 115 kV breakers.	Replace T22.**	2025
		Review recommendations of Ottawa 115 kV System Supply and Gatineau Corridor EOL studies to develop plan for Merivale TS.	2028

NOTES:

* Addition of two new breakers can be expedited following a formal request from Hydro Ottawa.

** Replacement of T22 with like for like transformer planned for completion by 2025. Inputs from the Gatineau Corridor EOL study and Ottawa 115 kV study may impact the timing of the replacement.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Study Team that consists Hydro One, Hydro One Inc. (Distribution), Hydro Hawkesbury Inc. ("Hydro Hawkesbury"), Hydro Ottawa Limited ("Hydro Ottawa") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

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 230 kV and 115 kV step-down transformer stations. The boundaries of the Region are shown in Figure 1-1 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.

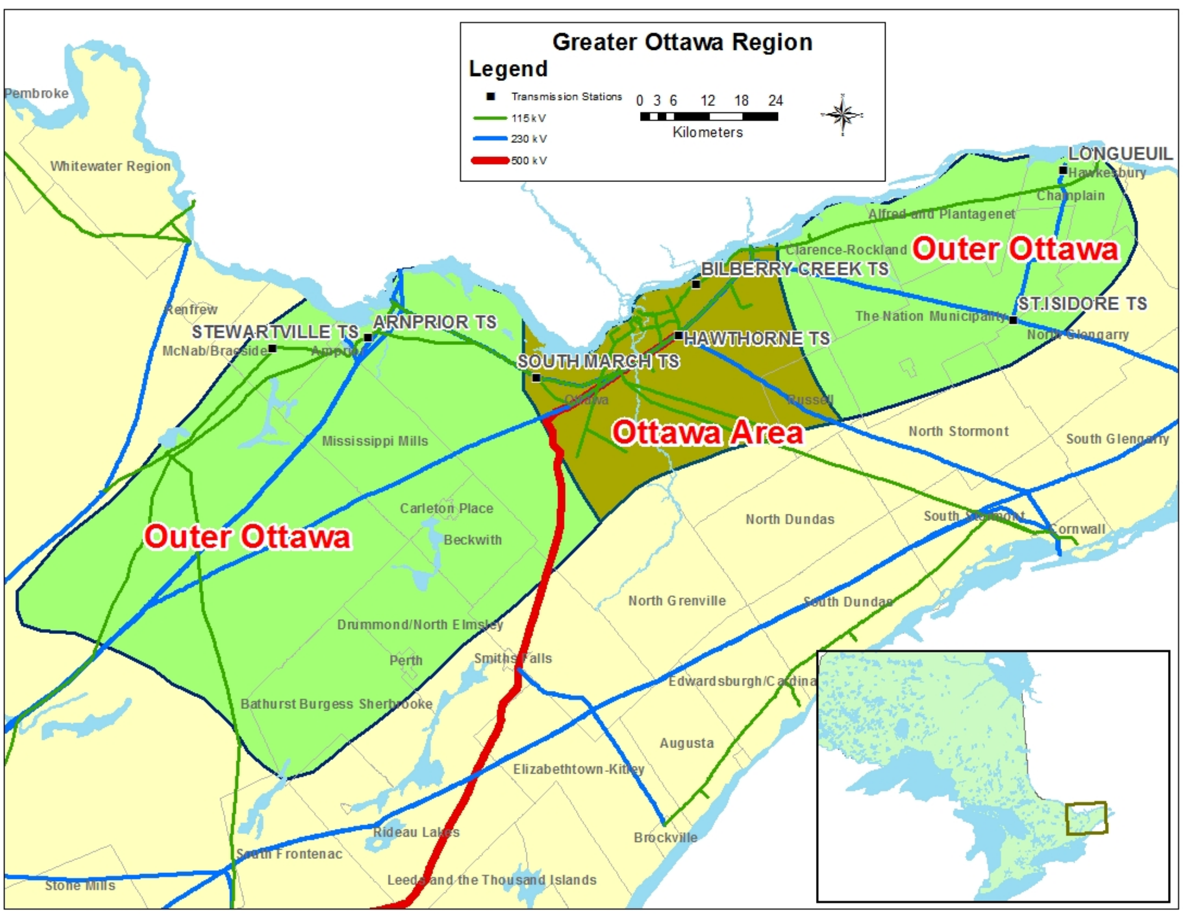


Figure 1-1 Greater Ottawa Region

1.1 Objectives and Scope

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;
- 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 needs and relevant plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans to address these needs based on new and/or updated information.
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

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.

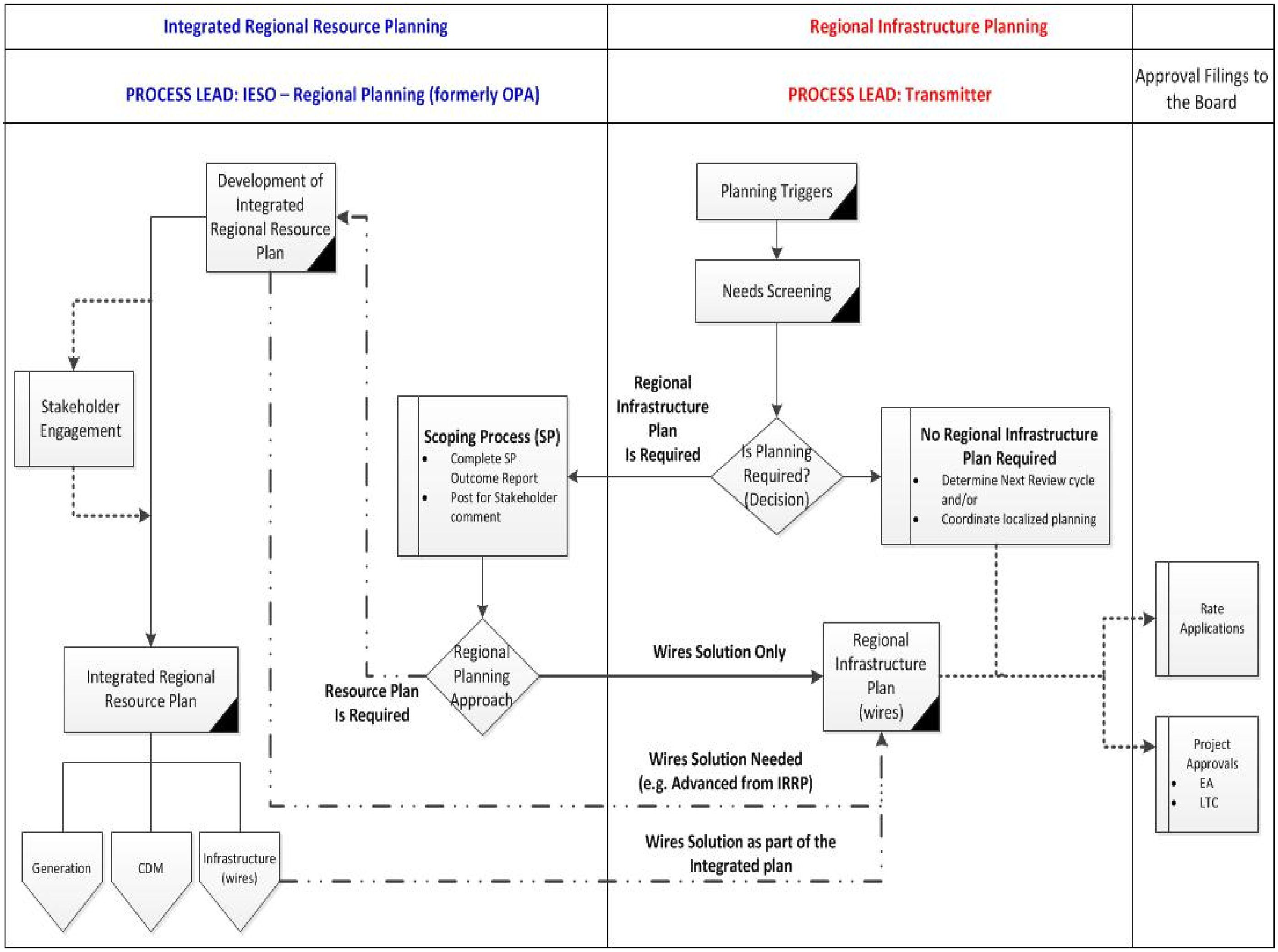


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Peak demand forecast at the transformer stations. This includes the effect of any distributed generation or conservation and demand management programs. The load forecasts from the NA and IRRP were reviewed before the start of the RIP against the actual historical peak loading observed in 2018 and 2019. The working group chose to readjust the load forecast for some stations and incorporate updated CDM values for all stations.
   - 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.

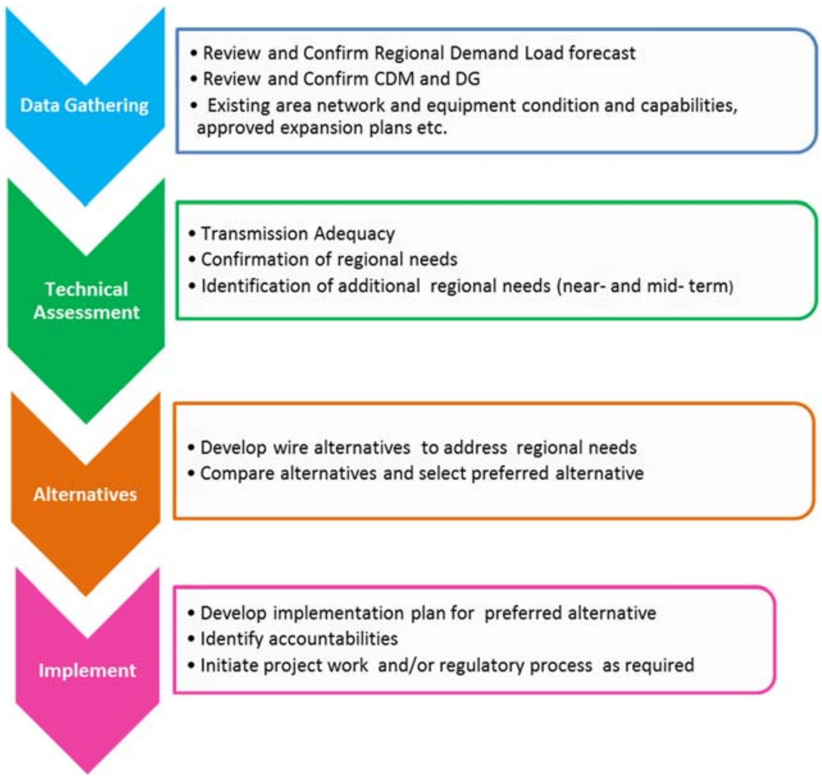


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER OTTAWA REGION COVERS THE MUNICIPALITIES BORDERING THE OTTAWA RIVER FROM ARNPRIOR IN THE WEST TO HAWKESBURY IN THE EAST AND NORTH OF HIGHWAY 43. AT THE CENTER OF THIS REGION IS THE CITY OF OTTAWA (SEE FIGURE 3-1). ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTY-TWO 230 KV AND 115 KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the Greater Ottawa Region is provided through the 500/230 kV Hawthorne TS 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 1-1 and described below:

- The Ottawa Sub-Region comprises primarily the City of Ottawa. It is supplied by two 230/115 kV autotransformer stations (Hawthorne TS and Merivale TS), eight 230 kV and thirty-three 115 kV transformer stations stepping down to a lower voltage. Local generation in the area consists of the 70 MW Ottawa Health Science Non-Utility Generator ("NUG") located near the downtown area and connected to the 115 kV network. The Ottawa Sub-Region is shown in Figure 3-1 below.

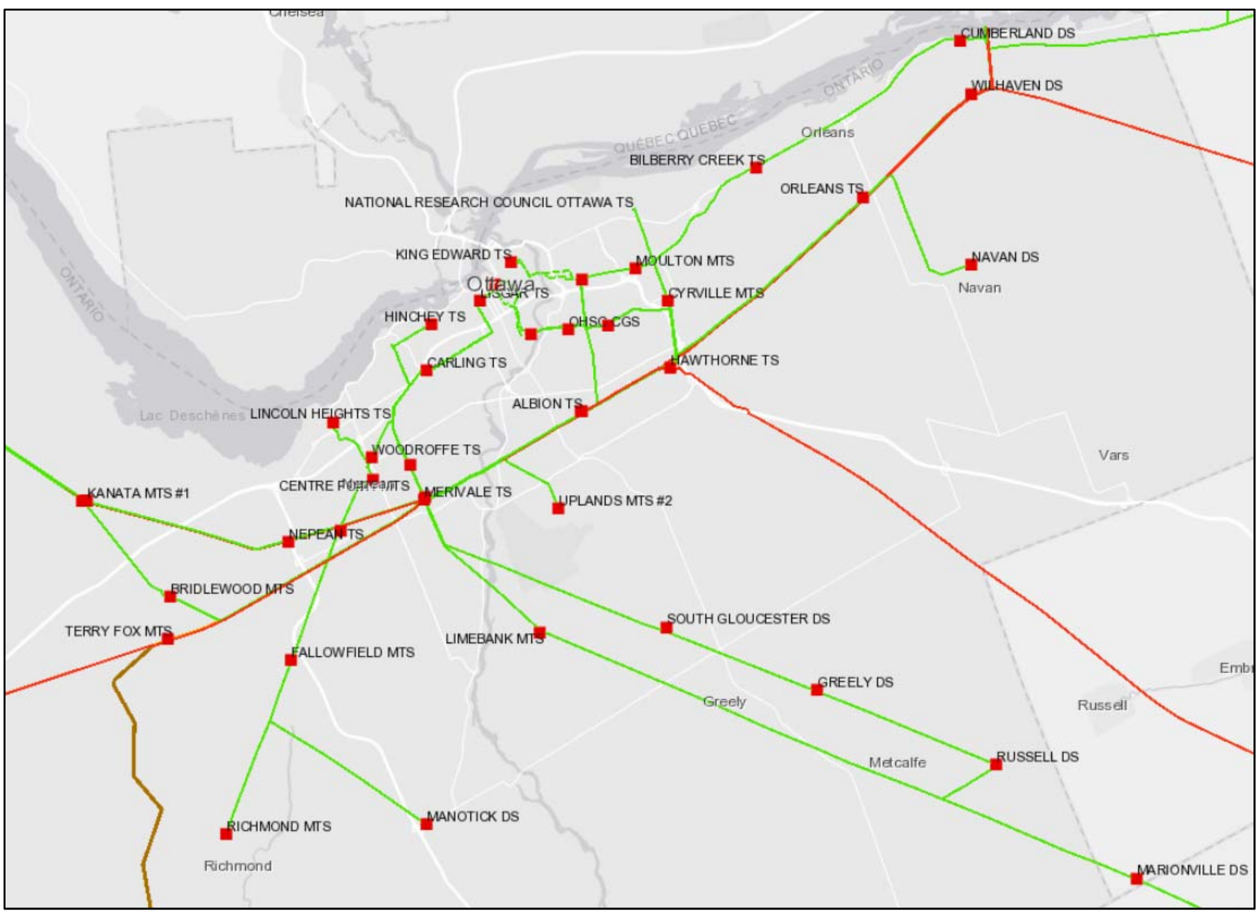


Figure 3-1 Ottawa Sub-Region

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 the end users, i.e. industrial, commercial and residential customers.

- The Outer Ottawa Sub-Region covers the remaining area of the Greater Ottawa Region. The eastern area (shown in Figure 3-2) is served by three 230 and five 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 the end use customers. It also includes a large industrial customer, Ivaco Rolling Mills, in L'Orignal, Ontario.

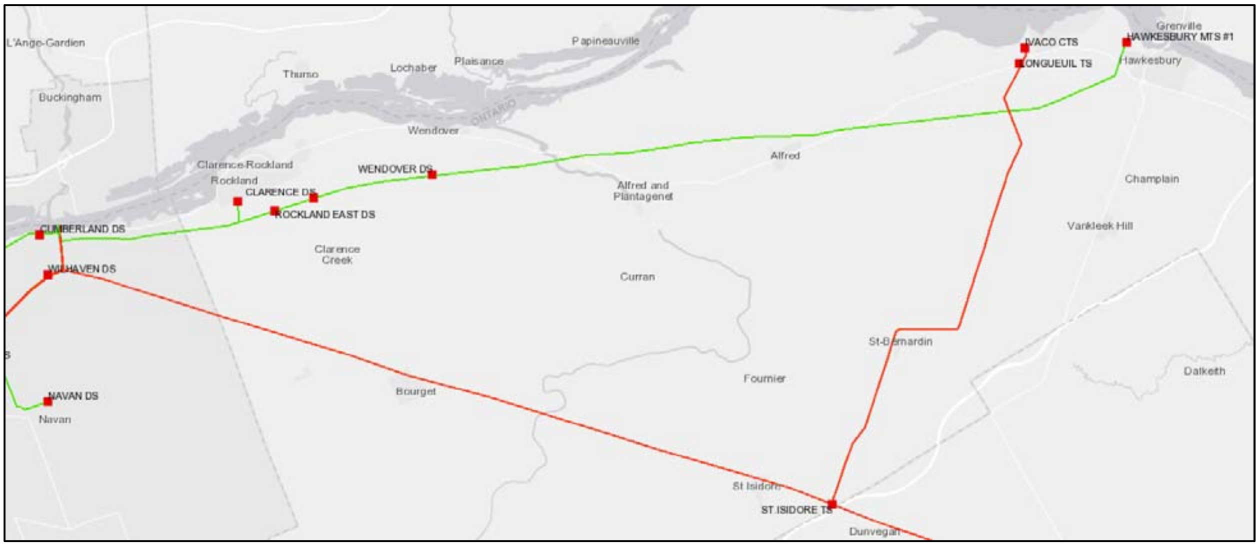


Figure 3-2 Outer Ottawa Sub-Region, Eastern Area

The western area of the Outer Ottawa Sub-Region is served by one 230 kV and two 115 kV step-down transformer stations. Hydro One Distribution is the LDC that supplies end use customers for these stations. 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.

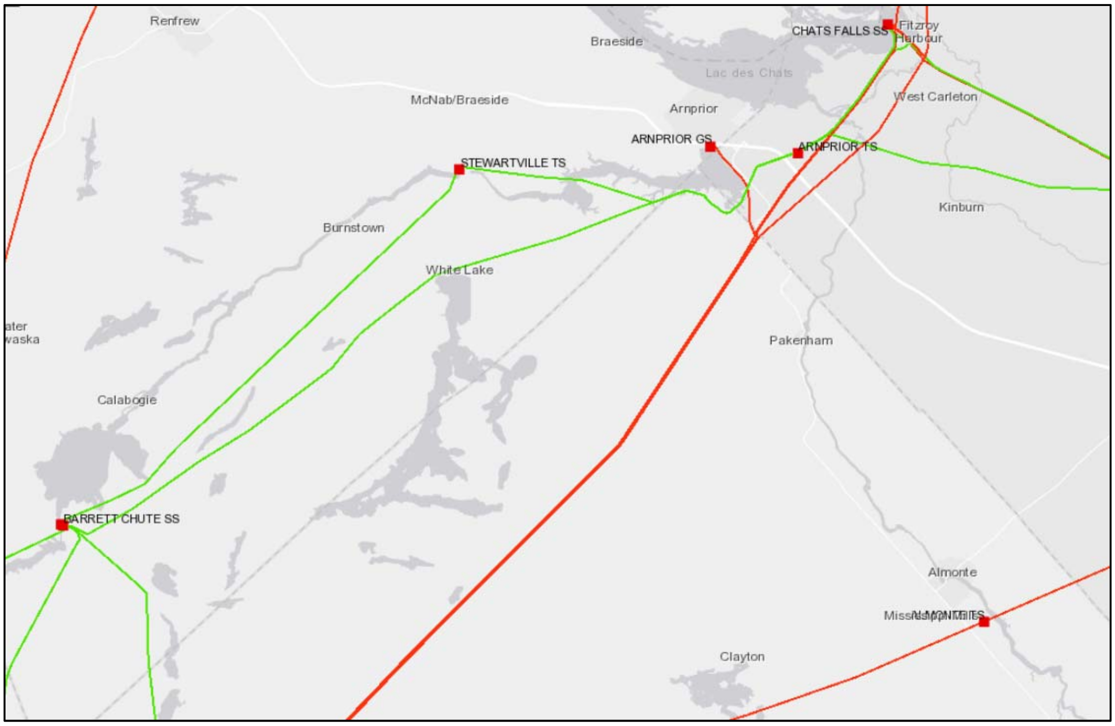


Figure 3-3 Outer Ottawa, Western Area

An electrical single line diagram for the Greater Ottawa Region facilities is shown in Figure 3-4.

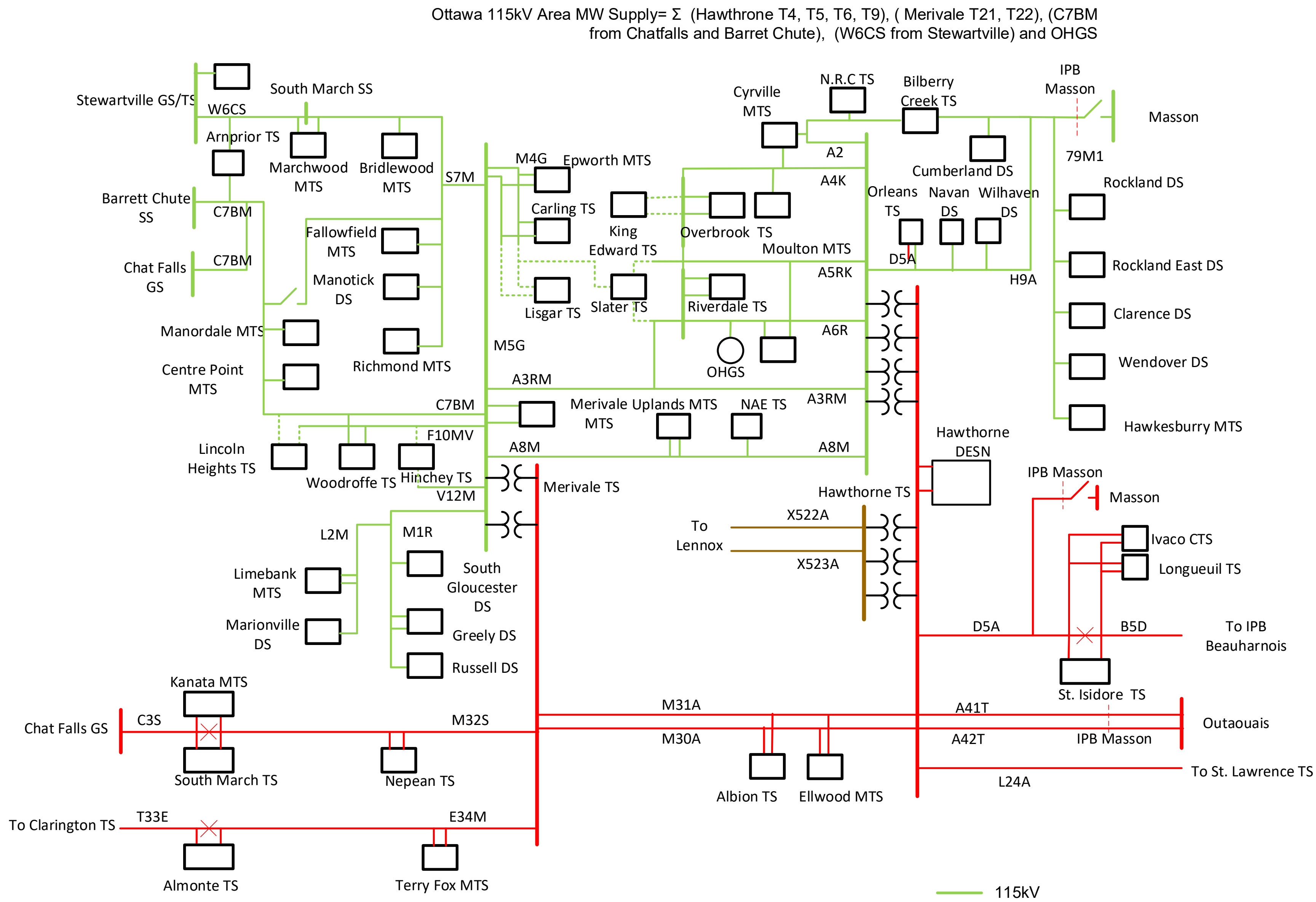


Figure 3-4 Greater Ottawa Region – Electrical Supply

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 GREATER OTTAWA REGION.

A summary and description of the major projects completed over the last 10 years is provided below:

- Connect Ellwood MTS (2012) – connected new Hydro Ottawa owned Ellwood MTS to 230 kV circuits M30A and M31A.
- Connect Terry Fox MTS (2013) – connected new Hydro Ottawa owned Terry Fox MTS to 230 kV circuit E34M (formerly M29C).
- Hawthorne TS 115 kV switchyard Upgrade (2014) – replaced 115 kV breakers with inadequate short circuit capability with new breakers of higher short circuit capability. This work improved system reliability by allowing 115kV switchyards to be operated with bus tie closed. This work also facilitated incorporation of DG in the Ottawa area.
- 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.
- 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.
- 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).
- 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 – replaced end-of-life transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.
- Hawthorne TS (2019): Replaced 50/67/83 MVA, 230/44 kV step down transformers with new 75/100/125 MVA, 230/44 kV units – replaced end-of-life transformers with higher capacity units to provide additional load meeting capability at the station due to anticipated load growth.

- 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.

- Connection of Crysler CGS wind farm (2020) – connection of 100 MW wind farm to 230 kV circuit L24A.

The following projects are currently underway:

- Hawthorne TS: Replace 225 MVA, 230/115 kV autotransformers T5 and T6 with new 250 MVA, 230/115 kV autotransformers (2021) to provide additional 230/115 kV transformation capacity – autotransformer T6 has been replaced and T5 replacement is expected to be completed in 2021.

- King Edward TS (2021): Replace 45/60/75 MVA, 115/13.8 kV step down transformer T3 with a new 60/80/100 MVA, 115/13.8 kV unit – the existing transformer is being replaced with a new higher capacity unit to match the existing rating of T4 and to provide additional load meeting capability at the station.

- Cambrian MTS and South Nepean Transmission reinforcement (2022) – Connection of a new Hydro Ottawa owned station in the south Nepean area. The station will normally be supplied by 230 kV circuit E34M with alternate supply from 115 kV circuit S7M. To connect this project, the section of S7M (single circuit 115 kV line) from Hunt Club road (STR673JCT) to Manotick JCT, and from Manotick JCT to Cambrian Road will be rebuilt as a double circuit 230 kV line. At STR673JCT, the new double circuit will connect to both S7M (to continue the supply to the area stations) and to E34M to supply the new Cambrian MTS. The two circuits will be extended for about 1.3km along Cambrian road to supply the new MTS.

- Slater TS (2023): Replace 45/75 MVA, 115/13.8 kV step down transformers T2 and T3 with new 60/80/100 MVA, 115/13.8 kV units – the existing transformers are being replaced with new units with higher rated capacity to match the rating of T1 and to provide additional load meeting capability at the station.

- Rebuilding Arnprior TS (2023) – A station rebuild at Arnprior TS is underway with replacement of existing 25/33/42 MVA step down transformers with new 25/33/42 MVA units and building of a new 44 kV switchyard to supply the station load.

- M30A/M31A circuit upgrade (2023) – reconductor 230 kV circuits M30A and M31A between Hawthorne TS and Merivale TS with twin-bundled conductors to increase the circuit ratings. The existing 1843.2kcmil conductors will be replaced with a twin-bundled 1443kcmil conductors. This work is expected to increase the interface limit from 648 MW to 1080 MW.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Greater Ottawa Region is anticipated to grow at an average rate of 2.0% between 2020 and 2025, 1.0% between 2026 and 2030 and 0.7% for the remainder of the study period.

Figure 5-1 shows the Greater Ottawa Region's net extreme summer peak coincident load forecast developed during the Outer Ottawa NA and Ottawa IRRP processes and updated in the RIP phase. The updated forecast also takes into account the most recent conservation programs and distributed generation resources assumptions. This forecast was used to determine any transmission system needs in the region. The forecast shows that the Region peak summer load increases from 2149 MW in 2020 to 2502 MW in 2030 and 2620 MW in 2037. The RIP load forecasts for the individual stations in the Greater Ottawa Region is given in Appendix D.

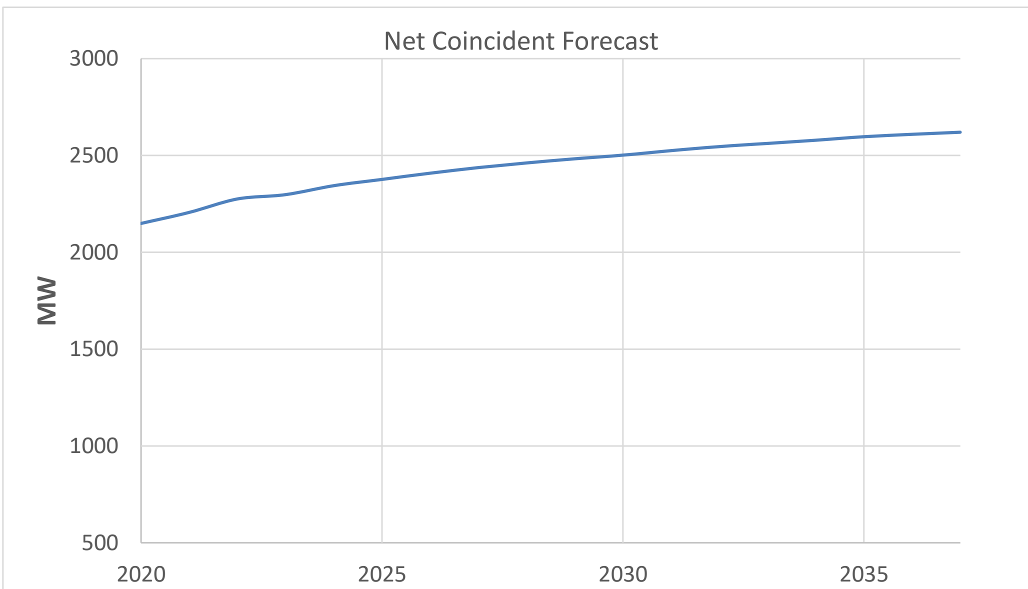


Figure 5-1 Greater Ottawa Region Summer Net Extreme Weather Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP adequacy assessment is 2020-2037.
- 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 load forecast with the station's normal planning supply capacity, assuming a 90% lagging power factor for all stations at the point of connection to the transmission grid. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating (LTR).
- 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.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE GREATER OTTAWA REGION OVER THE PLANNING PERIOD (UP TO 2037). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

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

- 2018 Outer Ottawa Sub-region Needs Assessment ("NA") Report
- 2020 Ottawa Sub-region Integrated Regional Resource Plan ("IRRP") and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the Greater Ottawa region including both the Outer Ottawa and City of Ottawa sub-regions. 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. End of life equipment needs were identified in previous phases of this regional planning cycle and are also addressed in Section 7 of this RIP report.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the Greater Ottawa Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and to the Hydro Quebec transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. These circuits are as follows (refer to Figure 3-4):

1. Hawthorne TS to Merivale TS 230 kV transmission circuits M30A/M31A – supply Albion TS and Ellwood TS.
2. Hawthorne TS to Cornwall 230 kV transmission circuits D5A/B5D/B31L/L24A – supply Orleans TS, St. Isidore TS and Longueuil TS. Also connects to Hydro Quebec at Beauharnois Station and to Lievre Power at Masson GS.
3. Merivale TS to Chats Falls 230 kV transmission circuits M32S/C3S – supply Nepean TS, South March TS and Kanata MTS
4. Merivale TS x Cherrywood TS 230 kV transmission circuits E29C/E34M (M29C) – supply Terry Fox MTS and Almonte TS.

Circuits M30A/M31A were identified for reinforcement and the IESO provided a hand off letter to Hydro One to proceed with the upgrades in 2019. The upgrades to the circuits is expected to be completed in 2023. With the M30A/M31A reinforcement in-service in 2023, the circuits will be adequate over the study period.

Based on the revised load forecast for the RIP and the study assumptions stated in Section 5.2, all other 230 kV circuits are expected to be adequate over the study period.

6.2 230/115 kV Transformation Facilities

Almost sixty percent of the Region load is supplied from the 115 kV transmission system. The primary source of 115 kV supply is from 230/115 kV autotransformers at Hawthorne TS and Merivale TS. Additional support is provided from 115 kV generation at Barrett Chute GS, Stewartville GS, part of Chats Falls GS, and the Ottawa Health Science NUG and the Ottawa River generation at Chaudière. Support from DG and CDM was considered as part of the load forecast.

Table 6-1 summarizes the results of the adequacy studies and identifies the need dates for reinforcement of the 230/115 kV autotransformer facilities at Hawthorne TS and Merivale TS. Assuming no change in the system configuration the Limited Time Rating ("LTR") of the Merivale autotransformers, T21 and T22, are exceeded in 2020. The continuous rating of the Merivale autotransformers are exceeded by 2024/25 for T21 and T22 respectively.

The need dates are sensitive to the availability and dispatch of hydraulic generation from Barrett Chute GS, Stewartville GS and Chats Falls GS and are based on 98% dependable generation availability as per ORTAC criteria. This corresponds to about 31 MW of available generation. A higher level of generator output and dispatch from these stations would defer the need dates. Voltage support is provided by some generating units used as synchronous condensers at Stewartville GS and Barrett Chute GS.

Replacement of autotransformer T6 at Hawthorne TS was completed in 2017 and T5 is undergoing replacement with a projected in-service date in Q2 2021. The need dates assume that the Hawthorne TS 225 MVA, 230/115 kV autotransformer T6 have been replaced with new 250 MVA unit.

Table 6-1 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	2020 MVA Loading	MVA Load Meeting Capability	Limiting Contingency	Need Date
Merivale TS 230/115 kV autotransformer T21	353	347(1)	T22	2020
Merivale TS 230/115 kV autotransformer T22	347	315(1)	T21	2020
Merivale TS 230/115 kV autotransformer T21	255	250	(2)	2024
Merivale TS 230/115 kV autotransformer T22	252	250	(2)	2025

(1) Limited time rating exceeded.

(2) Continuous rating exceeded with all elements in service based on existing system configuration

6.3 115 kV Transmission Facilities

The Greater Ottawa Region 115 kV transmission facilities can be divided in five main sections: Please see Figure 3-4 for the single line diagram.

1. Hawthorne 115 kV Center – has four circuits A3RM, A4K, A5RK and A6R. Circuit A4K approaches but does not exceed its LTR upon the loss of A6R in the long term horizon. This will be re-assessed in the next Regional Planning cycle. All circuits are adequate for the study period.
2. Hawthorne 115 kV East – has two circuits A2 and H9A/79M1. These are expected to be adequate over the study period.
3. Merivale 115 kV Center – has two circuits M4G and M5G. These are expected to be adequate over the study period.
4. Merivale 115 kV West – has five circuits C7BM, F10MV, S7M, V12M and W6CS. These are expected to be adequate over the study period. In the long term, C7BM was observed to approach its LTE limit for the loss of F10MV. Similarly S7M section from STR654 JCT to Bridlewood JCT also approaches its LTE for the loss of C7BM. It should be noted that Kanata area growth will likely result in a new 230 kV station which may impact the loading of the stations supplied by S7M. No violations were observed in the study period. The loading on these circuits will be re-evaluated in the next regional planning cycle.
5. Merivale 115 kV South – has two circuits L2M and M1R. Circuit L2M exceeds its continuous rating in the medium term. The need and recommendation are discussed in Section 7.4 and the area is shown in Figure 7-3.

The loading on the limiting sections is summarized in Table 6-2.

Table 6-2 Adequacy of 115 kV Circuits

Corridor	Section	Overloaded Circuit	Rating (A)	Contingency	2020 Loading (A)	Need Date
1. Merivale to Chesterville TS	Merivale x Limebank JCT	L2M	480	continuous loading	390	2028

6.4 Step-Down Transformation Facilities

There are a total of fifty-two step-down transmission connected transformer stations in the Greater Ottawa Region. The stations have been grouped based on the geographical area and supply configuration. The station loading in each area and the associated station capacity and need date for relief is provided in Table 6-3 below. However considerations such as feasibility of load transfers will also impact the transformation capacity need within a region. As shown, areas requiring additional transformation capacity are the Center 230/44 kV area, and the South 115 kV. Table 6-4 shows station loads for all areas which are adequate over the 2020-2037 study period. Details of the areas and associated stations are given in Appendix D.

Table 6-3 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2020 Loading (MW)	Need Date
Center 230/44 kV	143	115	2026
South 115	189	137	2029

Table 6-4 Adequacy of Step-Down Transformer Stations – Areas Adequate

Area/Supply	Capacity (MW)	2020 Loading (MW)	2037 Loading (MW)
East 115 kV	358	178	257
West 115 kV	453	346	398
Center 115 kV	574	487	559
South West 115 kV	98	67	65
Center 230/13.8 kV	134	96	97
West 230 kV	474	356	440
Outer East 115 kV	55	45	53
Outer West 115 kV	97	71	71
Outer East 230 kV	301	163	186
Outer West 230 kV	104	43	44

6.5 Load Restoration

Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfers) measures are considered when evaluating restoration capability. The load restoration criteria is defined in ORTAC and summarized in Figure 6-1.

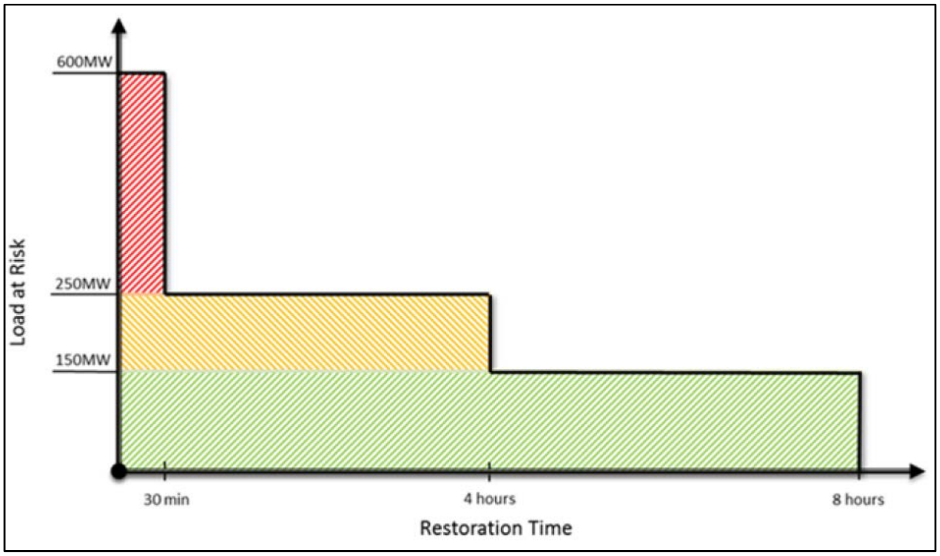


Figure 6-1. Illustration of ORTAC restoration criteria.

6.5.1 Load Restoration for M4G/M5G

Load restoration was assessed for 115 kV double circuit line M4G/M5G supplying stations Nepean Epworth MTS, Carling TS, and Lisgar TS in downtown Ottawa. Circuit M4G also supplies Slater TS, however this station is not considered in this analysis as this station is also fed from two different circuits. In case of a loss of both M4G and M5G, up to 165 MW can be lost. As per ORTAC, 15 MW have to be restored in 4 hours, and the remaining load in 8 hours. Hydro One expects that at least one of the overhead line can be restored in 4 hours for outages not caused by force majeure. The Study Team recommends that no further action is required at this time.

6.5.2 Load Restoration for C3S/M32S

M32S is a 230 kV circuit connecting Merivale TS to South March TS, and 230 kV 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 300 MW of load loss. As per ORTAC, 50 MW have to be restored in 30 minutes, 150 MW 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. The Study Team recommends that no further action is required at this time.

6.5.3 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 152 MW by the end of the study period. As per ORTAC, all load above 150 MW 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.

6.5.4 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 187 MW of load loss. Hydro One prepared a Local Planning report during the previous cycle of Regional Planning. The report considered the loss of up to 174 MW 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.

7. REGIONAL PLANS

This section discusses electrical infrastructure needs in Greater Ottawa Region, and presents wires alternatives and preferred wires solution for addressing these needs. Table 7-1 lists needs previously identified in the IRRP for the Ottawa Sub-Region [1] and the NA for the Outer Ottawa Sub-Region [2] as well as the adequacy assessment carried out as part of this RIP report.

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

Need Type	Section	Station/Circuit/Area	Timing
Area Capacity	7.1	South East Ottawa	Near Term
	7.2	Kanata-Stittsville Area	Near Term
Station Capacity	7.3.1	Orleans TS	Near Term
	7.3.2	Hawthorne TS	Medium Term
	7.3.3	Overbrook TS	Medium Term
Development & Sustainment	7.4	Transmission circuit L2M supply capacity	Medium Term
	7.5	Merivale TS: Autotransformation capacity and end of life of T22, 230 kV breakers, 115 kV breakers	Medium Term
	7.6	Bilberry Creek TS: End of life of transformers T1/T2 and LV circuit breakers and addition of two new LV circuit breakers for Hydro Ottawa	Near/Medium Term
Voltage Regulation	7.7	Circuit 79M1	NA
	7.8	Circuit E34M	NA
Station Capacity/ Sustainment	7.9	Hawkesbury MTS	Medium Term
Sustainment	7.10	Lincoln Heights TS: End of life of transformers T1/T2	Near Term
	7.11	Longueuil TS: End of life of transformers T3/T4	Near Term
	7.12	Riverdale TS: End of life of 115 kV breakers	Medium Term
	7.13	Albion TS: End of life of transformers T1/T2 and circuit breakers	Medium Term
	7.14	Russell TS: End of life of transformers T1/T2	Medium Term

7.1 Transformation Capacity in South East Ottawa

7.1.1 Description

There is significant load growth expected on the 27.6 kV distribution system in the south eastern part of Ottawa. The anticipated load will be connected to Uplands MTS, Limebank MTS and Leitrim MS (supplied through 44 kV feeders from Hawthorne TS). The stations are shown in Figure 7-1. Based on the RIP load forecast and existing station capacity, the loading at Limebank MTS, Uplands MTS and Leitrim MS would exceed its respective station capacity in in the first year of the load forecast as shown in Table 7.2.

In preparation for the load growth, Hydro Ottawa has initiated projects to increase transformation capacity at Uplands MTS and Limebank MTS. The existing 33 MVA transformer at Uplands MTS is being replaced by two new 50 MVA units. The transformer unit removed from Uplands MTS will be added as a fourth unit at Limebank MTS. Both projects are expected to complete in 2021. The transformation capacity at Leitrim MS is limited by the supply capacity of the 44 kV M2 feeder out of Hawthorne TS. Even after increasing capacity at Limebank MTS and Uplands MTS there is need for additional transformation capacity in the region.

Table 7-2 Transformation Capacity in South East Area before upgrades or new station

Station	LTR (MW)	2020	2022	2025	2030	2037
Limebank MTS	59.4$^{(1)}$	61.2	70.3	63.2	83.6	103.9
Uplands MTS	29.7$^{(2)}$	32.2	39.9	56.3	59.0	61.8
Leitrim MS (from Hawthorne TS)	22.5	30.4	34.5	32.0	43.3	56.0

(1) (2) Current LTR at Limebank & Uplands MTS before upgrades

Figure 7-1 South East area. Approximate location of the proposed station on L24A shown.

7.1.2 Alternatives and Recommendation

The following alternatives were previously considered to address the capacity need:

1. **Alternative 1 – Maintain Status Quo:** This alternative is rejected as it does not address the need for greater transformation capacity in the region.
2. **Alternative 2 – New DESN at Hawthorne TS:** This alternative proposes to put a new DESN station at Hawthorne TS. Due to the high volume of lines and feeders, the station feeder egress is very congested. Feeder runs are also expected to be longer due to geographic location of the load. Due to the reasons provided, this alternative was considered, but rejected by the Study Team.
3. **Alternative 3 – New station on circuit L24A:** This alternative proposes to construct a new Hydro Ottawa owned transformer station approximately 9 km south of Hawthorne TS. This is an ideal location to supply the new load, minimizing feeder runs out of the station. This alternative also gives Hydro Ottawa the opportunity to further interconnect their distribution network in the area and allow for greater supply diversity to new loads. Revised loading for the stations in the area has been provided in Table 7-3 after the addition of the new station on circuit L24A. The capability of circuit L24A has been assessed and determined adequate to supply the new station load forecast under study assumptions stated in section 5.2.

Table 7-3 Transformation Capacity in South East Area – After upgrades and new L24A Station

Station	LTR (MW)	2020	2022	2025(1)	2030	2037
Limebank MTS	89.1(2)	61.2	70.3	65.3	89.1	94.1
Uplands MTS	54.0(3)	32.2	39.9	45.9	49.1	52.2
Leitrim MS (from Hawthorne TS)	22.5	30.4	34.5	4.9	10.9	16.3
New L24A Station	TBD	0	0	40.1	46.5	52.8

(1) Expected in-service year for new station on circuit L24A
(2) (3) LTR after transformer upgrades to Limebank & Uplands MTS

Considering the above alternatives, the study team recommends that Hydro Ottawa proceed with Alternative 3 – new station on circuit L24A. This reaffirms the recommendation made in the IRRP phase. The new station is expected to be in-service by 2025. Until the new station is built, Hydro Ottawa will manage any overloads by transferring loads between stations, as an interim solution. In addition, Hydro One Distribution's Greely DS can also supply approximately 10 MVA of Hydro Ottawa's load until the new station is built.

7.2 Kanata-Stittsville Transformation Capacity

7.2.1 Description

Situated in the outskirts of the city, the Kanata-Stittsville area is a growing part of the Ottawa region. The area is supplied by multiple stations including South March TS, Bridlewood MTS, Kanata MTS, Marchwood MTS and Terry Fox MTS. Further increase in demand is anticipated in the area over the near and mid-term planning horizon. The new load is expected to connect to Hydro Ottawa's 27.6 kV distribution system supplied by stations Terry Fox MTS, Marchwood MTS and Kanata MTS, please refer to Figure 7-2.

The combined capacity of the three stations is exceeded in the first year of the forecast by 25 MW. This is slightly lower than the forecasted overload seen in the IRRP report. The overload gradually increases to 45 MW towards the end of the study period. Table 7-4 below shows the loading of the stations over the study period.

Table 7-4 Adequacy of Step-Down Transformer Stations – Kanata-Stittsville Area

Station	LTR (MW)	2020	2021	2025	2030	2037
Marchwood MTS	29.7	57.8	58.5	60.1	60.2	60.2
Kanata MTS	48.8	67.2	70.3	68.0	68.7	69.0
Terry Fox MTS	81	60.1	61.2	65.5	72.9	76.0
Grand Total	**160**	**185**	**190**	**194**	**202**	**205**

Figure 7-2. Kanata-Stittsville Area.

7.2.2 Alternatives and Recommendations

This near-term need can be managed via load transfers between stations until a permanent solution is implemented.

A potential solution identified in the IRRP report is to supply the overload in the area with a new station connected to the 230 kV network. Consistent with the IRRP review of the existing system capacity, the RIP reaffirms the adequacy of the system to supply the new 230 kV station to alleviate the overloaded stations. The ongoing Gatineau Corridor EOL study for the supply into Ottawa region may recommend changes to the 230 kV system that might impact the supply to the new station. The Study Team recommends Hydro One and Hydro Ottawa to develop a wires plan in Q3 2021 to address this need based on the recommendation stemming from the Gatineau Corridor EOL study currently underway.

7.3 Station Capacity

7.3.1 Description

Based on the RIP load forecast, several transformer stations are expected to reach their transformation capacity limits. The Study Team has reviewed the transformation capacity and load transfer capability of each area and concluded that in most cases, the capacity is sufficient to address the load growth in the near to medium term.

A few stations were identified where the load growth in the near term was high and would need further review. These stations are discussed below.

7.3.2 Recommended Plan and Current Status

7.3.2.1 Hawthorne TS

The DESN station at Hawthorne TS starts to overload in 2026 by approximately 2 MW and reaches 32 MW by the end of the study period. This overload is attributed to the significant load growth experienced on Leitrim MS fed through a 44 kV feeder out of Hawthorne TS.

As discussed in section 7.1.1, the recommended plan for a new station on circuit L24A will relieve the stations in the south area of any overloads, including Hawthorne TS. Please refer to Table 7-3 to see how the load is being transferred out of Hawthorne TS. As an interim measure the overloading at Hawthorne TS will be managed by load transfers out of the station. Once the new station on L24A is in service it will alleviate the overloading experienced at Hawthorne TS.

7.3.2.2 Overbrook TS

Overbrook TS is 115/13.8 kV transformer station in east of the Ottawa downtown core. Over the past few years, the station's load was fairly stable. However over the next five years, load growth is forecasted to reach and surpass the station's transformation capacity.

A review of the station's LTR indicate that the 13.8 kV cables from the transformers to the 13.8 kV switchgear are limiting the transformation capacity of the station. The Study Team recommends that Hydro One to review the capacity of the 13.8 kV cables to determine the cause of the limitation in 2021. The findings will be discussed between Hydro One and Hydro Ottawa to determine next steps, which could include LV cable upgrades or implementation of new feeder ties to transfer load out of the station. The plan should be implemented by 2026 when station is expected to reach its capacity.

7.3.2.4 Orleans TS

Orleans TS is a transformer station that was placed in service in 2015 that supplies Hydro One Distribution and Hydro Ottawa. The station's load has grown significantly over the past 5 years due to load transfers and load growth in the area. Based on the forecast, the station's transformation capacity is expected to reach its limit in the near term, and the load is expected to continue to grow. An overload of approximately 15 MW is expected within the next 10 years.

Other stations in the area, including Bilberry Creek TS, have sufficient transformation capacity to address the overload seen at Orleans TS. Hydro One Distribution has confirmed that transfer capability is available to nearby stations Bilberry Creek TS, Wilhaven DS, and Navan DS. To accommodate Hydro Ottawa load transfers, two new feeder breakers may be required at Bilberry Creek TS by 2024. Please see Section 7.6 for further details on the Bilberry Creek TS plan.

The Study Team recommends to manage any overload at Orleans TS by load transfers to neighboring stations. This need will be re-evaluated in the next cycle.

7.4 115 kV Transmission Circuit L2M Supply Capacity

L2M is a 115 kV circuit supplying two stations in southern Ottawa from Merivale TS: Limebank MTS and Marionville DS. The circuit extend to St Lawrence TS 115 kV network via a normally opened point at Chesterville TS (fed from St Lawrence TS). Stations transfers between the Merivale L2M network and the St Lawrence L2M network is possible for operating measures. Limebank MTS and Marionville DS are normally radially supplied by L2M from Merivale TS. The circuit is thermally limited to approximately 86 MW. Circuit L2M and its connected stations is shown in Figure 7-3.

Figure 7-3. Limebank MTS and Marionville DS connection to L2M.

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 medium term by 2029. The Study Team has reviewed the following alternatives to address the loading limitation.

7.4.1 Alternatives

The following alternatives were considered to address the capacity need:

1. **Alternative 1 - Increase the thermal rating of L2M**

The rating of circuit L2M between Merivale TS and Limebank MTS is currently limited due to clearance concerns. This option looks at increasing the thermal capacity of L2M by addressing the conductor sag issue. Hydro One has reviewed the work necessary to remove the limitation and has determine 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 rebuild is required. This work would remove the clearance limitation and would allow the circuit capacity to be increased to approximately 106 MW.

Based on the load forecast, this option would defer the capacity need to the long term, however this option may not be sufficient to meet demand in the final years of the load forecast.

2. **Alternative 2 – Circuit Rebuild**

This alternative would look at rebuilding the 7.8km of 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 115 kV 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 115 kV 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.

3. **Alternative 3 – Load Transfer**

This option looks at transferring load from Limebank MTS to Cambrian MTS, a new station planned to be in service in Q1 2022. Hydro Ottawa has confirmed that load can be transferred from Limebank MTS to Cambrian MTS to help mitigate the L2M loading concern. With these transfers, the need date for addressing L2M thermal constraint can be deferred into the long term. The cost of feeder transfers is expected to be minimal to Hydro Ottawa.

7.4.1 Recommendation

The Study Team recommends to monitor the load at Limebank MTS and implement load transfers out of the station when L2M reaches its thermal capacity. With the ongoing Gatineau Corridor EOL study, network changes could occur which would alleviate the thermal capacity need of L2M. This need will be re-evaluated in the next Regional Planning cycle when the Gatineau Corridor EOL study results are known.

7.5 Merivale TS

Merivale TS is a major 230/115 kV transformer station in the area that supplies load stations in west Ottawa. The station houses a 230 kV GIS switchgear with six SF6 breakers, two 230/115 kV auto-transformers T21 and T22 and a 115 kV switchyard with four oil circuit breakers and twelve SF6 circuit breakers.

7.5.1 Sustainment Need

The existing 230 kV breakers have been in-service from 1977 and are approaching end of life. The existing auto-transformer T22 has been in-service since 1978 and is approaching end of life. The 115 kV oil circuit breakers came to service between 1973-1976 and have been identified for replacement.

Based on the EOL timing, the replacement of autotransformer T22 is required by 2027. However, T22 replacement will be expedited during execution of the project at Merivale TS to help with the 230/115 kV transformation need described in the next section.

7.5.2 230/115 kV Transformation Capacity Need

As discussed in Section 6.2, about 60% of the Greater Ottawa load is supplied from the 115 kV network. The autotransformers at Merivale TS and Hawthorne TS supply the majority of this load with support from generating stations located west of Merivale TS, on the Madawaska and Ottawa rivers. At Merivale TS, the LTR of autotransformer T22 is rated at 315 MVA and T21 is rated at 347 MVA. As the load is growing on the 115 kV network, the autotransformers are approaching both their continuous and LTR ratings.

Based on the forecast and the generation assumptions described in Section 5.2, the station 230/115 kV transformation capacity is exceeded under the loss of an autotransformer in the first year of the forecast. In addition, the study results show that both autotransformers will reach their continuous loading limits of 250 MVA over the next five years. Please see results shown in Table 6-1 in Section 6.2.

In order to address the autotransformer loading concerns, additional 230/115 kV transformation capacity or load transfers from the 115 kV to the 230 kV system is required. The replacement of T22 discussed above will not be sufficient to address the autotransformer overload.

A joint planning study by Hydro One and IESO is currently underway for the Ottawa 115 kV System Supply, which will develop and review alternatives to resolve the autotransformation need at Merivale TS. Some of the alternatives that are being considered are discussed below.

1. **Alternative 1 - Addition of one new autotransformer at Merivale TS**

This alternative considers the addition of one new autotransformer at Merivale TS. This option requires modification to both the 230 kV and 115 kV switchyard.

The 230 kV SF6 switchgear is housed in a GIS building. There are no positions available on the existing diameters to connect a new autotransformer. To connect the new autotransformer to the 230 kV yard would therefore require expansion to provide a new breaker position. The 115kV yard is air insulated and no breaker position is available to connect a new autotransformer.

The configuration changes at Merivale TS, including the expansion required are shown in Figure 7-4 below. Please note: the yard configuration is shown as an example only to illustrate the expansion; if this option is selected, Hydro One will develop the 230 kV and 115 kV layouts configuration. Some circuit relocations may also need to be considered as shown in the figure below.

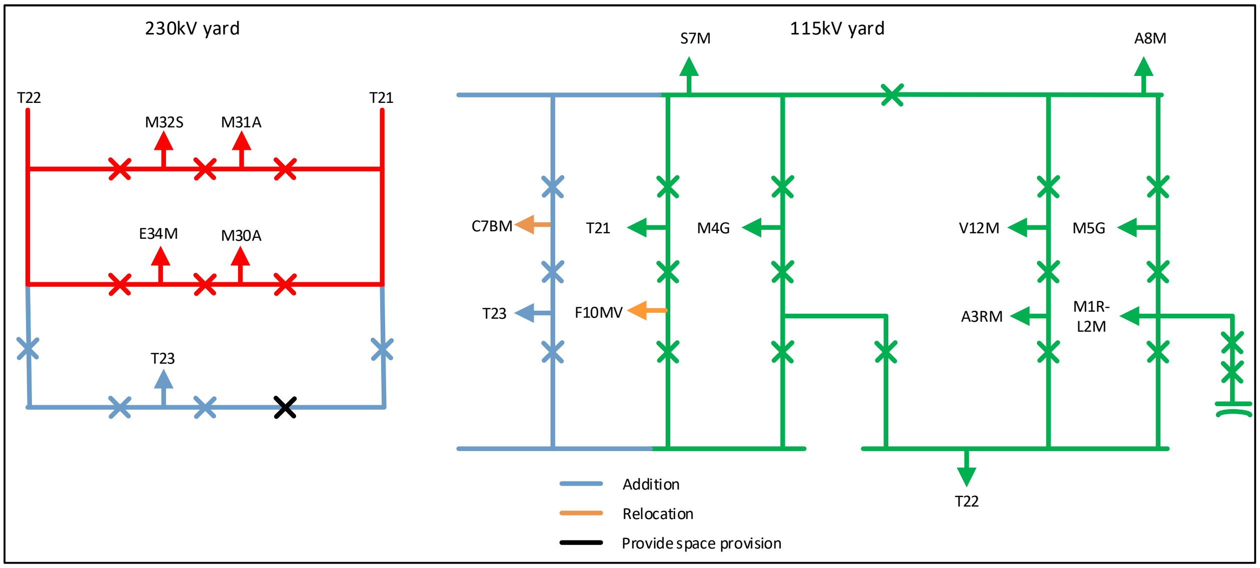


Figure 7-4. Merivale TS switchyard configuration with the addition of a third autotransformer.

2. Alternative 2 - Addition of two new autotransformers at Merivale TS

This alternative considers the installation of two new autotransformers at Merivale. To avoid having the 230 kV yard expansion discussed in the previous section, this option would share the 230 kV connection between two autotransformers. However, this option would require further work on the 115 kV yard compared with the previous alternative, as two new diameters would be required since the 115 kV terminations cannot be shared due to high load currents. This configuration would result in the loss of two autotransformers if the 230 kV breakers supplying the autotransformers open. However, two autotransformers will still remain in service to supply the load, similar to the Alternative 1.

The configuration changes at Merivale TS are shown in Figure 7-5 below. Note: the yard configuration is shown as an example only to show the expansion required. If this option is selected, Hydro One will develop the 230 kV and 115 kV layouts configuration.

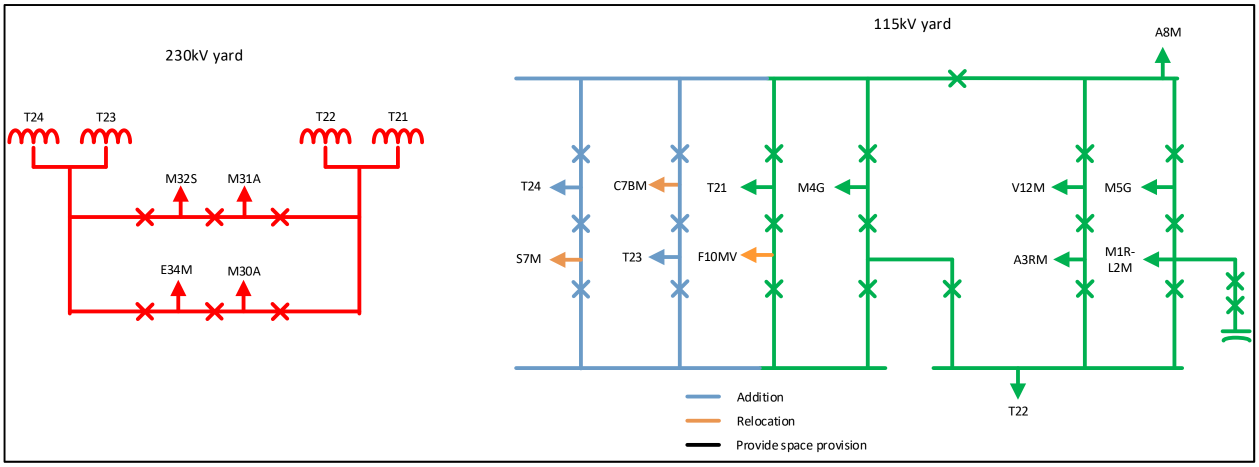


Figure 7-5. Merivale TS switchyard configuration with the addition of two new autotransformers.

7.5.3 Recommendation

The Gatineau Corridor EOL and Ottawa 115 kV System Supply studies could change the configuration at Merivale TS. The outcome of these studies is required to develop a plan to address the 230/115 kV transformation capacity and sustainment needs at the station. Both reports will be complete by Q2 2021.

The replacement for autotransformer T22 with a like for like unit (in situ) can be completed by 2025. The on-going studies can impact this timing based on their recommendations and necessary approvals including SIA.

The study team recommends Hydro One to monitor the health of all aging assets at the station and develop a plan to address both sustainment and development needs following completion of the aforementioned studies.

7.6 Bilberry Creek TS: Station refurbishment

Bilberry Creek TS is a transformer station located in the east end of Ottawa. The station is supplied by two 115 kV circuits A2 and H9A from Hawthorne TS. The station supplies electricity to Hydro Ottawa and Hydro One Distribution customers.

The two 50/67/83.3 MVA transformers T1 and T2 are 44 years old, and approaching the end of life. Five LV oil circuit breakers owned by Hydro One were installed in 1976 and are approaching end of life. Two feeder breakers at the station are owned by Hydro Ottawa. The Hydro One owned oil breakers are in need of replacement in the medium term planning horizon.

7.6.1 Alternatives and Recommendations

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the need to replace the assets identified in the previous section resulting in increased maintenance expenses and deteriorating supply reliability to load customer.
2. **Alternative 2 – Station Refurbishment:** Under this alternative the existing transformers at the station are replaced with new standard 50/67/83.3 MVA units. The existing breakers will be replaced with new SF6 breakers with similar rating. This alternative would address the end-of-life assets need and would maintain reliable supply to customers.

In addition to the sustainment need, the IRRP recommended the addition of two new feeder breakers for Hydro Ottawa's load transfers and possible growth in the area.

The current station transformation capacity is 85 MW. The expected forecast for Bilberry Creek is shown in the Table 7-5 after the addition of the new breakers. The forecast includes planned transfers from both Hydro Ottawa and Hydro One Distribution. The station is expected to reach about 65 MW by 2028 and will remain at that level for the remainder of the study period. The station is expected to be within its loading limit for the duration of the study period based on the RIP forecast.

Table 7-5 Bilberry Creek TS forecast including HOL/H1DX transfers

	2024	2025	2026	2027	2028	2029	2033	2037
Net load (MW)	62.1	62.3	63.6	64.8	65.0	65.2	65.9	65.9

The Study Team recommends Hydro One to continue with Alternative 2 for the replacement of assets at Bilberry Creek TS. The plan cost is currently estimated to be approximately $25-30 million. Additionally, Hydro One expects the two new feeders can be installed by 2024 subject to an early confirmation from Hydro Ottawa. Hydro Ottawa and Hydro One will work together to develop a plan for the new breakers in 2021.

7.7 Voltage Regulation on 115 kV Circuit 79M1

7.7.1 Description and Current Status

The 115 kV circuit 79M1 supplies Rockland DS, Rockland East DS, Clarence DS, Wendover DS, and Hawkesbury MTS as shown in Figure 7-6. The circuit is supplied from Hawthorne TS via circuit H9A. Total distance to the end station Hawkesbury MTS is approximately 80km. As a result of this long distance and circuit loading, lower voltage can be expected at the end of the line. The previous Greater Ottawa planning report identified that the voltage at Hawkesbury MTS will approach ORTAC limits under peak load and contingency conditions by 2023. The recommendation of the previous RIP report was to continue to monitor the situation.

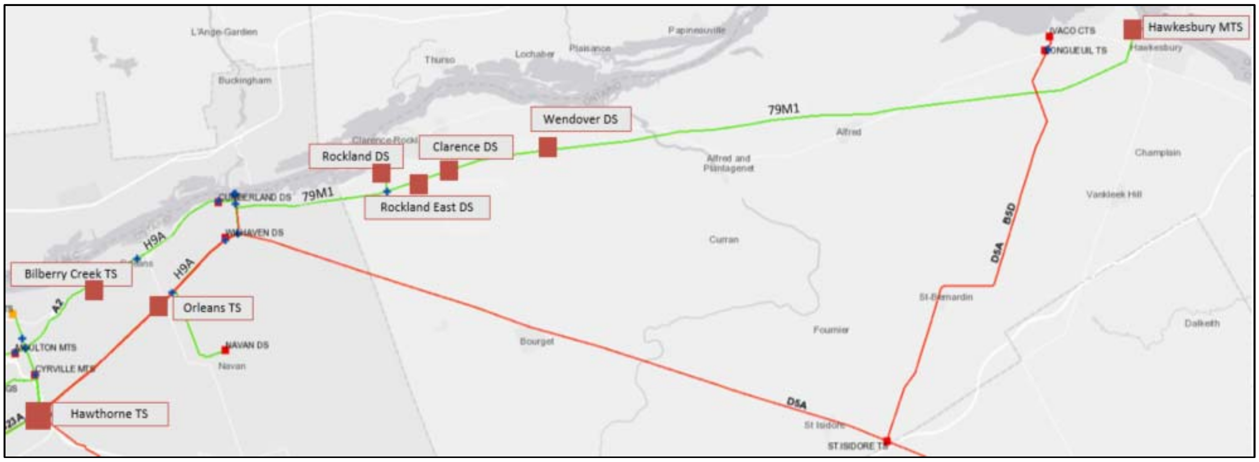


Figure 7-6. East Ottawa stations supplied by 115 kV circuits H9A and 79M1.

The voltage performance of circuits H9A/79M1 was reviewed as part of the RIP for this area. The worst contingency considered for the voltage on H9A/79M1 is the loss of 115 kV circuit A2, which results in all of Bilberry Creek TS load being supplied by H9A. This contingency increases the loading on circuit H9A and can cause lower voltages to be observed on the circuit.

Study results indicate that the voltage in the area and stations supplied by H9A/79M1 is within the limits of ORTAC for the near term. As mentioned in the Outer Ottawa Sub-Region NA report, Hydro One continues to monitor the loading in the area and voltage on the line. The Study Team recommends this need to be reassessed in the next regional planning cycle.

7.8 Voltage on E34M with Merivale End Open

7.8.1 Description

Circuits E34M (37.6km) and T33E (254.3km) tie Merivale TS to Clarington TS, through an in-line breaker at Almonte TS. If the circuit E34M (Almonte-Merivale) is open at the Merivale end, Terry Fox MTS, Almonte TS, and Cambrian MTS (once in service in 2022) will be supplied radially by Clarington TS. Clarington TS cannot supply the Ottawa stations with acceptable voltage levels when E34M is open at Merivale TS. This issue was identified in the previous regional planning cycle.

7.8.2 Recommended Plan and Current Status

Hydro Ottawa's new station, Cambrian MTS, will implement a scheme to remove the station load from circuit E34M and move it to its alternate supply S7M in the event of a line end open (LEO). A LEO at Merivale TS can results in load loss at Almonte TS and Terry Fox MTS. Terry Fox MTS is part of the Ottawa Area under voltage load rejection scheme ("UVLS"). This scheme is designed to shed the station load if the 230 kV supply voltage to the station drops below 204 kV when it is activated.

The combined load of both stations is less than 150 MW and can be restored within 8 hours as mandated by the ORTAC. As the load restoration criteria can be met, no further action is recommended by the Study Team.

7.9 Hawkesbury MTS: Capacity Upgrade

Hydro Hawkesbury is supplied from two transformer stations, Hawkesbury MTS and Longueuil TS. Currently Hawkesbury MTS has a 15 MVA transformers and a 7.5 MVA transformer to supply their load. Hydro Hawkesbury plans to replace their 7.5 MVA transformer with a new 15 MVA transformer.

The station capacity is limited to the rating of the smaller transformer. Hydro Hawkesbury plans to replace the 7.5 MVA transformer with a new 15 MVA transformer with a proposed in-service date in 2026. This upgrade will increase the station capacity and improve customer reliability such that if a transformer has to be taken out of service, the entire station load can be supplied without interruptions.

The Study Team recommends that Hydro Hawkesbury to proceed with the proposed upgrade.

7. 10 Lincoln Heights TS: End-of-Life Transformer T1/T2 Replacement

7.10.1 Description

Lincoln Heights TS is an indoor DESN station located in the city of Ottawa. The station houses two 45/60/75 MVA transformers with dual secondary windings. The station is supplied by two 115 kV circuits F10MV and C7BM. The station supplies electricity to Hydro Ottawa customers.

Transformers T1 and T2 are 40-45 years old and approaching end of life. There is limited load growth being experienced at the station over the course of the study period as seen in the RIP load forecast.

7.10.2 Alternatives and Recommendations

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the need to replace the assets identified in the previous section resulting in increased maintenance expenses and deteriorating supply reliability to load customer.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformers at Lincoln Heights TS are replaced with new standard 115/13.8 kV, 45/60/75 MVA units. This alternative would address the end-of-life assets need and would maintain reliable supply to customers.

The RIP Study Team recommends Hydro One continue with Alternative 2 for the refurbishment of Lincoln Heights TS. The cost is estimated to be approximately $22 million, and is expected to be in-service by late 2023.

7.11 Longueuil TS: End-of-Life Transformer T3/T4 & Component Replacement

7.11.1 Description

Longueuil TS is a DESN station located in the Outer Ottawa East region. The station is supplied by two 230 kV circuits D5A and B5D. The station supplies electricity to Hydro One Distribution customers.

The two 56/75/93 MVA transformers T3 and T4 are 55 years old and approaching end of life. The 10-day summer LTR of both transformers is 97 MVA. In additions, two 230 kV CVTs and two line traps are also approaching the end of their useful life.

7.11.2 Alternatives and Recommendations

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the need to replace the assets identified in the previous section resulting in increased maintenance expenses and deteriorating supply reliability to load customer.
2. **Alternative 2 - Replace with similar size or higher rated equipment as per current standard:** Under this alternative the existing transformers at Longueuil TS are replaced with new standard 230/44 kV, 50/66.7/83.3 MVA units or with new 75/100/125 MVA units. Replacing transformers with higher rated units is expected to have minimal incremental cost. A final determination will be made between Hydro One and Hydro One Distribution based on anticipated load at the station. This alternative would address the end-of-life assets need and would maintain reliable supply to customers.

The Study Team recommends Hydro One to continue with Alternative 2 in consultation with Hydro One Distribution for the refurbishment of Longueuil TS. The project cost will be determined based on the size selected for the replacement transformers. The project is expected to in-service by late 2024.

7.12 Riverdale TS: 115 kV Breaker Replacement

7.12.1 Description

Riverdale TS is a transformer station located in the city of Ottawa supplied by three 115 kV circuits A3RM, A5RK and A6R. The station comprises of a 115 kV switchyard and a DESN with two transformers and a 13.8 kV metalclad switchgear suppling station load. The station supplies electricity Hydro Ottawa customers.

There are three 115 kV busses connected together by two oil circuit breakers A1A2 and A1A3. The circuit breakers have been in service since 1953 and were rebuilt in 1994/95. The 115 kV circuit breakers are nearing the end of life.

7.12.2 Alternatives and Recommendations

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the need to replace the assets identified in the previous section resulting in increased maintenance expenses and deteriorating supply reliability to load customer.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing 115 kV oil circuit breakers will be replaced with SF6 circuit breakers of similar rating. This alternative would address the end-of-life assets need and would maintain reliable supply to customers.

The Study Team recommends Hydro One to continue with Alternative 2 for the replacement of circuit breakers at Riverdale TS. The plan cost is estimated to be approximately $6.5 million, and is expected to in-service by late 2024. In addition, Hydro One will look for opportunities to coordinate this project with Hydro Ottawa for their 13 kV switchgear replacement.

7.13 Albion TS: End-of-Life Transformer T1/T2 & Component Replacement

7.13.1 Description

Albion TS is a transformer station located in the city of Ottawa between Hawthorne TS and Merivale TS. The station is supplied by two 230 kV circuits M30A and M31A. The station supplies electricity to Hydro Ottawa customers.

The two 45/60/75 MVA dual secondary transformers T1 and T2 are 49 years old, and are at end of life. 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.

7.13.2 Alternatives and Recommendations

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the need to replace the assets identified in the previous section resulting in increased maintenance expenses and deteriorating supply reliability to load customer.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformers at Albion TS are 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 end-of-life assets need and would maintain reliable supply to customers.

The Study Team recommends Hydro One to continue with Alternative 2 for the replacement of assets at Albion TS. The plan cost is estimated to be approximately $40 million, and is expected to in-service by late 2026.

7.14 Russell TS: End-of-Life Transformer T1/T2 & Component Replacement

7.14.1 Description

Russell TS is a DESN transformer station located in the city of Ottawa. The station is supplied by two 115 kV circuits A5RK and A6R. The station supplies electricity to Hydro Ottawa customers.

The two 45/60/75 MVA dual secondary transformers T1 and T2 have been in service since 1975 and 1971 respectively. Both transformers are approaching end of life. The 13.8 kV air insulated metalclad switchgear at the station is jointly owned by Hydro One and Hydro Ottawa. The four LV bank breakers and two bus-tie breakers, owned by Hydro One, are approaching end of life in the medium term. Considering the multiple aging assets at the station this need requires addressing in the medium term planning horizon.

The revised load forecast for the RIP shows that loading at Russell TS marginally exceeds the LTR of the station. The replacement of the transformers will resolve any overload at the station for the duration of the study period.

7.14.2 Alternatives and Recommendations

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

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the need to replace the assets identified in the previous section resulting in increased maintenance expenses and deteriorating supply reliability to load customer.
2. **Alternative 2 - Replace with similar or higher rated equipment as per current standard:** Under this alternative the existing transformers at Russell TS are replaced with new, standard 115/13.8/13.8 kV, 45/60/75 MVA units or with new 60/80/100 MVA units. Replacing transformers with higher rated units is expected to have minimal incremental cost and provide flexibility to Hydro Ottawa. A final determination will be made by Hydro Ottawa and Hydro One based on anticipated load at the station.
   The 13.8 kV metalclad circuit breakers will be replaced with SF6 breakers with similar rating under this alternative. This alternative would address the end-of-life assets need and would maintain reliable supply to customers.

The Study Team recommends Hydro One to proceed with Alternative 2 in consultation with Hydro Ottawa for the replacement of assets at Russell TS. The project cost will be determined based on the size selected for the replacement transformers. The project is expected to in-service by late 2026.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER OTTAWA 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 Study Team in the near and mid-term planning horizon are provided in Table 8-1 below.

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 8-2.

Table 8-1. Recommended Plans in Greater Ottawa over the Next 10 Years.

No	Need	Recommended action plan	Expected I/S
1	Lincoln Heights TS: End of life of transformers T1/T2.	Replace end of life equipment.	2023
2	Longueuil TS: End of life of transformers T3/T4.	Replace end of life equipment.	2024
3	Riverdale TS: End of life of 115 kV breakers.	Replace end of life equipment.	2024
4	Transformation Capacity in South East Ottawa.	Hydro Ottawa to proceed with building transformer station.	2025
5	Albion TS: End of life of transformers T1/T2 and circuit breakers.	Replace end of life equipment.	2026
6	Russell TS: End of life of transformers T1/T2.	Replace end of life equipment.	2026
7	Overbrook TS: Station capacity.	Determine limitation of LV cables.	2021
		Upgrade cables or implement load transfers.	2026
8	Hawkesbury MTS: Capacity upgrade.	Hydro Hawkesbury to proceed with upgrade.	2026
9	Bilberry Creek TS: End of life of transformers T1/T2 and LV circuit breakers. Addition of two new LV circuit breakers for Hydro Ottawa.*	Install two new LV circuit breakers.	2024
		Replace end of life equipment.	2028
10	Merivale TS: Autotransformation capacity and end of life of T22, 230 kV breakers, 115 kV breakers.	Replace T22.**	2025
		Review recommendations of Ottawa 115 kV System Supply and Gatineau Corridor EOL studies to develop plan for Merivale TS.	2028

NOTES:

* Addition of two new breakers can be expedited following a formal request from Hydro Ottawa.

** Replacement of T22 with like for like transformer planned for completion by 2025. Inputs from the Gatineau Corridor EOL study and Ottawa 115 kV study may impact the timing of the replacement.

Table 8-2: List of Mid-Term Needs to be Reviewed in Next Regional Planning Cycle

No	Facilities
1	Orleans TS – Transformation capacity
2	Circuit 79M1 – voltage regulation
3	Circuit L2M – thermal rating

9. REFERENCES

[1]. Independent Electricity System Operator, "Ottawa Area Integrated Regional Resource Plan", 28 April 2015. http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Ottawa/2015-Ottawa-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Greater Ottawa Region – Outer Ottawa Sub Region", 28 July 2014. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Needs%20Assessment%20Report%20-%20Greater%20Ottawa%20-%20Outer%20Ottawa%20SubRegion.pdf

[3]. Hydro One, "Local Planning Report - B5D-D5A Load Restoration", 22 September 2015. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Local%20Planning%20Report%20-%20B5D-D5A%20Load%20Restoration.pdf

[4]. Hydro One, "Needs Assessment Report, Greater Ottawa Region", 15 June 2018. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/Greater%20Ottawa%20Needs%20Assessment%202018.pdf

[5]. Independent Electricity System Operator, "Ottawa Sub-Region: Integrated Regional Resource Plan", 4 March 2020 http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ottawa/Ottawa-Sub-Region-IRRP-20200304.pdf?la=en.

APPENDIX A: STATIONS IN THE GREATER OTTAWA REGION

No.	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	Carling TS	115	M4G, M5G
7	Centrepoint MTS	115	C7BM
8	Clarence DS	115	79M1
9	Cumberland DS	115	H9A
10	Cyrville MTS	115	A2, A4K
11	Ellwood TS	230	M30A, M31A
12	Epworth MTS	115	M4G, M5G
13	Fallowfield DS	115	S7M
14	Greely DS	115	M1R
15	Hawkesbury MTS	115	79M1
16	Hawthorne TS	230	-
18	Ivaco CTS	230	D5A
19	Kanata MTS	230	C3S, M32S
20	King Edward TS	115	A4K, A5RK
21	Limebank MTS	115	L2M
22	Lincoln Heights TS	115	C7BM, F10MV
23	Lisgar TS	115	M4G, M5G
24	Longueuil TS	115	B5D, D5A
25	Manordale MTS	115	C7BM
26	Manotick DS	115	S7M
27	Marchwood MTS	115	S7M, W6CS
28	Marionville DS	115	L2M
29	Merivale MTS	115	-
30	Moulton MTS	115	A4RK
31	Nation Research TS	115	A2
32	National Aeronautical CTS	115	A8M
33	Navan DS	115	H9A
34	Nepean TS	115	M32S
35	Orleans TS	230 & 115	D5A, H9A
36	Overbrook TS	115	A5RK, A6R
38	Riverdale TS	115	A3RM, A5RK
39	Rockland DS	115	79M1
40	Rockland East DS	115	79M1

41	Russell DS	115	M1R
42	Russell TS	115	A5RK, A6R
43	Slater TS	115	A3RM, A5RK, M4G
44	South Gloucester DS	115	M1R
45	South March TS	230	C3S, M32S
46	Cambrian MTS	230 & 115	E34M, S7M
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 B: TRANSMISSION LINES IN THE GREATER OTTAWA REGION

Location	Circuit Designations	Voltage (kV)
Hawthorne TS – Merivale TS	M30A, M31A	230
Hawthorne TS – St Isidore TS	D5A	230
Merivale TS – Almonte TS	E34M (formerly M29C)	230
Merivale TS – South March TS	M32S	230
South March SS – Chats Falls SS	C3S	230
Hawthorne TS – Bilberry Creek TS	A2	115
Hawthorne TS - Merivale TS	A3RM, A8M	115
Hawthorne TS – Overbrook TS	A4K, A5RK	115
Hawthorne TS – Riverdale TS	A6R	115
Hawthorne TS – Hawkesbury MTS	H9A/79M1	115
Merivale TS – Chats Falls TS	C7BM	115
Merivale TS – Hinchey TS	F10MV, V12M	115
Merivale TS – Lisgar TS	M4G, M5G	115
Merivale TS – South March SS	S7M	115
Stewartville TS – South March SS	W6CS	115
Stewartville TS – Barrett Chute TS	W3B	115

APPENDIX C: DISTRIBUTORS IN THE GREATER OTTAWA REGION

Distributor Name	Station Name	Connection Type
Hydro 2000	Longueuil TS	Dx
Hydro Hawkesbury	Hawkesbury MTS	Tx
	Longueil TS	Dx
Hydro One	Almonte TS	Tx
	Arnprior TS	Tx
	Bilberry Creek TS	Tx
	Clarence DS	Tx
	Cumberland DS	Tx
	Greely DS	Tx
	Hawthorne TS	Tx
	Longueil TS	Tx
	Manotick DS	Tx
	Marionville DS	Tx
	Navan DS	Tx
	Orleans TS	Tx
	Rockland DS	Tx
	Rockland East DS	Tx
	Russell DS	Tx
	South Gloucester DS	Tx
	St Isidore TS	Tx
	Stewartville TS	Tx
	Wilhaven DS	Tx
Hydro Ottawa	Albion TS	Tx
	Almonte TS	Dx
	Bilberry Creek TS	Tx
	Bridlewood MTS	Tx
	Cambrian MTS	Tx
	Carling TS	Tx
	Centrepoint MTS	Tx
	Cyrville MTS	Tx
	Ellwood MTS	Tx
	Nepean Epworth MTS	Tx
	Fallowfield DS	Tx
	Hawthorne TS	Tx
	Hinchey TS	Tx
	Kanata MTS	Tx

	King Edward TS	Tx
Hydro Ottawa	Limebank MTS	Tx
	Lincoln Heights TS	Tx
	Lisgar TS	Tx
	Manordale MTS	Tx
	Marchwood MTS	Tx
	Moulton MTS	Tx
	Merivale MTS	Tx
	Nepean TS	Tx
	Orleans TS	Tx
	Overbrook TS	Tx
	Richmond MTS	Tx
	Riverdale TS	Tx
	Russell TS	Tx
	Slater TS	Tx
	South Gloucester DS	Dx
	South March TS	Dx, Tx
	St Isidore TS	Dx
	Terry Fox MTS	Tx
	Upland MTS	Tx
	Woodroffe TS	Tx
Ottawa River Power Corporation	Almonte TS	Dx
Renfrew Hydro	Stewartville TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

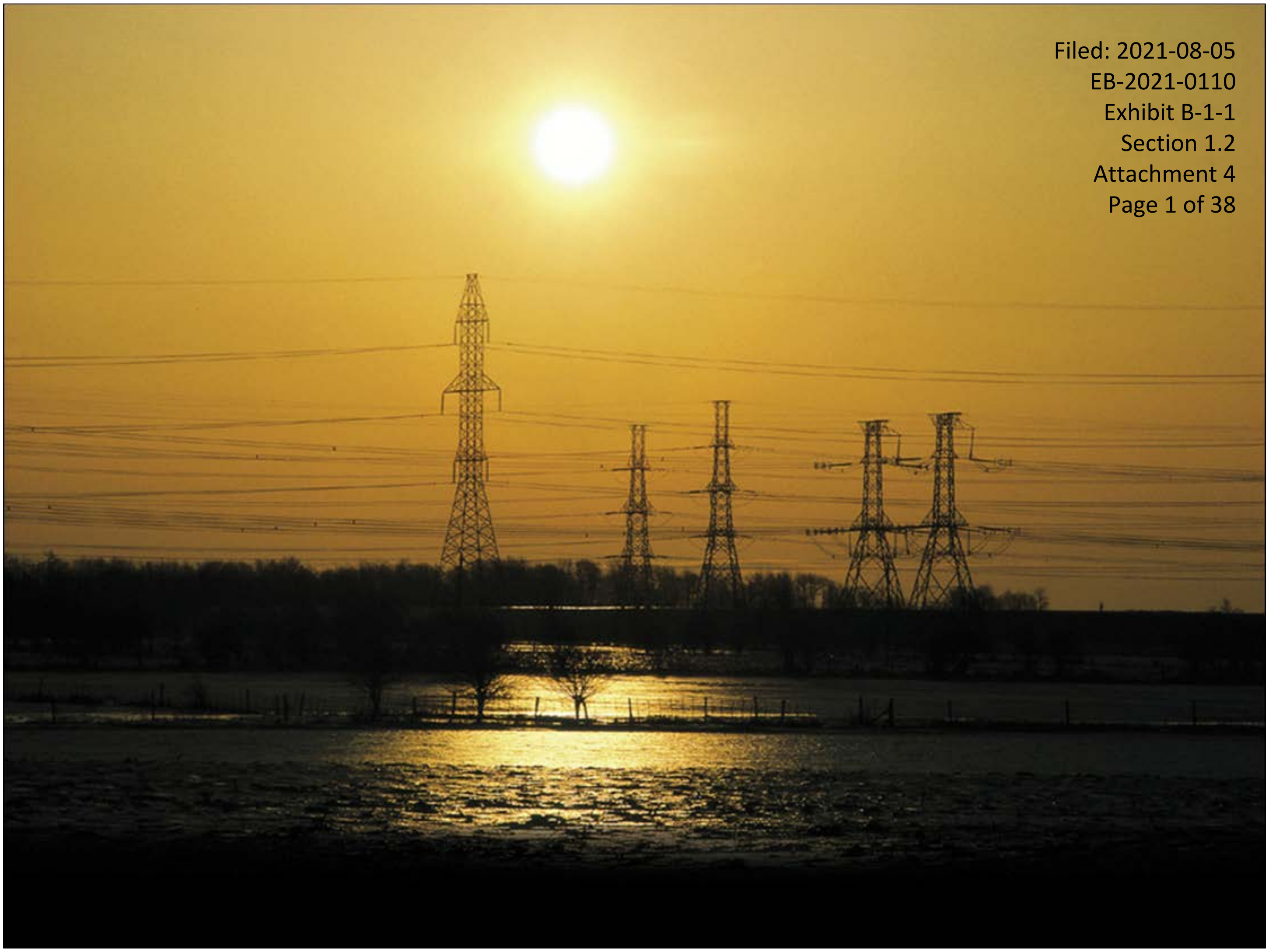
Table D-1. Greater Ottawa Net Coincident Load Forecast (extreme weather, low CDM)

Area & Station	LTR (MW)	Near and Medium Term Forecast (MW)										Long-Term Forecast (MW)		
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2037
Center 115 kV														
King Edward TS	82	88	88	88	87	87	87	88	88	89	89	90	90	90
Lisgar TS	75	55	55	60	60	61	61	61	64	64	65	65	68	69
Overbrook TS	95	75	76	78	83	87	93	100	104	108	110	112	123	127
Riverdale TS	106	85	87	88	88	88	88	89	89	90	90	91	96	97
Russell TS	70	76	76	75	74	74	73	73	73	73	73	73	73	73
Slater TS	146	108	107	106	104	104	103	103	102	102	102	102	103	103
Center 230 kV														
Albion TS	89	52	52	51	51	50	50	50	50	50	50	50	51	51
Ellwood MTS	45	44	45	46	46	45	45	45	45	45	45	45	45	45
Hawthorne TS	143	115	122	140	141	141	142	144	147	151	157	159	171	175
East 115 kV														
Bilberry Creek TS	85	40	51	54	59	59	58	58	58	58	58	58	58	58
Cumberland DS	7	6	6	6	6	6	6	6	6	6	6	6	6	6
Cyrville MTS	45	28	33	36	39	43	44	46	47	48	49	50	55	57
Moulton MTS	30	29	31	32	34	34	34	33	33	33	33	33	33	33
Nation Research TS	25	9	9	9	9	9	9	9	9	9	9	9	9	9
Navan DS	14	4	4	4	4	4	4	4	4	4	4	4	4	5
Orleans TS	117	52	56	60	61	61	62	64	65	66	66	67	69	69
Wilhaven DS	35	3	3	3	3	3	3	3	3	3	4	3	4	4
East 230 kV														
Orleans TS	117	52	56	60	61	61	62	64	65	66	66	67	69	69
South 115 kV														
Greely DS	21	24	29	29	29	29	29	29	30	30	30	30	31	32
Limebank MTS	89	63	65	71	64	67	63	66	70	75	79	84	99	104
Marionville DS	14	13	13	13	13	13	13	13	13	13	13	13	14	14
NRC Uplands CTS	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Russell DS	7	4	4	4	4	4	4	4	4	4	4	4	4	4
South Gloucester DS	7	5	5	5	5	5	5	5	5	5	5	5	5	5
Uplands MTS	54	29	31	37	42	47	56	57	57	58	59	59	61	62

	LTR	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2037
South West 115 kV														
Fallowfield DS	23	49	51	21	24	24	25	26	27	27	29	30	32	32
Manotick DS	8	8	9	10	11	12	12	12	12	12	12	12	12	12
Richmond DS	68	10	13	16	18	20	20	21	21	21	21	21	21	21
West 115 kV														
Bridlewood MTS	23	18	19	19	20	20	20	23	26	27	27	27	27	27
Carling TS	95	75	76	76	74	79	79	78	78	79	79	79	79	79
Centrepoint MTS	13	16	16	16	16	16	16	16	16	15	15	15	15	15
Epworth MTS	13	18	18	18	17	17	17	17	17	17	17	17	17	17
Hinchey TS	86	55	40	41	42	45	48	49	51	52	54	56	63	65
Lincoln Heights TS	72	44	46	46	45	45	54	54	54	54	54	53	53	53
Manordale MTS	9	10	10	10	10	10	9	9	9	9	9	9	9	9
Marchwood MTS	30	58	58	59	59	60	60	61	60	60	60	60	60	60
Merivale MTS	23	20	20	20	20	20	20	20	21	21	21	21	22	22
Woodroffe TS	91	32	33	33	34	50	50	50	49	49	49	49	49	49
West 230 kV														
Kanata MTS	49	67	70	70	69	68	68	68	69	69	69	69	69	69
Nepean TS	145	142	145	123	122	121	121	120	120	120	120	120	120	120
South March TS	110	87	87	96	95	93	93	94	93	92	90	90	93	93
Cambrian MTS	90	0	0	40	44	47	50	54	58	61	64	67	81	81
Terry Fox MTS	81	60	61	62	63	64	66	67	68	70	71	73	76	76
Outer East 115 kV														
Clarence DS	3	3	5	5	5	5	5	5	5	5	5	5	5	5
Hawkesbury MTS	18	13	14	14	13	13	13	13	13	13	13	13	13	13
Rockland DS	13	8	8	8	8	8	8	8	8	8	8	8	8	8
Rockland East DS	8	12	12	13	14	14	15	15	15	15	15	15	15	15
Wendover DS	14	10	12	12	13	13	13	13	13	13	13	13	13	13
Outer East 230 kV														
Ivaco CTS	100	81	82	83	84	85	86	87	87	87	87	87	87	87
Longueuil TS	87	42	45	47	48	48	49	49	49	49	49	49	49	49
St. Isidore TS	114	40	40	50	50	50	50	50	50	50	50	50	50	50
Outer West 115 kV														
Arnprior TS	46	44	45	45	45	45	45	45	46	46	46	46	46	46
Stewartville TS	50	26	26	25	25	25	25	25	25	25	25	25	25	25
Outer West 230 kV														
Almonte TS	104	43	43	44	45	46	46	45	45	44	44	44	44	44

APPENDIX E: LIST OF ACRONYMS

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



GTA 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.

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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.

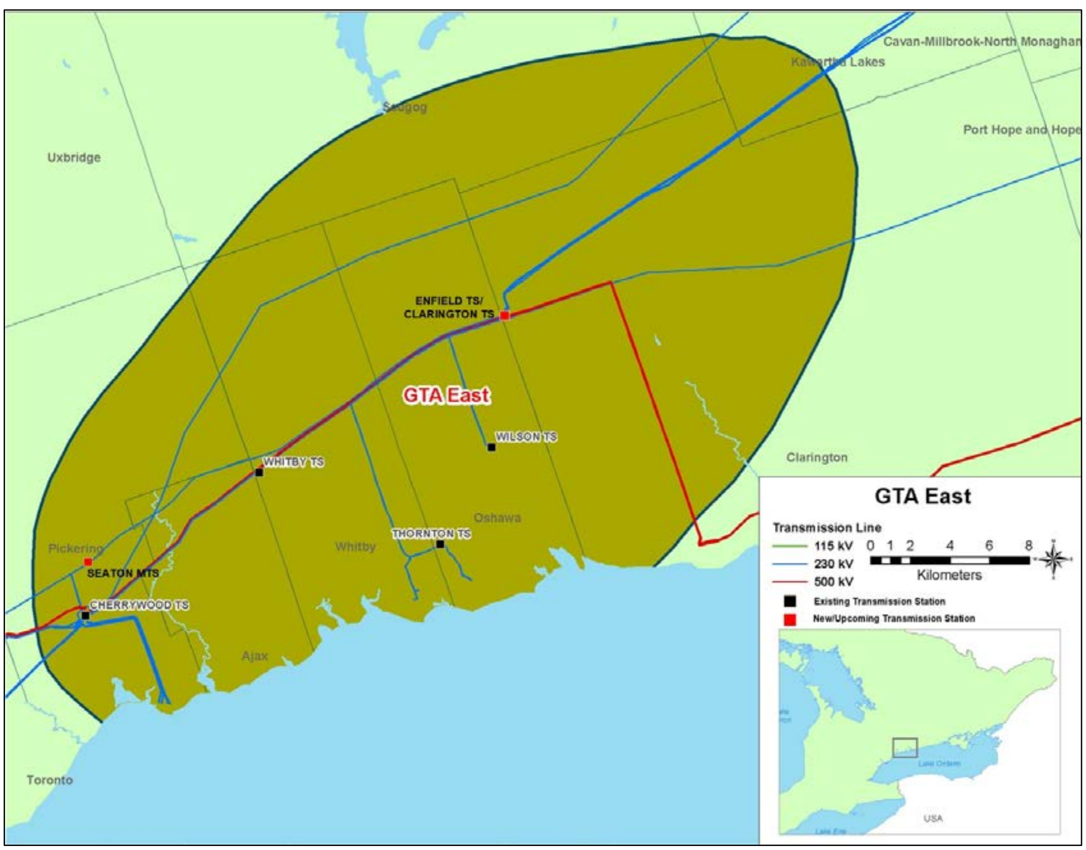

Figure 1-1: GTA East Region

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.

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[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.

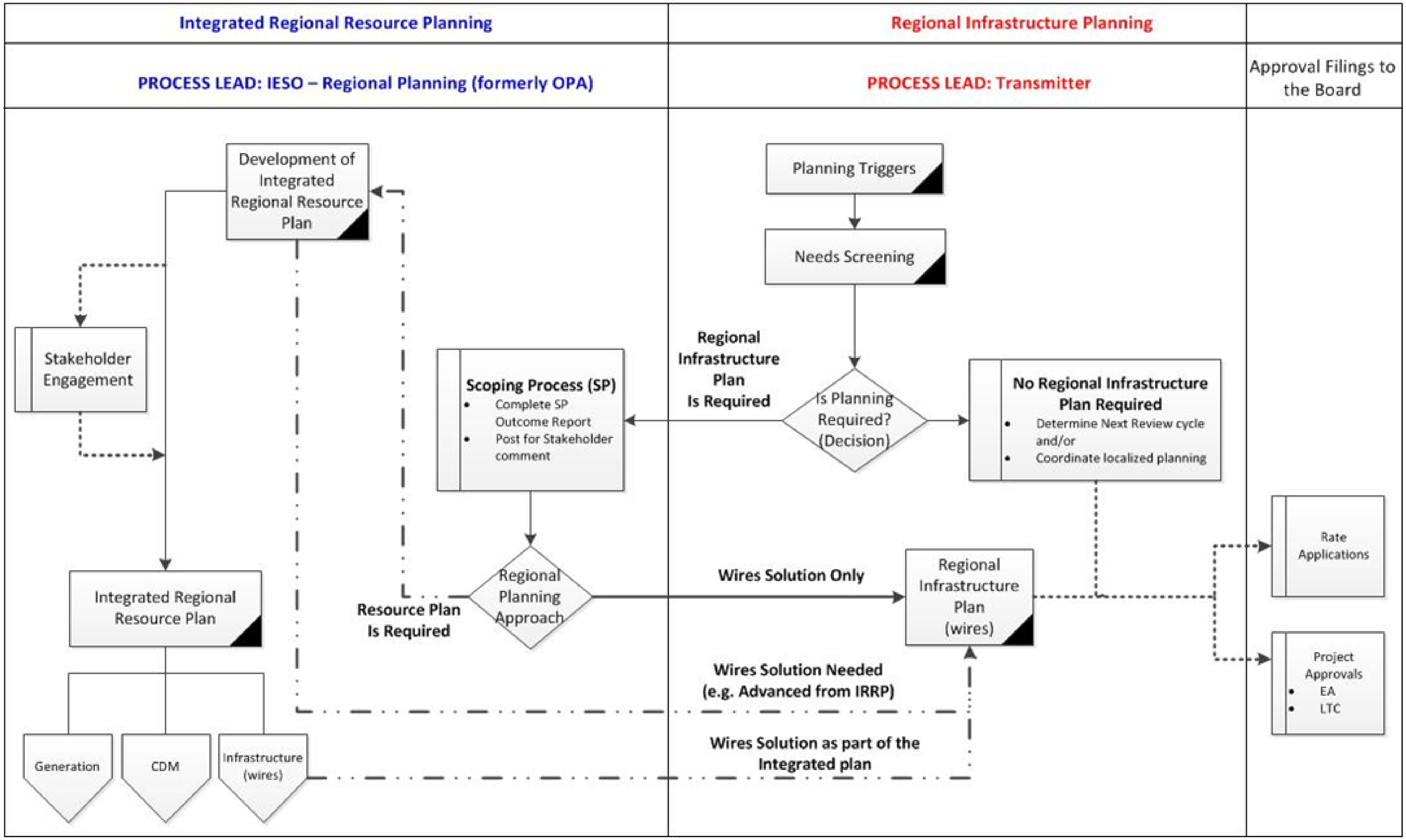


Figure 2-1: Regional Planning Process Flowchart

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.

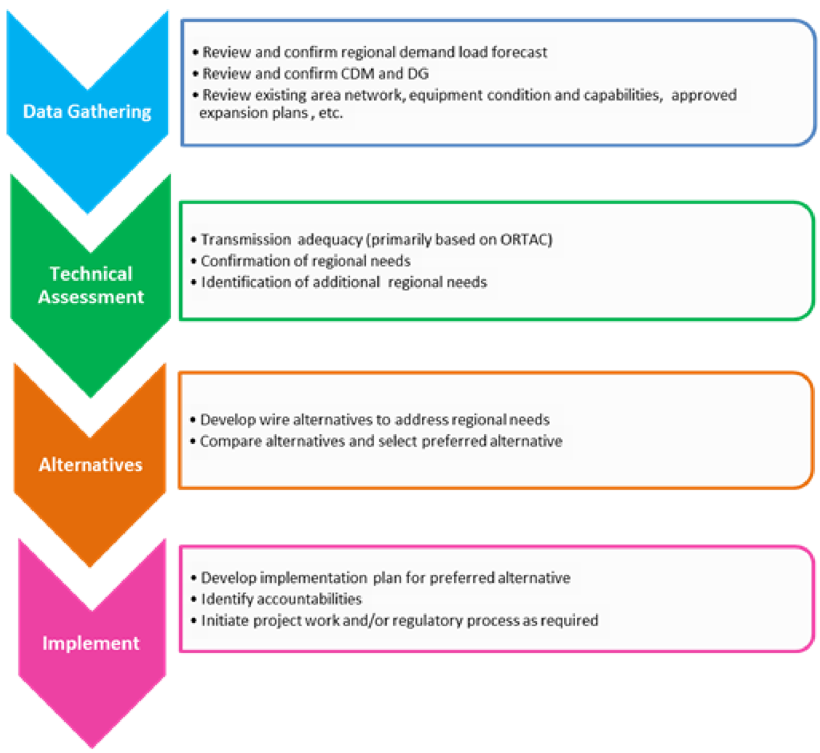


Figure 2-2: RIP Methodology

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.

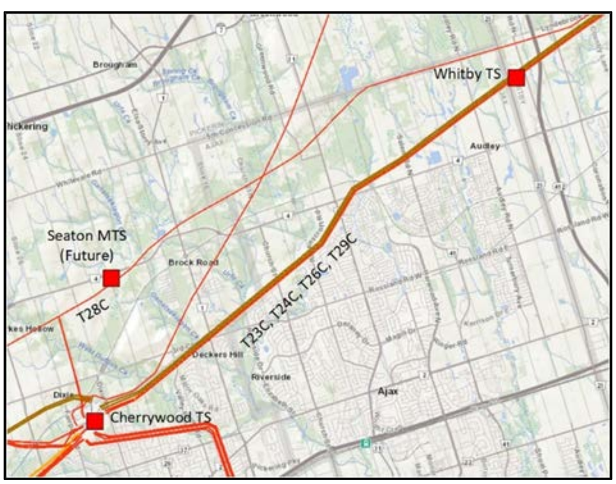


Figure 3-1: Pickering-Ajax-Whitby Sub-region

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.

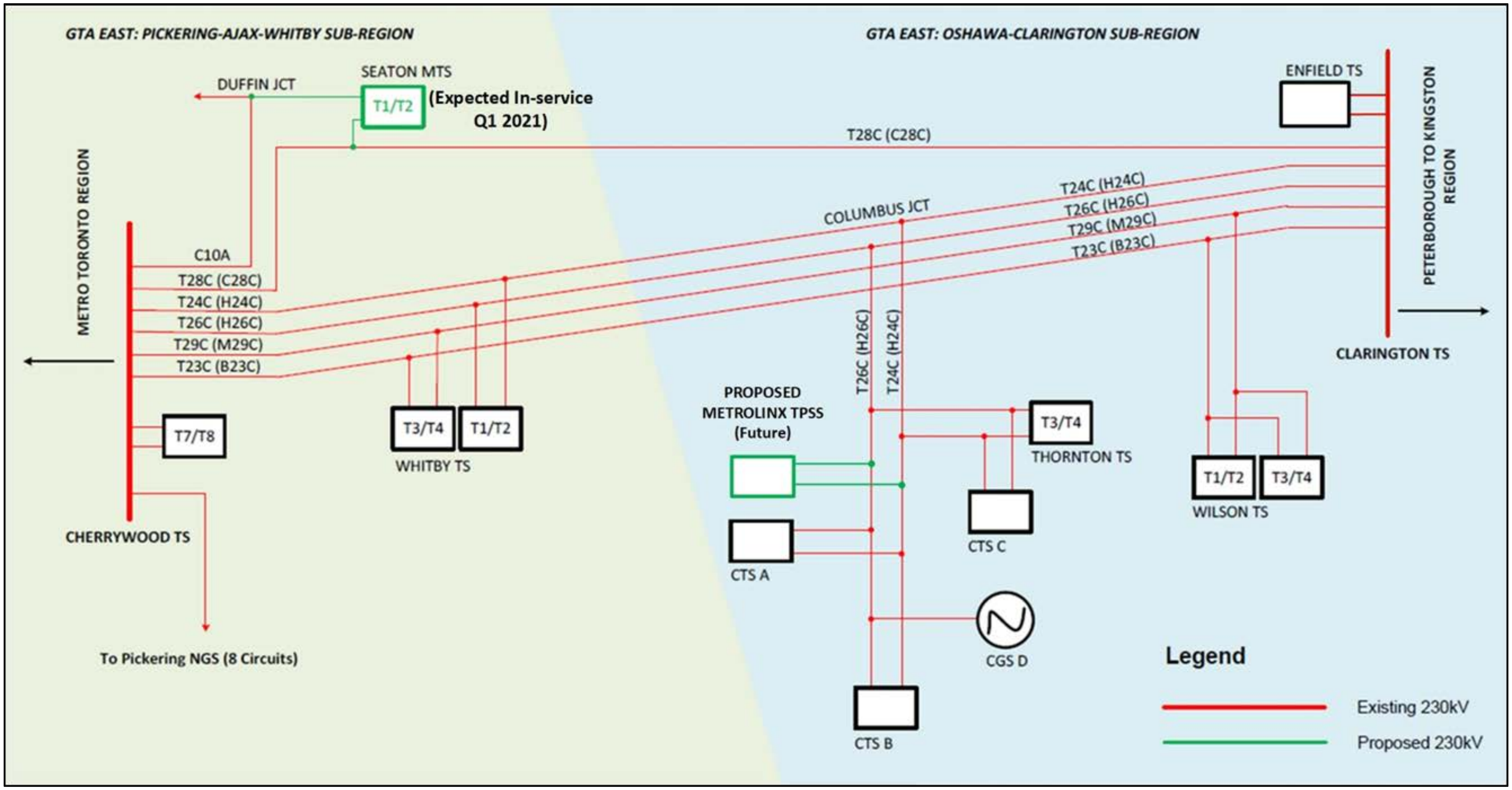


Figure 3-3: Single Line Diagram of GTA East Region

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.

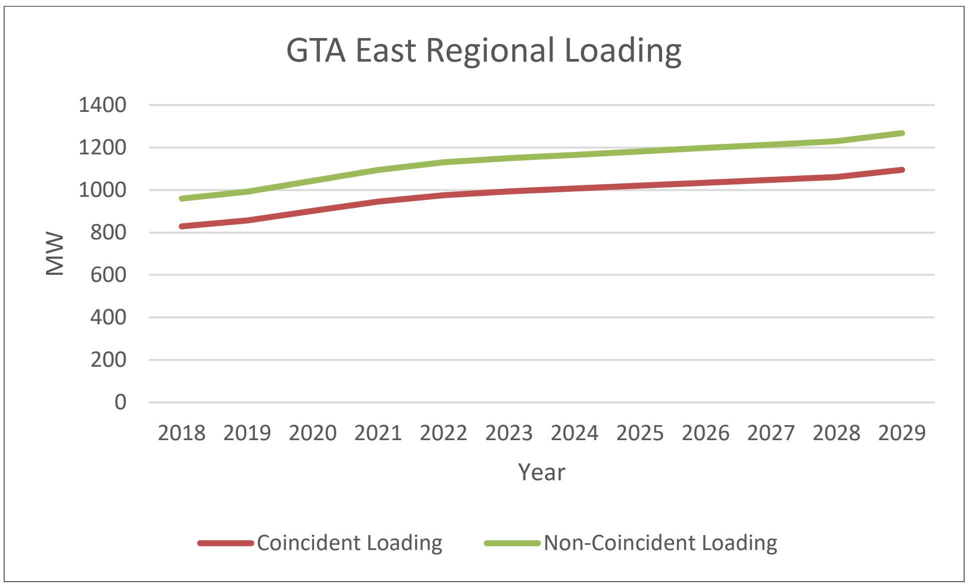


Figure 5-1 GTA East Region Net Load Forecast

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.

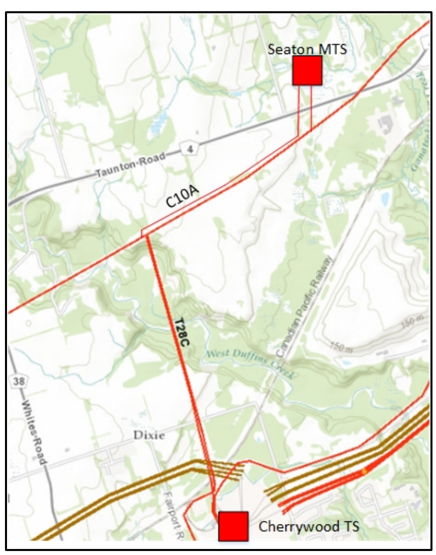


Figure 7-1: Location of Seaton MTS

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.

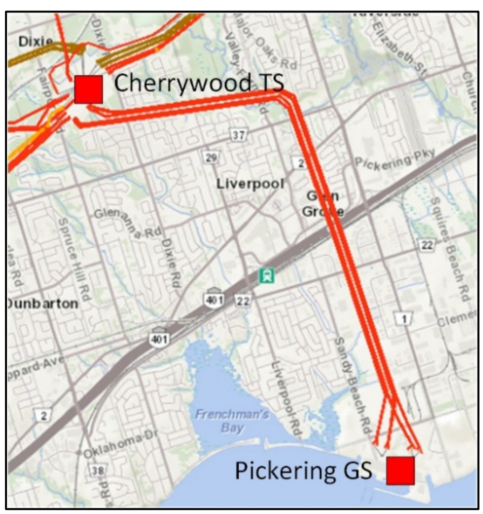


Figure 7-2: Cherrywood TS

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.

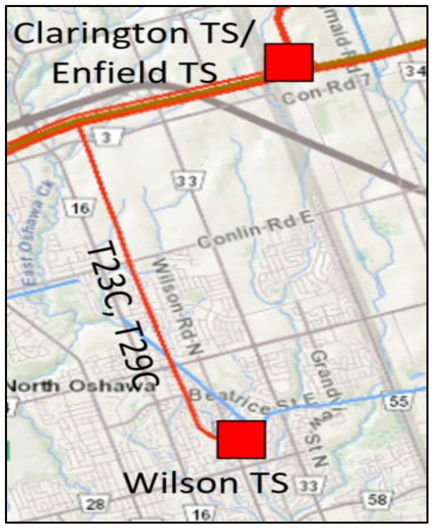


Figure 7-3: Wilson TS

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

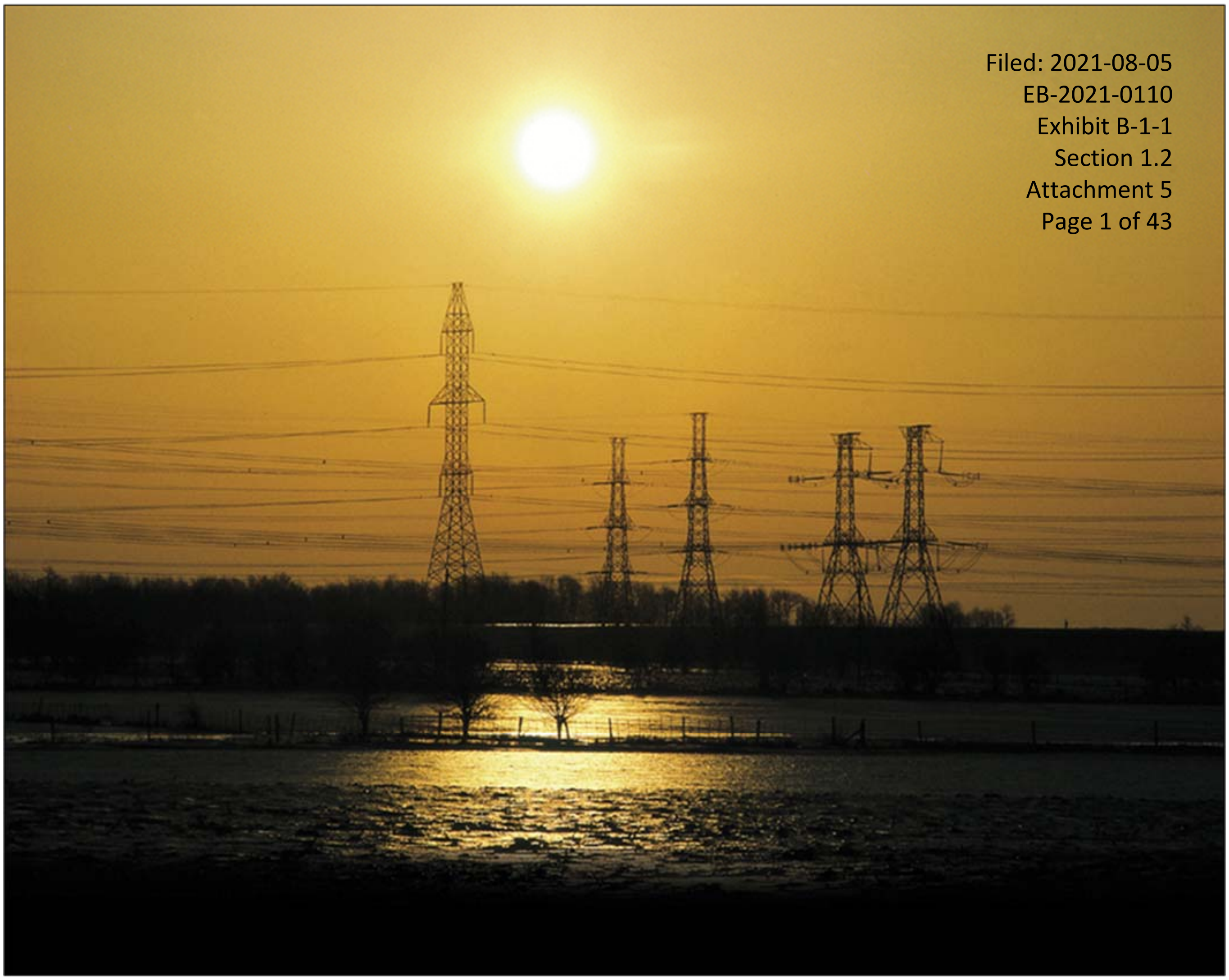
Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	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



GTA North

REGIONAL INFRASTRUCTURE PLAN

October 22, 2020

hydro one

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Prepared by:

Hydro One Networks Inc. (Lead Transmitter)

With support from:

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

DISCLAIMER

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

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

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 GTA NORTH REGION.

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

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

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

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

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

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

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

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

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

The Study Team recommends that:

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

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1 INTRODUCTION

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

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

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

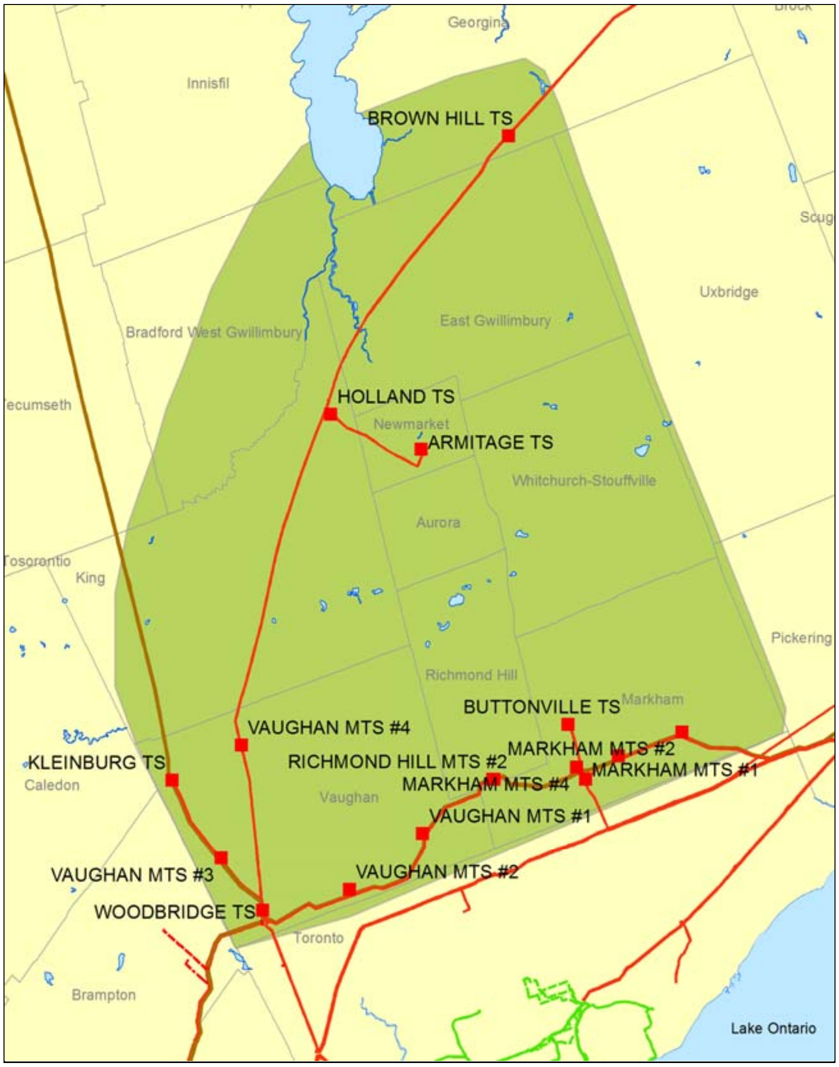


Figure 1-1: GTA North Region Map

1.1 Objectives and Scope

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

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

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

The scope of this RIP is as follows:

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

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by Hydro One and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in Hydro One's rate filing submissions and as part of LDC rate applications with a planning status letter provided by Hydro One.

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

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

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

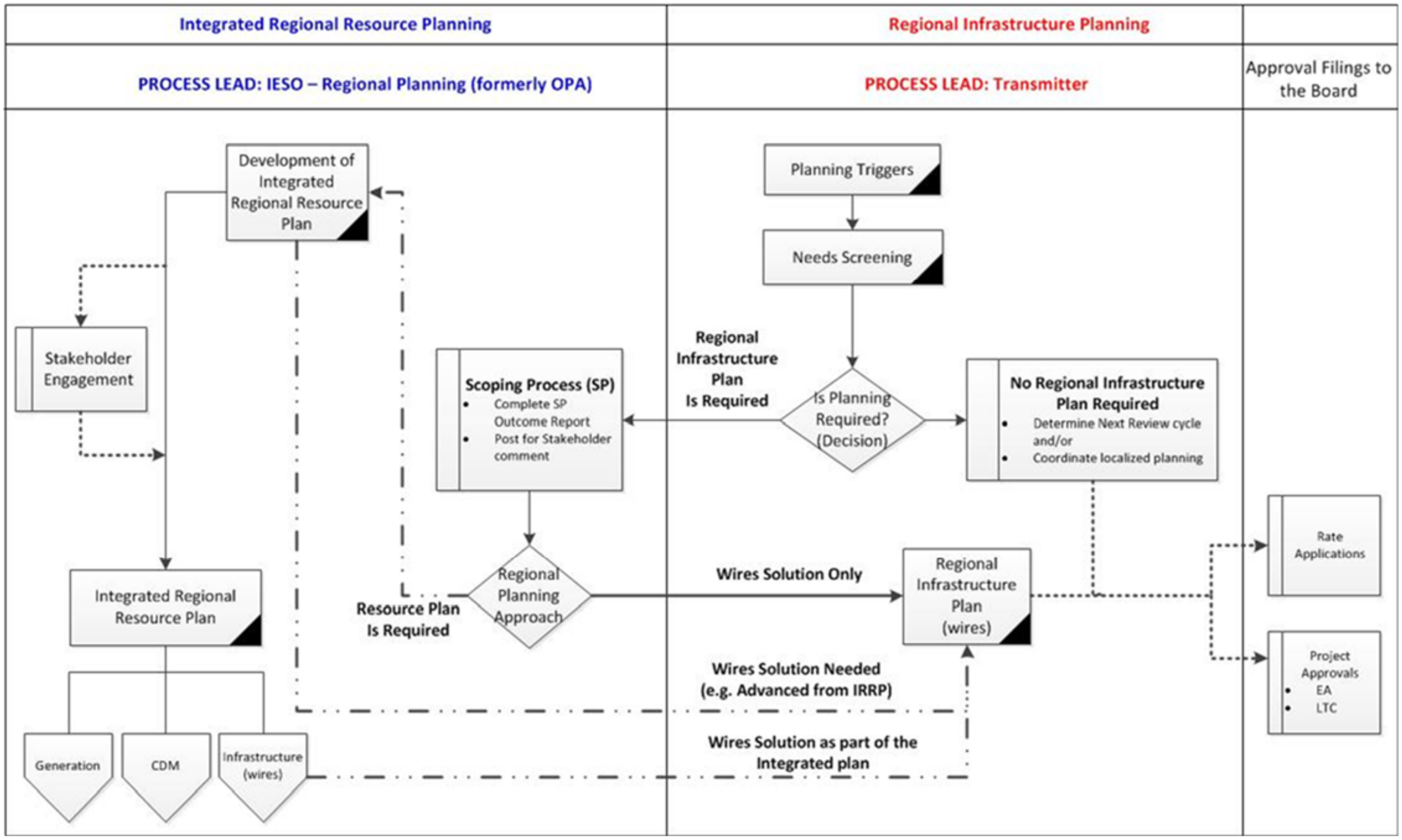


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other

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

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

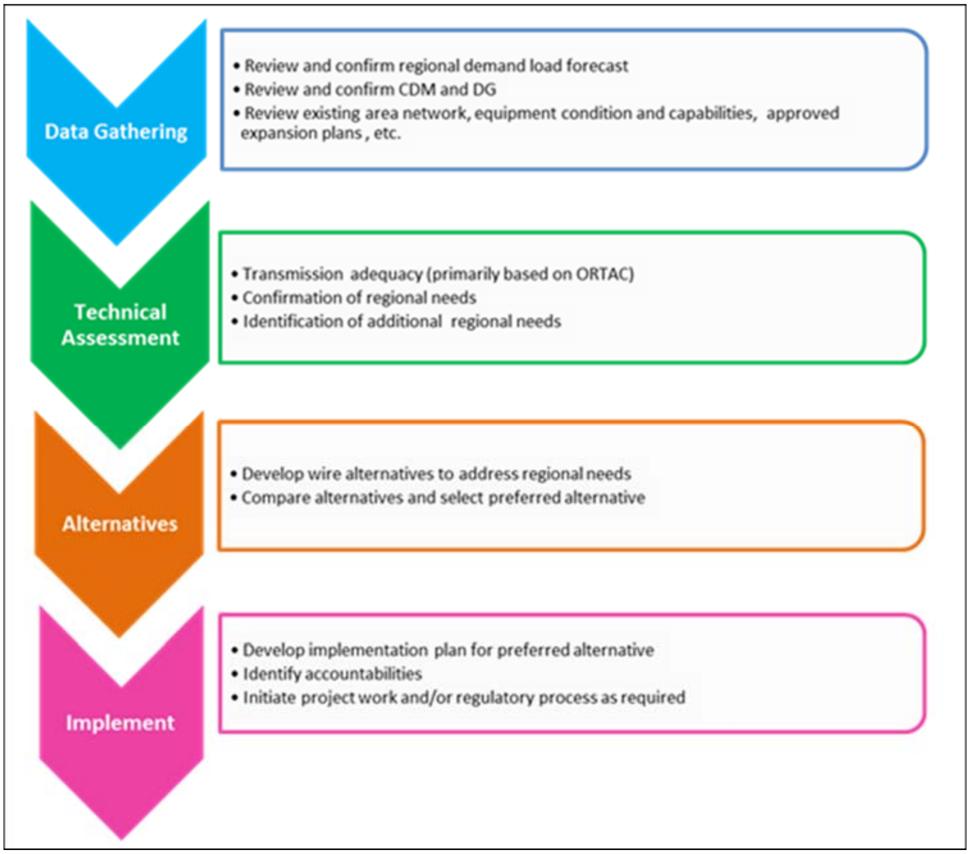


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

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

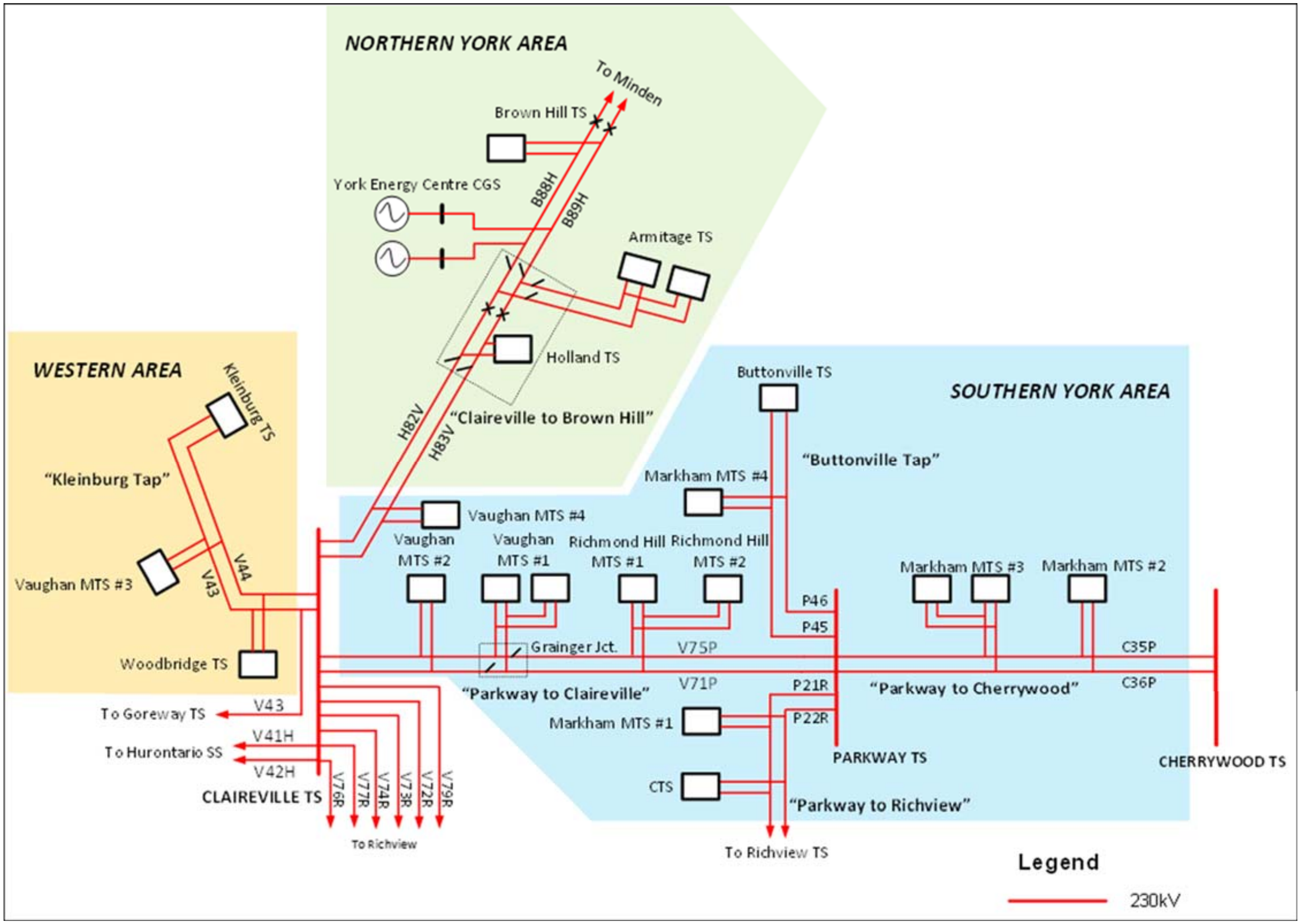
Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the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

The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and four 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and Alectra.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes seven municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is Alectra. Please refer to Figure 3-1.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the “Kleinburg tap”) that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro. Please refer to Figure 3-1

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



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

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

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

- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.

- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the Northern York area.

- Inline switches on the Parkway belt (V71P/V75P) at Grainger Jct. (2018)

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

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

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

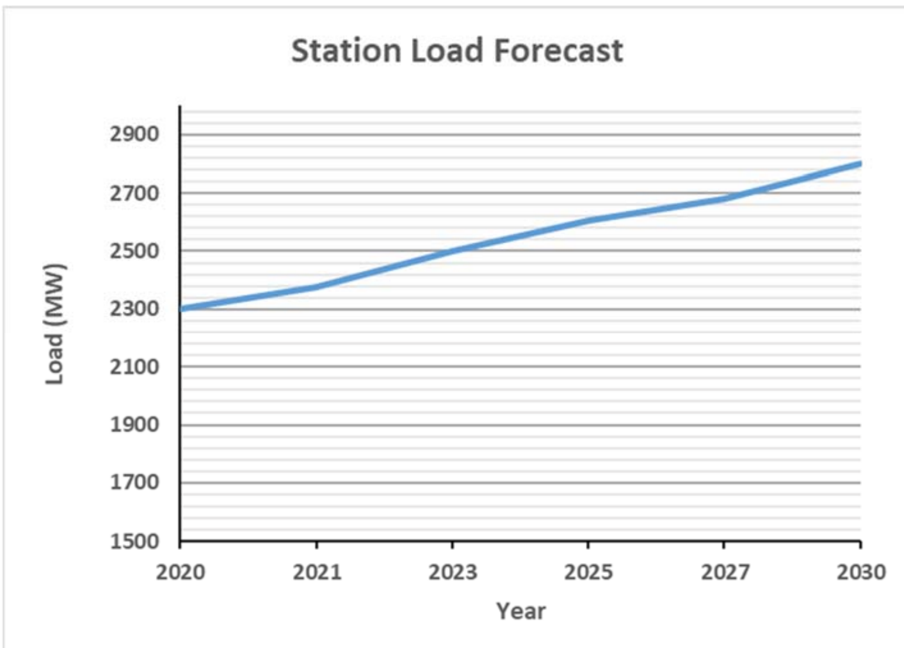


Figure 5-1: GTA North Region Load Forecast

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

5.2 Study Assumptions

The following other assumptions are made in this report.

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

- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations, which is consistent with Ontario Resource Transmission Assessment Criteria (ORTAC). Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using peak loads in the area.

6 ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

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

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

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

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

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

6.1 Adequacy of Northern and Southern York Area Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 3-1.

Southern York Area:

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

Northern York Area:

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

The RIP review shows that based on current forecast station loadings and bulk transfers, circuits P45 and P46 need to be uprated due to the future connection of Markham MTS #5. The other 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of thirteen step-down transformers stations in the Northern and Southern York Areas as follows in Table 6-1 Step-Down Transformer Stations below:

Table 6-1 Step-Down Transformer Stations

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

*Stations owned by Alectra

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

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

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

6.2 Adequacy of Western Area Facilities

6.2.1 230 kV Transmission Facilities

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

6.2.2 Step down Transformation Facilities

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

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

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by Alectra

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

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

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

6.3 Other Needs Identified During Regional Planning

6.3.1 Load Restoration in the Western Area

There is a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.1.

6.3.2 Load Restoration in the Northern York Area

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

6.3.3 Load Security and Restoration in the Southern York Area

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

6.3.4 High Voltages on Circuits M80B/ M81B

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

6.3.5 End of Life of Woodbridge TS- Transformer-T5

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

6.4 Longer Term Regional Needs (2030-2040)

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

Table 6-5: Longer Term Adequacy of Transmission Facilities

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

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

7 REGIONAL NEEDS AND PLANS

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

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

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

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

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

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

7.1 Woodbridge TS: T5 End-of-Life Transformers

7.1.1 Description

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

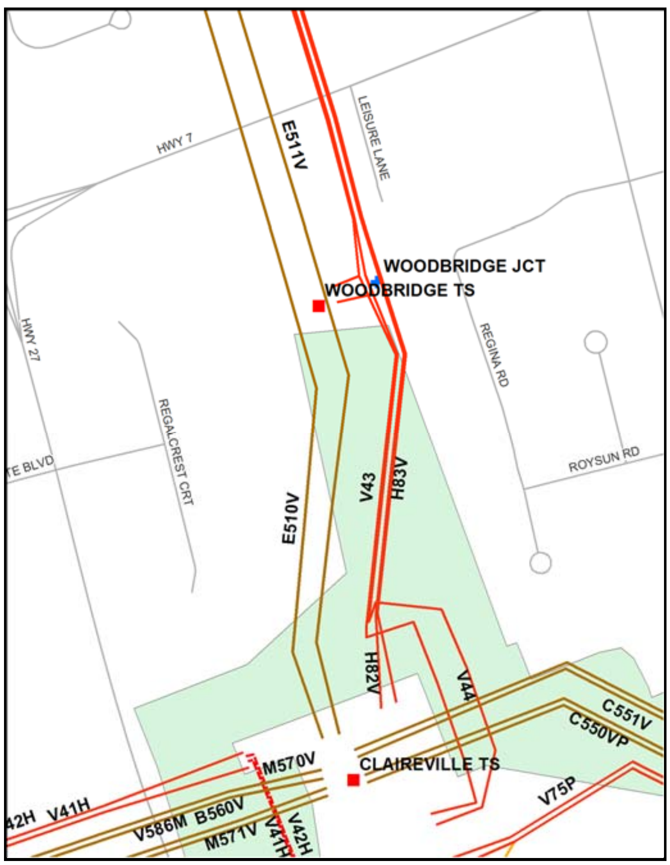


Figure 7-1: Woodbridge TS

7.1.2 Alternatives and Recommendation

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

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

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

7.2 Station Supply Capacity Needs and Plans

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

7.2.1 Markham MTS #5 Transformer Station

In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station in the north Markham area. Based on the current load forecast, the additional transformation capacity is required by the year 2025.

7.2.1.1 Alternatives and Recommendation

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

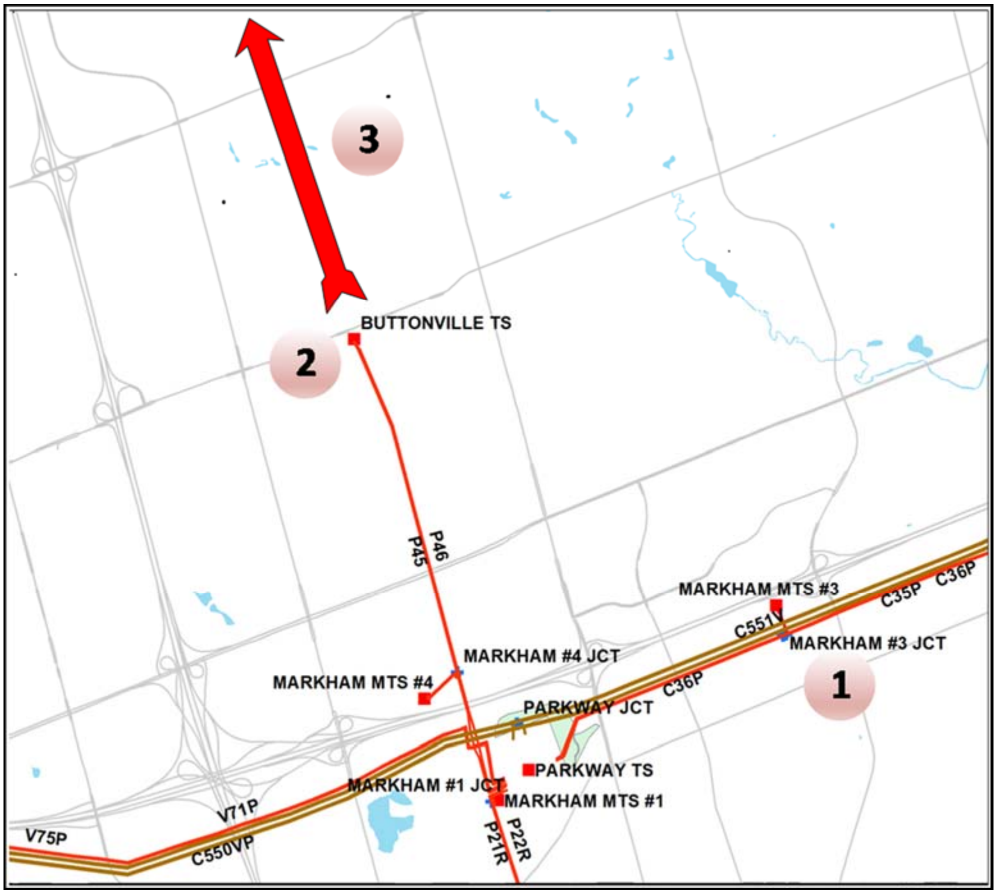


Figure 7-2: Location options for Markham #5 MTS

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

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

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

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

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

7.2.2 Northern York Area Transformer Station

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

Table 7-3: Northern York Area Peak Loading

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

7.2.2.1 Alternatives and Recommendation

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

7.2.3 Vaughan Area Transformer Station

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

7.2.3.1 Alternatives and Recommendation

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

7.3 System Capacity Needs and Plans

The Study Team has identified the following system capacity needs

7.3.1 Transmission Line uprate- P45/P46

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

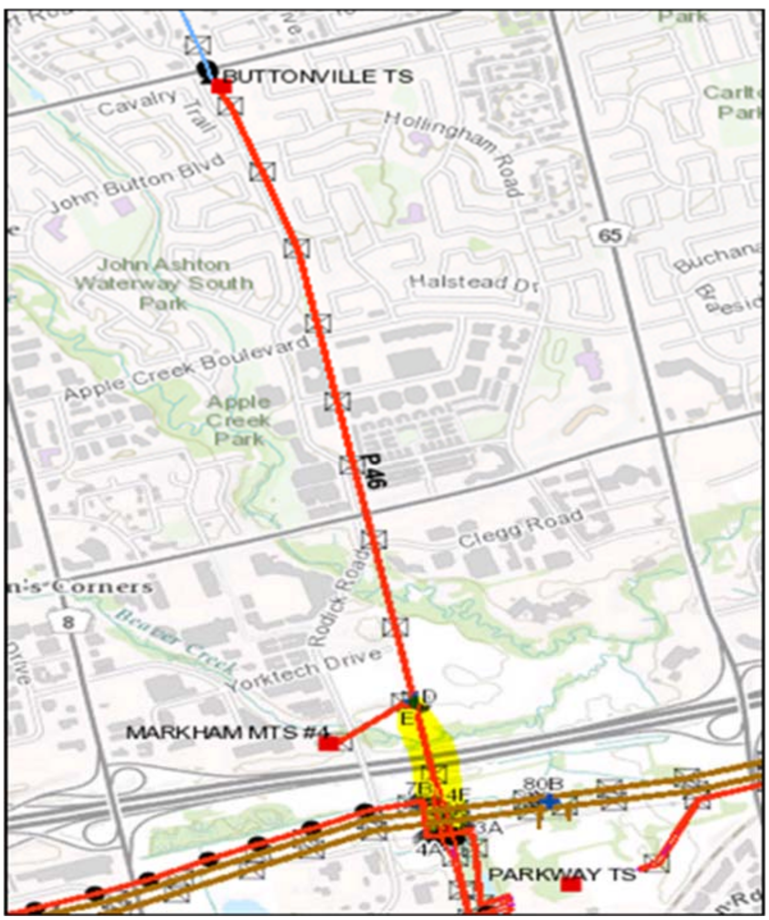


Figure 7-3: Buttonville Tap P45/P46 Limiting Section

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

Table 7-4: Loading on Buttonville Tap Circuits

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

7.3.1.1 Alternatives and Recommendation

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

1- **Alternative 1 - Increase thermal capability of existing line.** It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying the forecasted load on these circuits. A high level estimate for this work is $2-3 million.
2- **Alternative 2 – Reduce loading on the P45/P46 circuits by transferring Markham MTS#4 to the Cherrywood TS x Parkway TS C35P/C36P circuits:** This alternative frees up capacity on the P45/P46 circuits to supply MTS#5. It requires building a new 1.5 km long 230kV double circuit line from Markham MTS#4 Jct to the C35P/C36P. This alternative was ruled out due to higher cost and greater disruption to the local community.

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

7.3.2 High Voltages on M80B/M81B

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

7.3.2.1 Alternatives and Recommendations

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

1- **Alternative 1 – Switch LV caps manually at Beaverton and Lindsay:** The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage (i.e. 262.5 kV) for up to 30 minutes. This capability provides sufficient time for operators to manually adjust the system. Under this alternative the operator will remotely switch out capacitor banks at Beaverton and Lindsay to mitigate high voltages when required.
2- **Alternative 2 - Expanding the York Region Special Protection Scheme (SPS):** The problem of overvoltage can be mitigated by modifying the York Region SPS to automatically remove capacitor banks at Lindsey TS and/or Beaverton TS under high load conditions following specific contingencies.

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

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

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

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

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

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

Thermal Limitations

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

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

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

Voltage Limitations

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

7.3.3.1 Alternatives and Recommendations

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

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

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

7.4 Load Restoration

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

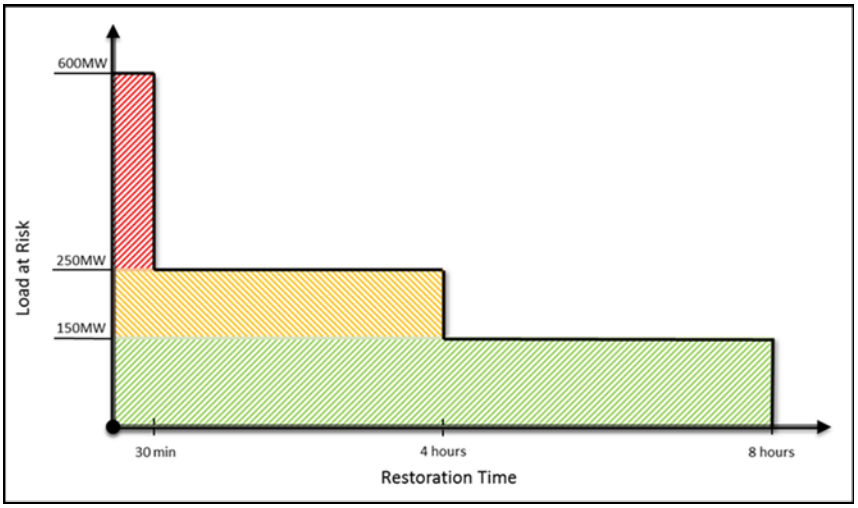


Figure 7-4: Load Restoration Criteria as per ORTAC

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

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

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

Table 7-6: Load Restoration on Kleinburg Radial Tap

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

7.4.1.1 Alternatives and Recommendations

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

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

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

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

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

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

7.4.2.1 Alternatives and Recommendations

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

7.5 Improve Load Security on the Parkway to Claireville Line

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. The load security criteria in ORTAC limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.

7.5.1 Alternatives and Recommendations

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

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

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

8 CONCLUSIONS AND NEXT STEPS

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

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

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

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

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

The Study Team recommends that:

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

9 REFERENCES

[1] GTA North Regional Infrastructure Plan – February 2016

[2] GTA North Needs Assessment – March 2018

[3] York Region Scoping Assessment Outcome Report - 2018

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

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

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

10 APPENDIX A. STATIONS IN THE GTA NORTH REGION

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

11 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

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

12 APPENDIX C. DISTRIBUTORS IN THE GTA NORTH REGION

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

13 APPENDIX D. GTA NORTH REGION LOAD FORECAST

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

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

GTA West

REGIONAL INFRASTRUCTURE PLAN

January 25, 2016

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

With support from:

Company
Burlington Hydro Electric Inc.
Enersource Hydro Mississauga Inc.
Halton Hills Hydro Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution Inc.

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DISCLAIMER

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

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

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM 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 DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA WEST REGION.

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

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the regional planning process and it follows the completion of the Northwest GTA Integrated Regional Resource Plan ("IRRP") in April 2015; and the GTA West Southern Sub-Region's Needs Assessment ("NA") and Scoping Assessment ("SA") in May 2014 and September 2014, respectively.

This RIP provides a consolidated summary of needs and recommended plans for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region.

The major infrastructure investments planned for the GTA West Region over the near and medium-term (2016-2025), identified in the various phases of the regional planning process, are given in the table below with anticipated in-service date and estimated cost. Several long-term needs beyond 2026 have been identified, and further assessments are currently underway as part of the IESO Bulk System Study.

No.	Project	I/S Date	Cost
1	Build new Halton Hills Hydro MTS	2018	$19M (1)
2	Build new Halton TS #2	2020	$29M (1)
3	Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	2018-2019	$5M
4	Upgrade (reconductor) circuits H29/H30 (2)	2023-2026	$6.5M

Notes:

(1) Excludes cost for distribution infrastructure

(2) The plan will be reviewed and finalized in the next regional planning cycle

The following needs will be considered in the scope of the Bulk System Study led by the IESO:

- Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity need;
- Radial supply to Halton TS (T38/T39B) circuit capacity need;
- Supply security and restoration to several load pockets in GTA West Region.

The IESO's Northwest GTA IRRP has identified that Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow by 849-1132 MW by 2031, as forecast by the Province "Places to Grow" program. A new electricity corridor will be required for additional transmission facilities required to meet this long-term need in the area. The RIP Working Group recommends further assessments to be carried out and complete technical details, layout of high voltage electricity infrastructure no later than Q4 2016. Following this, Environmental Approval and acquisition of land rights would be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier 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 GTA WEST REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) (“Hydro One”) on behalf of the Working Group 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:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator (“IESO”)
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses 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, 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 500/230 kV Trafalgar TS autotransformers, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. The summer 2015 peak load of the region was approximately 2900 MW.

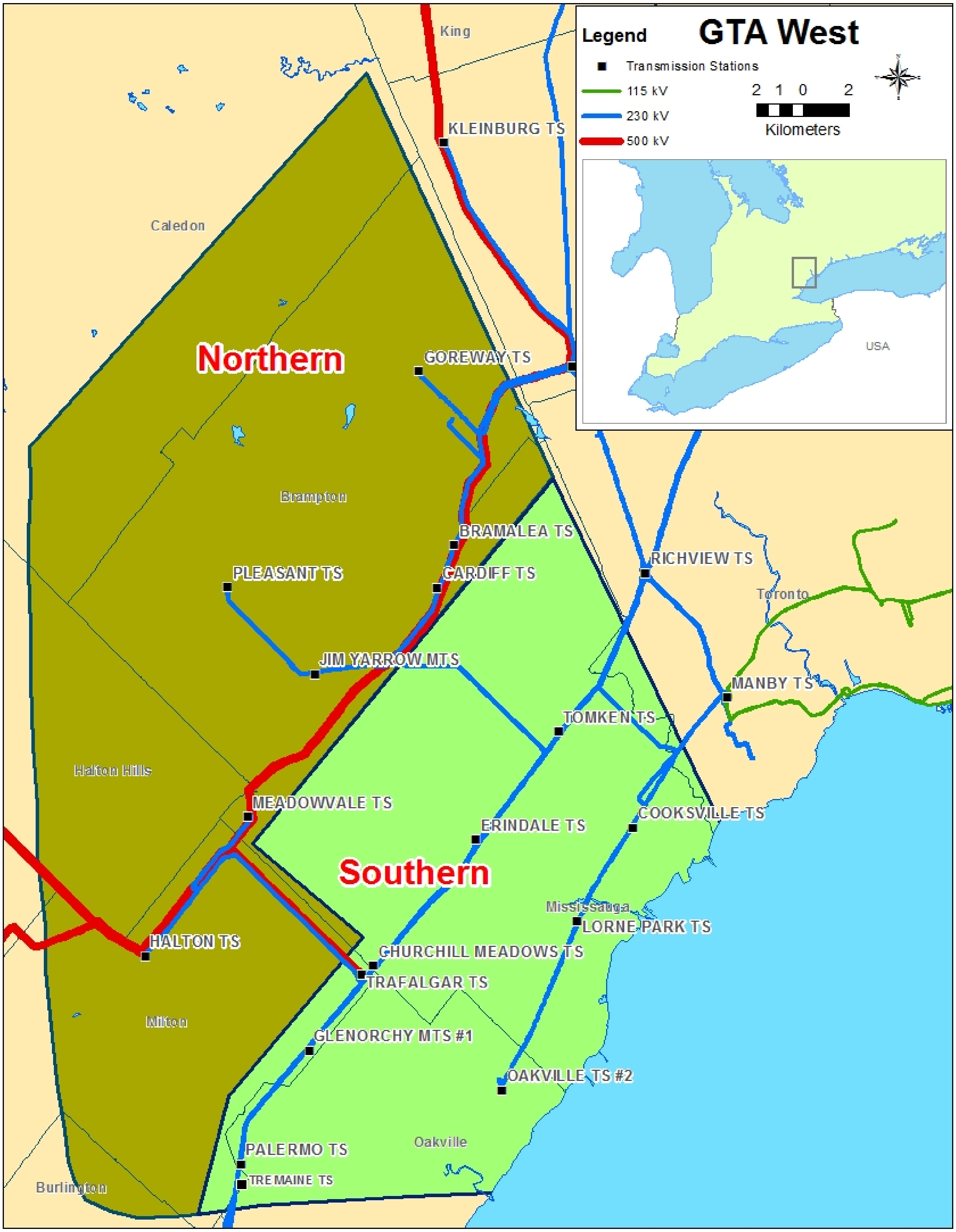

Figure 1-1 GTA West Region Map

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 (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and wires plans to address these needs based on new and/or updated information;
- Develop a plan to address any longer terms 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 the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

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

[1] also referred to as Needs Screening

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

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

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

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

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

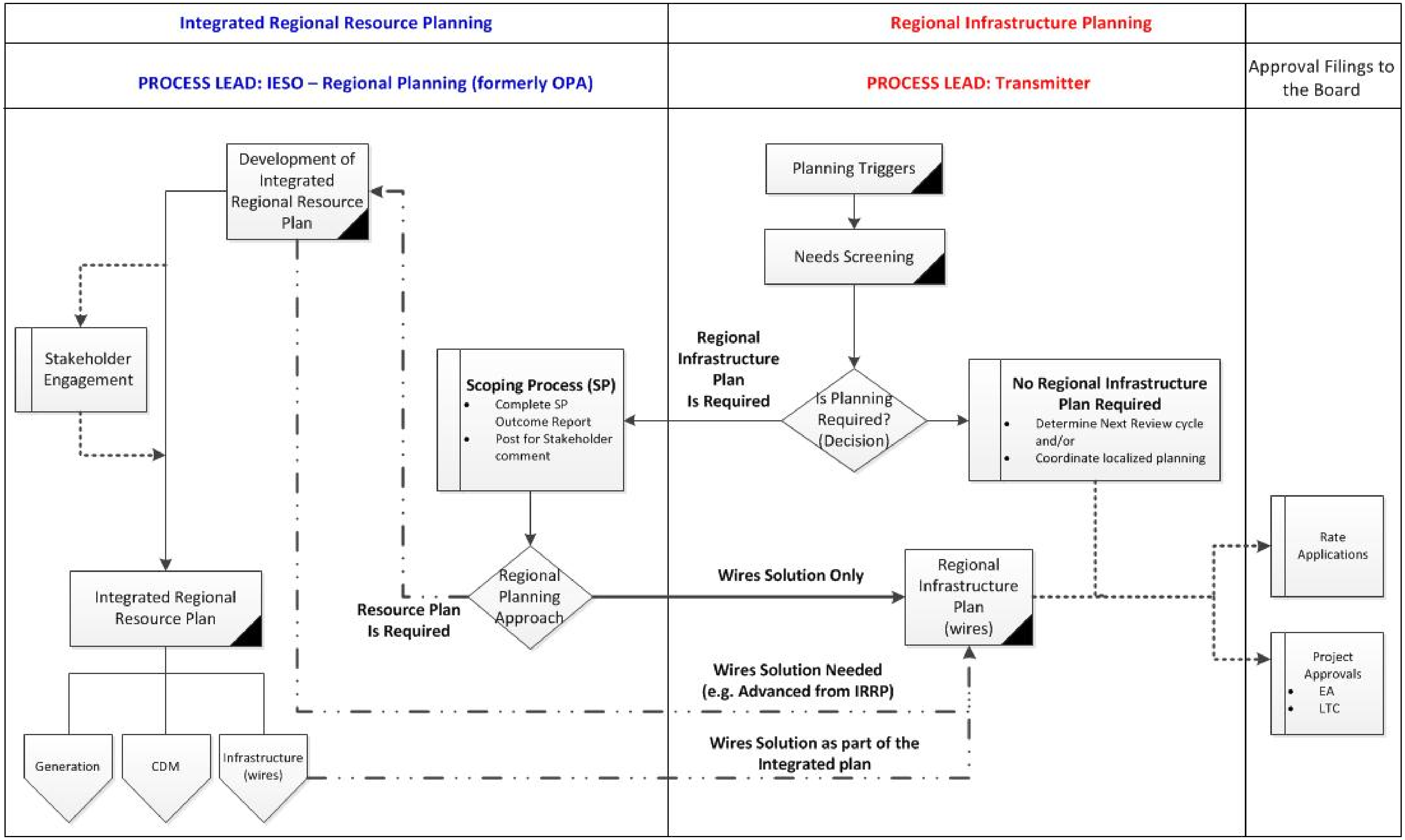

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

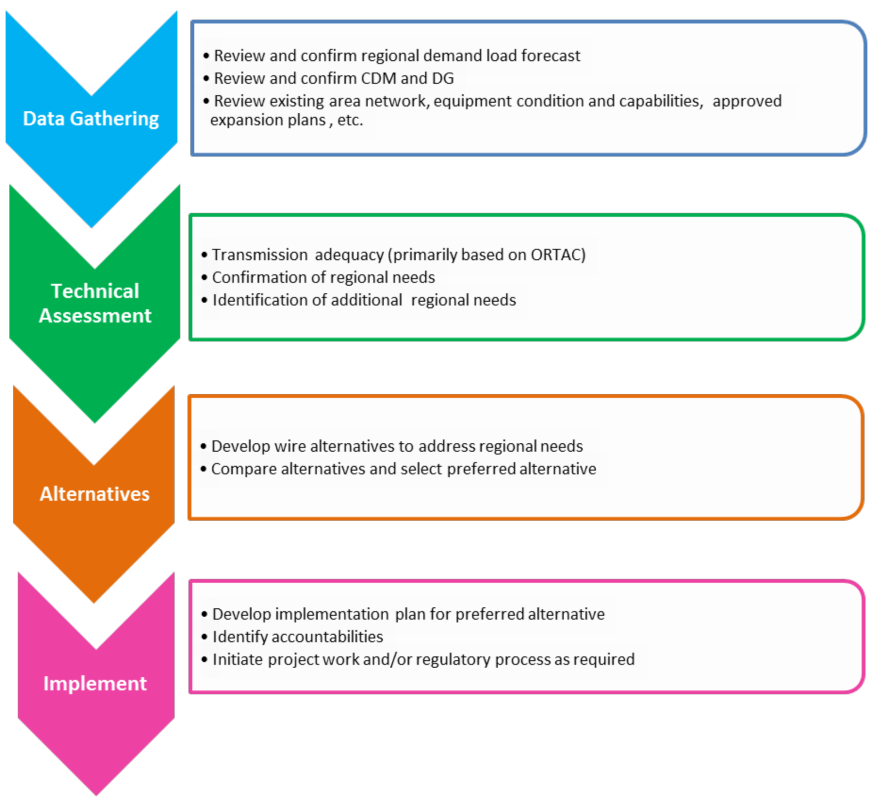

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION ENCOMPASSES 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 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. Local generation in the region includes the two gas fired plants: Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity). The summer 2015 regional coincidental peak load of the region is approximately 2900 MW.

LDCs supplied from electrical facilities in the GTA West Region are Burlington Hydro Electric Inc., Enersource Hydro Mississauga Inc., Halton Hills Hydro Inc., Hydro One Brampton Networks Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Northwest GTA IRRP report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Northern Sub-Region which included the 230 kV facilities in the northern part of Region. The May 2014 Southern GTA Needs Assessment report, prepared by Hydro One, considered the remainder of the GTA West Region.

For the purpose of regional planning, the GTA West Region is divided into Northern and Southern Sub-Regions. A single line diagram showing the electrical facilities of the GTA West Region, consisting of the two sub-regions, is shown in Figure 3-1. More details regarding transformer stations and transmission lines in the region are provided in Appendix A and B, respectively.

GTA West – Northern Sub-Region

The Northern Sub-Region covers the GTA West Region area north of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Claireville TS and Hurontario SS through seven 230/44 kV or 230/27.6kV step down transformer stations, local generation consist of the Sithe Goreway GS located in Brampton and the TransCanada Halton Hills GS located in Halton Hills, Generation is also connected to the LV buses of Bramalea TS in Brampton.

Enersource, Hydro One Brampton, Milton Hydro and Halton Hills Hydro are the three main Local Distribution Companies in the Sub-Region. They receive power at the step down transformer stations and distribute it to the end use customers.

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

GTA West – Southern Sub-Region

The Southern Sub-Region covers the GTA West Region area south of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. There are a total of nine steps down 230/44 kV or 230/27.6 kV step down transformer stations serving the area customers.

Enersource Hydro Mississauga and Oakville Hydro are the main LDCs serving the GTA West - Southern Sub-Region. There is one large industrial customer (Ford Motor Company) in Oakville.

The NA and SA for the Southern Sub-Region were completed in May and September 2014, respectively. A Local Plan has also been developed in this sub-region to address a near-term station capacity need at Erindale TS, further discussed in Section 7.2.

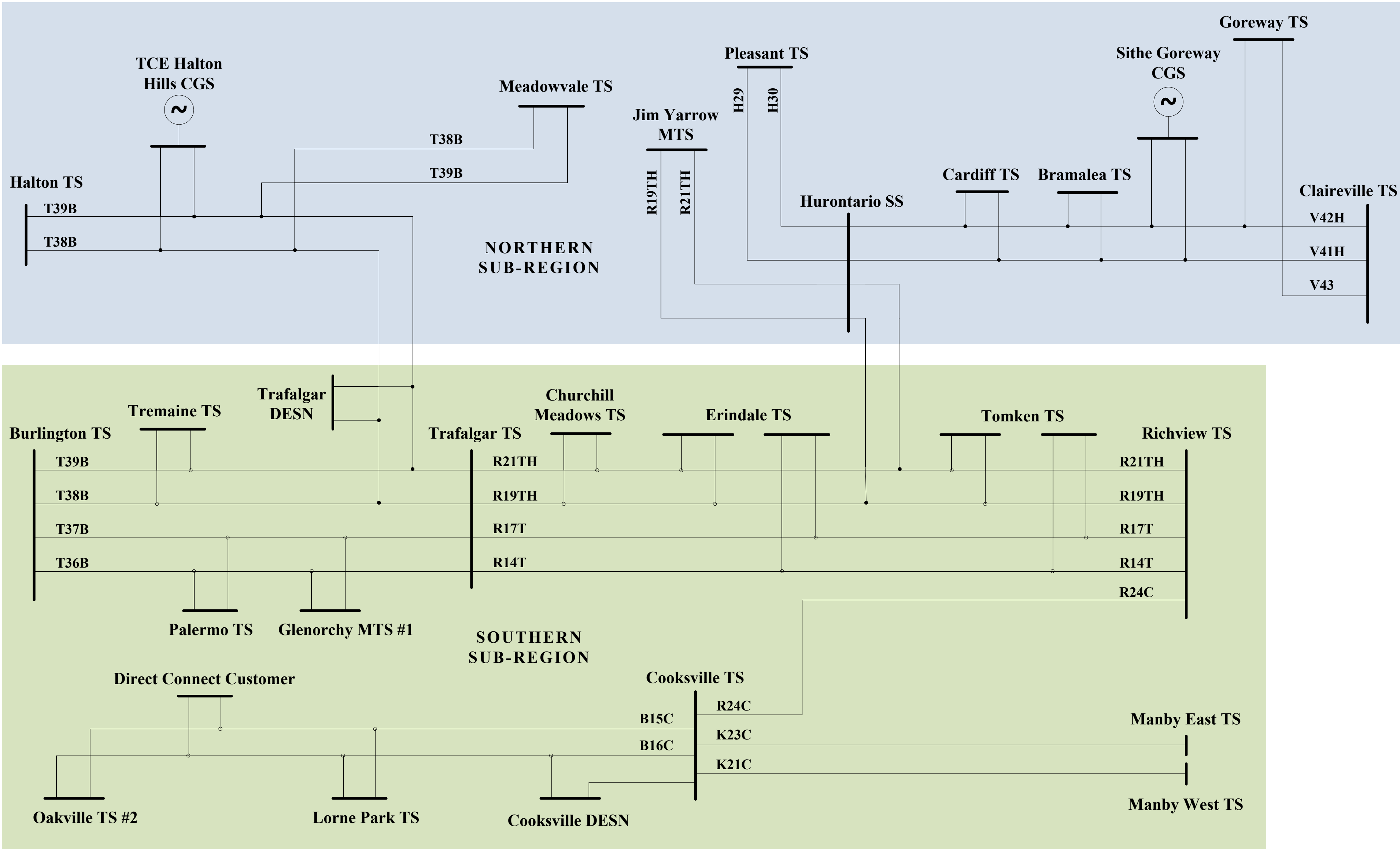

Figure 3-1 GTA West Region Single Line Diagram

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 COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE GTA WEST REGION.

A brief listing of those projects is given below:

- Cardiff TS (2005) – built a new step down transformer station consisting of two 50/83 MVA transformers in Brampton supplied from 230 kV circuits V41H and V42H. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.

- Sithe Goreway CGS (2008) – connect a new 839 MW gas-fired combined cycle generation station in Brampton connected to 230 kV circuits V41H and V42H. This generation station provided necessary local power to supply the GTA West Region.

- Halton TS Shunt Capacitor - installed 43.2 MX of shunt capacitor banks at Halton TS 27.6 kV bus for voltage support (2009).

- 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 Enersource Hydro Mississauga Inc. requirements.

- Hurontario SS and underground cable work - 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 TS (2010). 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 CGS (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 (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.

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 0.8% annually from 2015 to 2025, and 0.5% from 2025 to 2035. The growth rate varies across the region ranging from 1.1% in the Northern Sub Region to 0.5% in the Southern Sub Region over the first 10 years. Longer term is a more uniform growth rate of 0.5% across both Northern and Southern Sub Regions. .

Figure 5-1 shows the GTA West Region load forecast from 2016 to 2035. The forecast shown is the regional coincidental forecast, representing the sum of the load in the area for the 17 step-down transformer stations at the time of the regional peak, and is used to determine any need for additional transmission reinforcements. The coincidental regional peak is forecast to increase from approximately 2900 MW in 2015 to 3300 MW in 2035. 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.

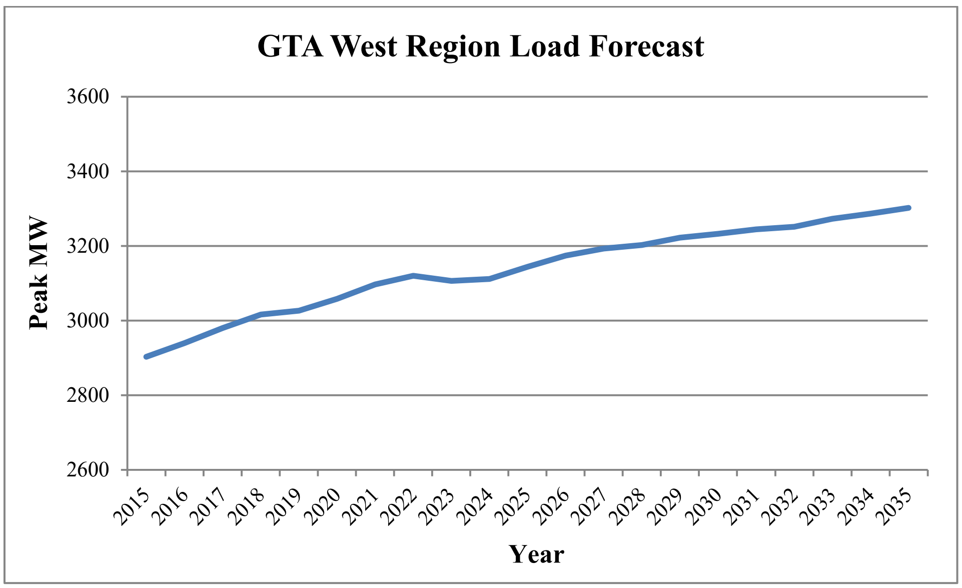

Figure 5-1 GTA West Region Extreme Weather Peak Load Forecast

The regional coincidental load forecast was developed by projecting the 2015 summer peak loads corrected for extreme weather, using the area station growth rates as per the 2015 IESO Northwest GTA IRRP and as per the 2014 Hydro One's Need Assessment Study for the GTA West Southern Sub-Region. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used in this report are provided in the Northwest GTA IRRP and the Southern Sub-Region's NA, and 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 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is 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).

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2016-2025 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are input to the RIP. These assessments are:

1) The Northwest GTA Integrated Regional Resource Plan (IRRP), April 2015 [1]
2) The GTA West Southern Sub-Region's Needs Assessment (NA) Report, May 2014 [2]
3) The GTA West Southern Sub-Region's Scoping Assessment (SA) Report, September 2014 [3]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demand over the 2016-2025 period. These regional needs are summarized in Table 6-1. Table 6-1 also includes the longer-term needs (up to 2035) that have been identified in the Northern Sub-Region. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the GTA West Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review.

Table 6-1 Needs Identified in Previous Phases of the GTA West Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	Halton TS	2018-2020
	7.2	Erindale TS (T1/T2)	Today
Transmission Circuit Capacity	7.3	Richview x Trafalgar (R14T/R17T & R19TH/R21TH)	Within 5 years
	7.4	Radial Supply to Pleasant TS (H29/H30)	2023-2026
	7.5	Radial Supply to Halton TS (T38B/T39B)	2029+
Supply Security	7.6	Supply Security to Halton Radial Pocket (T38B/T39B)	2027
Supply Restoration	7.7	Supply Restoration in Northern Sub-Region [(1)]: - Halton Radial Pocket (T38B/T39B) - Pleasant Radial Pocket (H29/H30) - Cardiff/Bramalea Supply (V41H/V42H)	Today
	7.8	Supply Restoration in Southern Sub-Region: - West of Cooksville (B15C/B16C) - Richview x Trafalgar x Hurontario (R19TH/R21TH) - Richview x Trafalgar (R14T, R17T)	Today
Long-Term Growth	7.9	Pleasant TS (T1/T2) NWGTA Electricity Corridor	2026-2033+

(1) The Northwest GTA IRRP also identified an issue and need to assess “Kleinburg Radial Pocket” supply restoration. This need is being assessed as part of the IESO led Bulk System Study and is not part of this RIP.

6.1 230 kV Transmission Facilities

All 230 kV transmission facilities in the GTA West Region, with the exception of Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System (BES). A number of 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 3-1):

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, radial tap to Halton TS and Meadowvale TS (230 kV Circuits T38B, T39B) – Supply Halton TS, Meadowvale TS, and Trafalgar DESN
4. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine 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

Based on current forecast station loadings and bulk transfers, the H29/H30 circuits will require reinforcement by 2023-2026. The H29/H30 upgrade will be addressed by Hydro One based on the recommendation stemming from the Northwest GTA IRRP led by the IESO. The Trafalgar to Richview 230 kV circuits (R14T/R17T) will require reinforcement in the near term based on GTA West Southern Sub-Region’s NA. This need will be further assessed in the IESO led Bulk System Study.

6.2 500/230 kV Transformation Facilities

All loads are supplied from the 230 kV transmissions system. The primary source of 230 kV supply is the 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS. Additional support is provided from the 230 kV generation facilities at Halton Hills CGS and Sithe Goreway CGS. Based on the long term forecast in the Northwest GTA IRRP, Trafalgar TS and Claireville TS may require relief in the next 10 years. This need will be studied under the IESO led Bulk System Study.

6.3 Step-Down Transformation Facilities

There are a total of sixteen step-down transformer stations in the GTA West Region. Based on the local station load forecast, Halton TS and Erindale TS would require station capacity relief in the near term, as shown in Table 6-2.

Table 6-2 Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2015 Loading (MW)	Need Date
Halton TS	185.9	176.4	2018
Erindale TS (T1/T2)	181.3	208.3	Now
Pleasant TS (T1/T2)	148.1	124.8	2026-2033 (1)

(1) 2026 under the "Higher Growth" scenario, while 2033 under the "Expected Growth" scenario. Please refer to Northwest GTA IRRP [1]

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NORTHWEST GTA IRRP AND THE NA FOR THE GTA WEST SOUTHERN SUB-REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 Halton TS Station Capacity

7.1.1 Description

Halton TS supplies Halton Hills Hydro through 3 feeders and Milton Hydro through 9 feeders at the station. As the load in Halton Hills and Milton continues to grow, the peak load at Halton TS is expected to exceed the station peak load by 2018.

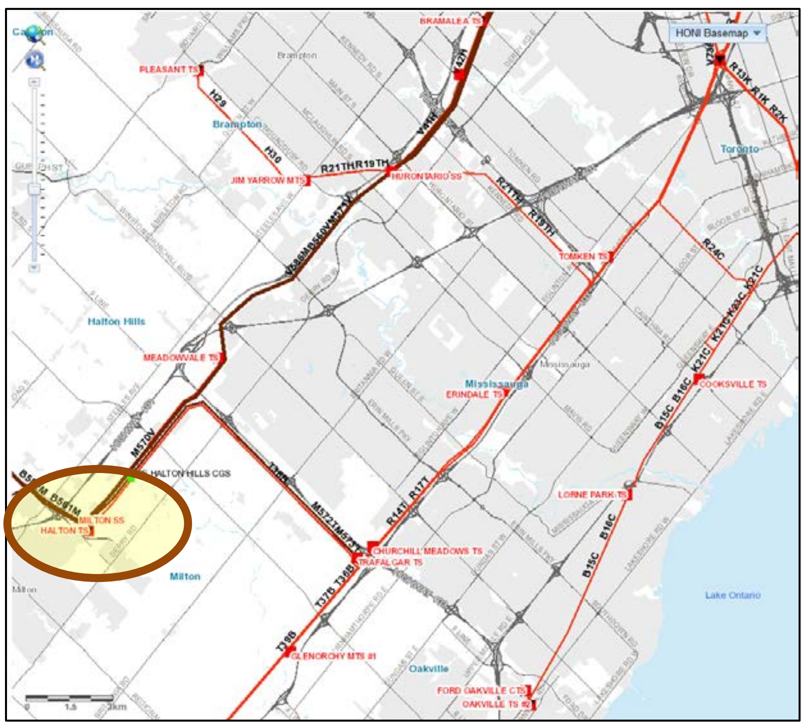

Figure 7-1 Halton TS and Surrounding Areas

7.1.2 Recommended Plan and Current Status

The recommendation of the IRRP is to build two new step-down stations: one to provide supply for Halton Hills Hydro loads and second to supply Milton Hydro load. The Halton Hills Hydro station is expected to be required in 2018, while the Milton Hydro station is expected to be required in 2020.

The IRRP recommends that Halton Hills Hydro proceed to gain the necessary approvals to construct, own, and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018. Halton Hills Hydro has started a Request for Proposal for the work to construct Halton Hills MTS. The station will consists of two 50/83 MVA transformers with capacity to connect eight distribution feeders. The existing Halton Hills CGS will be expanded to accommodate the HV connection of Halton Hills MTS. There are no transmitter costs for this station. The expected in-service date is spring of 2018. The cost for this station is estimated to be $19 million.

The IRRP recommends Hydro One to initiate engineering work for the development of Halton TS #2 in 2017 (3 year lead-time), at the site of the existing Halton TS, with a tentative in-service date of 2020. The Halton Hills TS #2 will consist of two 75/125 MVA transformers with capacity to connect eight distribution feeders. It will tap to circuits T38B and T39B. The cost for Hydro One to build Halton TS #2 is estimated to be $29 million.

7.2 Erindale TS (T1/T2) Station Capacity

7.2.1 Description

Erindale TS solely supplies Enersource Hydro Mississauga Inc. The existing Erindale TS (T1/T2) DESN load currently exceeds the normal supply capacity. However, there is extra capacity available in the area's 44 kV system that can be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated in Local Planning for Erindale TS T1/T2 DESN Capacity Relief [4]. As per the Local Plan, Hydro One and Enersource agreed that this is primarily a distribution planning issue that will involve planning and building a new DS by Enersource to utilize the extra 44 kV station capacity in the area.

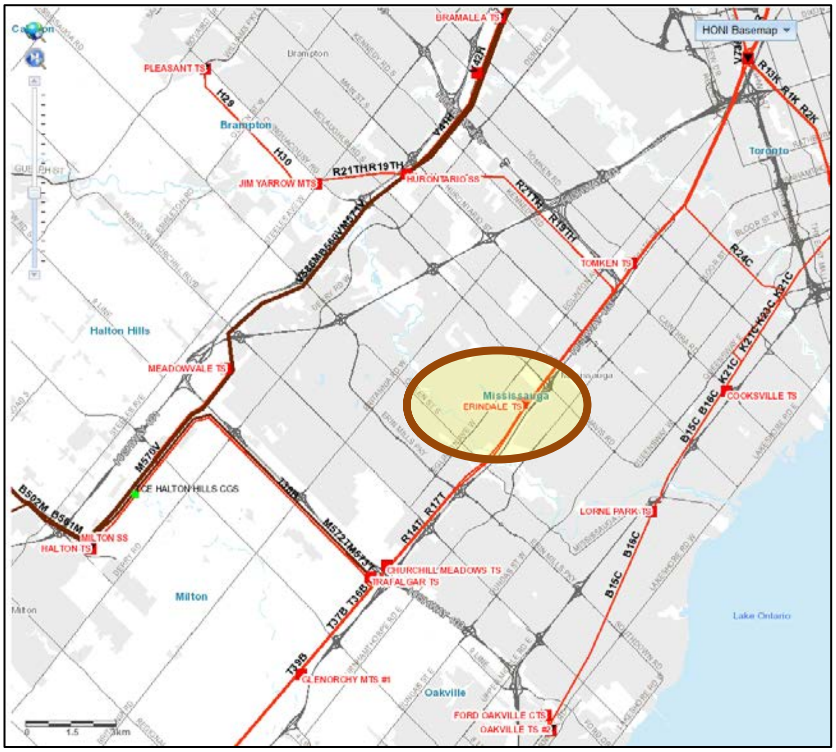

Figure 7-2 Erindale TS and Surrounding Areas

7.2.2 Recommended Plan and Current Status

The proposed DS ("Mini-Britannia MS") is planned to be supplied from Churchill Meadows TS (44 kV system) and provide additional capacity to feed the 27.6 kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on 44 kV system via Churchill Meadows TS.

At completion, the substation will house two power transformers (40 MVA capacity), two high voltage switchgears and two low voltage switchgears that will deliver power via four 27.6 kV feeders.

This option is expected to cost $5 million. Under this option, Enersource will build the new DS, own it and recover the costs through the distribution rates. The expected in-service date for the DS is 2018-2019.

7.3 Richview x Trafalgar Transmission Circuit Capacity

7.3.1 Description

As identified in the GTA West Southern Sub-Region's NA, with a single-circuit contingency and high Flow East Towards Toronto (FETT) interface flows, loading on the Richview TS to Trafalgar TS circuits (R14T, R17T, R19TH, R21TH) exceeded their summer long-term emergency ratings in the near-term.

7.3.2 Recommended Plan and Current Status

As these circuits are part of the Bulk Electric System, this need is being further assessed in the IESO-led bulk power system planning.

7.4 Radial Supply to Pleasant TS Transmission Circuit Capacity

7.4.1 Description

Pleasant TS consists of 3 DESNs supplied by 230 kV H29/H30 circuits. Due to growth in load forecasted at Pleasant TS, these circuits are expected to reach their thermal capacity by 2023 at the earliest.

The IRRP process, completed in April 2015, identified the need, discussed alternatives, and recommended a solution to resolve this need.

7.4.2 Recommended Plan and Current Status

The existing conductors used for 230kV circuits H29/H30 going to Pleasant TS are 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). They extend 8.5km north from Hurontario SS to Pleasant TS. Based on the study conducted in the Northwest GTA IRRP, this rating limits the maximum load-carrying capacity to approximately 417 MW of load at Pleasant TS.

Preliminary feasibility study shows that the existing towers can support larger conductors. The recommended new conductors would be 1192.5 kcmil ACSR 54/19 with summer long term emergency rating of approximately 1400 A (at 127°C). As per the load flow study conducted in the IRRP, this would supply over 500 MW of load at Pleasant TS. The estimated budgetary cost of this upgrade is about $6.5 million.

The Working Group recommends regularly monitoring the actual load growth and reassessing this issue during the next regional planning cycle.

7.5 Radial Supply to Halton TS Transmission Circuit Capacity

7.5.1 Description

The Northwest GTA IRRP study identified that the thermal capacity of supply circuit to Halton TS from Trafalgar TS to Burlington TS (T38B/T39B) may be exceeded with a single-circuit contingency and Halton Hills GS out of service in the mid-term. However, under this scenario, the ORTAC permits up to 150 MW of load shedding to prevent system overloads. With this control action in place, this need is observed in the long-term in 2029 at the earliest.

7.5.2 Recommended Plan and Current Status

As per the IRRP recommendation, this regional need is being further assessed in the IESO-led bulk power system planning.

7.6 Supply Security to Halton Radial Pocket (T38B/T39B)

7.6.1 Description

As the load connected to T38B/T39B continues to grow, it is expected by 2027 the Halton Radial Pocket will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted due to a loss of two major power system elements, as shown in Table 7-1.

Table 7-1 Halton Radial Pocket Load Forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Halton Radial Pocket Load (MW)	463	471	482	490	491	492	503	512	562	571	585	598	**609**

7.6.2 Recommended Plan and Current Status

The Working Group recommends that the bulk power system study led by IESO account for this supply security issue on T38B/T39B in their planning process.

7.7 Supply Restoration in Northern Sub-Region

The Northwest GTA IRRP study identified that the following circuits are currently at risk of not meeting the supply security and restoration criteria:

Table 7-2 Supply Restoration Need in Northern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)
Halton Radial Pocket • Tremaine • Trafalgar DESN • Meadowvale • Halton • Halton Hills Hydro MTS (1) • Halton #2 (1) Supply: T38B/T39B	463	146	**67**
Pleasant Radial Pocket • Pleasant DESNs Supply: H29/H30	359	52	**57**
Bramalea/Cardiff Supply • Bramalea DESNs • Cardiff Supply: V41H/V42H	456	140	**66**

(1) Available 30-min restoration through emergency distribution load transfer following the loss of transmission supply (based on IRRP)
(2) Calculated as follows: Actual Load minus 250 MW minus 30minRestorationCapability. 250 MW is the maximum amount of load not restored within 30-min following loss of two elements.
(3) Halton Hills Hydro MTS and Halton TS #2 are expected to be in-service in 2018 and 2020.

The Northwest GTA IRRP also identified "Kleinburg Radial Pocket" supply restoration need. However, this need will be discussed in more details in the IESO's Bulk System Studies.

As per the IRRP recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

It is expected that with new increased forecasted load at Tremaine TS provided by Milton Hydro and Burlington Hydro, circuitsT38B/T39B Burlington TS to Trafalgar TS will experience higher power flow, and the need date may be moved closer. Therefore, the Working Group recommends that the bulk power system study led by IESO account for this increased flow on T38B/T39B in their planning process.

7.8 Supply Restoration in Southern Sub-Region

The GTA West Southern Sub-Region SA identified that the following circuits are at a risk of not meeting the supply security and restoration criteria in the medium term to long term time frame:

Table 7-3 Supply Restoration Need in Southern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)	Load (MW) That Can Be Restored Within 4-hour (1)	4-hour Restoration Shortfall (MW) (3)
West of Cooksville • Oakville #2 • Ford Oakville • Lorne Park Supply: B15C/B16C	304	46	**8**	110	**44**
Richview x Trafalgar x Hurontario • Churchill Meadows • Erindale T5/T6 • Tomken T3/T4 • Jim Yarrow Supply: R19TH/R21TH	555	165	**140**	465	None
Richview x Trafalgar • Erindale T1/T2 • Erindale T3/T4 • Tomken T1/T2 Supply: R14T/R17T	498	115	**133**	390	None

As per the Southern Sub-Region's SA recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

7.9 Long-Term Growth & NWGTA Electricity Corridor Need

Growth projections in the Ontario Governments - Growth Plan for the Greater Golden Horseshoe [5] indicates that the population in Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow significantly over the 20 years period, from 930,000 people in 2011 to 1.5 million people in 2031. Growth plan of this magnitude translates to an overall electrical demand of approximately 849 to 1132 MW by 2031 [1]. Supply electrical demand related to this growth will require new transmission and distribution infrastructure in the area because current electricity infrastructure in the area is limited and at its capacity. Planning and Environmental Approval for a proposed new 400 series Highway, extending from Highway 400 to the Highway 401/407 ETR interchange, has been paused by the Ministry of Transportation. However, opportunities for multi-use transportation/ electricity transmission line corridor must be investigated as new transportation and electricity plans for the area are developed, to maintain consistency with direction outlined in the Provincial Policy Statement.

Existing electricity supply to new developments in the area is technically limited by transmission line and transformer station supply capacity. In addition, there are customer service quality concerns, such as reliability performance and low voltage levels on the LDC's distribution feeders due to the long distance between the locations of new development and existing transformer stations.

Based on the latest load forecast, electrical load at Pleasant TS, which supplies Brampton, is anticipated to exceed its station capacity as early as 2026 [1]. As the result, new station will be required to meet growing electrical needs.

Since a typical 75/125 MVA 230 kV step-down transformer station is capable of supplying up to 170 MW of load, up to 6 new stations in strategic locations could be required to effectively meet load growth in the area over the next 10-20 years. In order to provide adequate supply to these new step-down stations, new 230 kV transmission lines will be required within the general vicinity of the area's load growth centers.

In addition to the need for supply capacity to meet growth, several locations are at risk for not meeting ORTAC criteria following the loss of two transmission elements: Halton radial pocket, Pleasant radial pocket, Bramalea/Cardiff supply, and Kleinburg radial pocket. These needs should also be studied and addressed in a coordinated manner to develop optimal solutions for both GTA North and GTA West Region. As a result, a high degree of integration will be required between regional planning in the two adjacent regions going forward.

Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Currently it is estimated that over 250 MW of load will not be restored within the timelines prescribed by the criteria. The situation and risk will continue to worsen with continued growth and load will be at higher risk of prolonged power outages following major system contingencies.

An important first phase for providing the required transmission capacity is to identify land / right of ways, which can accommodate economical overhead transmission lines. This includes completing an Environmental Approval followed with an application to the OEB for Leave to Construct (Section 92). The EA process and acquisition of land rights process may take up to five years. Allowing the area to develop without identifying the electricity corridor in municipal plans and not acquiring land rights for transmission corridor now would be significantly arduous after municipal and community development has already taken place without consideration of electricity needs. Identifying and preserving rights-of-way ahead of the forecasted need will help rate payers and municipalities avoid cost associated with underground cables in the future, which is significantly more costly ranging from 5 to 10 times higher than overhead lines.

Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk transmission system's capacity. One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better overall bulk system performance in the long-term.

Existing projections of electricity corridor needs can be as early as 2025. The RIP concludes that based on growth projections outlined in the Growth Plan for the Greater Golden Horseshoe [5] a new electricity corridor will be ultimately required to provide additional transmission capacity to meet load growth; provide alternate supply route to various locations to meet restoration criteria; and improve bulk electricity transfer capability.

The RIP Working Group recommends that:

a) The required transmission corridor be identified within the appropriate Regional and Municipal Official Planning documents.

b) Hydro One, the IESO and LDCs undertake immediate action to further assess the location and pace of growth, as well as the related high voltage electrical facilities required for inclusion in a future electricity infrastructure plan. The plan should include but not limited to details with respect to conceptual layout of transmission lines, line terminations, switching stations and the number and approximate location of step-down transformer stations.

c) Following this, Environmental Approval and acquisition of land rights should be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

d) Hydro One, the IESO and LDCs should complete the assessment, technical details, layout of high voltage electricity infrastructure no later than Q4 2016.

8. CONCLUSIONS

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

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

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

No.	Need Description
I	Halton TS station capacity
II	Erindale TS T1/T2 station capacity
III	Radial supply to Pleasant TS (H29/H30) circuit capacity
IV	Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity
V	Radial supply to Halton TS (T38B/T39B) circuit capacity
VI	• Supply security to Halton Radial Pocket • Supply restoration to Halton Radial Pocket, Pleasant Radial Pocket, and Bramalea/Cardiff Supply load pockets • Supply restoration to West of Cooksville, Richview x Trafalgar, and Richview x Trafalgar x Hurontario load pockets
VII	Long term need for a new NWGTA electricity transmission corridor

Next steps, lead responsibility, and timeframes for implementing the wires solutions are summarized in the Table 8-2 below. Investments to address the long-term need where there is time to make a decision (Need III) will be reviewed and finalized in the next regional planning cycle.

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

Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
Build new Halton Hills Hydro MTS	LDC to carry out the work	Halton Hills Hydro	2018	$19M (1)	I
Build new Halton TS #2	Transmitter to carry out the work	Hydro One	2020	$29M (1)	I
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	LDC to carry out the work	Enersource	2018-2019	$5M	II
Upgrade (reconductor) circuits H29/H30 (2)	Transmitter to carry out the work, and monitor growth	Hydro One	2023-2026	$6.5M	III
• R14T/R17T & R19TH/R21TH circuit capacity need • T38/T39B circuit capacity need • Supply security and restoration need	IESO to carry out Bulk System Study	IESO	TBD	TBD	IV, V, VI
Need for a new transmission corridor in NWGTA	Working Group to complete assessments, technical details & layout by Q4 2016	Hydro One, IESO, LDCs	TBD	TBD	VII

Notes:

(1) Excludes cost for distribution infrastructures
(2) The plan will be reviewed and finalized in the next regional planning cycle

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

9. REFERENCES

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[3] GTA West Southern Sub-Region Study Team. "GTA West Southern Sub-Region Scoping Assessment Outcome Report". September 19, 2014.
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[4] Hydro One Networks Inc., Enersource Hydro Mississauga Inc. "Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief – GTA West Southern Sub-Region". July 9, 2015.
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[5] Ministry of Infrastructure. Places to Grow: "Growth Plan for the Greater Golden Horseshoe, 2006". Office Consolidation June 2013.
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Appendix A. Stations in the GTA West Region

Station (DESN)	Voltage (kV)	Supply Circuit
Halton TS	230/27.6	T38B/T39B
Meadowvale TS	230/44	T38B/T39B
Jim Yarrow MTS	230/27.6	R19TH/R21TH
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
Cardiff TS	230/27.6	V41H/V42H
Bramalea TS (T1/T2)	230/27.6	V41H/V42H
Bramalea TS (T3/T4)	230/44	V41H/V42H
Bramalea TS (T5/T6)	230/44	V41H/V42H
Goreway TS (T1/T2)	230/27.6	V42H/V43
Goreway TS (T5/T6)	230/27.6	V42H/V43
Goreway TS (T4)	230/44	V42H/V43
Tremaine TS	230/27.6	T38B/T39B
Trafalgar TS	230/27.6	T38B/T39B
Palermo TS	230/27.6	T36B/T37B
Glenorchy MTS #1	230/27.6	T36B/T37B
Churchill Meadows TS	230/44	R19TH/R21TH
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
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Oakville TS #2	230/27.6	B15C/B16C
Lorne Park TS	230/27.6	B15C/B16C
Cooksville TS (T1/T2)	230/27.6	B16C
Cooksville TS (T3/T4)	230/27.6	B16C

Appendix B. Transmission Lines in the GTA West Region

Location	Circuit Designations	Voltage (kV)
Hurontario SS to Pleasant TS	H29, H30	230
Richview TS to Trafalgar TS	R14T, R17T	230
Richview TS to Trafalgar TS & Hurontario SS	R19TH, R21TH	230
Trafalgar TS to Burlington TS	T36B, T37B, T38B, T39B	230
Claireville TS to Hurontario SS	V41H, V42H	230
Claireville TS to Kleinburg TS (1)	V43	230
Cooksville TS to Oakville TS	B15C, B16C	230
Manby TS to Cooksville TS	K21C, K23C	230
Richview TS to Cooksville TS	R24C	230

(1) Only V43 sections that supplies Goreway TS is included

Appendix C. Distributors in the GTA West Region

Distributor Name	Station Name	Connection Type
Burlington Hydro Inc.	Palermo TS	Tx
	Tremaine TS	Tx
Enersource Hydro Mississauga Inc.	Bramalea TS	Dx
		Tx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS #2	Dx
	Tomken TS	Tx
Halton Hills Hydro Inc.	Halton TS	Dx
		Tx
	Pleasant TS	Dx
Hydro One Brampton Networks Inc.	Bramalea TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Pleasant TS	Tx
Hydro One Networks Inc. (Distribution)	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Milton Hydro Distribution Inc.	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS #1	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

Appendix D. GTA West Stations Load Forecast

GTA West Non-Coincident Stations Load Forecast (MW)

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bramalea TS T1/T2	N	188.4	124.6	124.7	124.3	124.2	122.0	122.7	122.7	122.5	121.7	119.9	119.2	121.4	121.0	119.7	119.6	118.3	118.2	118.1	119.0	119.3	119.5
Bramalea TS T3/T4	N	105.7	99.5	99.4	99.3	99.0	97.5	97.2	97.0	96.7	96.0	94.8	94.4	94.8	94.2	93.3	93.1	92.3	91.9	91.6	92.1	92.0	91.9
Bramalea TS T5/T6	N	159.1	122.9	123.0	122.7	122.6	120.3	120.9	120.7	120.4	119.4	117.4	116.7	118.2	117.6	116.2	116.0	114.6	114.4	114.3	115.2	115.4	115.6
Cardiff TS T1/T2	N	113.5	108.8	109.1	109.8	110.0	109.4	108.8	109.2	109.4	109.6	109.3	109.6	109.8	109.8	109.6	109.9	110.1	110.0	110.0	111.0	111.3	111.6
Goreway TS T1/T2	N	184.0	35.5	39.7	41.8	44.8	44.5	49.7	52.6	55.0	55.0	54.2	58.9	62.0	63.4	62.5	63.1	62.4	62.0	61.9	63.7	64.1	64.6
Goreway TS T4	N	84.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Goreway TS T5/T6	N	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2
Halton Hills Hydro MTS	N	97.1	0.0	0.0	0.0	3.5	8.1	11.7	15.8	19.7	23.5	26.9	32.2	37.2	42.1	46.7	51.7	51.9	51.9	52.0	52.9	53.2	53.6
Halton TS T3/T4	N	185.9	176.4	179.1	184.4	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Halton TS #2	N	146.3	0.0	0.0	0.0	0.0	0.0	2.3	11.0	18.5	66.2	72.5	80.2	87.2	93.5	99.0	105.9	112.1	118.2	116.9	117.9	120.0	122.1
Jim Yarrow MTS T1/T2	N	156.6	132.3	134.9	136.3	138.3	138.3	142.6	144.6	146.1	146.1	145.2	148.1	149.6	149.8	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Meadowvale TS T1/T2	N	180.8	128.7	127.1	126.0	124.4	121.9	119.4	118.1	116.5	115.0	113.0	111.6	110.1	108.5	106.7	105.4	104.0	102.4	100.9	100.2	99.0	97.8
Pleasant TS T1/T2	N	148.1	124.8	127.5	131.2	134.3	134.3	135.0	136.3	137.6	138.5	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4	150.0	151.6
Pleasant TS T5/T6	N	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3
Pleasant TS T7/T8	N	187.7	45.1	54.5	56.8	57.9	57.9	63.5	66.7	69.3	70.0	68.0	74.7	77.8	79.4	77.0	77.0	76.7	76.1	75.8	79.0	79.8	80.6

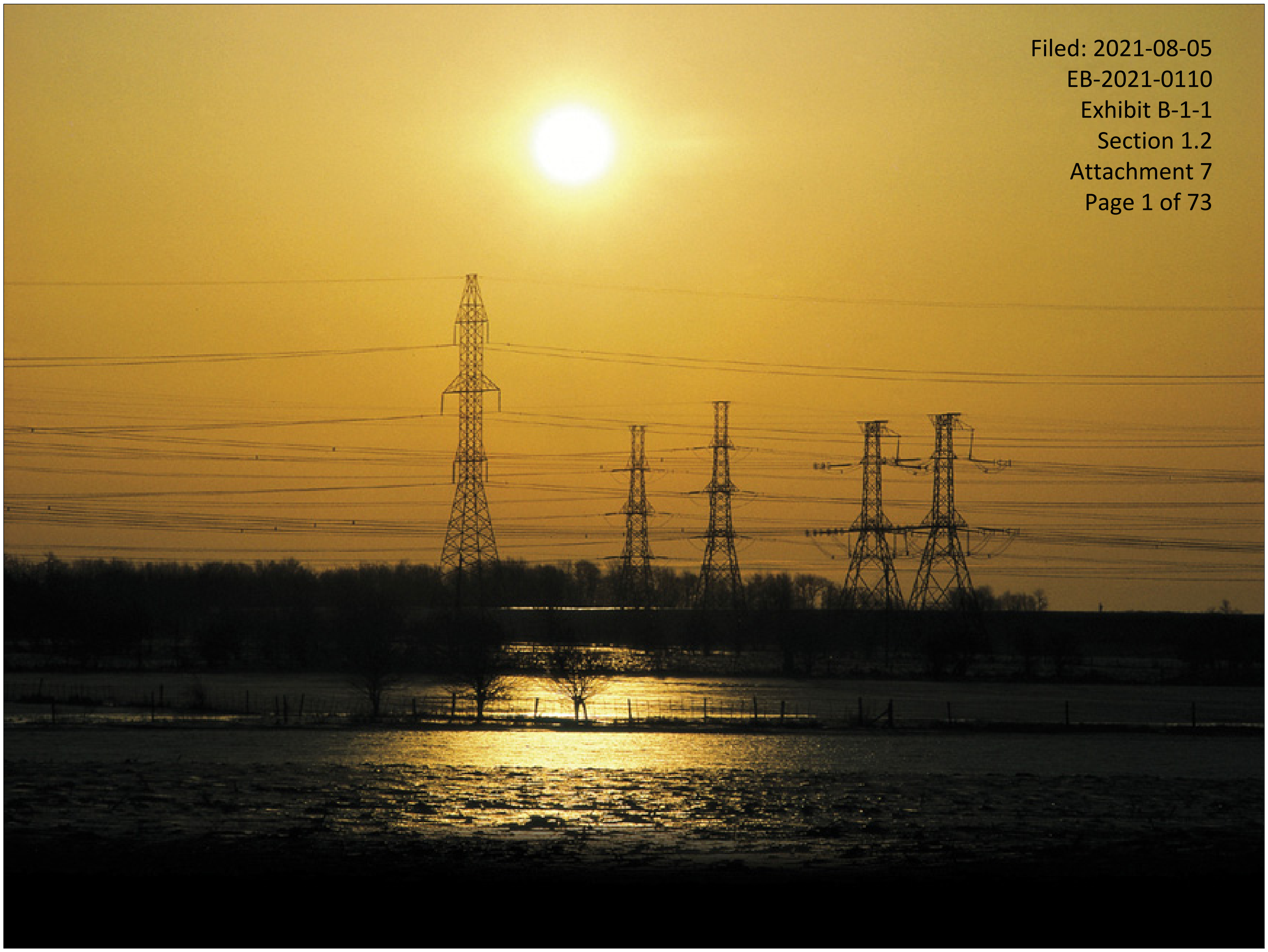
DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Churchill Meadows TS T1/T2	S	172.5	101.6	102.0	102.3	102.2	101.3	100.5	100.5	100.4	100.2	100.0	99.9	99.7	99.5	99.3	99.2	99.0	98.8	98.7	98.5	98.3	98.1
Cooksville TS T3/T4	S	119.8	52.9	52.4	53.3	54.2	54.5	54.8	55.6	56.5	57.5	58.1	58.7	59.3	60.0	60.6	61.2	61.9	62.5	63.2	63.8	64.5	65.2
Cooksville TS T1/T2	S	119.7	49.8	49.4	50.1	51.0	51.3	51.6	52.3	53.2	54.1	54.7	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.4	60.0	60.6	61.3
Erindale TS T1/T2	S	181.3	208.3	210.2	211.9	212.6	210.9	208.7	208.2	207.4	206.5	206.3	206.1	205.8	205.6	205.4	205.2	205.0	204.8	204.5	204.3	204.1	203.9
Erindale TS T3/T4	S	193.0	150.6	150.9	151.0	150.8	149.4	148.0	148.0	147.8	147.5	147.1	146.7	146.4	146.0	145.6	145.2	144.8	144.5	144.1	143.7	143.4	143.0
Erindale TS T5/T6	S	195.1	171.9	172.2	172.4	172.2	170.6	169.0	169.0	168.8	168.4	168.0	167.5	167.1	166.7	166.3	165.8	165.4	165.0	164.6	164.1	163.7	163.3
Glenorchy MTS #1 T1/T2	S	153.0	50.1	57.5	68.0	80.7	107.4	133.5	152.4	158.9	91.0	94.9	98.9	103.1	107.6	112.2	117.0	122.0	127.2	132.6	138.3	144.2	150.4
Lorne Park TS T1/T2	S	144.6	119.4	118.4	120.4	122.5	123.3	123.9	125.6	127.7	130.0	131.4	132.8	134.2	135.7	137.1	138.6	140.1	141.6	143.1	144.6	146.2	147.8
Oakville TS #2 T5/T6	S	185.2	157.8	157.0	157.7	158.2	157.2	156.1	156.5	156.8	157.2	157.1	157.1	157.0	156.9	156.8	156.8	156.7	156.6	156.5	156.5	156.4	156.3
Palermo TS T3/T4	S	109.5	82.6	84.0	87.1	90.4	89.2	88.1	87.8	87.3	86.8	87.3	87.9	88.5	89.0	89.6	90.2	90.7	91.3	91.9	92.5	93.1	93.7
Tomken TS T1/T2	S	173.3	138.8	140.6	142.0	142.4	141.1	139.7	139.4	138.9	138.3	138.2	138.2	138.1	138.1	138.0	138.0	137.9	137.8	137.8	137.7	137.7	137.6
Tomken TS T3/T4	S	192.8	149.7	151.7	153.2	153.6	152.3	150.7	150.5	149.9	149.3	149.3	149.2	149.2	149.1	149.1	149.0	149.0	148.9	148.9	148.8	148.8	148.8
Trafalgar TS T1/T2	S	124.0	85.1	84.7	84.5	83.9	82.8	81.6	81.2	80.7	80.2	79.6	79.0	78.4	77.9	77.3	76.7	76.1	75.6	75.0	74.5	73.9	73.4
Tremaine TS T1/T2	S	189.5	72.9	79.7	86.8	92.6	91.8	91.1	91.1	90.9	90.7	93.3	96.0	98.7	101.5	104.4	107.4	110.4	113.6	116.8	120.1	123.6	127.1

Notes:

- Northern (N) Sub-Region's stations load forecast is based on the IRRP [1] "Expected Growth" Scenario.
- Southern (S) Sub-Region's stations load forecast is based on the NA [2] non-coincident stations load forecast.
- Halton Hills Hydro MTS and Halton TS #2 are assumed to be in-service in 2018 and 2020, respectively. Some load from Glenorchy MTS will be transferred to the new Halton TS #2 in 2023, as shown by the corresponding increase and decrease at those stations.
- Load forecast were updated for Palermo TS, Tremaine TS, and Glenorchy MTS based on new information provided by Milton Hydro and Burlington Hydro.

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



Kitchener-Waterloo-Cambridge-Guelph

REGIONAL INFRASTRUCTURE PLAN

December 15, 2015

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Cambridge and North Dumfries Hydro Inc.
Centre Wellington Hydro
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Distribution
Independent Electricity System Operator
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address 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 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 DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER-WATERLOO-CAMBRIDGE-GUELPH ("KWCG") REGION.

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

- Cambridge and North Dumfries Hydro Inc.
- Centre Wellington Hydro
- Guelph Hydro Electric System Inc.
- Halton Hills Hydro One
- Hydro One Distribution
- Hydro One Transmission
- Independent Electricity System Operator
- Kitchener Wilmot Hydro Inc.
- Milton Hydro
- Waterloo North Hydro Inc.
- Wellington North Power Inc.

This RIP provides a consolidated summary of needs and recommended plans for the KWCG Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified at this time.

This RIP is the final phase of the regional planning process and it follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015.

The major infrastructure investments planned for the KWCG 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	Guelph Area Transmission Reinforcement	May 2016	$95 M
2	Arlen MTS: Install Series reactors	May 2016	$0.95 M
3	M20D/M21D – Install 230 kV In-line Switches	May 2017	$6 M
4	Waterloo North Hydro: MTS #4	2024	TBD

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 may be started earlier 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 KWCG 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, Kitchener-Wilmot Hydro Inc. (“Kitchener-Wilmot Hydro”), Waterloo North Hydro Inc. (“WNH”), Cambridge & North Dumfries Hydro Inc. (“CND”), Guelph Hydro Electric Systems Inc. (“Guelph Hydro”), 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.

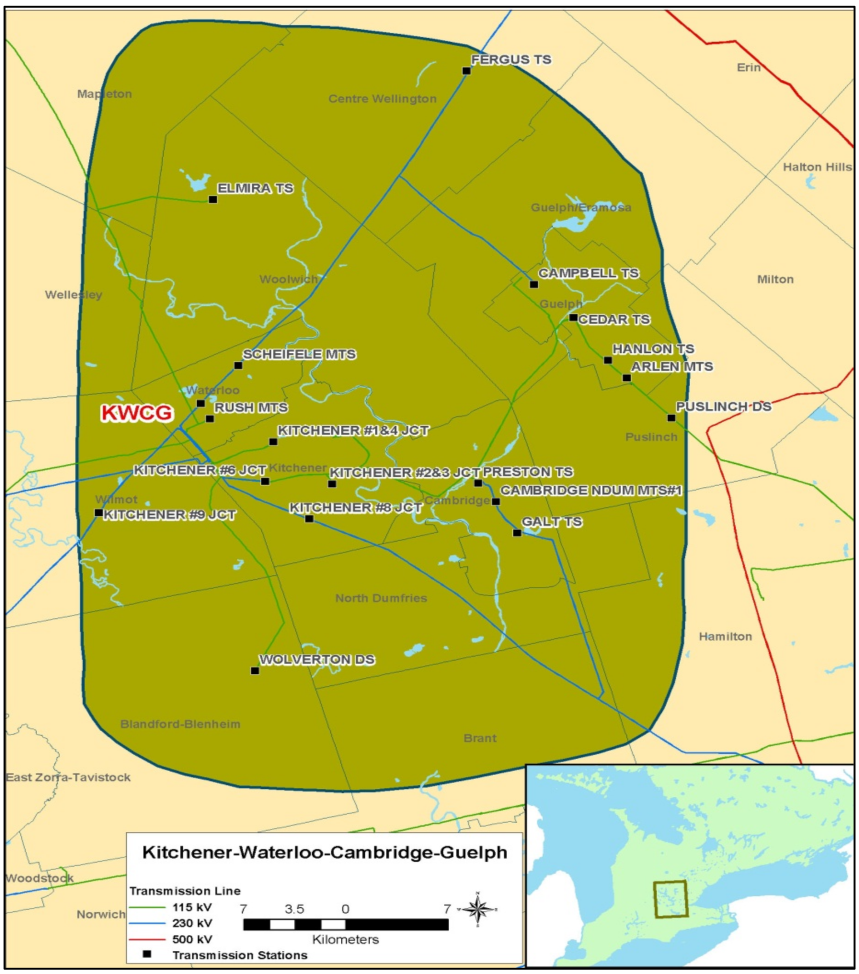

Figure 1-1 KWCG Region

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 2015 coincident regional load was about 1240 MW. The boundaries of the Region are shown in Figure 1-1 above.

1.1 Scope and Objectives

This RIP report examines the needs in the KWCG 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)
- To assess and develop a wires plan to address these needs
- 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 reviews factors such as load forecast, transmission and distribution system capabilities along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

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

The IRRP or RIP Working Group did not identify any long term needs at this time. If required, further assessment will be undertaken in the next planning cycle because adequate time is available to plan for required facilities.

1.2 Structure

The rest of the report is organized as the 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 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusions 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[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

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

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

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation ("DG")) options 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

[1] Also referred to a Needs Screening

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 would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the 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 LDCs for the region as part of and/or in parallel with:

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

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

Note that as the KWCG Region was identified as a “transitional” region at the onset of the OEB defined Regional Planning process in 2013, the Needs Assessment and Scoping Assessment phases were deemed complete and the region was placed into the IRRP phase of the process.

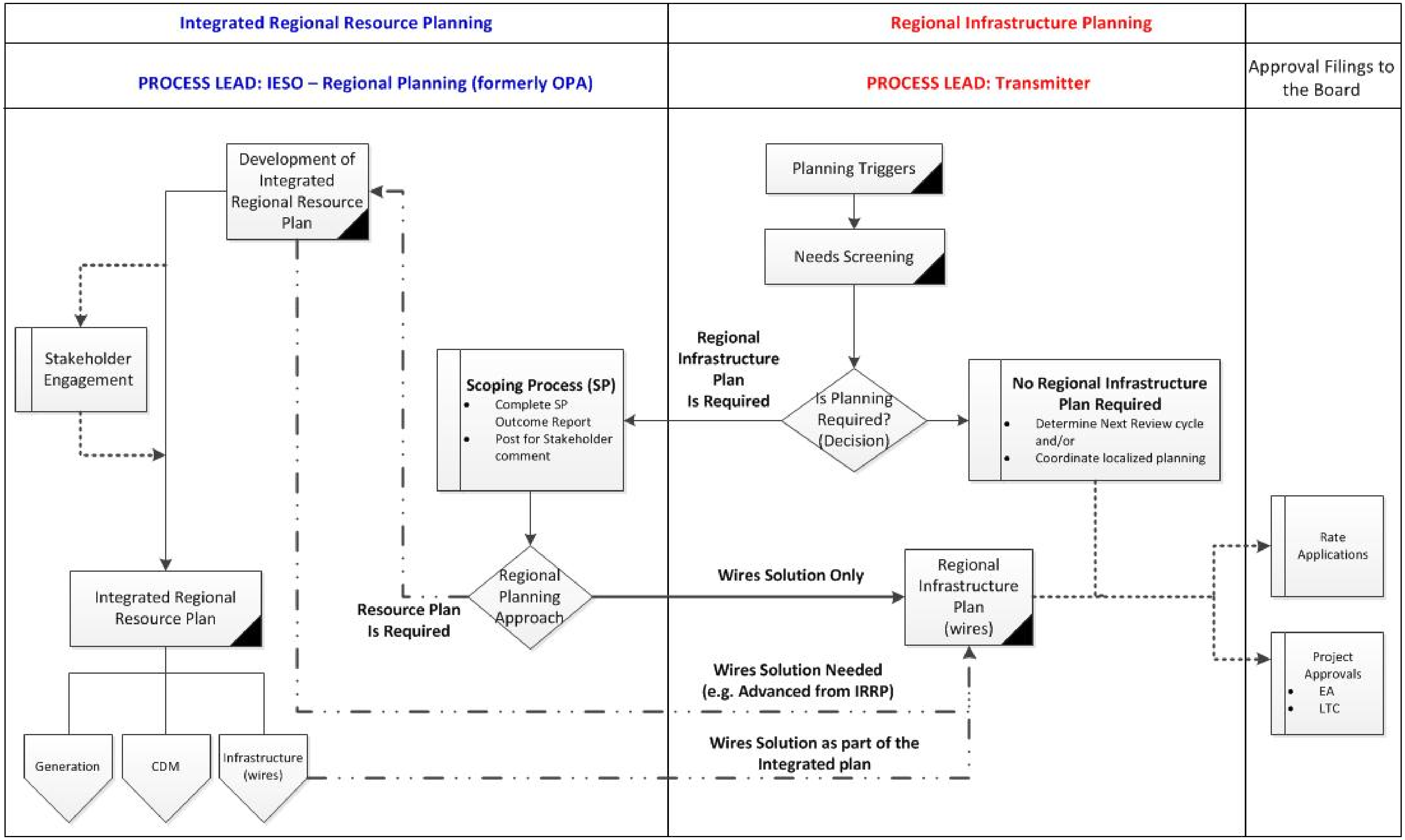

Figure 2-1 Regional Planning Process Flowchart

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

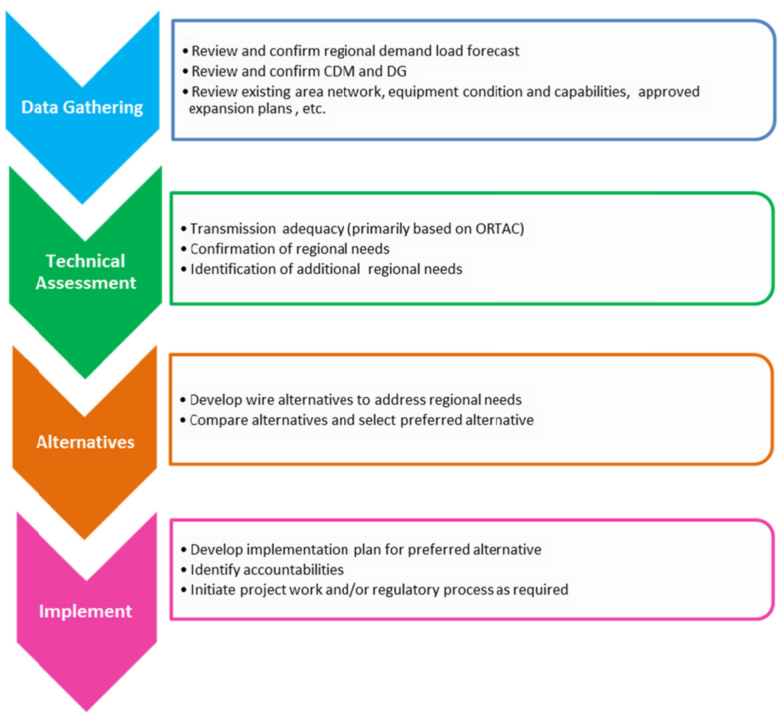

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE 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 stations: Middleport 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, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by 24 step-down transformer stations. Figure 3-2 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. Appendix A lists all step-down transformer stations in the KWCG Region, Appendix B lists all transmission circuits in the KWCG Region and Appendix C lists LDCs in the KWCG Region.

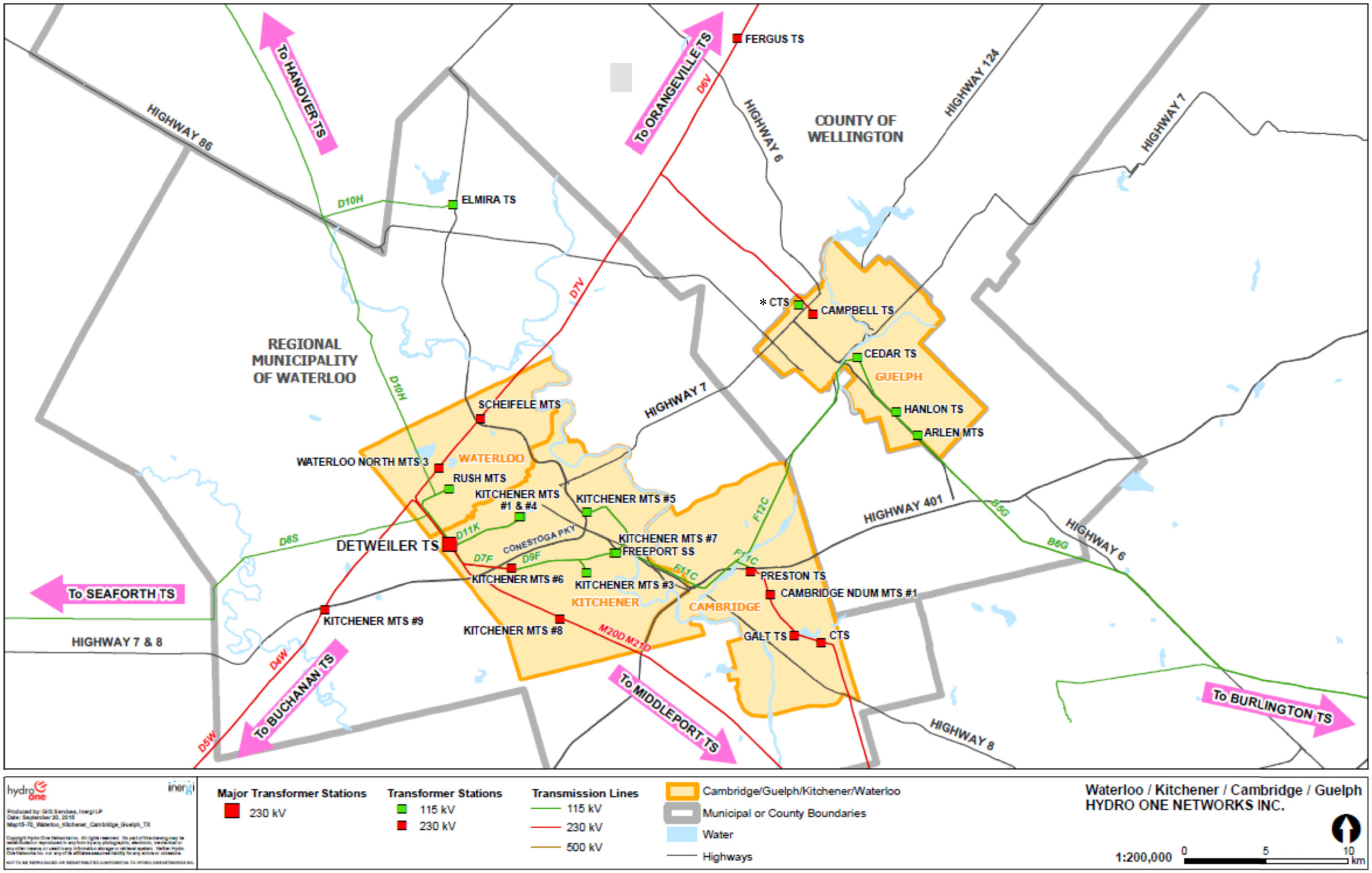

Figure 3-1 Geographical Area of the KWCG Region with Electrical Layout

*CTS relocated to the distribution system as part of the GATR project

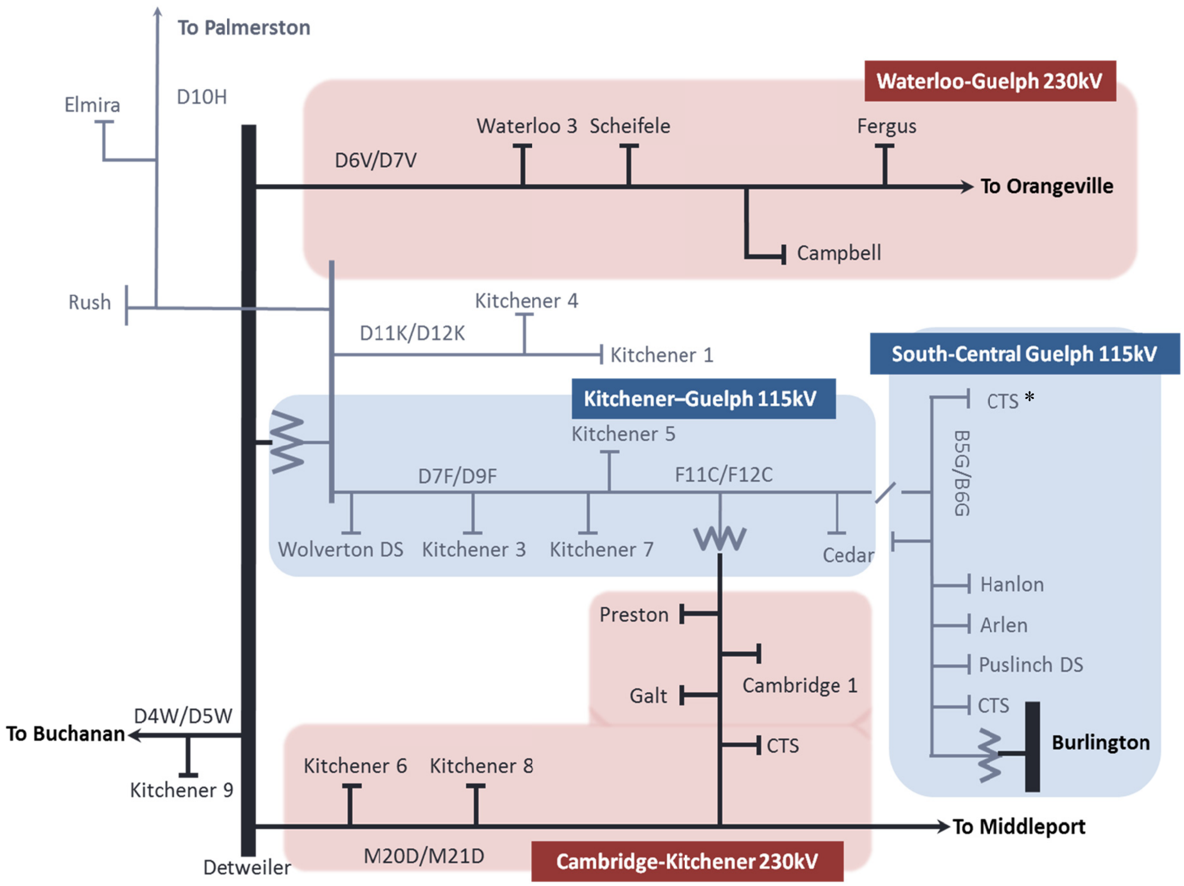

Figure 3-2 KWCG Single Line Diagram

*CTS relocated to the distribution system as part of the GATR project

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

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

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 transmission voltage level transformation capacity needs:

- 250 MVA 230/115 kV autotransformer T4 at Burlington TS replaced in 2006
- 250 MVA 230/115 kV autotransformer T6 at Burlington TS replaced in 2009

For distribution voltage level transformation capacity needs:

- Kitchener MTS#9 connected to replace the Detweiler TS DESN in 2010
- Arlen MTS connected in 2011

For reactive and voltage support needs:

- a 13.8 kV shunt capacitor bank installed at Cedar TS in 2006
- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008
- a 230 kV shunt capacitor bank installed at Burlington TS in 2010
- a 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For transmission circuit capacity needs:

- M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For transmission load security needs:

- Freeport SS installed to sectionalize circuits D7G/D9G (Detweiler TS by Cedar TS) in 2008

For transmission load restoration needs:

- 250 MVA 230/115 kV autotransformer T2 installed at Preston TS in 2007

The following projects are underway:

- Guelph Area Transmission Reinforcement (GATR) project that entails the extension the 230kV circuits D6V/D7V to Cedar TS; the installation of two new 250MVA, 230/115kV autotransformers at Cedar TS; and the installation of two 230 kV in-line switches onto circuits D6V/D7V at Guelph North Junction. 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. This project is identified in the IESO KWCG IRRP, reference [1].

- The installation of a 13.8 kV series reactor to mitigate short circuit levels at Arlen MTS. This project was identified in the RIP phase.

- The installation two new 230kV in-line switches onto circuits M20D/M21D near Galt Junction to improve restoration capability in the Cambridge-Kitchener 230 kV sub-system. This project is identified in Hydro One's KWCG Adequacy of Transmission Facilities & Transmission Plan 2016-2025 report, reference [2]/Appendix F as well as reference [1].

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the KWCG Region is forecast to increase at an average rate of approximately 1.7% annually between 2015 and 2025. The growth rate varies across the Region with most of the growth concentrated in the cities of Waterloo and Guelph, each at an average rate of 2.5% over the next ten years.

Figure 5-1 shows the KWCG Region's planning load forecast (summer net, regional-coincident extreme weather peak). The regional-coincident (at the same time) forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. By 2025 the forecasted coincident regional peak load is approximately 1765 MW.

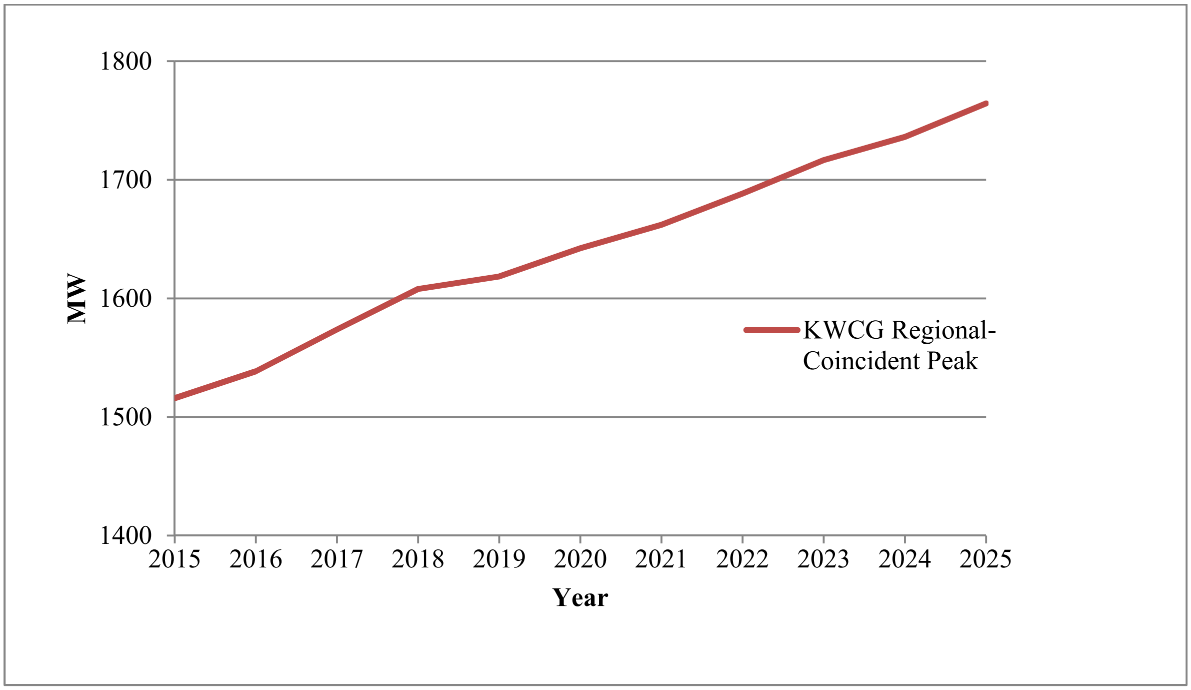

Figure 5-1 KWCG Region's Planning Forecast

The KWCG 2015 RIP planning load forecast is provided in Appendix D and is based upon the KWCG IRRP planning load forecast prepared by the IESO and was reaffirmed by the Working Group upon initiation of the RIP phase. In the IRRP phase, the LDC's provided the IESO with a 10 year gross, normal weather, regional-coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective CDM capacity, applying an extreme weather factor and then subtracting the effective DG capacity. Further details regarding the CDM and connected DG are provided in reference [1]. The RIP forecast is identical to the IRRP forecast except as otherwise noted in Appendix D.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

1) The Study period for the RIP assessment is 2015-2025.
2) All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
3) Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
4) 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.
5) Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR), while some LDCs use different methodologies for determining transformer station LTR.
6) Adequacy assessment is done as per the Ontario Resource and Transmission Adequacy Criteria ("ORTAC").

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

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND DELIVERY STATION FACILITIES SUPPLYING THE KWCG 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 KWCG Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's KWCG Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Adequacy of Transmission Facilities and Transmission Plan 2016-2025 – dated April 1, 2015 with revision 1 – dated October 30, 2015[2] (please see Appendix F)

The IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Guelph Area Transmission Reinforcement (GATR) project was initiated to provide adequate load supply capability to the KWCG area while the IRRP study was still underway. A detailed description and status of the GATR project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the KWCG Region assuming the GATR project is in-service. Sections 6.1-6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Medium Term Regional Needs

Type	Section	Needs	Timing
Needs Identified in the IRRP [1] and the Adequacy Report [2]			
Transmission Circuit Capacity	7.1.1	South-Central Guelph 115 kV sub-system- Capacity of 115kV circuits B5G/B6G	Immediate
	7.1.2	Kitchener–Guelph 115 kV sub-system – Capacity of 115kV circuits D7F/D9F and F11C/F12C	Immediate
Load Restoration	7.1.3	Waterloo-Guelph 230 kV sub-system	Immediate
	7.2.1	Cambridge-Kitchener 230 kV sub-system	Immediate
Step-down Transformation Capacity	7.3.1	Waterloo North Hydro Inc.	2018
Additional Needs identified in RIP Phase			
Station Short Circuit Capability	7.4.1	Arlen MTS: Short Circuit capability	2016

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 (refer to Figure 3-2):

1) Detweiler TS to Orangeville TS 230 kV transmission circuits D6V/D7V – supplies Fergus TS, Campbell TS, Waterloo North MTS#3 and Scheifele MTS
2) Detweiler TS to Middleport TS 230 kV transmission circuits M20D/M21D – supplies Kitchener MTS #6, Kitchener MTS # 8, Cambridge MTS #1, Galt TS, Preston TS and Customer #1 CTS
3) Detweiler TS to Buchanan TS 230 kV transmission circuits D4W/D5W – supplies Kitchener MTS#9.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period. Refer to section 3.4.2 of Appendix F for the detailed analysis.

6.2 500/230 kV and 230/115 kV Transformation 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:

1) Two 500/230 kV autotransformers at Middleport TS
2) Four 230/115 kV autotransformers at Burlington TS
3) Three 230/115 kV autotransformers at Detweiler TS
4) Two 230/115 kV autotransformers at Cedar TS
5) One 230/115 kV autotransformer at Preston TS

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. Refer to section 3.4.1 of Appendix F for the detailed analysis.

6.3 Supply Capacity of the 115 kV Network

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F – supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
2) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C – supplies Kitchener MTS#5 and Cedar T1/T2 transformers
3) Burlington TS to Cedar TS 115 kV transmission circuits B5G/B6G – supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
4) Detweiler TS 115 kV radial transmission circuit D11K/D12K – supplies Kitchener MTS#1 and Kitchener MTS#4
5) 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

The RIP review shows that based on current forecast station loadings and bulk transfers, the supply capacity of the 115 kV network is adequate over the study period. Refer to section 3.4.3 of Appendix F for the detailed analysis.

6.4 Step-down Transformer Stations

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected industrial customer 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.

As part of the IRRP, step-down transformation station capacity was reviewed and resulted in the IRRP forecast which was reaffirmed by the Working Group for use in the RIP phase. According to the load forecast, Waterloo North Hydro anticipates requiring additional step-down transformation capacity in 2018.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Impact Assessment for the GATR project

Based on the Customer Impact Assessment [3] for the GATR project, Guelph Hydro identified the need to mitigate short circuit levels at Arlen MTS in order to ensure the short circuit levels remain within the TSC limits and equipment ratings. The project need date is May 2016 so as to correlate with the completion of the GATR project.

6.5.2 System Impact Assessment for the GATR Project

A System Impact Assessment ("SIA") [4] was performed for Hydro One's application to the IESO for the Guelph Area Transmission Reinforcement (GATR) project.

Several findings emanated from the SIA report due to conservative assumptions made for the Bulk Power System. The Working Group has reviewed these findings and recommends that the assumptions be looked at in greater detail within a Bulk Power System study. If the Bulk Power System study results in regional needs then an early trigger of the next Regional Planning cycle may occur.

6.5.3 Load Restoration to the Cambridge area

The IRRP recommended Hydro One to continue to explore options with Cambridge and North Dumfries Hydro ("CND") to further improve the load restoration capability to the Cambridge area. During the RIP phase Hydro One presented to CND a detailed explanation of its capability to restore power to transformer stations that service the Cambridge area. Based on this discussion, CND and Hydro One have agreed that, at this time, no additional infrastructure is required and the restoration capability afforded by the GATR project and the 230 kV in-line switches at Galt Junction is acceptable for the study period.

6.6 Long-Term Regional Needs

The IRRP examined high-growth and low-growth scenarios to identify long-term needs. Under the high-growth scenario, there is sufficient transmission capacity afforded by the GATR project to meet demand in the long-term; however the need for additional step-down transformation capacity may arise. LDC's to closely monitor their load to determine the timing of potential step-down transformation needs. Under the low-growth scenario, no needs were identified in the long-term.

Consistent with the IRRP, the Working Group did not identify any additional long-term needs during the RIP phase. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions..

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE KWCG REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP AS WELL AS THE NEEDS IDENTIFIED DURING THE RIP PHASE.

7.1 Transmission Circuit Capacity and Load Restoration

7.1.1 South-Central Guelph 115 kV Sub-system

The South-Central Guelph area is supplied by the 115 kV double circuit line B5G/B6G. As per section 6.2.1 of the IRRP, historical peak demand on the B5G/B6G line has already exceeded the 100 MW line Load Meeting Capability ("LMC").

7.1.2 Kitchener-Guelph 115 kV Sub-system

The Kitchener-Guelph area is supplied by two 115 kV double-circuit lines D7F/D9F and F11C/F12C supported by 230/115 kV autotransformers at Detweiler TS and Preston TS. As per section 6.2.1 of the IRRP, the planning forecast peak demand in the Kitchener-Guelph 115 kV sub-system will exceeded the 260 MW line LMC by summer 2014.

7.1.3 Waterloo-Guelph 230 kV Sub-system

As per section 6.2.2 of the IRRP, the transmission infrastructure supplying load in the Waterloo-Guelph 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, D6V and D7V.

7.1.4 Recommended Plan and Current Status

To address the transmission circuit capacity needs for the South-Central Guelph 115 kV sub-system and the Kitchener-Guelph 115 kV sub-system, the IRRP Working Group recommended reinforcement of the 115 kV transmission system by introducing a new 230 kV – 115 kV injection point. The new injection point is to be located at Cedar TS using two new 230 kV/115 kV autotransformers in conjunction with a 5 km extension of the existing 230 kV double-circuit transmission line, D6V/D7V from Campbell TS to Cedar TS. This reinforcement is covered under the GATR project.

To address the load restoration need of the Waterloo-Guelph 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches near Guelph North Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is also covered under the GATR project.

Current Status of the GATR Project

Hydro One initiated construction on the GATR project in fall 2013 following the OEB approval in September 2013. The project has three components:

- Campbell TS x Cedar TS: Extend the 230 kV D6V/D7V tap from Campbell TS to Cedar TS. This requires replacing approximately a 5 km section of the existing 115 kV double circuit transmission section between CGE Junction and Campbell TS with a new 230 kV double circuit transmission line,
- Cedar TS: Install two new 230/115 kV autotransformers and associated 115 kV switching facilities at Cedar TS. Connect 115 kV switching facilities to the existing B5G/B6G line and the F11C/F12C at Cedar TS.
- Guelph North Junction: Install two in-line 230 kV switches at Guelph North Jct.

This investment will provide for sufficient 230/115 kV autotransformation capacity beyond the study period. The current in-service date of the project is May 2016.

The cost of this project is approximately $95 million. The project is a transmission pool investment as the autotransformers provide supply to all customers in the Region.

7.2 Load Restoration

7.2.1 Cambridge-Kitchener 230 kV Sub-system

As per section 6.2.2 of the IRRP and the section 3.4.8 of the Adequacy of Transmission Facilities report, transmission infrastructure supplying load in the Cambridge-Kitchener 230 kV sub-system does not meet reliability requirements to quickly restore supply in the event of a major outage involving the loss of both transmission circuits, M20D and M21D.

7.2.2 Recommended Plan and Current Status

To address the load restoration need of the Cambridge-Kitchener 230 kV sub-system, the IRRP Working Group's preferred alternative is to install two new 230 kV in-line switches on the M20D/M21D line near Galt Junction. The switches will enable Hydro One to quickly isolate a problem and allow the resupply of load to occur expeditiously. This work is covered under the M20D/M21D Install 230 kV In-line Switches project.

Current Status of the 230 kV In-Line Switches near Galt Junction

Hydro One has established a project to install the two 230 kV in-line switches onto the M20D/M21D double circuit line. One set of switches to be installed onto each circuit. One set of switches to be installed north of the Junction while the other to be installed south of Galt Junction. The switches will enable

Hydro One to quickly isolate a problem on either side of the junction and initiate the restoration of load to the Cambridge-Kitchener 230 kV sub-system.

The project is currently in the detailed design and estimation phase which also includes real estate negotiations. The cost of this project is approximately $6 million and it will be a transmission pool investment. The planned in-service date is May 2017.

7.3 Step-down Transformation Capacity

7.3.1 Waterloo North Hydro

The RIP/IRRP planning load forecast indicates that additional step-down transformation capacity is required by 2018, specifically Waterloo North Hydro's MTS #4.

7.3.2 Recommended Plan and Current Status

To address step-down transformation capacity needs of Waterloo North Hydro, Waterloo North Hydro will, wherever possible, manage load growth by maximizing the utilization of existing stations by increasing distribution load transfer capability between those stations and will continue to explore opportunities for CDM and DG. In addition Waterloo North Hydro will also explore, with other LDCs, opportunities to coordinate possible joint use and development of step-down transformer stations in the Region over the long term. With this in mind, additional step-down transformation capacity is not anticipated prior to 2024. This need will be reviewed in the next cycle of regional planning.

7.4 Station Short Circuit Capability

7.4.1 Arlen MTS

Arlen MTS is a 115/13.8 kV step-down transformer station owned by Guelph Hydro. As a result of the new 230/115 kV injection point afforded by the GATR project, the short circuit levels at Arlen MTS's 13.8 kV bus will exceed the TSC limit and equipment capability.

7.4.2 Recommended Plan and Current Status

To address the station short circuit capability need at Arlen MTS, Guelph Hydro will install series reactors to bring station short circuit levels within TSC limits and within equipment ratings.

Current Status of Short Circuit Mitigation

Guelph Hydro has initiated a project to install series reactors to bring station short circuit levels within TSC limits and equipment ratings. The cost of this project is $0.95 million and the expected completion date is May 2016 so as to correlate with the completion of the GATR project.

8. CONCLUSIONS

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

Six near and mid-term needs were identified for the KWCG Region. They are:

I. Transmission capacity in the South-Central Guelph 115 kV sub-system
II. Transmission capacity in the Kitchener-Guelph 115 kV sub-system
III. Load restoration capability in the Waterloo-Guelph 230 kV sub-system
IV. Load restoration capability in the Cambridge-Kitchener 230 kV sub-system
V. Step-down transformation capacity for Waterloo North Hydro
VI. Station Short Circuit Capacity at Arlen MTS

This RIP report addresses all six of these needs. Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near and mid-term needs 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	I/S Date	Cost	Needs Mitigated
1	Guelph Area Transmission Reinforcement	Construction in the final stages	Hydro One	May 2016	$95M	I, II, III
2	Mitigate Short Circuit Levels at Arlen MTS	Construction underway	Guelph Hydro	May 2016	$0.95M	VI
3	M20D/M21D – Install 230 kV In-line Switches	Transmitter to carry out this work	Hydro One	May 2017	$6M	IV
4	Waterloo North Hydro: MTS #4	LDC to monitor growth	Waterloo North Hydro	2024	TBD	V

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] Independent Electricity System Operator, Kitchener-Waterloo-Cambridge-Guelph Region Integrated Region Resource Plan, 28 April 2015. http://www.ieso.ca/Documents/Regional-Planning/KWCG/2015-KWCG-IRRP-Report.pdf

[2] Hydro One Networks Inc., Kitchener-Waterloo-Cambridge-Guelph Area – Adequacy of Transmission Facilities and Transmission Plan 2016-2025, 1 April 2015, revised 30 October 2015.

[3] Hydro One Networks Inc., Customer Impact Assessment Guelph Area Transmission Refurbishment Project, 28 May 2013,

[4] Independent Electricity System Operator, System Impact Assessment, CAA ID: 2012-478, Project: Guelph Area Transmission Refurbishment, 17 May 2013. http://www.ieso.ca/Documents/caa/CAA_2012-478_GATR_Final_Report.pdf

Appendix A. Step-Down Transformer 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
Cambridge 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	B5G/B6G
Arlen MTS	115 kV	B5G/B6G
Hanlon TS	115 kV	B5G/B6G
Cedar TS (T8/T7)	115 kV	B5G/B6G
Customer #2 CTS	115 kV	B5G
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

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	B5G/B6G	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
Cambridge and North Dumfries Hydro Inc.	Cambridge NDum MTS#1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Guelph Hydro Electric System - Rockwood Division	Fergus TS	Dx
Guelph Hydro Electric Systems Inc.	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
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 Regional Load Forecast (2015-2025)

Table D-1 RIP Planning Demand Forecast (MW)

Station	LDC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS (1)	Cambridge & North Dumfries Hydro	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Kitchener MTS #6	Kitchener-Wilmot Hydro	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Wolverton DS	Hydro One Distribution	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Cedar TS T1/T2	Guelph Hydro	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cambridge MTS # 2 (2)	Cambridge & North Dumfries Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #5	Kitchener-Wilmot Hydro	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Cedar TS T7/T8	Guelph Hydro	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Puslinch DS	Hydro One Distribution	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Arlen MTS	Guelph Hydro	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo North MTS #3	Waterloo North Hydro	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
MTS #4(2)	Waterloo North Hydro	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Fergus TS	Hydro One Distribution	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Kitchener MTS #1	Kitchener-Wilmot Hydro	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Kitchener MTS #4	Kitchener-Wilmot Hydro	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Elmira TS (3)	Waterloo North Hydro/ Hydro One Distribution	38.0	32.6	33.5	33.3	34.8	35.4	36.0	36.8	38.4	39.0	40.6
Rush MTS	Waterloo North Hydro	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS (4)	Customer Station	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Station (Assumed Values)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Table D1 -is based upon KWCG 2015 IRRP Planning Load Forecast except as noted.

(1) Cambridge and North Dumfries Hydro ("CND") has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expected to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

(2) Both CND and Waterloo North Hydro ("WNH") are monitoring the load closely to determine the timing of potential transformation needs. For planning purposes, WNH has moved back the in service date of MTS #4 from 2018 to 2024. WNH is closely monitoring the need for additional transformation capacity to determine if the load growth indicated at MTS #4 in the forecast can be managed through a combination of improving transformer station interties, CDM and DG in the Waterloo Region. Where possible, these LDCs are exploring opportunities to coordinate possible joint use and development of step-down transformer station facilities in the KWCG Region over the long term.

(3) Updated to include Hydro One Distribution load

(4) Based on information provided by the transmission-connected customer

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

Appendix F. KWCG Adequacy of Transmission Facilities and Transmission Plan 2016-2025

Revision 1

KITCHENER/WATERLOO/CAMBRIDGE/GUELPH AREA

ADEQUACY OF TRANSMISSION FACILITIES

AND

TRANSMISSION PLAN 2016 – 2025

October 30, 2015

Prepared by Hydro One Networks Inc. in Consultation with the KWCG Working Group

Foreword

This report is the result of a joint study by KWCG Working Group. It has been prepared by Hydro One Networks in consultation with the Working Group.

The working group members were:

Entity	Member
Kitchener-Wilmot Hydro	Shaun Wang L. Frank G. Cameron
Waterloo North Hydro Inc.	Herbert Haller David Wilkinson Dorothy Moryc
Cambridge & North Dumfries Hydro	Ron Sinclair Shawn Jackson
Guelph Hydro Electric System Inc.	Michael Wittemund K. Marouf Eric Veneman
Hydro One Distribution	Charlie Lee
Ontario Power Authority	Bob Chow Bernice Chan
Independent Electricity Operator	Peter Drury
Hydro One Networks Inc.	Alessia Dawes Farooq Qureshy Emeka Okongwu Qasim Raza

The preferred plan has been selected based on technical and economic considerations. The issue of cost allocation between utilities was not addressed.

Prepared by: Qasim Raza – Transmission Planning Officer

Reviewed by: Alessia Dawes – Senior Transmission Planning Engineer

Approved by: Farooq Qureshy – Manager, Transmission System Development, Central & East

October 30, 2015

Revision History

Revision	Date	Author	Description of change
1	October 30, 2015	Qasim Raza	Refreshed based on 2015 IRRP/RIP load forecast (April/August2015)
0	April 1, 2015	Alessia Dawes	Original- based on May 2013 forecast

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EXECUTIVE SUMMARY

In 2010 an integrated regional planning study was initiated to assess the electricity supply and reliability over a twenty year period for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) areas and continues to be conducted by a Working Group led by the Ontario Power Authority (OPA) and includes staff from the Independent Electricity System Operator (IESO), Hydro One Networks Inc., Kitchener-Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro, Guelph Hydro Electric Systems Inc. and Hydro One Distribution.

The early results of the integrated regional planning study identified the need to reinforce supply capacity for the South-Central Guelph and the City of Cambridge over the near and medium term. It also identified the need to minimize the impact of double circuit interruptions in the area[1]. As a result, the Working Group recommended two transmission projects in conjunction with conservation and distributed generation:

1. The Guelph Area Transmission Reinforcement (GATR) project – comprising a new 230/115kV autotransformer station at Guelph Cedar TS, upgrading the circuit section between Campbell TS and CGE Junction to 230 kV and in-line switching on the Orangeville TS x Detweiler TS 230kV circuits D6V/D7V – to reinforce supply to South Central Guelph,
2. The Preston TS Autotransformer Project – comprising the installation of a second 230/115kV autotransformer at Preston TS - to reinforce supply to the City of Cambridge.

Work on the GATR project was started in 2014 following approval from the Ontario Energy Board and the Ministry of Environment. The project's planned in-service date is June 2016.

For the Preston project, the OPA issued Hydro One a hand off letter to develop a "Wires" solution to improve the supply to the Cambridge area and to facilitate the connection of a future Cambridge and North Dumfries Hydro transformer station by 2018.

This report presents the results of Hydro One led "Wires" study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016. The main conclusions of the report are as follows:

- The supply capability to the KWCG 115kV area has been significantly increased to meet all 2025 forecast loads by the addition of the GATR project. The need for the Preston autotransformer can be deferred to beyond 2025.
- There is inadequate load restoration capability for load connected to Middleport TS x Detweiler TS 230kV double circuit line M20D and M21D

This report recommends that the most cost effective plan to improve load restoration capability for load connected to circuits M20/21D is to install 230 kV in-line switches onto circuits M20/21D.

[1] OPA Submission to the OEB for the GATR Project – Document EB-2013-0053 dated March 8, 2013 entitled, "Kitchener-Waterloo-Cambridge-Guelph Area

1.0 INTRODUCTION

This transmission adequacy assessment focused on the electrical supply to the municipalities of Kitchener, Waterloo, Cambridge and Guelph and their surrounding areas of Ontario, collectively referred to as the KWCG area in this report. Its primary focus was to confirm the near and mid-term transmission needs for the area and to provide a 10-year transmission plan in order satisfy those Needs.

Geographically, the KWCG area consists of 4 municipalities – Kitchener, Waterloo, Cambridge, Guelph and portions of two counties - Perth and Wellington. Hydro One Networks Inc. is the sole high voltage transmitter in the KWCG area; however the low voltage distribution of electricity in the KWCG area is carried out by Cambridge and North Dumfries Hydro Inc., Guelph Hydro Electric System Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc., and Waterloo North Hydro. A geographic map of the area is shown in Appendix A, Map 1 while an electrical map of the area is shown in Appendix A, Map 2.

The KWCG area is a major regional load centre in Ontario. The area has a well-established history in manufacturing and technology. The area peak load is approximately 1400 MW.

This report presents the results of the Hydro One led “Wires” study of the adequacy of supply to the City of Cambridge and the wider KWCG area based on the planned in-service of the GATR project in summer 2016.

2.0 EXISTING TRANSMISSION INFRASTRUCTURE

2.1 TRANSMISSION IN KWCG

Electrical Supply in this area is provided through 230 kV and 115 kV transmission lines and step down transformation facilities (transmission stations, TS) as show in Appendix A, Map 2.

The main sources of electricity into the KWCG Region are Middleport TS, Detweiler TS, Orangeville TS, Cedar TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively. The KWCG Region transmission system is connected as follows:

- Two 230 kV circuits (D6V/D7V) that run North-East from Detweiler TS to Orangeville TS that supply five load serving stations;
- Two 230 kV circuits (M20/21D) that run South-East from Detweiler TS to Middleport TS that supply five load serving stations and one transmission-connected customer;
- Two 230 kV circuits (D4W/D5W) that run South-West from Detweiler TS to Buchanan TS (in the "London area") that supply one load serving station;
- Four 115 kV circuits (D7F/D9F, F11C/F12C) that run East-West: D7/9F from Detweiler TS to Freeport SS that supply three load serving stations and F11/12C from Freeport SS to Cedar TS that supply one load serving station;
- Two 115 kV circuits (B5G/B6G) that run North-West from Burlington TS to Cedar TS that supply three load serving stations and one transmission-connect customer;
- Two 115 kV radial circuits (D11K/D12K) emanating East from Detweiler TS that supply two load serving stations; and,
- Two 115 kV circuit (D8S and D10H) emanating North from Detweiler TS that supply two load serving stations in the KWCG area.

Voltage support is provided in the area by:

- Four high voltage shunt capacitor banks and one SVC at Detweiler TS
- Four high voltage shunt capacitor banks at Middleport TS
- Three high voltage shunt capacitor banks at Burlington TS
- One high voltage shunt capacitor bank at Orangeville TS
- 43.2 MVar low voltage station shunt capacitor at Galt TS
- 21.6 MVar low voltage station shunt capacitors at Campbell TS
- 59.81 MVar low voltage station shunt capacitors at Cedar TS
- 9.92 MVar low voltage station shunt capacitors at Elmira TS
- Low voltage feeder shunt capacitors were lumped at: C&ND MTS#1, Waterloo North Hydro MTS #3, Scheifele MTS

All stations in the KWCG Region were considered in the analysis to determine the adequacy of the existing transmission system. Transformation capacity at individual load serving stations was previously analyzed by the OPA as part of the Integrated Regional Resource Plan (IRRP). The result of that analysis was a load forecast that included proposed new stations, as shown in Appendix C. Therefore, transformation capacity at individual load serving stations was not considered in this study.

2.2 TRANSMISSION-CONNECTED GENERATION

There are no existing large-scale transmission-connected generation plants in the KWCG area; however two contracted renewable transmission-connected wind farms were included in the study area and are listed in Appendix B.

3.0 ADEQUACY OF EXISTING TRANSMISSION INFRASTRUCTURE IN KWCG AREA

3.1 STUDY ASSUMPTIONS

Assumptions were made in order to assess the effects of contingencies to verify the adequacy of the transmission system. The assumptions used in the study were:

1. A 10 year load forecast: years 2016 to 2025; shown in Appendix C
2. Forecasted loads were provided by the LDC's in MW. The MVAR portion of the load was set to 40% of the MW load which is a reasonable assumption to achieve a power factor of 0.9 at the defined meter point of load serving transformer stations (TS, CTS, MTS)
3. A summer assessment was performed as the KWCG area is summer load peaking while the equipment is at its lowest rating during summer ambient conditions. This was deemed to be the most conservative approach;
4. Equipment continuous and Limited Time Ratings (LTR) were based on an ambient temperature of 35°C for summer and a wind speed of 4 km/hour;
5. The Guelph Area Transmission Reinforcement (GATR) project would be in-service in June 2016;
6. Circuits M20D and M21D are assigned their updated long-term emergency rating (LTE) based on a maximum temperature of 127°C;
7. Simulation of year 2025 load forecast was performed as it was the maximum loading of the area for the duration of the study period; year 2016 was simulated as necessary;
8. Waterloo North Hydro's Snider MTS #4 (MTS #4) will connect to 230 kV circuit D6/7V between Scheifele MTS and Guelph North Jct., projected in-service date 2024 (refer to Note 2 in Appendix C, Table C1)
9. The flows on Ontario's major internal transmission interfaces were assumed as follows:
    - FETT ~ 4500 MW
    - FS ~1250 MW
    - FABCW ~ 5800MW
    - NBLIP ~ 1650 MW (the slightly high NBLIP was offset by the lower FABCW)
    - QFW ~ 1550 MW

3.2 STUDY CRITERIA

The adequacy of the transmission system is assessed as per the IESO Ontario Resource and Transmission Assessment Criteria, Issue 5.0.

3.3 LOAD FORECAST

The load forecast used in this assessment is the KWCG 2015 RIP forecast as shown in Appendix C. This summer forecast is an extreme weather, area coincident, net, peak load forecast.

The KWCG 2015 RIP forecast is based upon the KWCG 2015 IRRP forecast. The LDC's provided the IESO with a 20 year gross, normal weather, area coincident, peak load forecast in MW. The IESO adjusted the forecast by subtracting the effective conservation and demand management (CDM) capacity, applying an extreme weather factor and then subtracting the effective Distribution Generation (DG) capacity.

3.4 SUPPLY CAPACITY NEEDS

Single element contingencies were considered in assessing the adequacy and reliability of the local transmission system that serves the KWCG area. Figure 1 summarizes the local KWCG area Needs for the 10-year period under study. Appendices D, F and G detail the technical study and results.

At stations, within the KWCG area, classified as NPCC Bulk Power System (BPS) additional contingencies were considered to establish their impact to the local KWCG area. Appendix E details the technical study and results.

3.4.1 AUTO-TRANSFORMATION SUPPLY CAPACITY

There is no major generation station in the KWCG area. Hence, the majority of supply to the load is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV auto-transformers. The number and location of these auto-transformers are as follows:

- Two 500/230 kV autotransformers at Middleport TS
- Four 230/115 kV autotransformers at Burlington TS[2]
- Three 230/115 kV autotransformers at Detweiler TS
- Two 230/115 kV autotransformers at Cedar TS
- One 230/115 kV autotransformer at Preston TS

Single autotransformer contingencies were performed to assess the adequacy of the transmission system to supply bulk power into the KWCG area via the autotransformers for year 2025 loading.

The results indicate that there are no thermal overloads and no voltage violations for the loss of a single autotransformer.

[2] The loading of the autotransformers at Burlington TS is mainly driven by the load connected in the Burlington to Nanticoke area. Only a small percentage of the autotransformer load is due to local Guelph load and as such, analysis of the Burlington TS autotransformers was undertaken in the 'Burlington to Nanticoke' Regional Infrastructure Plan.

3.4.2 SUPPLY CAPACITY OF THE 230 KV NETWORK

The KWCG area contains three pairs of double circuit 230 kV lines: M20D/M21D, D6V/D7V and D4W/D5W.

Single circuit contingencies were performed to assess the adequacy of the local 230 kV transmission system for year 2025 loading[3].

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 230 kV circuit.

3.4.3 SUPPLY CAPACITY OF THE 115 KV NETWORK

The KWCG area contains five pairs of double circuit 115 kV lines: D7F/D9F, F11C/F12C, B5G/B6G, D11K/D12K and D8S/D10H.

Single circuit contingencies were performed to assess the adequacy of the local 115 kV transmission system for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for the loss of a single 115 kV circuit. Appendix H details supply capacity on circuit D8S and D10H as request by the LDC.

3.4.4 VOLTAGE PERFORMANCE

Single circuit contingencies as well as single element HV shunt capacitor bank contingencies were performed to determine the overall voltage performance of the KWCG area for year 2025 loading.

As indicated in Appendix D there are no thermal overloads and no voltage violations for these contingencies. Appendix H details voltage performance at Elmira TS and Rush MTS as request by the LDC.

3.4.5 LOAD SECURITY ANALYSIS

The most stringent load security criterion that applies to the KWCG area states that with any two elements out of service:

- Voltage must be within applicable emergency ratings and equipment loading must be within applicable short-term emergency ratings;
- Load transfers to meet the applicable long-term emergency ratings must be able to be made in the time afforded by short-time ratings;
- Planned load curtailment or load rejection in excess of 150 MW is not permissible (except for local generation outages) and;

[3] Note, if another element such as an autotransformer, circuit or capacitor bank shared the same “switching position” and/or zone of protection with the circuit under contingency, both were removed from service.

- Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment or load rejection excluding voluntary demand management with any two transmission elements out of service.

There are three pairs of 230 kV double circuit lines and five pairs of 115 kV double circuit lines in the KWCG area. While one circuit of a double circuit line is out of service, the loss of the companion circuit in the pair would result in the loss of all load stations connected to the pair by configuration. Tables F1 and F2 in Appendix F illustrate the load lost due to configuration in both years 2016 and 2025.

There are five stations in the KWCG area that have autotransformers. Overlapping autotransformer contingencies were taken and Table F3 in Appendix F illustrates any load transfer requirements due to two overlapping autotransformer outages.

As seen in Appendix F, the load forecasted on all circuit pairs is less than 600 MW within the 10-year study period and the loss of two autotransformers within this local area does not result in equipment loading beyond their applicable emergency ratings; therefore there is no concern with Load Security in the KWCG area for the study period.

3.4.6 Load Restoration Capability Analysis

The load restoration criteria requires that the transmission system be planned such that following local area design criteria contingencies, the affected loads can be restored within the restoration times indicated below[4]:

- All load lost must be restored within 8 hours;
- Load lost in excess of 250 MW must be restored within 30 min; and
- Load lost between the amount of 150 MW and 250 MW must be restored within 4 hours.

Each pair of double circuit 230 kV and 115 kV lines were assessed to verify their load restoration capability. This assessment is detailed in Appendix G.

The results indicated the existing transmission system can adequately restore load to each circuit pair with the exception of M20/21D. Therefore, improvement to the restoration capability of load connected to circuits M20D and M21D is required.

3.4.7 Impact of Contingencies on the BPS to the KWCG Area

Northeast Power Coordinating Council (NPCC) Bulk Power System stations in the KWCG area are:

- Middleport TS 500 kV bus
- Middleport TS 230 kV bus
- Detweiler TS 230 kV bus

[4] As per ORTAC: “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.”

All elements connected to BPS buses are considered BPS facilities. Elements refer to circuit breakers, transmission lines, generators, transformers and reactive devices (e.g. SVC or capacitor bank).

Appendix E: Technical Results-Bulk Power System Considerations provides a list of BPS contingencies and the results. A *limited* number of BPS contingencies were performed in order to establish the impact of contingencies on the BPS to the local KWCG area.

Three NPCC Directory 1 contingency events were utilized in this study:

1. Simultaneous loss of two adjacent transmission circuits on a multiple circuit tower
2. Loss of any element with delayed fault clearing (a.k.a. Breaker Failure)
3. Loss of a critical element, followed by system adjustment, then loss of a critical element.

These BPS contingency events were applied to BPS buses only. The results can be summarized as follows:

- As per Table E3 and E5 when two of the three auto-transformers at Detweiler TS are not available the remaining auto-transformer may become overloaded. Since the loading of the remaining auto-transformer is within its 15-minute Short-Term Emergency Rating (STE) operational control actions can be taken to reduce the loading to within acceptable limits. Control actions could entail isolation of the faulted element e.g. circuit breaker, bus or transformer, and placing back in-service a healthy auto-transformer (at Detweiler TS and/or Preston TS). Another control action could entail opening of 115kV breakers at Freeport SS to redirect flows through the Cedar TS autotransformers.

3.4.8 Summary of Needs

Figure 1 illustrates the Needs timeline for the KWCG region.

Figure 1: Transmission Needs in the KWCG Area

4.0 Options to Address the Need

Options were considered to address the insufficient load restoration capability for loads connected to circuits M20D and M21D. These options are shown in Table 1. Although there are several metrics that can be utilized to measure and compare options, the simple metric "initial capital cost/MW of load restored" was selected because it compares the unit costs of remedial measures. This was deemed sufficient in order to select the preferred option

Table 1: Options to Improve M20/21D Load Restoration

Option	**Options to Improve Restoration**	**Fault on the Main Line – Restorable Load** (Note 1)	**Fault on the Tap – Restorable Load** (Note 1)	**Initial Capital Cost** (Note 3)	**Initial Capital Cost/ MW Load Restored**
--	Existing (Benchmark)	100 MW (Preston TS only)	100 MW (Preston TS only)	0	$0/MW
1	230 kV in-line switches on M20/21D at **Preston Junction**	100 MW (C&ND load only-Note 2)	100 MW (C&ND load only-Note 2)	$6M	$60k/MW
2	230 kV in-line switches on M20/21D at **Galt Junction** (main line)	368 MW - 484 MW	234 MW (100 MW via existing Preston Auto)	$6M	$12k/MW to $26k/MW
3	One 230 kV cap bank at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	140 MW (Note 4) (C&ND load only-Note 2)	140 MW (Note 4) (C&ND load only-Note 2)	$11M	$79k/MW
4	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction**	200 MW (Note 4) (C&ND load only-Note 2)	200 MW (Note 4) (C&ND load only-Note 2)	$21M	$105k/MW
5	2nd autotransformer at Preston TS plus 230 kV in-line switches on MxD at **Preston Junction** plus two 230 kV cap banks at Preston TS	280 MW (Note 4) (C&ND load only-Note 2)	280 MW (Note 4) (C&ND load only-Note 2)	$31M	$111k/MW

NOTE 1 Restorable load values are approximate values only as the actual amount of restorable load will depend on the prevailing system conditions and Operating/Control Centre protocols and priorities

NOTE 2 "C&ND load only" means that only those customers connected to Galt TS, C&ND MTS#1 and Preston TS will benefit. Cambridge and North Dumfries Hydro customers are the sole customers of these three stations.

NOTE 3 All prices are based on historical data: taxes extra, overhead extra, no escalation considered, no assumptions are made to feasibility or constructability, no assumptions made as to space requirements, real estate and environmental cost extra

NOTE 4 Restoration of 230 kV load (Cambridge and North Dumfries load) via the Preston TS auto-transformer may require operational measures on the 115 kV system to secure the transmission system to handle a subsequent contingency e.g. open the low voltage bus-tie breakers/switches at 115kV connected stations

5.0 DISCUSSION OF PREFERRED OPTIONS

5.1 PREFERRED OPTION TO IMPROVE RESTORATION TO M20/21D LOAD

Currently, loads connected to circuits M20/21D do not meet the restoration criteria.

Of the five options, option #2: 230 kV in-line switches on M20/21D at/near Galt Junction is the preferred option to satisfy the Need as it will provide the capability to restore the most load supplied from M20/21D.

Not only does Option #2 allow for more load to be restored, it provides for better operational flexibility; and is the most economical solution. As option 2 substantially meets the need by significantly improving the existing restoration capability, it is therefore the preferred option.

6.0 DEVELOPMENT PLAN

The transmission infrastructure development plan for the KWCG area is as followings:

1) Immediate Action: Install 230 kV In-Line Switches

Install 230 kV Load Interrupter type in-line switches on circuits M20D and M21D on the main line near Galt Junction. Note that load interrupter type switches cannot be used to interrupt fault current.

7.0 CONCLUSIONS

The following conclusions can be reached from the analysis performed by this study.

Local Area Performance

1. Improvement to the load restoration capability of transmission-connected customers on circuits M20D and M21D is required. The preferred option can be implemented by summer 2017.

BPS Performance

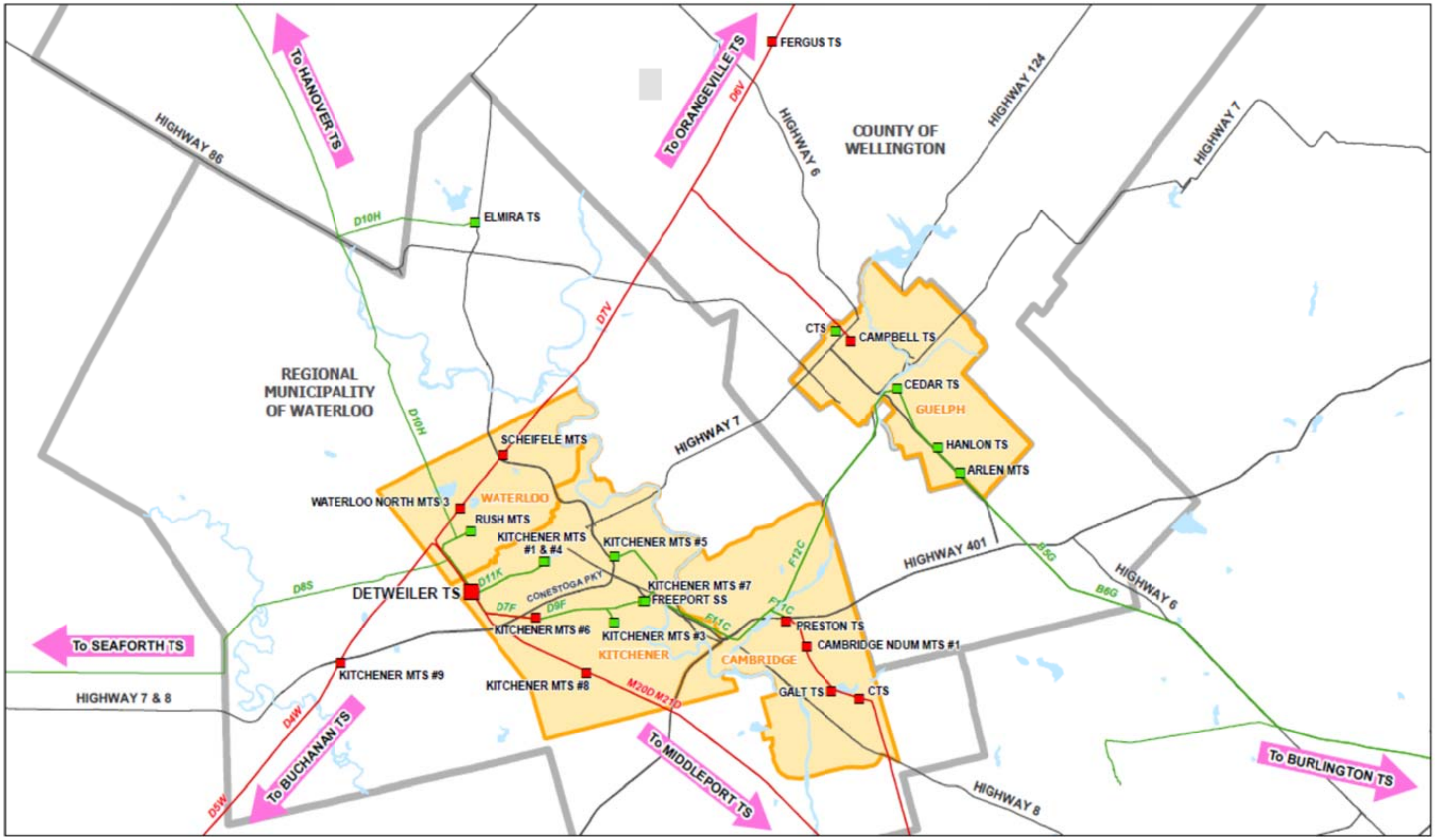
2. Autotransformer T2 at Detweiler TS is expected to be at 104.4% of LTE loading for year 2016 for the following contingency:
    i. Detweiler T4 outage plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS). Since the post-contingency flow is below the auto-transformer STE, operational control actions can be taken to reduce loading to within the LTE rating.

8.0 RECOMMENDATIONS

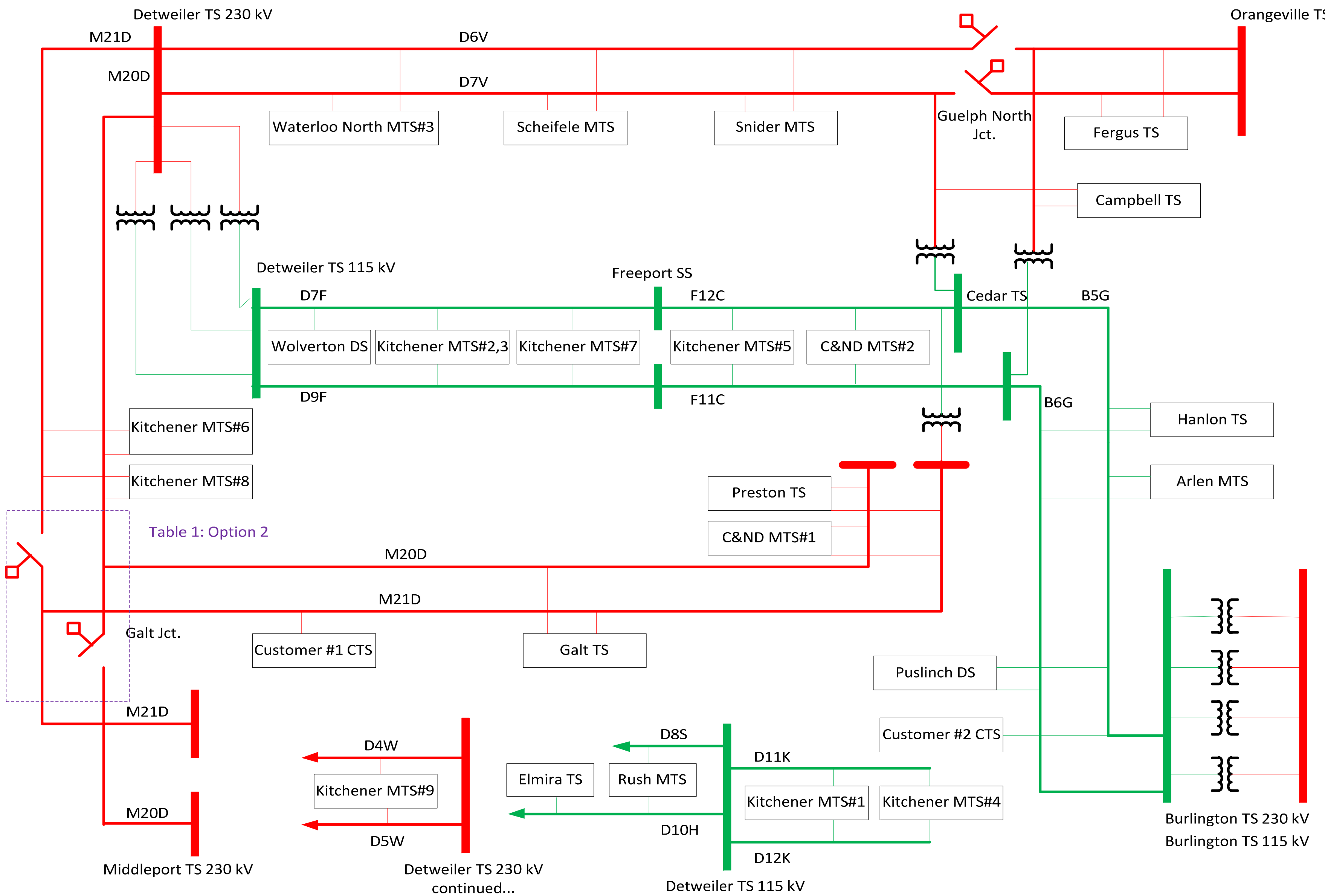
The following recommendations are to address the transmission infrastructure deficiencies within the study period for the KWCG area. These recommendations are:

1. Hydro One Networks to install a set of 230 kV in-line switches onto the main line of circuits M20D and M21D near Galt Junction as soon as possible.
2. Hydro One Networks, the LDCs and the IESO to review the KWCG local area in 2019 with updated KWCG load forecasts to decide on appropriate actions to meet longer-term needs as they emerge.

APPENDIX A: KWCG MAPS



Map 1: Geographical Area of KWCG with Electrical Layout



Map 2: KWCG Electrical Single-Line

APPENDIX B: TRANSMISSION-CONNECTED GENERATION IN THE KWCG AREA

Name	Installed Capacity	Peak Capacity Contribution[5]	Location	Existing or Contracted
Dufferin Wind Farm	97	13.6	Orangeville TS	Existing
Conestoga Wind Farm	67	10.8	D10H	Contracted (future i/s date unknown)

[5] Percentage of installed capacity is 14 % for wind generation

APPENDIX C: KWCG CUSTOMER & LDC LOAD FORECASTS

Table C1: KWCG 2015 RIP Load Forecast*

TS	LDC	Load Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambridge MTS #1	Cambridge & North Dumfries Hydro	Planning Demand	92.3	93.8	95.6	98.1	99.7	102.7	101.8	102.1	102.4	102.2	101.6
Galt TS	Cambridge & North Dumfries Hydro	Planning Demand	108.1	109.5	112.3	113.7	116.1	119.0	122.8	127.9	134.8	141.9	148.8
Preston TS-Note 1	Cambridge & North Dumfries Hydro	Planning Demand	108.0	100.3	102.0	104.4	105.9	108.7	109.6	111.8	111.9	111.5	111.8
Cambridge MTS # 2-Note	Cambridge & North Dumfries Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #6	Kitchener-Wilmot Hydro	Planning Demand	72.8	72.8	73.0	73.0	72.4	72.1	71.7	71.6	71.5	71.1	71.1
Kitchener MTS #8	Kitchener-Wilmot Hydro	Planning Demand	44.2	37.6	40.3	43.1	45.3	38.6	41.1	43.5	46.0	48.2	50.6
Kitchener MTS #3	Kitchener-Wilmot Hydro	Planning Demand	54.3	64.4	66.5	67.3	67.5	77.0	77.5	78.1	78.7	79.0	79.6
Kitchener MTS #7	Kitchener-Wilmot Hydro	Planning Demand	44.9	45.1	45.9	46.0	45.6	45.6	45.6	45.7	39.9	39.8	39.9
Kitchener MTS #5	Kitchener-Wilmot Hydro	Planning Demand	73.9	73.8	74.6	74.5	73.8	73.5	73.2	73.1	78.8	78.3	78.2
Detweiler TS	Kitchener-Wilmot Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener MTS #4	Kitchener-Wilmot Hydro	Planning Demand	67.8	68.2	69.1	69.3	69.0	69.0	68.9	69.2	69.3	69.1	69.3
Kitchener MTS #9	Kitchener-Wilmot Hydro	Planning Demand	33.7	33.9	34.3	34.6	34.5	34.7	34.9	35.0	35.3	35.4	35.5
Kitchener MTS #1	Kitchener-Wilmot Hydro	Planning Demand	29.1	29.6	31.1	31.6	31.8	32.1	32.4	32.9	33.3	33.5	33.9
Wolverton DS	Hydro One Distribution	Planning Demand	21.2	21.4	21.6	21.6	21.6	21.6	21.6	21.7	21.8	21.7	21.9
Fergus TS	Hydro One Distribution	Planning Demand	108.9	108.8	109.5	109.7	108.5	108.3	108.2	108.5	108.7	108.3	108.7
Puslinch DS	Hydro One Distribution	Planning Demand	35.6	36.2	36.8	37.3	37.5	37.9	38.3	38.7	39.2	39.5	39.9
Cedar TS T1/T2	Guelph Hydro	Planning Demand	72.3	74.9	75.8	77.4	78.3	79.5	79.8	82.2	84.6	85.5	87.9
Cedar TS T7/T8	Guelph Hydro	Planning Demand	30.2	32.0	32.0	32.8	32.3	33.0	33.7	33.4	34.2	34.8	35.5
Hanlon TS	Guelph Hydro	Planning Demand	29.8	30.7	31.6	32.5	33.0	33.7	34.4	35.1	34.9	35.5	35.3
Arlen MTS	Guelph Hydro	Planning Demand	30.0	33.0	37.0	40.9	33.3	37.9	41.4	43.0	44.6	45.9	47.5
Campbell TS	Guelph Hydro	Planning Demand	131.9	136.3	139.0	140.2	141.2	142.8	144.4	148.4	152.2	156.2	160.1
Scheifele MTS	Waterloo North Hydro	Planning Demand	169.0	166.0	170.7	150.3	151.2	152.7	154.3	156.2	158.1	153.4	155.4
Waterloo MTS #3	Waterloo North Hydro	Planning Demand	61.9	70.8	72.7	75.3	79.3	64.6	58.0	75.3	76.8	76.9	78.4
Snider MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	30.6	35.2	50.9	60.3	61.9	64.4	65.6	68.1
Bradley MTS-Note 2	Waterloo North Hydro	Planning Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	Waterloo North Hydro	Planning Demand	30.4	25.1	26.0	25.8	27.4	28.1	28.8	29.6	31.3	31.9	33.6
Rush MTS	Waterloo North Hydro	Planning Demand	54.9	63.8	65.7	67.4	67.4	67.8	69.1	53.0	53.6	60.7	61.3
Customer #1 CTS-Note 3	Customer Tx Stations	Planning Demand	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Customer #2 CTS	Customer Tx Stations (Assumed values)	Planning Demand	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Planning demand (MW) = ((Gross-CDM) x Extreme Weather Factor) – DG

*Based upon KWCG 2015 IRRP Planning Load Forecast except where otherwise noted.

Note 1: The LDC has confirmed 9.2 MW of cogeneration at a large customer to be accounted for in the Preston TS forecast starting year 2016. The generation plant is expect to run most of the time and would offset the customer's load. This cogeneration was not factored into the KWCG 2015 IRRP Planning Load Forecast.

Note 2: The LDC has confirmed that additional transformation capacity (Snider/Bradley TS) would not be required until after 2024. The exact location and timing of these TS's have not been determined at this time. The load growth indicated at Snider and Bradley in the forecast can be managed by existing TS's/impact of CDM/DG in the Waterloo Region. LDCs are monitoring the load closely to determine the timing of potential transformation needs. Where possible, these LDCs are exploring opportunities to coordinate use and development of TS facilities in the KWCG Region over the long term. Cambridge #2 is assumed to be supplied off the KWCG 115kV system

Note 3: Slight modification from KWCG 2015 IRRP Planning forecast based on information provided by the transmission-connected customer

Note: Guelph CTS 1 forecast was removed as the LDC confirmed the load was already accounted for within their forecast

APPENDIX D: TECHNICAL RESULTS – LOCAL AREA ANALYSIS

Single element contingencies were considered in order to determine the presence of thermal overload and/or voltage violations.

Table D1: Single Element Contingencies (single zone of protection)

Loss of a Single Circuit (N-1)					
D11K	D12K	D8S	D10H	D7F	D9F
F11C	F12C	B5G	B6G	D4W	D5W
M20D*	M21D**	D6V***	D7V****		
Loss of a Single Autotransformer (N-1)					
Detw. T2	Detw. T3♦	Detw. T4♦♦	Cedar T3♦♦♦	Cedar T4♦♦♦♦	Preston T2**
Middleport T3♦♦♦♦♦		Middleport T6♦♦♦♦♦♦			

Loss of a Single HV Reactive Element (N-1)			
Detweiler 230 kV cap. bank	Middleport 230 kV cap. bank(K1D1)	Orangeville 230 kV cap. bank	Burlington 230 kV cap. bank
Detweiler 230 kV SVC	Middleport 230 kV cap. bank(K2D2)	Detweiler 115 kV cap bank	Burlington 115 kV cap bank

*M20D (includes Detweiler T3 and Preston T2 via Preston Special Protection Scheme)

**M21D (includes Preston T2)

***D6V (includes Detweiler T4 and Cedar T3)

****D7V (includes Cedar T4)

♦Detweiler T3 (includes circuit M20D and Preston T2 via Preston SPS)

♦♦Detweiler T4 (includes circuit D6V and Cedar T3)

♦♦♦Cedar T3 (includes circuit D6V and Detweiler T4)

♦♦♦♦Cedar T4 (includes circuit D7V)

♦♦♦♦♦Middleport T3 (includes circuit N580M and V586M due to Line End Open)

♦♦♦♦♦♦Middleport T6 (includes circuit N581M and M585M due to Line End Open)

Results: Thermal Overload and Voltage Violations

Table D3: Thermal Analysis (>100% LTE), year 2025

Element	Contingency	%LTE
All circuits and auto-transfers are within ratings		

Table D4: Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX E: TECHNICAL RESULTS – BULK POWER SYSTEM CONSIDERATIONS

Applicable contingencies were considered on BPS elements to establish their impact on the local area.

Table E1: N-2 Contingencies

Loss of a Double Circuit Line (N-2) emanating from a BPS station		
B22D and B23D	D4W and D5W	M20D and M21D
D6V and D7V	--	--
Breaker Failure (B/F) Contingencies at BPS station (N-2)		
Detweiler TS 230 kV bus	B/F of AL6	Loss of: D6V, Cedar T3, Detw T4, M21D, Preston T2
	B/F of AL7	Loss of: D7V, Cedar T4, M21D, Preston T2
	B/F of L7L20	Loss of: D7V, Cedar T4, M20D, Detw T3, Preston T2
	B/F of HT1A	Loss of: M21D, Preston T2, SVC1
	B/F of ACS21	Loss of : M21D, Preston T2, SC21
	B/F of HL20	Loss of: M20D, Detw T3, D5W, SC22
	B/F of T2SC21	Loss of: Detw T2, SC21
	B/F of HT2	Loss of: Detw T2, SC21, D5W
	B/F of DL22	Loss of: B22D, D6V, Cedar T3, Detw T4
Middleport TS 500 kV bus	Covered under Loss of Middleport T3 and T6 autotransformers for the local area analysis (Appendix D)	
Middleport TS 230 kV bus	There are no B/F conditions that would be critical to the supply to the KWCG area.	

Table E2: N-1-1 Contingencies

Loss of a Critical Element, System Adjustment, Loss of a Critical Element (N-1-1)
Loss of: Detw T4 plus Detw T3 (plus M20D by configuration which also includes the loss of Preston T2 via Preston SPS)
Loss of: Preston T2 plus D7V (plus Cedar T4 by configuration)

Note that during the simulations no System Adjustment was afforded; this is considered a conservative approach.

Results: Thermal Overloads and Voltage Violations

As per Table E3 and E5: Detweiler TS 230/115 kV autotransformer T2 will become overloads when Detweiler TS autotransformer T4 is out-of-service followed by the loss of Detweiler TS autotransformer T3 in conjunction with circuit M20D by configuration. Preston TS autotransformer T2 is also removed from service via the Preston SPS.

Table E3: Thermal Analysis (>95% LTE), year 2016

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	104.4 (74.2% STE*) %

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E4: Voltage Analysis, year 2016

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

Table E5: Thermal Analysis (>95% LTE), year 2025

Element	Contingency	%LTE
Detweiler TS T2 autotransformer	Detweiler T4 plus Detweiler T3 with M20D (includes Preston T2 via Preston SPS)	114.2 (81.4%STE*)

*STE rating of Detweiler T2 auto-transformer is 396 MVA.

Table E6 Voltage Analysis, year 2025

Element	Contingency	%Voltage Decline	Voltage kV
All voltages are within criteria			

APPENDIX F: LOAD SECURITY ANALYSIS

Load connected to each circuit pair that is lost by configuration following an [N-2] double circuit contingency is:

Table F1: Load Lost Due to Configuration, year 2016

Circuit Pair	MW
M20/21D	420
D6/7V	482
D4/5W	34
D7/9F	131
F11/12C	74
B5/6G	105
D11/12K	98
D8S/D10H	89

Table F2: Load Lost Due to Configuration, year 2025

Circuit Pair	MW
M20/21D	489
D6/7V	571
D4/5W	36
D7/9F	141
F11/12C	78
B5/6G	128
D11/12K	103
D8S/D10H	95[6]

Table F1 illustrates that none of the double circuit contingencies result in more than 482 MW of load lost in year 2016.

Table F2 illustrates that none of the double circuit contingencies result in more than 571 MW of load lost in year 2025.

[6] D8S and D10H emanate out of Detweiler TS as a double circuit line however after ~ 5 km they each become a single circuit 115 kV line. Based on their N/O open points, the loss of the double circuit line within the 5 km span out of Detweiler TS, will results in approximately 95 MW of load lost.

Table F3: Two Elements Out of Service

Loss of a Double Circuit Line		
D7F and D9F	F11C and F12C	B5G and B6G
D4W and D5W	M20D and M21D	D11K and D12K
D6V and D6V		

Loss of Two Autotransformers[7]				
Station	**Detweiler Auto**	**Preston Auto**	**Cedar Auto**	**Burlington Auto**
Detweiler Auto	N/A	Detweiler T3 + Preston T2	Cedar T3 + Detweiler T4	Burlington T6 + Detweiler T3
Preston Auto	Detweiler T3 + Preston T2	N/A	Cedar T4 + Preston T2	Burlington T6 + Preston T2
Cedar Auto	Cedar T3 + Detweiler T4	Cedar T4 + Preston T2	Cedar T3 + Cedar T4	Burlington T6 + Cedar T3
Burlington Auto	Burlington T6 + Detweiler T3	Burlington T6 + Preston T2	Burlington T6 + Cedar T3	N/A

Results: Thermal Overload and Voltage Violations

Table F5: Thermal Analysis (>100% STE), year 2025

Element	**Contingency**	**%STE**
All circuits and auto-transfers are within ratings		
Element	**Contingency**	**%LTE**
All circuits and auto-transfers are within ratings		

Table F6: Voltage Analysis (> emergency ratings), year 2025

Element	**Contingency**	**%Voltage Decline**	**Voltage kV**
All voltages are within criteria			

7 For stations that have three or more autotransformers connected in parallel typical operating practice after the loss of one autotransformer is to make load transfers to other interconnected autotransformer station(s) such that the remaining load at the affected station would be at or below the station's reduced Limited Time Rating (LTR). It is assumed the in this case that sufficient time between single autotransformer contingencies is available for such load transfers to be carried out by operator response.

APPENDIX G: LOAD RESTORATION ANALYSIS

Restoration of Load Connected to M20/21D

By year 2025 the total forecasted load connected to circuits M20/21D is 489 MW. Loss of this double circuit line would result in the loss of all 489 MW. In order to restore load to these stations at least one circuit would have to be placed back in service**,** noting that to restore Customer #1 CTS circuit M21D must specifically be placed back in service due to the customer's single-circuit transmission-connection

Based on criteria:

Load Required to be Restored	Duration
239MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Existing infrastructure allows for only the restoration of 100 MW of load in approximately 30 min. 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.

Restoration of Load Connected to D6/7V

By year 2025 the total forecasted load connected to D6/7V is 571 MW. Loss of this double circuit line would result in the loss of all 571 MW. As part of the Guelph Area Transmission Reinforcement project, two 230 kV in-line switches will be installed in year 2016 on the main line between Detweiler TS and Orangeville TS at Guelph North Junction. To restore load to these stations, the operator will utilize these switches 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.

Based on criteria:

Load Required to be Restored	Duration
321MW	30 min.
100 MW	Within 4 hrs.
150 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and

3. the relative distance from the nearest field maintenance centre[8]

the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D4/5W

By year 2025 the total forecasted load connected to D4/5W is 36 MW. Loss of this double circuit line would result in the loss of all 36 MW. To restore load to this station at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
36 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D7/9F

By year 2025 the total forecasted load connected to D7/9F is 141 MW. Loss of this double circuit line would result in the loss of all 141 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
141 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

---

[8] The KWCG area is considered an urban area and as such, access to transmission facilities, repair materials and personnel in order to make a repair within 8 hours is realistic. A Hydro One field maintenance centre is located in Guelph.

Restoration of Load Connected to F11/12C

By year 2025 the total forecasted load connected to F11/12C is 78 MW. Loss of this double circuit line would result in the loss of all 78 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
78 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to B5/6G

By year 2025 the total forecasted load connected to B5/6G is 128 MW. Loss of this double circuit line would result in the loss of all 128 MW. To restore load to Enbridge Westover CTS's circuit B5G must be placed back in service due to the CTS's single-circuit transmission connection. To restore load at the other stations at least one circuit would to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
128 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

Restoration of Load Connected to D11/12K

The total forecasted load serviced by radial circuits D11/12K will not exceed 103 MW by 2025. Loss of this double circuit line would result in the loss of all 103 MW. To restore load to these stations at least one circuit would have to be placed back in service.

Based on criteria:

Load Required to be Restored	Duration
103 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

<u>Restoration of Load Connected to D8S/D10H</u>

The total forecasted load serviced by these radially operated 115 kV circuits will not exceed approximately 95 MW by year 2025. Loss of this double circuit line would result in loss of all 95MW. To restore Rush MTS either circuit can be placed back into service or the station could possibly be fed via circuit L7S out of Seaforth TS; however to restore Elmira TS circuit D10H must be placed back in service due to Elmira TS's single-circuit transmission-connection.

Based on criteria:

Load Required to be Restored	Duration
95 MW	Within 8 hrs.

Depending on:

1. the severity of the double circuit contingency;
2. the prevailing system conditions and
3. the relative distance from the nearest field maintenance centre

the load restoration criteria can be met. Therefore, no additional transmission restoration capability is warranted at this time.

APPENDIX H: SUPPLY TO ELMIRA TS AND RUSH MTS

Study Results:

Table H1: Station Capacity: Summer Ratings and Summer Load Forecast

Station	Transformer Capacity (10-day LTR)	Year 2025 Load Forecast
Rush MTS	69 MVA*	61.3 MW / 69.9 MVA (0.88 pf** at defined meter point, 115 kV side)
Elmira TS	58.5 MVA	33.6 MW / 37.1 MVA*** (0.91 pf at defined meter point, 115 kV side)

*The limiting component is a low voltage cable; when required the limiting component will be modified and the rating to be 75 MVA

** Power factor at the defined meter point improves to 0.92 when 5.4 MVar of installed feeder capacitor banks assumed lumped at the LV bus and results in 66.8 MVA loading

*** A 9.2 MVar @ 27.6 kV shunt capacitor bank is installed at Elmira TS not in-service; when in-service power factor improves and loading through the transformers decrease.

Table H2: Transmission Capacity of circuits D8S and D10H

Year	Contingency	D10H – Detweiler TS x Waterloo Jct.	D8S – Detweiler TS x Leong Jct.
		590 A Continuous *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*	*590 A Continuous* *640 A Long-Term Emergency (LTE)* *660 A Short-Term Emergency (15-min.)*
2016	Pre	287 A	285 A
	Loss of D8S	454 A	--
	Loss of D10H	--	459 A
2025	Pre	319 A /	302 A
	Loss of D8S	511	--
	Loss of D10H	--	500 A

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Table H3: Voltage Profile at Rush MTS and Elmira TS

Year	Contingency	Rush MTS 115 kV D8S	Rush MTS 115 kV D10H	Rush MTS 13.8 kV	Elmira TS 115 kV	Elmira TS 27.6 kV
2016	Pre	122.2	122.2	14.4	120.8	27.2
	Loss of D8S	--	121.8	13.7	120.6	27.1
	Loss of D10H	121.5	--	13.7	--	--
2025	Pre	123.2	123.1	14.2	121.6	27.3
	Loss of D8S	--	122.6	13.6	121.1	27.2
	Loss of D10H	122.4	--	13.6	--	--

-assume all St. Mary's TS load is supplied by D8S (as this is more conservative for the study), assume Conestogo Wind Farm not-service (as it would displace load on D10H) and the normally-open point on D10H is between Elmira TS and Palmerston TS

Analysis:

D8S

Circuit D8S has a normally open point at St. Mary's TS separating the circuit from circuit L7S. D8S normally supplies half the load at Rush MTS and half the load at St. Mary's TS. The other half of the load at Rush MTS is normally supplied by circuit D10H and the other half of the load at St. Mary's TS is normally supplied by L7S. Referring to Table H2, for the loss of circuit D10H, circuit D8S has sufficient capacity to supply all load at Rush MTS and St. Mary's TS for year 2025 and beyond.

D10H

Circuit D10H runs between Detweiler TS and Hanover TS and has a normally open point between Elmira TS and Palmerston TS. Elmira TS is normally supplied from Detweiler TS while Palmerston TS is normally supplied from Hanover TS. Referring to Table H2, D10H has sufficient capacity to supply all load at Elmira TS for year 2025 and beyond. When circuit D8S is out of service, D10H has sufficient capacity to supply all load at Elmira TS and Rush MTS (while St. Mary's TS is supplied by circuit L7S).

Rush MTS

Since this station is a Municipal owned station, Waterloo North Hydro is to ensure there is sufficient transformation capacity to accommodate load growth. According to load forecasts and referring to Table H1, over the next 10-years load will fluctuate above and below the year 2025 forecast but will be remain within the station's Limited Time Rating (LTR). Waterloo North Hydro is to inform Hydro One if the connection requires modification and/or if a new station connection is required in order to accommodate load growth. Waterloo North Hydro has already incorporated their future Snider MTS and Bradley MTS into the KWCG regional plan to cater for load growth.

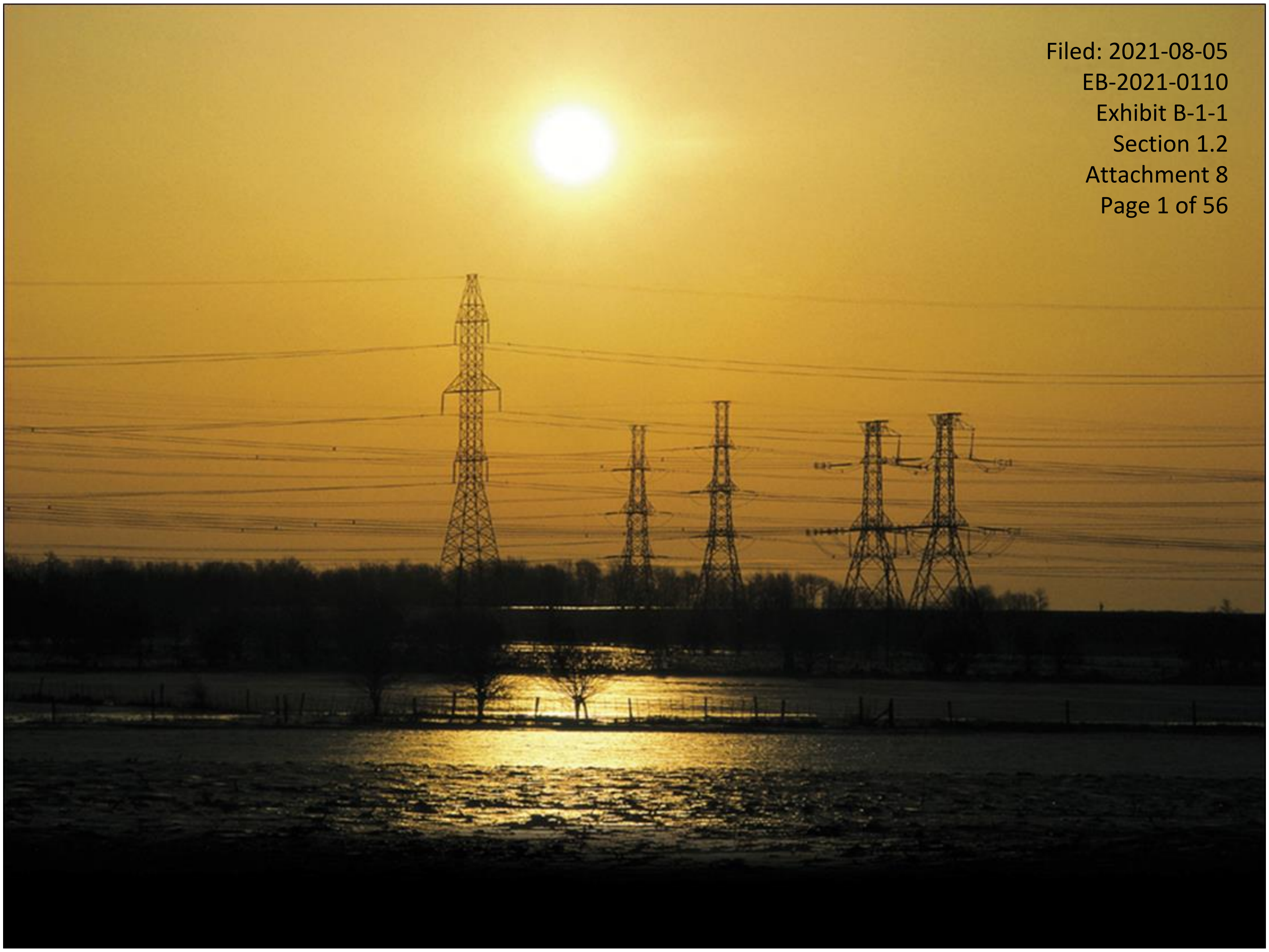
Rush MTS is supplied by two 115 kV circuits, D8S and D10H. Referring to Tables H2 and H3, when one of these circuits is out of service, the voltage profile at Rush MTS is healthy and the other circuit has sufficient capacity to supply all load to Rush MTS.

Elmira TS

According to the forecast and referring to Table H1, transformers at Elmira TS have sufficient capacity for year 2025 loading and beyond.

Elmira TS is supplied by one 115 kV circuit, D10H. Referring to Tables H2 and H3, the voltage profile at Elmira TS is healthy and the circuit has sufficient capacity to supply load to Elmira TS for year 2025 loading and beyond.

When circuit D10H out of Detweiler TS is unavailable, Elmira TS may also be supplied by D10H out of Hanover TS (by closing the normally open point between Palmerston TS and Elmira TS). Assuming Palmerston TS is at its forecasted year 2025 normal weather peak load, approximately 25 MW of load at Elmira TS may be supplied out of Hanover TS. The limiting factor being the 115 kV voltage profile on D10H as Elmira TS is nearly 80 circuit km from Hanover TS.



Toronto

REGIONAL INFRASTRUCTURE PLAN

March 6, 2020

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Prepared and supported by:

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

DISCLAIMER

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

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

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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 TORONTO REGION.

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

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

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

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

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

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

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

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

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

The Study Team recommends that:

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

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1 INTRODUCTION

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

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

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

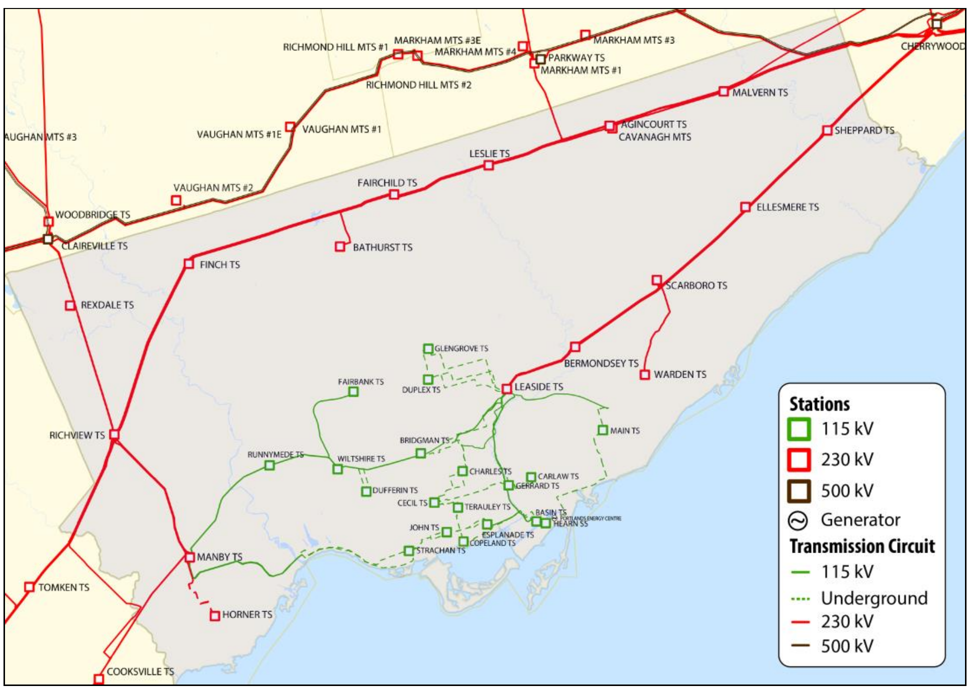

Figure 1-1: Toronto Region Map

1.1 Objectives and Scope

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

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

- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

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[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

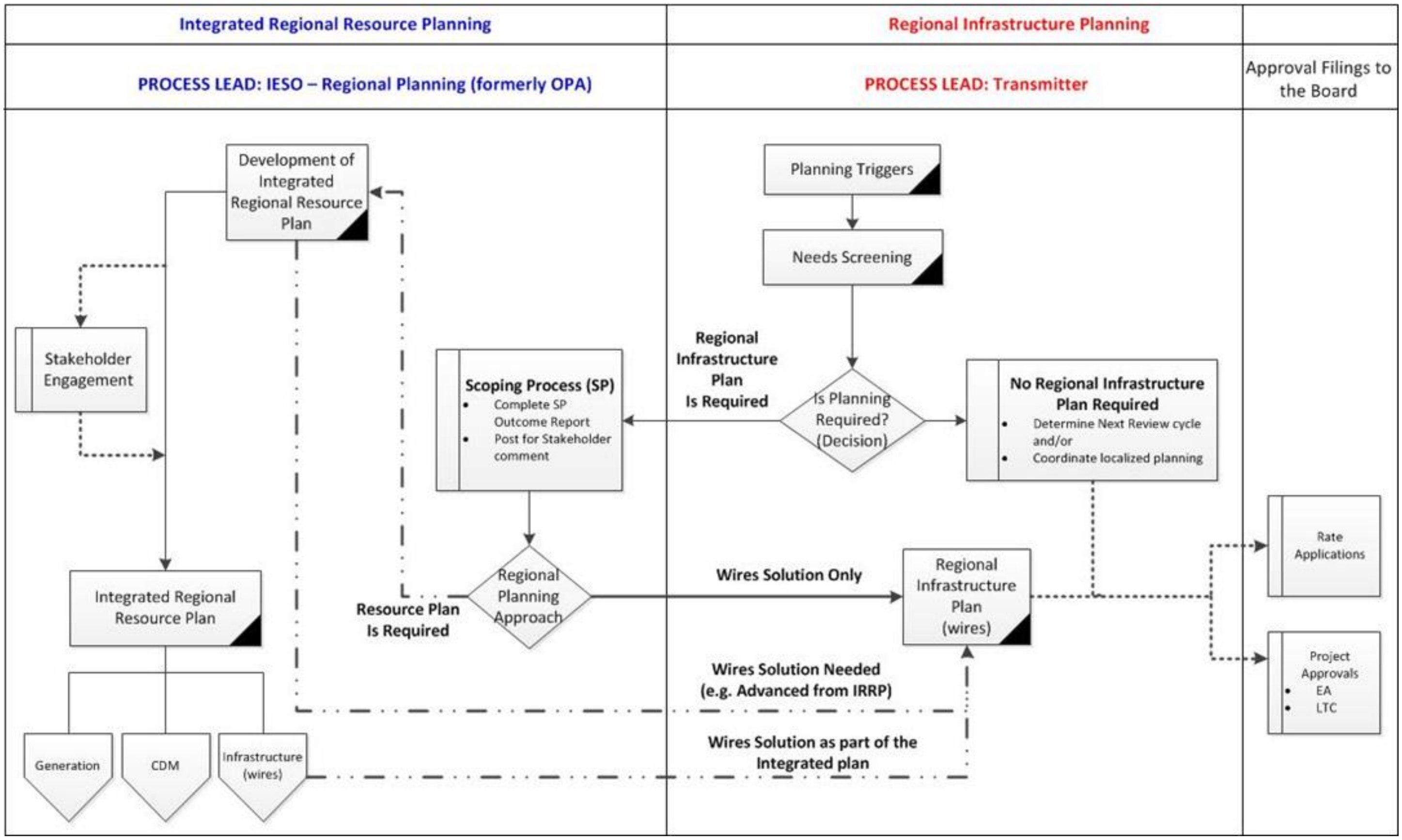


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

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

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

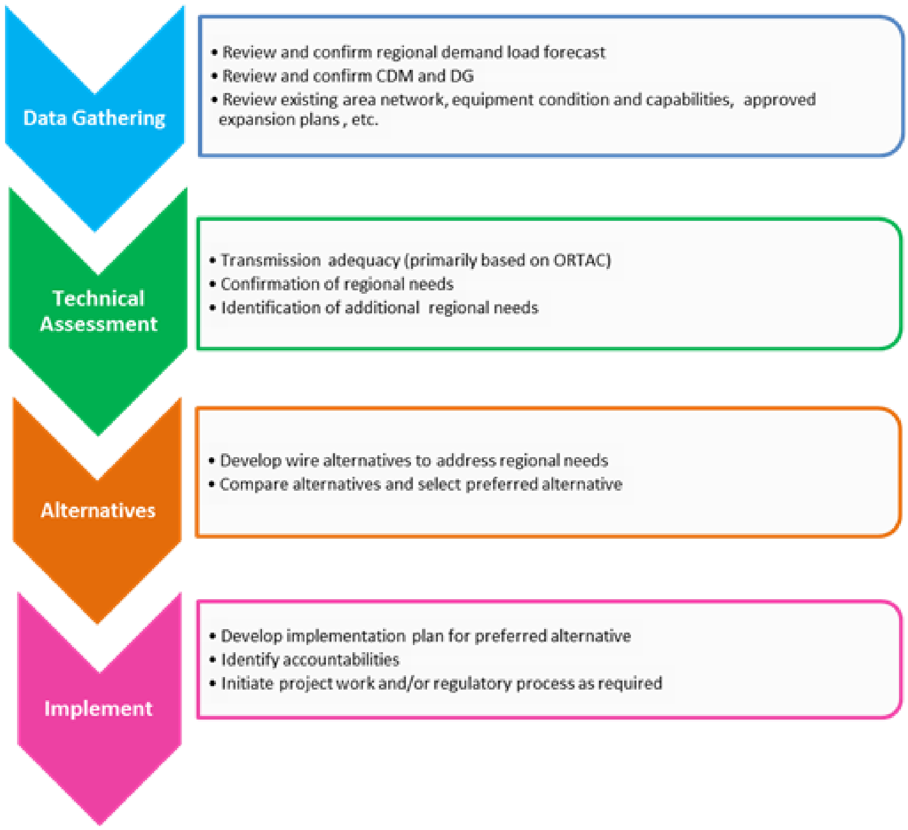


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

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

Bulk electrical supply to the Toronto Region is provided through three 500/230 kV transformers stations at Claireville TS, Cherrywood TS, and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near the Downtown area and connected to the 115 kV network at Hearn Switching Station ("SS"). The Toronto Region summer coincident peak demand in 2018 was about 4,660 MW which represents about 20% of the gross total demand (23240 MW) in the province.

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

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

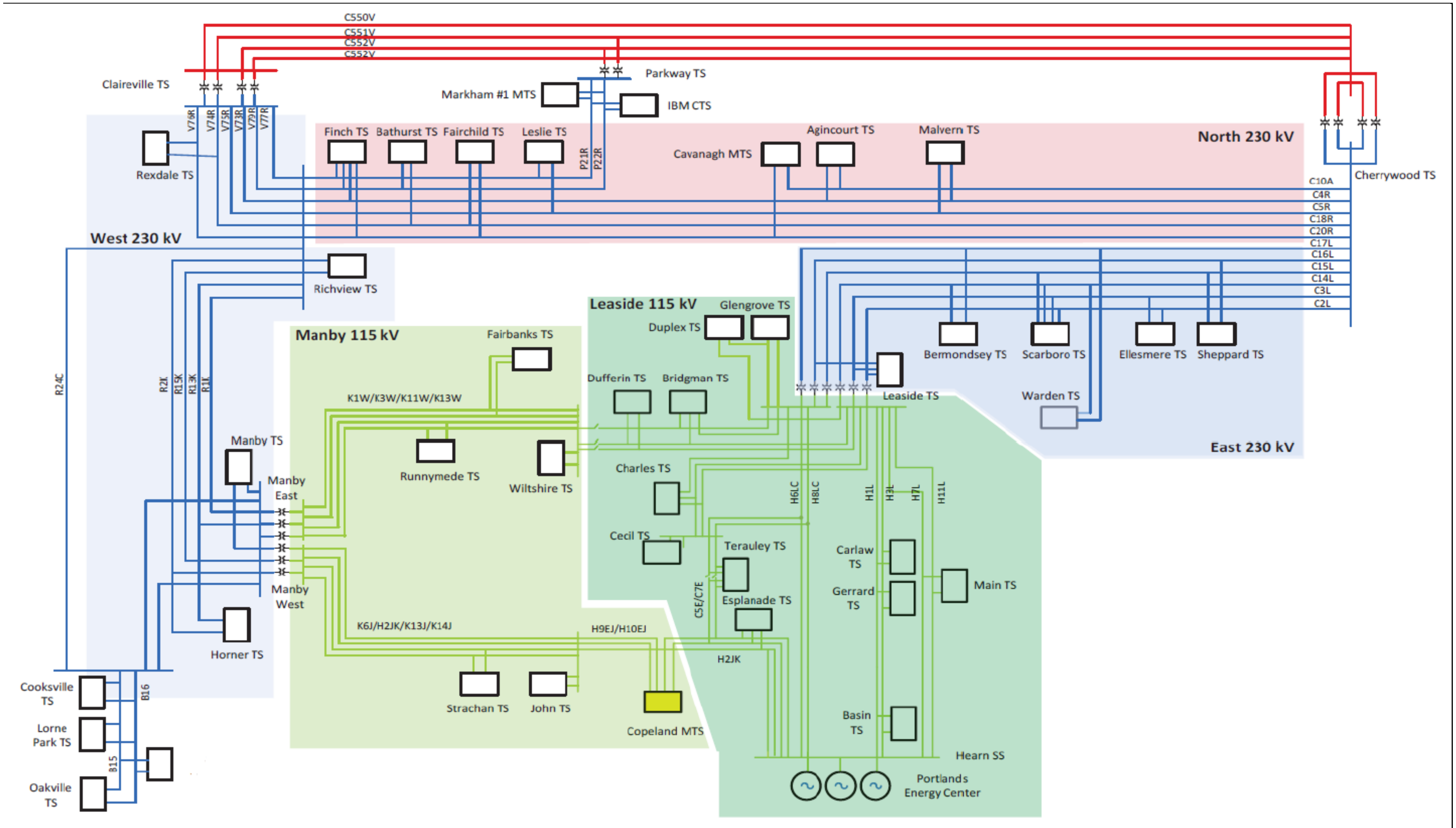


Figure 3-1: Single Line Diagram of Toronto Region's Transmission Network

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

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

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

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

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

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

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

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

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

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

- 115 kV Switchyard Work at Hearn SS, Leaside TS, and Manby TS (2013, 2014) – Includes replacement of the aging 115 kV switchyard at Hearn SS with a new gas-insulated switchgear ("GIS") and replacement of all 115 kV oil breakers at Leaside TS and Manby TS.

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

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

- Midtown Transmission Reinforcement Project (completed in 2016) – Covered replacement of the aging L14W underground cable and addition of a new 115 kV circuit between Leaside TS and Bridgman TS.

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

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

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

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

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

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

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

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

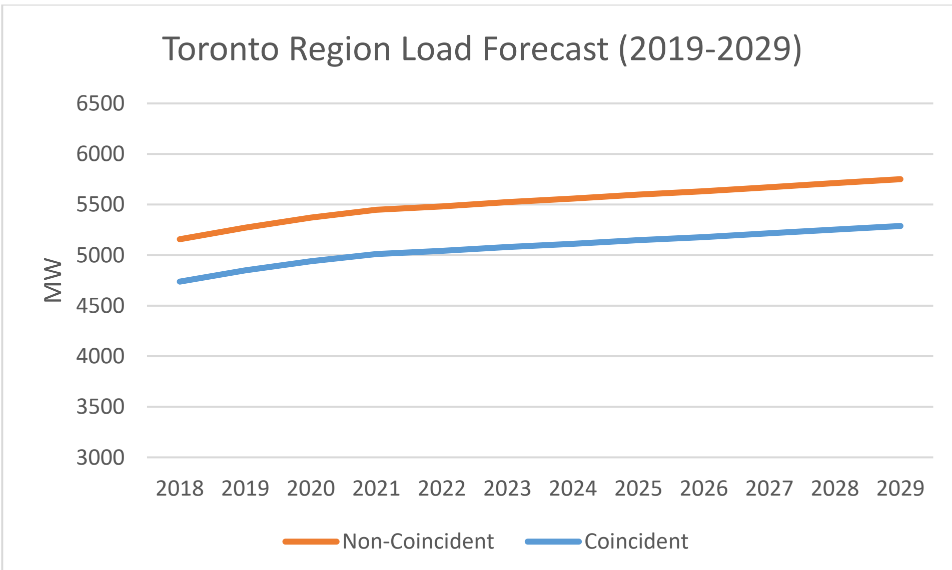


Figure 5-1: Toronto Region Load Forecast

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

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

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect three Traction Power Substation (TPSS) to Hydro One's 230 kV circuits in Toronto area for GO Transit electrification – Mimico TPSS to K21C and K23C close to Manby TS; City View TPSS to V73R and V77R north of Richview TS; and Scarborough TPSS to C2L and C14L at Scarboro TS. Metrolinx have advised that their current electrification schedule is uncertain and new facilities would be built likely beyond 2023. Appendix F of the 2019 Toronto IRRP ("Richview TS x Manby TS Study") verified that the reinforcement of Richview TS to Manby TS Transmission Corridor is required by 2021 and that Metrolinx new load do not affect the need and timing of the project. After the completion of Richview TS to Manby TS Transmission Reinforcement, the new TPSS loads can be connected without need of any new facilities.

6 ADEQUACY OF EXISTING FACILITIES

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

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

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

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

Table 6-1: New Facilities Assumed In-Service

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

6.1 230 kV Transmission Facilities

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

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

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

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

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

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

6.2 230/115 kV Autotransformers Facilities

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

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

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

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

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

6.3 115 kV Transmission Facilities

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

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

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

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

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

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

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

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

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

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

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

6.4 Step-Down Transformer Station Facilities

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

Table 6-2: Toronto Step-Down Transformer Stations

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

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

6.5 Longer Term Outlook (2030-2040)

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

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

Table 6-3: Longer Term Adequacy of Transmission Facilities

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

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

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

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

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

7 REGIONAL NEEDS AND PLANS

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

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

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

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

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

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

7.1 Main TS: End-of-Life Transformers

7.1.1 Description

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

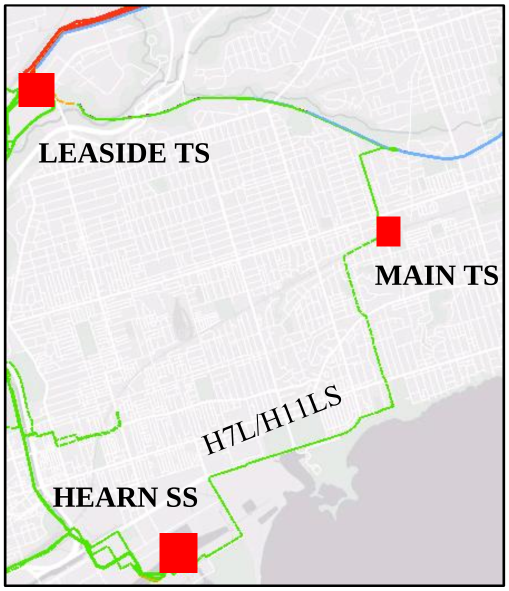


Figure 7-1: Main TS

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

7.1.2 Alternatives and Recommendation

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

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

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

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

7.2.1 Description

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

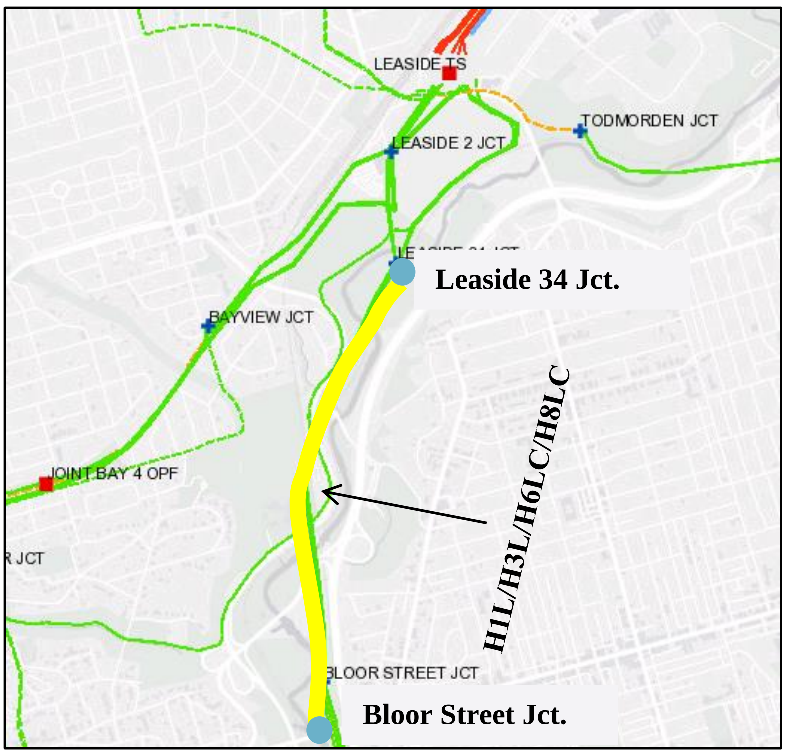


Figure 7-2: H1L/H3L/H6LC/H8LC Section between Leaside 34 Jct. and Bloor St. Jct.

7.2.2 Alternatives and Recommendation

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

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

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

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

7.3.1 Description

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

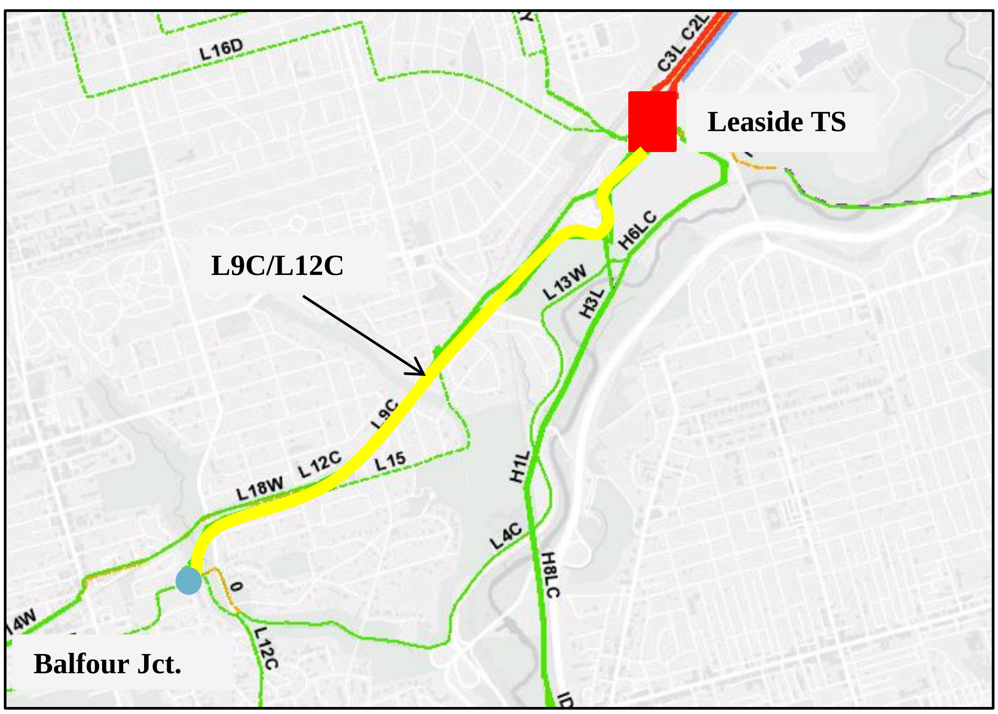


Figure 7-3: L9C/L12C Section between Leaside TS and Balfour Jct.

7.3.2 Alternatives and Recommendation

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

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

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

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

7.4.1 Description

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

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

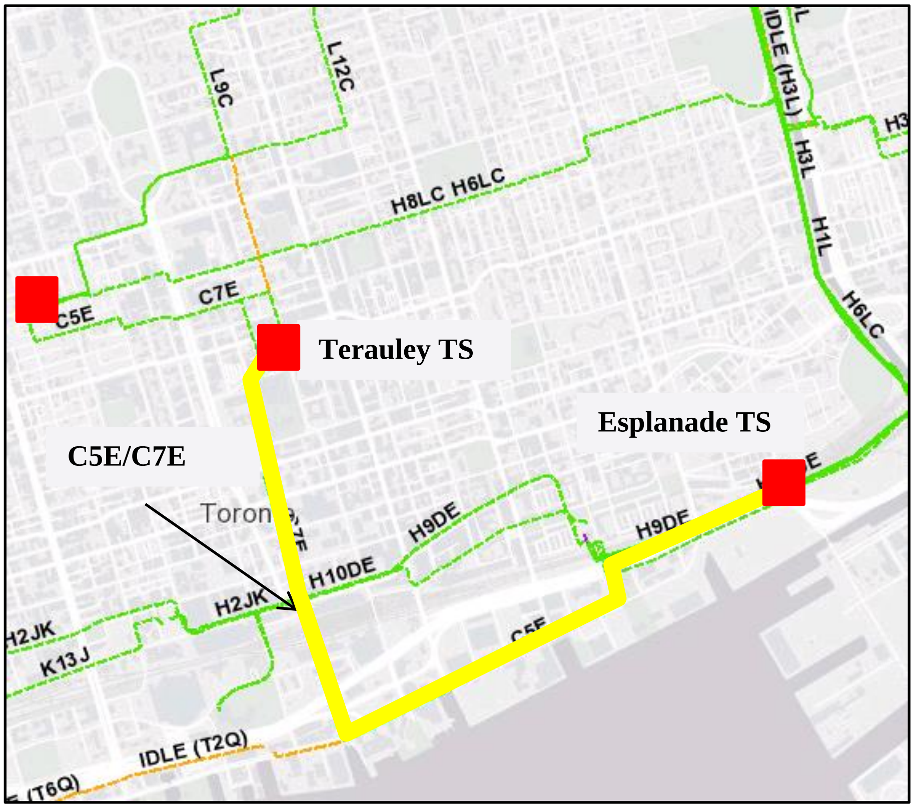


Figure 7-4: C5E/C7E Underground Cable Section between Esplanade TS and Terauley TS

7.4.2 Alternatives and Recommendation

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

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

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

7.5 Richview TS to Manby TS 230 kV Corridor

7.5.1 Description

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

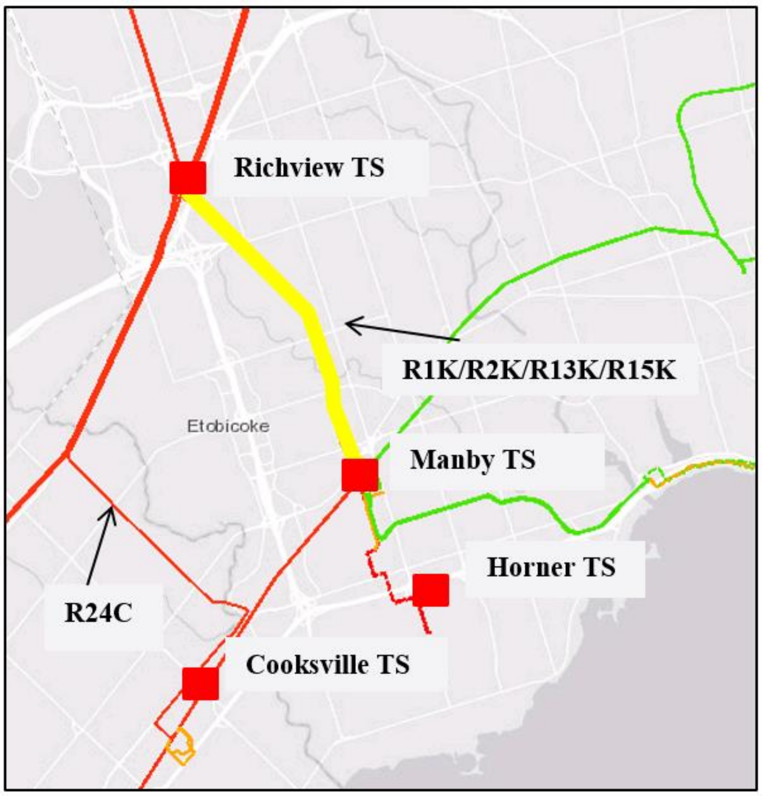


Figure 7-5: Richview TS to Manby TS 230 kV Corridor

7.5.2 Alternatives and Recommendation

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

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

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

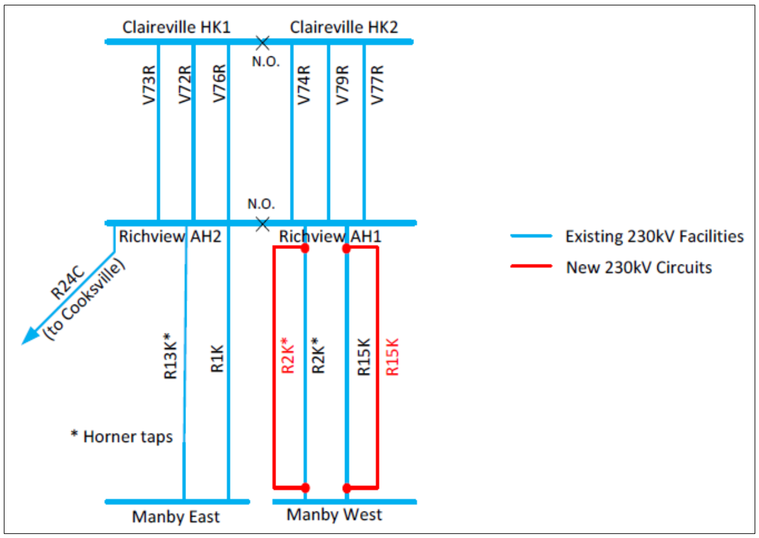


Figure 7-6: Richview TS to Manby TS 230 kV Corridor – Phase 1

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

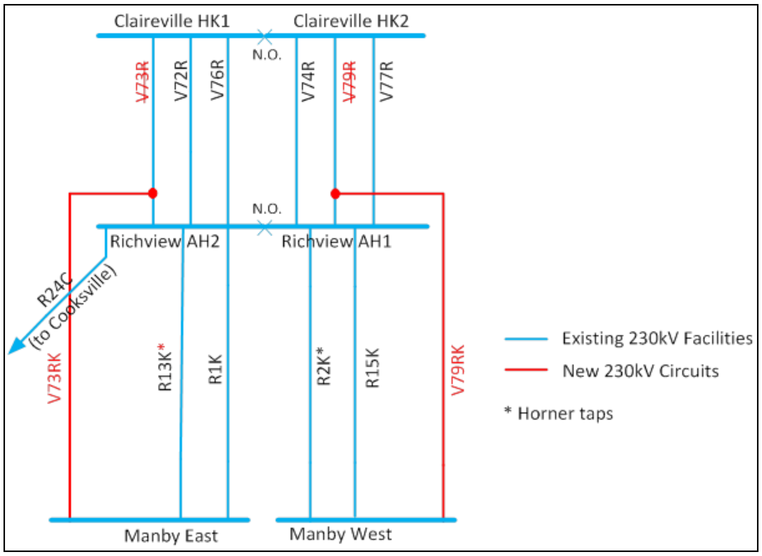


Figure 7-7: Richview TS to Manby TS 230 kV Corridor – Phase 2

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

7.6.1 Description

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

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

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

Figure 7-8: Manby TS

7.6.2 Alternatives and Recommendation

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

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

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

7.7 Bermondsey TS: End-of-Life Transformers

7.7.1 Description

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

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

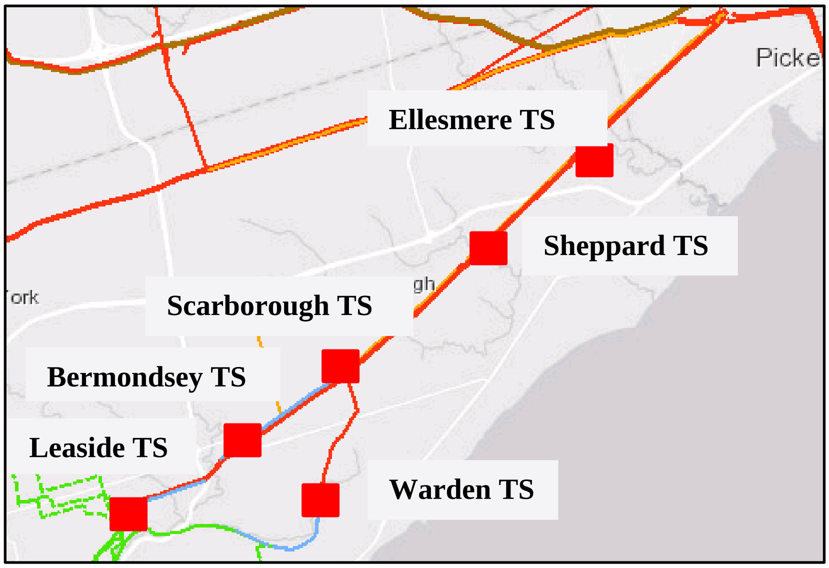


Figure 7-9: Bermondsey TS and Surrounding Stations

7.7.2 Alternatives and Recommendation

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

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

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

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

7.8.1 Description

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

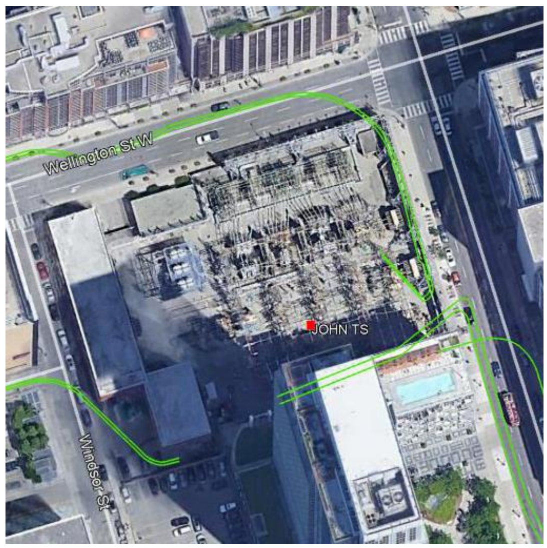


Figure 7-10: John TS

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

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

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

7.8.2 Alternatives and Recommendation

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

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

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

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

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

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

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

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

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

7.9 Long-Term Capacity Needs

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

7.9.1 Fairbank TS Capacity Need

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

7.9.2 Sheppard TS Capacity Need

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

7.9.3 Strachan TS Capacity Need

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

7.9.4 Basin TS Capacity Need

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

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

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

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

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

7.9.5 Manby West TS to Riverside Jct. Corridor Capacity Need

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

7.9.6 Manby West TS Autotransformers T12 Capacity Need

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

7.9.7 Leaside TS to Wiltshire TS Corridor Capacity Need

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

7.9.8 Leaside TS Autotransformers T16 Capacity Need

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

8 CONCLUSIONS AND NEXT STEPS

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

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

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

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

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

The Study Team recommends that:

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

9 REFERENCES

[1] **Metro Toronto Regional Infrastructure Plan (2016)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/RIP%20Report%20Metro%20Toronto.pdf

[2] **Toronto Region Needs Assessment (2017)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

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

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

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

APPENDIX A. STATIONS IN THE TORONTO REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15
Dufferin TS T2/T4	115/13.8	L13W/L15
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R
Fairchild TS T3/T4	230/27.6	C18R/C20R

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

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

APPENDIX B. TRANSMISSION LINES IN THE TORONTO REGION

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	D11J, D12J, H9DE, H10DE	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

APPENDIX C. DISTRIBUTORS IN THE TORONTO REGION

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

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
Alectra Utilities	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
	Richview TS	Dx
Elexicon Energy Inc.	Malvern TS	Dx
	Sheppard TS	Dx

APPENDIX D. TORONTO REGION LOAD FORECAST

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

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

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

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

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

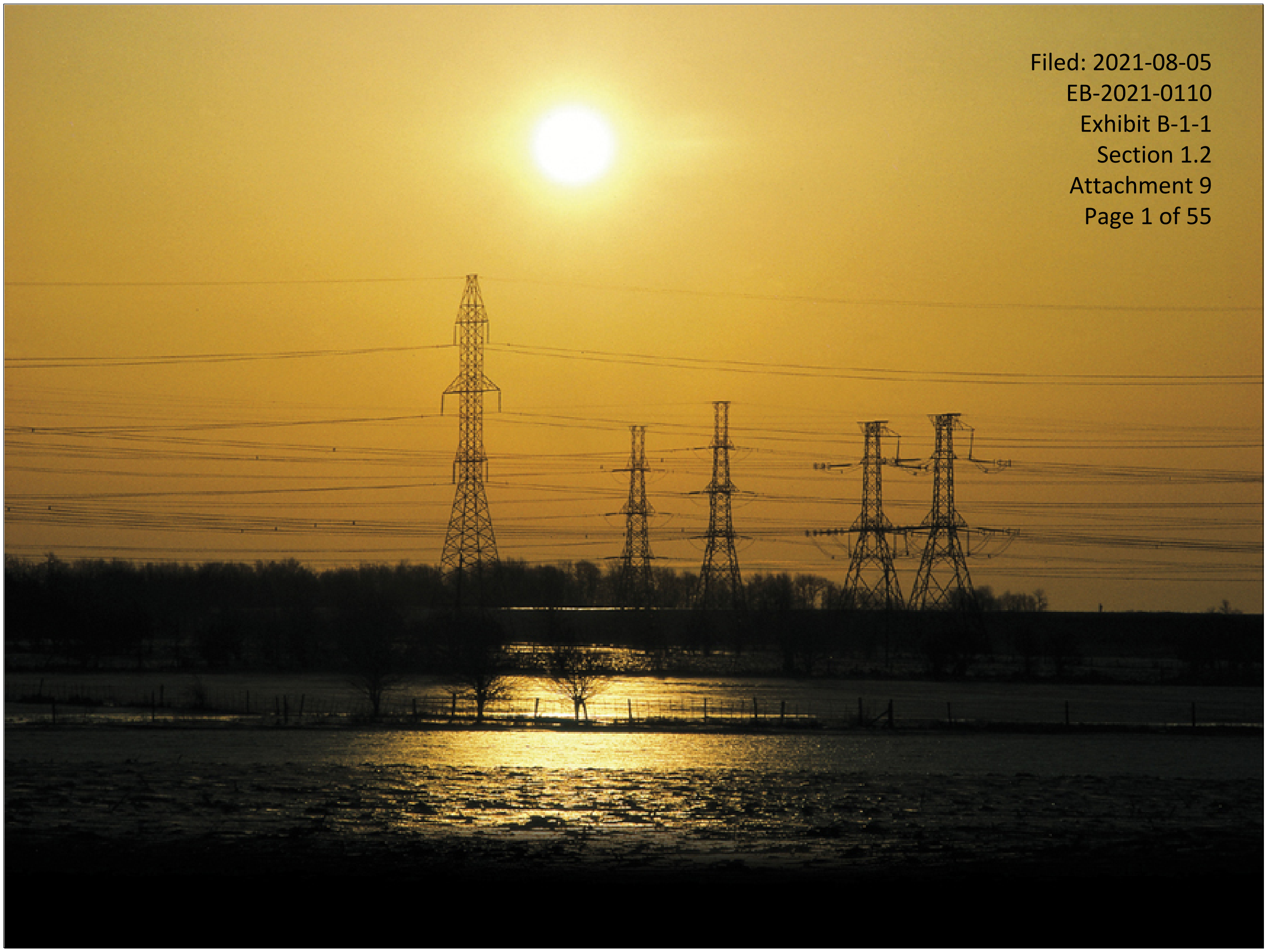
Table D-3: Toronto IRRP Load Forecast, with the Impacts of Energy-Efficiency Savings

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

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

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

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



Northwest Ontario

REGIONAL INFRASTRUCTURE PLAN

June 9, 2017

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Prepared by:
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Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
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Thunder Bay Hydro Electricity Distribution Inc.
Sioux Lookout Hydro Inc.
Fort Frances Power Corporation

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DISCLAIMER

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

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

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

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EXECUTIVE SUMMARY

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

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

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Atikokan Hydro Inc.
- Kenora Hydro Electric Corporation Ltd.
- Thunder Bay Hydro Electricity Distribution Inc.
- Sioux Lookout Hydro Inc.
- Fort Frances Power Corporation

This RIP is the final phase of the regional planning process and it follows the completion of Integrated Regional Resource Plan ("IRRP") by the IESO for the North of Dryden Sub-Region in January 2015, Greenstone-Marathon Sub-Region in June 2016, and West of Thunder Bay in July 2016 and for Thunder Bay Sub-Region in December 2016 [2-5]. This report also references the IESO Draft Remote Community Connection Plan report [6].

This RIP provides a consolidated summary of needs and recommended plans for North of Dryden, Greenstone-Marathon, West of Thunder Bay, and Thunder Bay Sub -Regions that make up the Northwest Ontario Region. The potential needs of the bulk system is not within the scope of the Regional Planning, however, some aspects of the bulk system needs and plans are discussed in this report in the context of regional plans.

The Working Group has reassessed and updated the LDC load forecasts, which have remained consistent with the forecasts used in the IRRPs. Accordingly, this RIP has confirmed the needs and the proposed or recommended infrastructure (wires) plans for the sub-regions as indicated in the IRRP reports.

The needs in the region are largely driven by the industrial load growth, particularly the mining sector. Considering the uncertainties in the forecast of the industrial loads, this RIP uses the forecast scenarios and assumptions developed for the Northwest IRRPs. The connection of remote communities to the electricity grid, as well as the load growth as a result of economic developments, are also contributing factors. Since the development timelines and plans for connection of the mining and other industrial loads are uncertain and frequently depend on the customer decision, the IRRP and RIP have both considered low, medium (or reference) and high load growth scenarios and identified alternatives and recommended plans to address the needs under each scenario in near-term (present-5 years), mid-term (5-10 years) and long term (10-20 years).

The following is the summary of the currently recommended or proposed near/mid/long-term wires plans for the sub-regions under low, medium and high load growth scenarios. The current status of these plans is also indicated in the following.

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

[1] The Medium growth scenario for North-of-Dryden sub-region corresponds to the “Reference Scenario” in the IRRP
[2] The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario “A” of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario “B” of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario “D” of Greenstone, scenario “C” of Marathon and scenario “A” of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

West of Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	Need	Wires Options	Load Growth	Term	Status
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

The IRRP for Thunder Bay sub-region identified a near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This upgrade has been completed in Q4 2016.

Most of the above plans are highly dependent on the needs of industrial customers in the region. Proceeding to the Development phase for the customer-driven projects requires request by, and agreement with, the customer(s). Currently, only Project No. 1 has proceeded to the Development phase. The only supply point in the region which is presently at its load-meeting capability limit is Pickle Lake and Project No. 1 will address the need at this location.

Additionally, the IESO Draft Remote Community Connection Plan report [6] has recommended the connection of 21 First Nations communities in the northern part of the region to the electricity grid. An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's transmitter licence to develop and seek approvals for the connection of sixteen remote communities and the Dryden-Pickle Lake transmission line, i.e. Project No. 1 identified above.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. There is adequate time to review the proposed or recommended plans to meet the long-term needs and develop preferred alternatives in the next planning cycle. Should there be a need that emerges prior to the next planning cycle such as but not limited to change in load forecast, the regional planning cycle will be started earlier 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 NORTHWEST ONTARIO REGION.

The report was prepared by Hydro One Networks Inc. - Transmission ("Hydro One") with input and on behalf of the Working Group that consists of Hydro One, Hydro One Networks Inc. - Distribution, the Independent Electricity System Operator ("IESO"), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Thunder Bay Hydro Electricity Distribution Inc., Sioux Lookout Hydro Inc. and Fort Frances Power Corporation in accordance with the Regional Planning process established by the Ontario Energy Board in 2013.

Northwest Ontario region is divided into 4 sub-regions: City of Thunder Bay, West of Thunder Bay, North of Dryden, and Greenstone-Marathon. The IESO has also assessed the economic case for connecting the Remote Communities north of Red Lake and Pickle Lake to the provincial grid. Electrical supply to the Region is provided by fifty two 230kV and 115kV transmission and distribution stations. Some of the stations are shown in Figure 1-1.

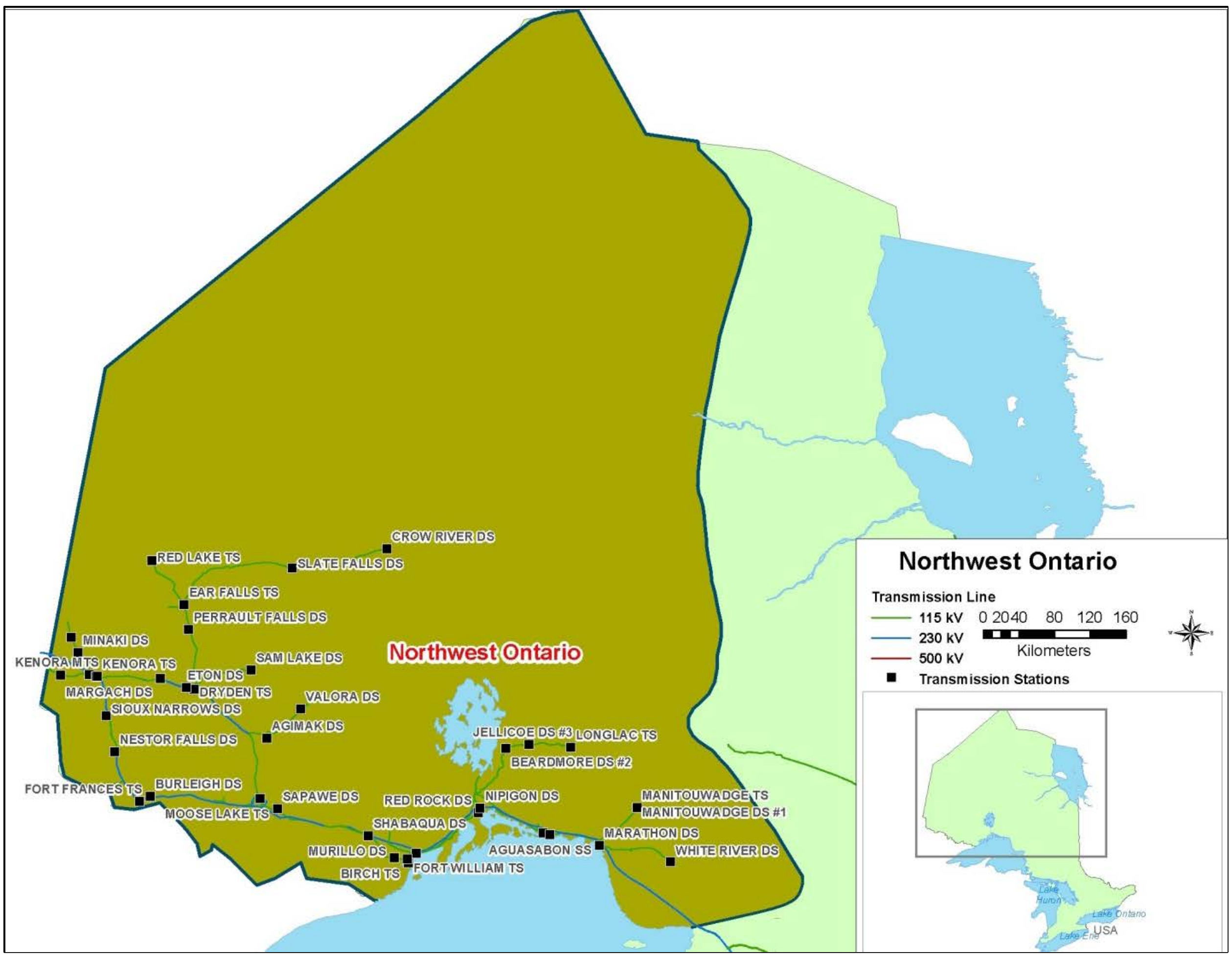


Figure 1-1 Map of Northwest Ontario Region

1.1 Scope and Objectives

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

- Review of needs (near and medium-term) identified through the IRRP process.
- Develop a wires plan to address all needs where wires solution is the most appropriate.
- Discuss long-term needs identified during the planning process

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

The scope of this RIP is as follows:

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

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 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 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 [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. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address one or more of the needs. If no further regional coordination is required and localized needs cannot be met by non-wires solutions, 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 localized needs. Ultimately, local plans are also incorporated into the RIP report.

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 and/or different needs.

The IRRP phase will generally assess integrated alternatives consisting of infrastructure (wires) and/or resource (CDM and Distributed Generation). Detailed information regarding wires options may not be available or necessary within the scope of the IRRP. The level of detail for wires options as part of the IRRP will be to a level which is 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 refine the assessment of specific wires alternatives, and recommend a preferred

[3] Also referred to as Needs Screening.

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 may establish Local Advisory Committees (LAC) in the region or sub-region. For the Northwest Ontario Region, community engagement through a number of LACs is on-going.

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

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

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

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

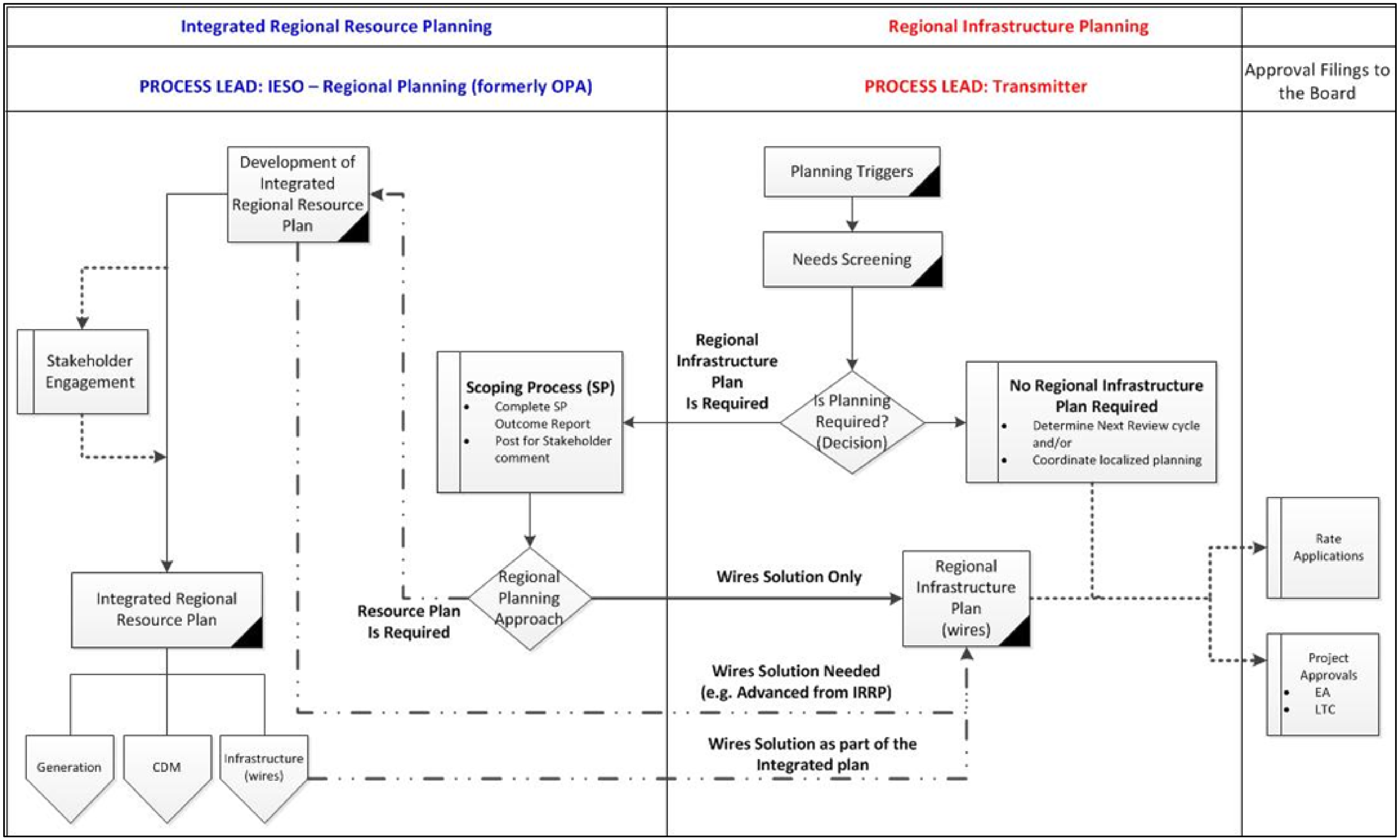


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

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

The extent and scope of each step naturally depends on the outcome of the previous step. The outcome of the previous stage of the regional planning process, i.e., IRRP, also influences the scope of Step 2 to a large extent.

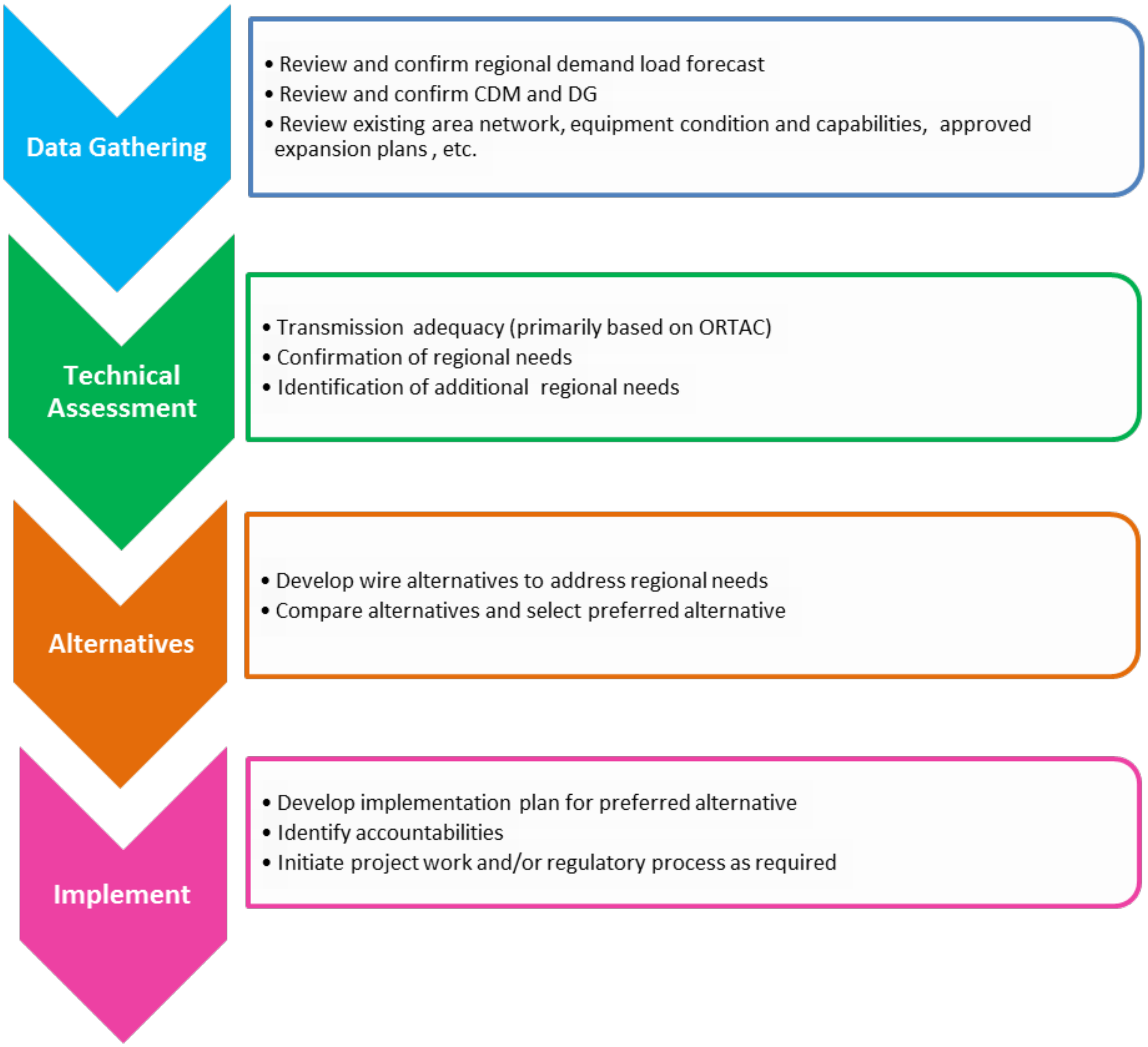


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

NORTHWEST ONTARIO REGION IS ROUGHLY BORDERED 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.

Bulk electrical supply to the Northwest Ontario Region is provided through a combination of local generation stations connected to the 230 kV and 115 kV network, and the East-West Tie transmission corridor.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Kenora Hydro Electric Corporation Ltd., Sioux Lookout Hydro Inc., Thunder Bay Hydro Electricity Distribution 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.

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 LDC. A map and a single line diagram showing the electrical facilities of the Northwest Ontario Region, consisting of the sub-regions, is shown in Figure 3-1 and Figure 3-2, respectively.

3.1 North of Dryden Sub-Region

A radial single-circuit 115 kV transmission line ("E4D") supplies electricity to the customers in the North of Dryden sub-region from Dryden TS. The major supplying station for this sub-region is Dryden TS, where the voltage is stepped down from the 230 kV to 115 kV, to serve local and industrial customers. Electricity demand in the North of Dryden sub-region is also supplied by local hydroelectric generation.

3.2 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 two 230 kV lines - W21M and W22M. Marathon TS steps down 230 kV to 115 kV and supplies customers in the

Town of Marathon, White River and Manitouwadge through a 115 kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS.

Alexander SS connects Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS - to the system. A 115 kV single-circuit A4L, connected to the Alexander SS, supplies electricity to the Municipality of Greenstone and its surrounding areas. Nipigon GS is also connected to the circuit A4L.

3.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230 kV transmission system consisting of the Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230 kV to 115 kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230 kV transmission lines – K21W and K22W. Fort Frances TS steps down 230 kV to 115 kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115 kV transmission line – F3M. Dryden TS steps down 230 kV to 115 kV 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 230 kV to 115 kV 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

3.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230 kV step-down transformation facility which steps down 230 kV to 115 kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115 kV by three step-down transformer stations - Birch TS, Fort William TS, and Port Arthur TS #1.

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

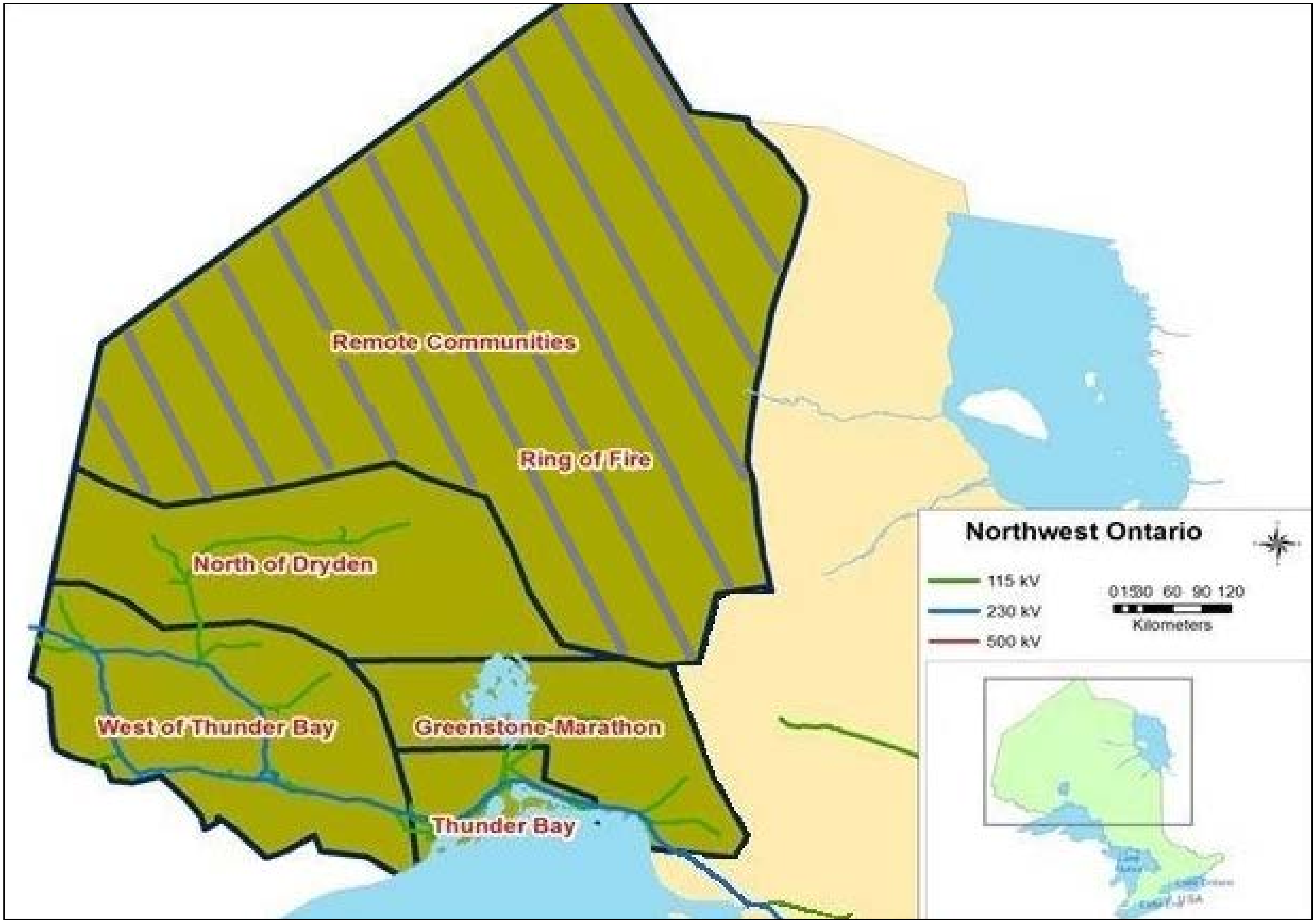


Figure 3-1 Northwest Ontario Region – Supply Areas

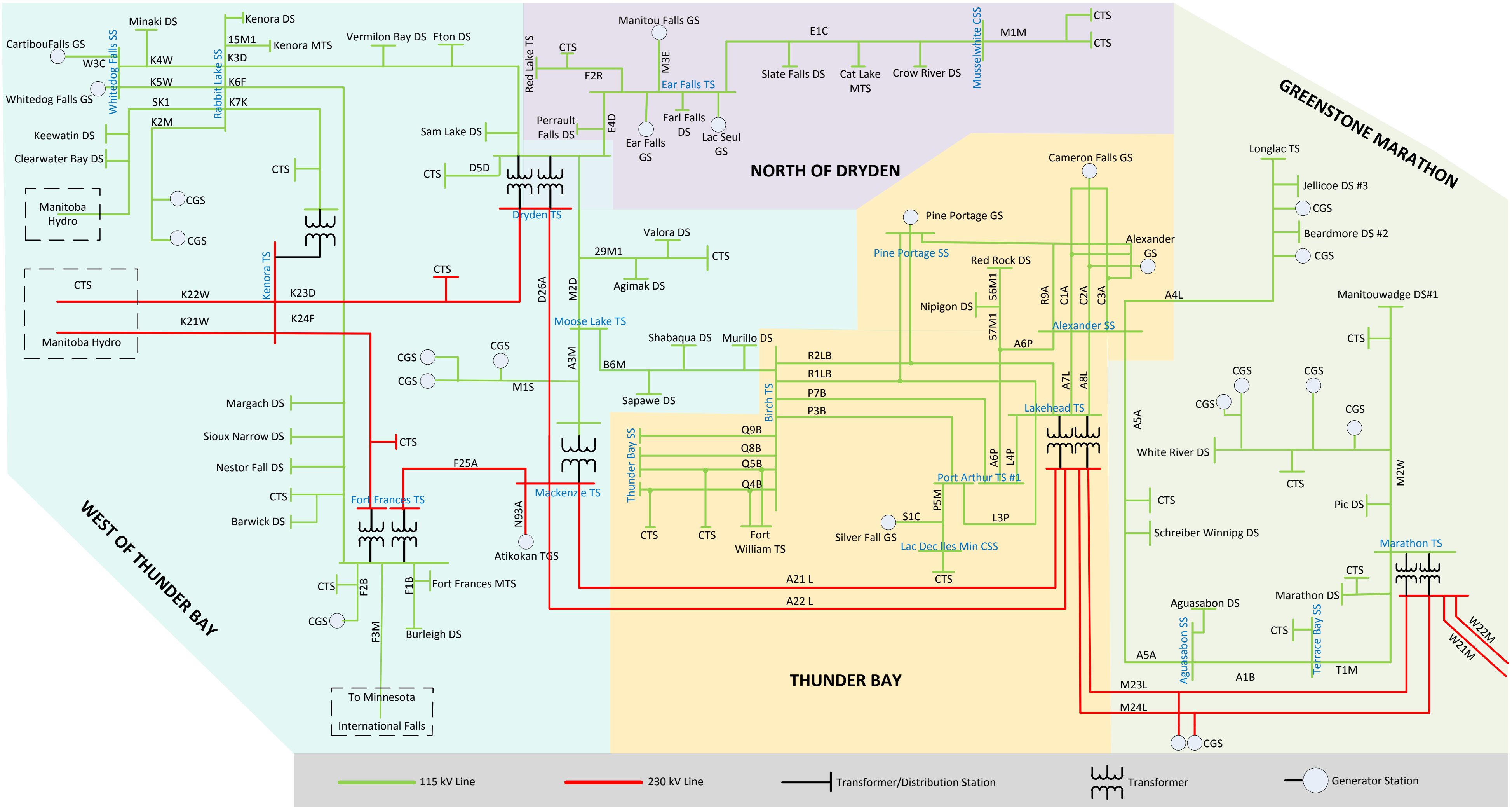


Figure 3-2 Northwest Ontario Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS AND PLANNED FOR NEAR FUTURE

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, ARE UNDERWAY, OR ARE PLANNED FOR THE COMING YEARS, AIMED AT IMPROVING THE SUPPLY TO THE NORTHWEST ONTARIO REGION IN GENERAL.

This section describes the completed development and sustainment projects in the region, as well as the sustainment projects that are in the execution stage or planned for the coming years.

4.1 Past Major Projects

In the past 10 years, the following are some of the major projects completed in the Northwest Ontario Region.

1. **Barwick TS** –Barwick TS was built in the second and third quarter of 2013 to replace load-serving facilities at Fort Frances TS as majority of these assets were reaching the end of their useful life. The new facilities include: two 42 MVA 115/44 kV transformers and the associated breakers, switches, surge arresters, etc. and two cap banks, each rated 4.9 MVAR at 44 kV, and the associated breakers and switches.

2. **Birch TS –** One of three 42 MVA step down transformers (115/25 kV) at Birch TS was replaced in December 2015.

3. **Dryden TS** – In addition to replacing 5 HV breakers, 2 LV breakers and 12 switches between 2014-2016, 2x40 MVAR Shunt reactors at Dryden TS were installed in Q3 2014.

4. **Fort Frances** – In addition to replacing 2 LV breakers and 8 switches (2010-2016), 21.6 MVAR/13.8 kV capacitor bank was installed at Fort Frances in November 2010.

5. **Kenora TS** – 1 LV breaker and 4 switches were replaced between 2009 and 2015.

6. **Lakehead TS** – 3 HV breakers, 1 LV breaker, 5 switches, and 1 autotransformer (230/13.9 kV) were replaced between 2009 and 2016 as part of the sustainment work. In addition, one synchronous condenser at Lakehead TS was replaced by a +60/-40 MVAR SVC in December 2009.

7. **Longlac TS** –Transformers T2 and T3 were replaced with two 42 MVA 115/44 kV transformers and associated equipment protections i.e. breakers, switches, surge arresters, etc. In addition, four capacitor banks; each rated at 4.9 MVAR at 44 kV with associated breaker and switches were installed. This work was completed mid-2011.

8. **Manitouwadge TS** – 1 LV breaker, 1 switch, and 1 step down transformer (115/44 kV) were replaced in July 2016.

9. **Marathon TS** – In addition to replacing 1 HV breaker, 2 LV breakers, and 4 switches between 2009 and 2016, 2x40 MVAR shunt reactors were installed in December 2013 and March 2014.

10. **Moose Lake TS** – 5 HV breakers were replaced in 2014.

11. **Port Arthur TS #1** – 10 switches were replaced between 2009 and 2015. In addition, 2x0.5 ohms LV current limiting reactors were replaced with 2x1 ohm reactor. Work was completed in December 2014.

12. **Rabbit Lake SS** – 2 HV breakers and 4 switches were replaced between 2011 and 2016.

13. **Red Lake TS** –Five capacitor banks were upgraded by 2.5 MVAR each to 7.4 MVAR (at 44 kV). This work also included upgrading associated breakers and switches and was completed between December 2015 and July 2016.

4.2 Current or Planned Major Sustainment Projects

The following major sustainment projects are currently under execution or planned for the coming years. These projects are based on the assessment of end of life issues of the aging station's equipment and replacing those that represent risk to the security of the bulk transmission system and reliability for connected customers.

1. **Dryden TS**– is located in the city of Dryden and supplies majority of the customers in the area. It consists of three 115/44 kV power transformers rated at 15MVA each, which are non-standard units and are about 69 years old.

   Hydro One has planned to replace the three EOL transformers with two new standard-size transformers, rated at 42MVA each. The scope of work also includes the replacement of other deteriorating infrastructure, such as LV switchyard (which will be built to current standard), 115 kV OCBs, and select switches.

   This project is currently planned to be completed in 2018.

2. **Ear Falls TS** – supplies customers in the city of Ear Falls in the North of Dryden Sub-Region, through a single transformer T5 (115/44 kV, 19 MVA), backed-up by a spare transformer T5SP (115/44 kV, 8 MVA). The 44 kV LV voltage is further stepped-down to 12.5 kV through Ear Falls DS transformer T1 (44/12.5 kV). Ear Falls TS transformers T5 and T5SP are approximately 47 and 69 years old, respectively, while Ear Falls DS T1 is currently 49 years old.

   Hydro One has planned to eliminate the need for 44 kV to 12.5 kV conversion at Ear Falls DS by replacing T5 and T5SP transformers with 115/13.2 kV transformer units (rated at 12.5 MVA each). The scope of work also involves replacing 44kV equipment with 13.2 kV, replacing 115 kV circuit breakers, and replacing EOL protections, controls, and telecom in new relay building to ensure the integrity of power system protection is maintained.

   This project is currently planned to be completed in 2018.

3. **Alexander SS** – is a 115 kV switching station located in the Thunder Bay Sub-Region and was originally built in 1955. The station terminates five 115 kV circuits for the supply of customers in the area and connects 161 MW of generation from the Nipigon River and Cameron Falls. It consists of ten 115 kV breakers, nine of which are non-standard.

Hydro One has planned to replace all non-standard and EOL equipment at the station. The scope of work involves replacing 115 kV oil circuit breakers with new SF6 breakers, replacing select switches, upgrade of all protection & control facilities and AC station service system.

This project is currently planned to be completed in 2019.

4. **Birch TS** – is a 115 kV transmission station located in City of Thunder Bay in the Thunder Bay Sub-Region and was put in-service in 1955. Birch TS is comprised of a DESN station which supplies local load in the port area of Thunder Bay, as well as being a 115 kV bulk station with 9 lines and the three DESN transformers connected to it.

   Due to the criticality of the station to both transmission and distribution systems, protection and control equipment that is presently located in the basement will be relocated to a new relay building. The scope of work involves replacing 115 kV circuit breakers and 25 kV capacitor banks, and replacing/relocating end of life protections in the new relay building.

   This project is currently planned to be completed in 2019.

5. **Pine Portage SS** – is a 115 kV switching station located in the Greenstone-Marathon Sub-Region and was put in-service in 1954. The switching station has three outgoing 115 kV transmission lines connecting to Lakehead TS, Birch TS and Alexander SS. Pine Portage GS is also connected to this switching station.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing five 115 kV oil circuit breakers with new 2000A SF6 breakers, associated disconnect switches, protection, control and teleprotection facilities.

   This project is currently planned to be completed in 2020-2023.

6. **Aguasabon SS** – is a 115 kV switching station in Greenstone-Marathon Sub-Region and was put in-service in 1948. The station has two transmission lines connecting to Alexander SS and Terrace Bay SS. The station is also critical to the connection of Aguasabon DS.

   Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service, and replacing equipment protections.

   This project is currently planned to be completed in 2021-2024.

7. **Port Arthur TS #1** – Port Arthur TS #1 is a 115/25 kV station located in the Thunder Bay Sub-Region and was put in-service in 1950.

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing AC/DC station service systems, 25kV switchyard and associated protection equipment in the new building, and 115 kV associated protection equipment in the existing building

   This project is currently planned to be completed in 2021-2024.

8. **Rabbit Lake SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has seven 115 kV 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 115 kV oil circuit breakers and two 115 kV SF6 circuit breakers in the yard.

Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing EOL 115 kV circuit breakers, select switches, and equipment protections.

This project is currently planned to be completed in 2021-2024.

9. **Terrace Bay SS** – is located in the Greenstone-Marathon Sub-Region and was put in-service in 1973. The switching station has two 115 kV transmission lines connecting to Marathon TS and Aguasabon SS. The station is also critical to the connection of a Customer Transformer Station (CTS).

   Hydro One has planned to replace all end of life equipment at the station. The scope of work involves replacing protections, controls, telecom, select switches, and AC/DC station service system.

   This project work is currently planned to be completed in 2021-2024

10. **Whitedog Falls SS** – is a 115 kV switching station located in the West of Thunder Bay Sub-Region. The switching station has three 115 kV transmission lines, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing 115 kV circuit breakers and select switches. In addition, scope of work includes replacing/upgrading of DC station supply system.

    This project is currently planned to be completed in 2021-2024.

11. **Moose Lake TS** – is a 115/44 kV transformer station built in 1948. It is located on Moose Lake near Atikokan in the West of Thunder Bay Sub-Region. Moose Lake TS consists of two non-standard step-down transformers T2 and T3 rated at 8MVA and 15MVA, respectively. In addition, the two transformers are 69 years old.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing the two non-standard power transformers (T2, T3) with standard 110-44 kV, 25/41.7 MVA units, two low voltage oil circuit breakers with new SF6 breakers, and replacing and upgrading the protection, control and AC/DC station service facilities

    This project is currently planned to be completed in 2022-2025

12. **Kenora TS** – is a 230/115 kV station located in the West of Thunder Bay Sub-Region and critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing/upgrading AC/DC station service systems and replacing protection equipment.

    This project is currently planned to be completed in 2024-2027.

13. **Mackenzie TS** – is a 230/115 kV station is located in the West of Thunder Bay Sub-Region. Mackenzie TS has six 230 kV breakers which are about 46 years old.

Hydro One has planned to replace all EOL equipment at the station. The scope of work involves replacing 230 kV circuit breakers, select protections, and AC/DC station service system.

This project is currently planned to be completed in 2024-2027.

14. **Fort Frances TS** – is located in the Town of Fort Frances and was put in-service in 1947.

    Hydro One has planned to replace the EOL equipment at the station. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service system and protection equipment.

    This project is currently planned to be completed in 2025-2028.

15. **Lakehead TS** – is a 230/115 kV transformer station located in the Thunder Bay Sub-Region and was put in-service in 1955. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer.

    Hydro One has planned to replace all EOL equipment at the station to ensure 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 four LV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115 kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

    This project is currently planned to be completed in 2025-2028.

16. **Marathon TS** – is a 230/115 kV transformer station, located in the City of Marathon in the Greenstone-Marathon Sub-Region. It was put in-serviced in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115 kV oil circuit breakers at the station are about 40 years old. Whereas, three 230 kV circuit breaker at the station are about 48 years old.

    Hydro One has planned to replace all EOL equipment at the station to ensure reliability of the transmission system and supply to customers. The scope of work involves replacing three EOL 230 kV circuit breakers with new SF6 breakers, and four EOL 115 kV circuit breakers with new SF6 breakers. In addition, the scope of work also includes replacing disconnect switches, protection equipment, and AC station service system.

    This project is currently planned to be completed in 2025-2028.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast Scenarios

For the purpose of this RIP, the LDCs reviewed their load forecasts and confirmed that they have not changed significantly from the load forecasts reported in the Northwest IRRPs. Based on the load forecasts from the LDCs and the industrial (mining) load forecasts of the Northwest IRRPs, three scenarios of future demand has been considered for each Northwest sub-region in this RIP. Table 5-1, Table 5-2, Table 5-3, and Table 5-4 show the forecasted load for the Low, Medium and High growth scenarios.

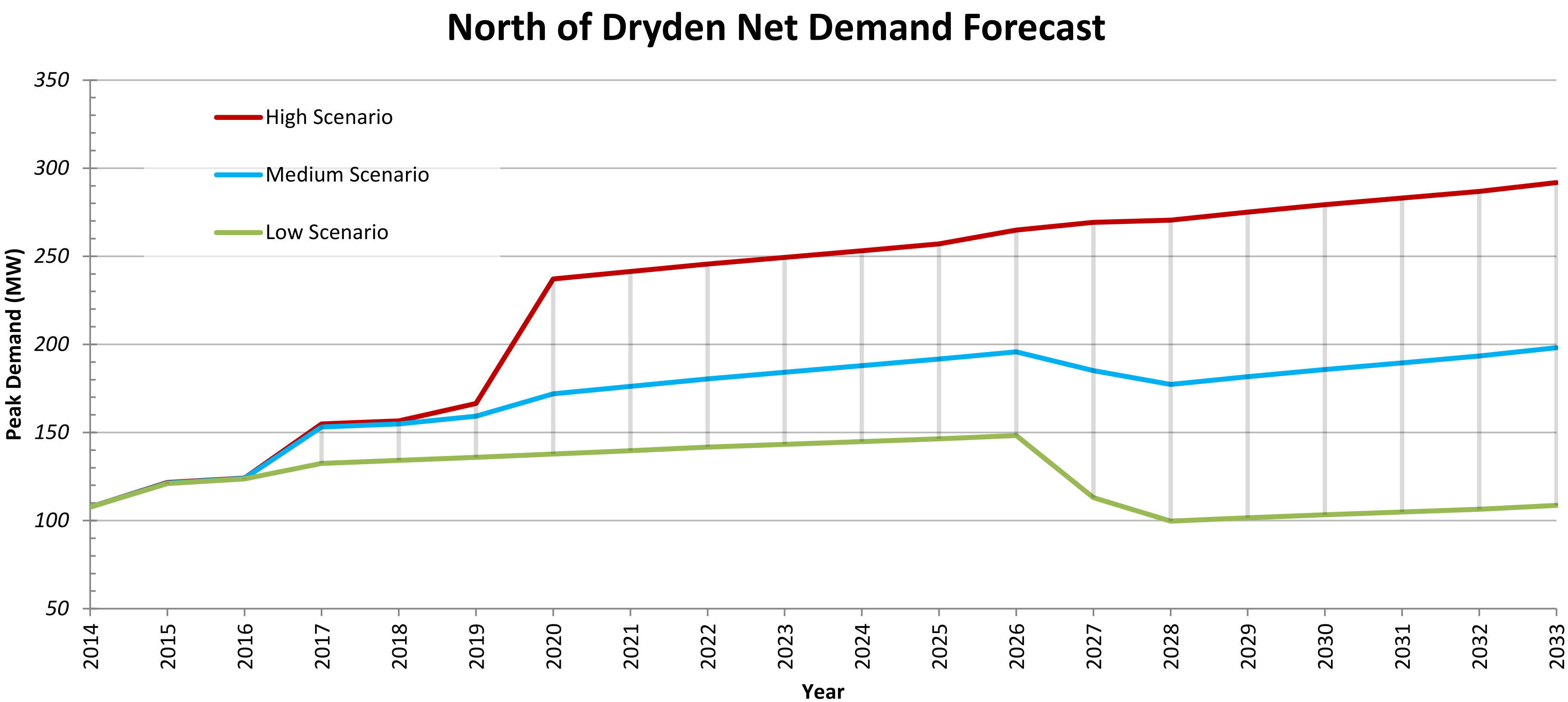
5.2 Other Study Assumptions

The other assumptions made in this RIP report include,

- The study period is 2016-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be available by the specified in-service dates.
- Since in the Northwest region winter peak is more critical than the summer peak, the study is based on winter peak conditions.

Table 5-1 North of Dryden Load Forecast Scenarios

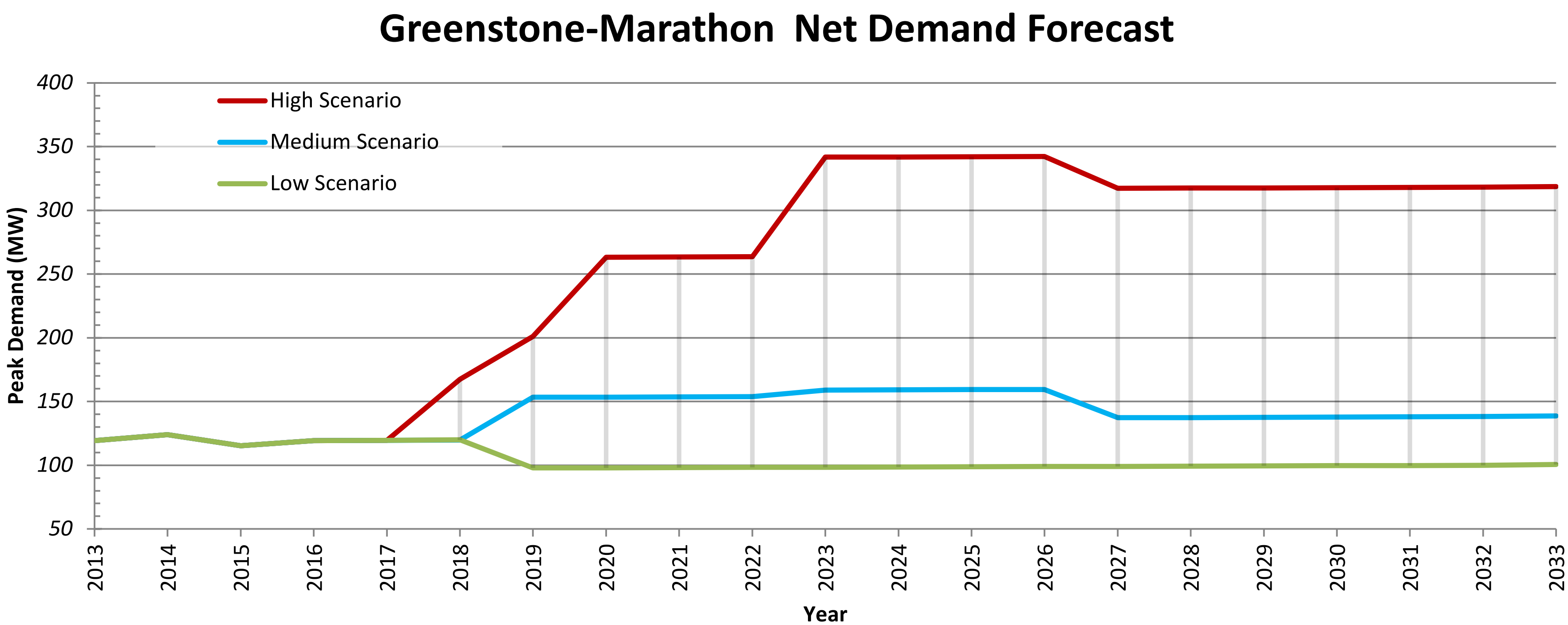
Net Demand Forecast (MW)																				
Scenario	2014 Historic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low	107.6	121.1	123.7	132.4	134.1	135.9	137.8	139.7	141.7	143.3	144.8	146.5	148.2	113.0	99.7	101.6	103.3	104.9	106.5	108.7
Medium[5]		121.4	124.0	153.1	154.8	159.3	171.9	176.1	180.3	184.1	187.9	191.7	195.7	185.2	177.3	181.6	185.7	189.5	193.3	198.0
High		121.6	124.2	154.9	156.6	166.5	237.1	241.3	245.5	249.3	253.1	256.9	264.9	269.3	270.6	275.0	279.2	283.1	286.8	291.7



[4] In the North of Dryden IRRP, load forecast starts from year 2015. For consistency, instead of the actual load in 2015 and 2016, the above table shows the IRRP load forecast for these years.
[5] The Medium scenario in the above table corresponds to the Reference scenario in the North of Dryden IRRP

Table 5-2 Greenstone-Marathon Load Forecast Scenarios[7]

Net Demand Forecast (MW)																					
Scenario	2013 Historical	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Low		124.0	115.2	119.3	119.5	120.0	97.9	97.9	98.2	98.3	98.5	98.6	98.8	99.0	99.1	99.3	99.4	99.6	99.8	100.0	100.6
Medium	119.2	124.0	115.2	119.3	119.5	119.9	153.4	153.4	153.7	153.8	159.0	159.1	159.3	159.5	137.3	137.4	137.6	137.8	137.9	138.1	138.7
High		124.0	115.2	119.3	119.5	167.4	201.0	263.3	263.5	263.6	341.8	341.9	342.1	342.2	317.4	317.5	317.6	317.8	317.9	318.1	318.6



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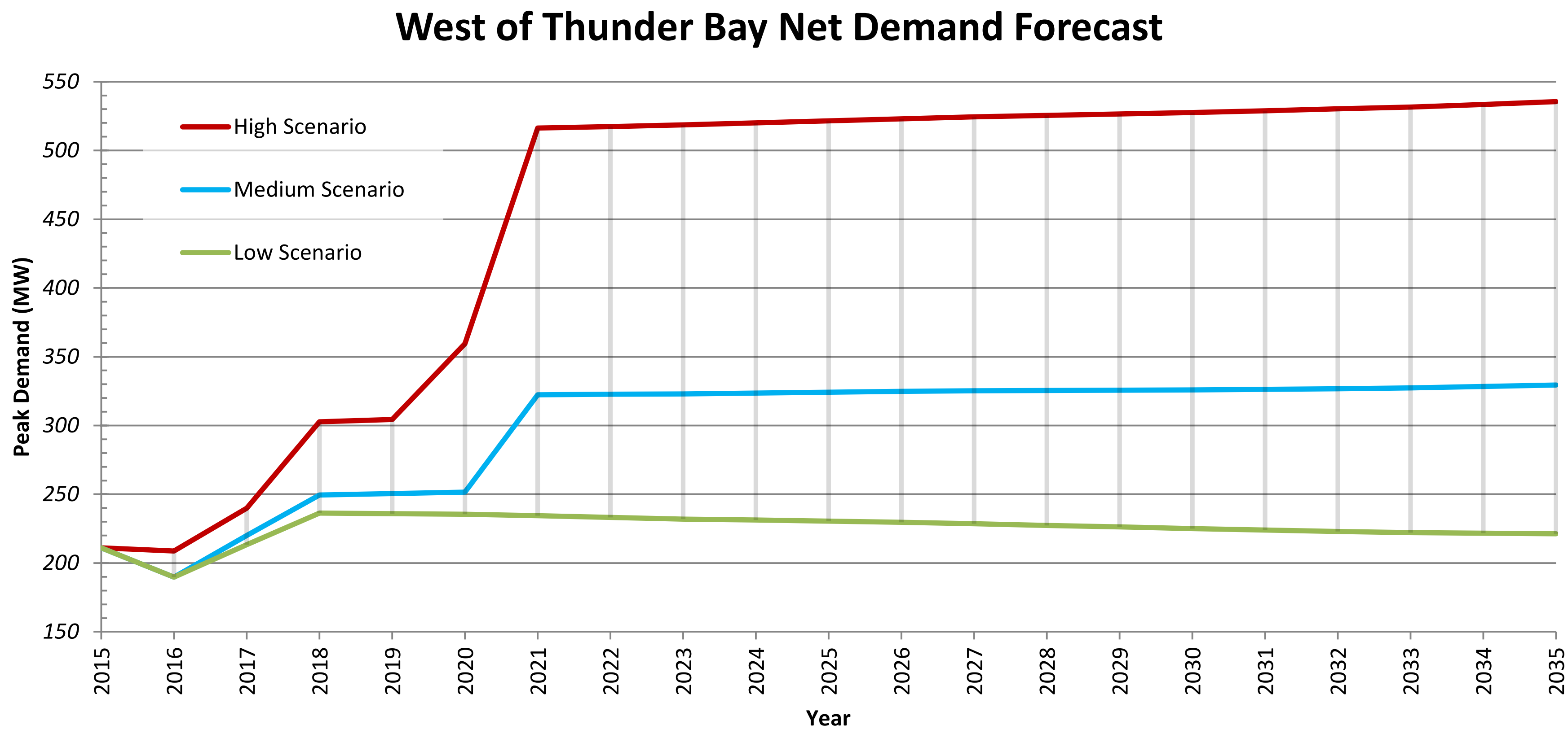
[6] In the Greenstone-Marathon IRRP, load forecast starts from year 2014. For consistency, instead of the actual load in 2014 to 2017, the above table is based on the IRRP load forecast for these years.

[7] . The Low growth scenario for Greenstone-Marathon sub-region corresponds to scenario "A" of the three sub-systems in the IRRP, the Medium growth scenario corresponds to scenario "B" of Greenstone and Marathon and scenario A of Northshore sub-systems in the IRRP, and the High growth scenario corresponds to scenario "D" of Greenstone, scenario "C" of Marathon and scenario "A" of Northshore sub-systems in the IRRP (see section 5 for details of Load Forecast Scenarios).

Table 5-3 West of Thunder Bay Load Forecasts Scenarios

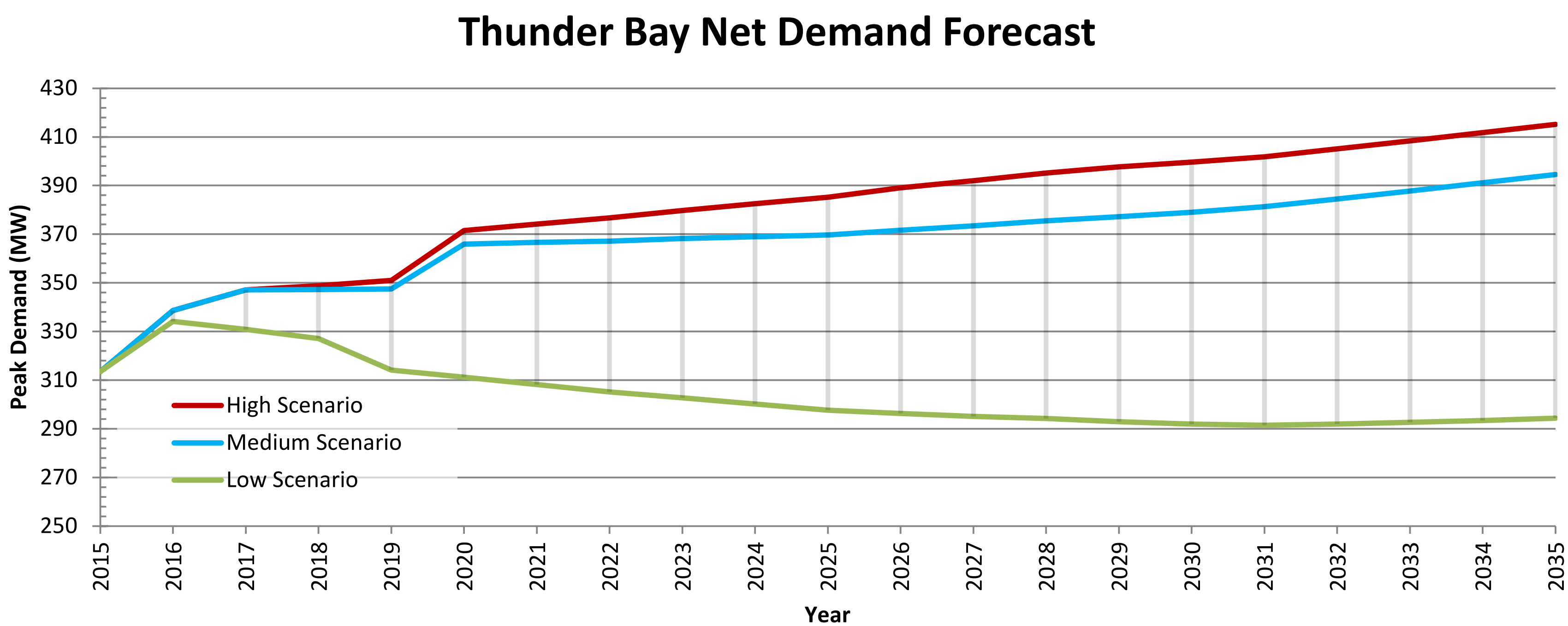
Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low		189.7	213.4	236.3	235.9	235.5	234.4	233.2	232.0	231.2	230.4	229.5	228.6	227.4	226.2	225.0	223.9	223.0	222.1	221.7	221.3
Medium	211.1	189.8	220.1	249.6	250.5	251.6	322.4	322.7	322.9	323.6	324.2	324.8	325.3	325.4	325.7	325.9	326.3	326.8	327.3	328.3	329.4
High		208.8	239.9	302.6	304.5	359.6	516.3	517.4	518.5	520.0	521.5	523.0	524.4	525.4	526.6	527.6	528.9	530.2	531.6	533.5	535.4



[8] In the West of Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

Table 5-4 Thunder Bay Load Forecast Scenarios

Net Demand Forecast (MW)																					
Scenario	2015 Historical	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low	313.6	334.1	330.9	327.1	314.2	311.2	308.2	305.1	302.7	300.2	297.6	296.4	295.1	294.2	292.9	292.0	291.5	292.0	292.6	293.4	294.3
Medium		338.7	347.1	347.3	347.5	365.9	366.7	367.1	368.2	369.0	369.7	371.6	373.4	375.5	377.1	379.0	381.3	384.5	387.8	391.2	394.6
High		338.7	347.1	348.8	351.0	371.5	374.2	376.7	379.7	382.5	385.2	389.1	391.9	395.1	397.7	399.6	401.9	405.1	408.4	411.7	415.1



[9] In the Thunder Bay IRRP, load forecast starts from year 2016. For consistency, instead of the actual load in 2016, the above table shows the IRRP load forecast for this year.

6. SUMMARY OF REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE WIRE NEEDS FOR THE NORTHWEST ONTARIO REGION AND SUMMARIZES THE RECOMMENDED WIRES PLANS FOR ADDRESSING THE NEEDS.

This section provides a summary of the needs and plans for the four Northwest sub-regions. The load forecasts from the LDCs have not materially changed since the completion of the previous phase (IRRP) of Regional Planning for the Northwest. Therefore, the assumptions and load growth scenario for industrial loads, as well as the needs and plans identified in this RIP are consistent with the Northwest IRRPs. The needs and recommended plans in the region are largely driven by the industrial load growth, particularly the mining sector. Proceeding to the Development phase of the customer-driven projects requires formal request by the customers and commercial agreements between Hydro One and the customers.

6.1 North of Dryden Sub-Region

Most of the demand in the North of Dryden sub-region is from the mining sector. The demand growth is driven by the expansion of this sector, as well as the connection of up to 21 remote communities in the northern parts of the region to Red Lake and Pickle Lake and growth in the mining sector, including potential developments in the Ring of Fire which may be supplied from Pickle Lake.

The North of Dryden IRRP [2] for this sub-region has assumed Low, Medium (referred to as Reference in IRRP [2]) and High load growth scenarios. Based on these scenarios, it has identified the needs and recommended wires plans in near-term, mid-term and long-term. The following are summaries of the needs and recommended plans for this sub-region, which consists of Pickle Lake sub-system, Red Lake sub-system, and Ring of Fire sub-system.

6.1.1 Pickle Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the existing single supply to Pickle Lake, i.e. the 115 kV circuit E1C, is serving 24 MW of load and is at its capacity. Any load growth in the near-term from the existing mine or connection of remote communities will require increase of LMC. The additional capacity needs, based on the medium (reference) load growth scenario are 18 MW, 28 MW and 47 MW in near-term, mid-term and long-term, respectively.

Pickle Lake LMC is limited by voltage stability. Providing dynamic voltage support, e.g. installing Static VAR Compensator (SVC) at Pickle Lake offers moderate increase in LMC, assuming the remaining capacity of circuit E4D will be available for this load increase. One alternative assessed in the IRRP is to install a new 115 kV single-circuit line from Valora, south of Dryden, to Pickle Lake to provide additional LMC that meets the near-term needs of Pickle Lake and releases some capacity on circuit E4D. However, in the long-term, with the development of new mines and potential for connection of the Ring of Fire to Pickle Lake (one the alternatives identified in the IRRP), an increase of over 130 MW in LMC may be required under the high growth forecast. As a result, the recommendation is to proceed with a plan required to meet the needs of the medium (reference) and high growth scenarios in the long-term. This plan can make the full capacity of circuit E4D available to serve the Red Lake sub-system.

<u>Recommended Plan:</u>

- Install a new 230 kV transmission line to Pickle Lake from either the Dryden area (e.g. Dinorwic) or Ignace area;

- Install a new 230 kV switching station to connect the new line to the existing circuits D26A;
- Install a new 230/115 kV auto-transformer at the end of the new line in Pickle Lake;
- Install new 115 kV switching facilities (circuit breakers) to connect the existing circuit E1C, existing customers at Pickle Lake and the new connections of the remote communities to the new auto-transformer; and
- Install required reactive compensation for voltage control

An Order in Council from the government, dated July 20, 2016, has directed the OEB to amend Wataynikaneyap Power LP's (Watay Power) licence for Watay Power to develop and seek approvals for the Line to Pickle Lake and the connection of sixteen remote communities. Watay Power has initiated the Development phase of the project for these connections. Currently the planned in-service date of the 230 kV line to Pickle Lake is Q2 2020, based on Watay Power's active connection assessment with the IESO.

6.1.2 Red Lake Needs and Recommended Plans

The North of Dryden IRRP [2] has identified that the current LMC of 61 MW at Red Lake, supplied by circuits E2R and E4D, is insufficient to meet the needs of the mining load, based on the expected growth at this location, even in near-term. The additional capacity needs, based on the medium (reference) load growth scenario are 30 MW, 44 MW and 48 MW in near-term, mid-term and long-term, respectively. Additional capacity needs increase to 75 MW under high load growth scenario.

The wires plans to meet the near-term needs are the following.

Recommended Plan:

- Upgrade circuit E4D to a summer rating of 660 A
- Upgrade circuit E2R to a summer rating of 610 A
- Provide additional voltage control at Ear Falls and/or Red Lake

However, since the load increase in the mining sector has not materialized at the same pace as previously anticipated, the initial plans for the upgrade of circuits E4D and E2R have been put on hold, awaiting customer request. A recent System Impact Assessment by the IESO for a load increase at Red Lake has determined that although the existing system can meet the demand, circuit E4D is reaching its thermal limit. Therefore, the above plan for the upgrade of circuit E4D (and E2R) can proceed in case of a request by, and agreement with, customers for additional load. Alternatively, operating measures can be used until additional firm capacity becomes available in the mid-term.

In the mid/long-term, assuming that the planned 230 kV line to Pickle Lake (see the previous section) is completed, which can make the full capacity of circuit E4D available to serve the Red Lake sub-system, there will be sufficient capacity to meet the needs under medium (reference) and high load growth scenarios. Only if the needs exceed the high growth forecast of this planning horizon, or the planned 230 kV line to Pickle Lake is not completed, a new 115 kV or 230 kV line from Dryden to Ear Falls will be one of the alternatives for meeting the demand.

6.1.3 Ring of Fire Sub-system Needs and Potential Options

The North of Dryden IRRP [2] has indicated that as the Ring of Fire sub-system is remote from the existing transmission system, any additional capacity needs would require new facilities. The IRRP has also indicated that transmission supply is the most economic option under all of the forecast scenarios, which considers the five remote communities in the vicinity of the Ring of Fire that have been identified as being economic to connect in the IESO's Remote Community Connection Plan [6] as well as possible mining customers. If mining load does not fully materialize, the North of Dryden IRRP [2] concluded that an east-west supply from the Pickle Lake area was the most economic option. If mining load fully materializes, the IRRP concluded that the economic option is either an east-west supply from the Pickle Lake area or a north-south supply from a point along the East-West Tie. Development in the area is still at an early stage and no firm recommendations can be made at this time.

6.2 Greenstone-Marathon Sub-Region:

The identified needs and recommended wire plans for this sub-region are directly related to a few large industrial developments. Based on the current load meeting capability (LMC) of the sub-region, all circuits except circuit A4L in Greenstone-Marathon sub-region are adequate to meet the projected demand forecast under all scenarios during the planning cycle. Circuit A4L is also adequate under the low demand scenario. The IRRP report [3] has recommended near term (present-5 years), medium term (5-10 years) and long term (10-20 years) actions to address the A4L limitations under the medium and high demand scenarios as described below.

6.2.1 Low Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Low Scenario assumptions are as follows:

- Hydro One Distribution customer growth
- Two saw mill re-starts

The existing circuits have sufficient LMC to meet Low Scenario's forecasted demand.

No wire plans are required for this scenario.

6.2.2 Medium Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, Medium Scenario assumptions are as follows:

- Low Scenario assumptions
- Development of Geraldton mine
- Development of Beardmore mine
- Life extension of the existing Marathon Area mine

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Geraldton mine – Increase Circuit A4L Capacity:

Single-circuit 115 kV line A4L runs from Alexander SS to Longlac TS. A mining development in Geraldton area, with the proposed in-service date of 2019, would increase the near-term demand on circuit A4L to 51 MW, which is higher than its current LMC of approximately 25 MW. The LMC of circuit A4L is limited by voltage.

A major deciding factor in the recommendation for meeting the forecasted demand is the lead time relative to the proposed timelines for the mine development.

<u>Recommended Plan:</u>

If the proposed in service date of 2019 does not change, Installing Reactive Compensation and gas-fired generation in the near term is the recommended solution.

Installing reactive compensation of about +40 MVARs in the form of either synchronous condenser or Static Synchronous Compensators (STATCOM) at the Geraldton mine site would increase the LMC of circuit A4L to 45 MW, making full thermal capability of the circuit available. This form of Reactive Compensation is recommended considering the low short-circuit level at the end of circuit A4L relative to the requirements of the mine. The remaining short fall of approximately 6 MW to meet the needs of the mine can be provided by a customer-based grid-connected gas-fired generation plant with sufficient redundancy, for example, installing two 10 MW gas-fired units.

If the in-service date of the mine is delayed, replacing a section of circuit A4L, between Nipigon and Longlac, along with the installation of the above reactive compensation, would increase the LMC of circuit A4L to about 60 MW. Replacing the section of circuit A4L has a lead time of approximately five years.

Accommodate Beardmore mine – Increase Circuit A4L Capacity

A potential gold mine near Beardmore may be operational within the medium term. If Geraldton mine doesn’t connect to circuit A4L as described above, the existing system would be sufficient to support the Beardmore mine.

If the Geraldton mine connects to circuit A4L and the plans for the high-demand scenario (described below) do not proceed, in order to accommodate the Beardmore mine, additional capacity would be required.

Recommended Plan:

Upgrading a section of circuit A4L from Alexander SS to Beardmore Junction is a medium term wires option for supplying the potential mine.

6.2.3 High Scenario Needs and Recommended Plans

Consistent with the Greenstone-Marathon IRRP, High Scenario assumptions are as follows

- Medium Scenario assumptions
- Development of the proposed Energy East pipeline
- Development of additional mines in Marathon Area
- Development of Ring of Fire, with connection to the Greenstone area

Under this scenario, the needs and recommended wires plans are the following.

Accommodate Energy East Pipeline and, potentially, the Ring of Fire – Install New Wires:

Potential Energy East load is subjected to customers’ request for connection of the pumping stations to the provincial electricity grid. The medium or long term recommended plans for the High Scenario depend on the Energy East plans and timelines for connecting some or all of the pumping stations, in one or two phases.

The Greenstone-Marathon Sub-Region IRRP [3] also indicates that the Ring of Fire could be potentially connected by an east-west corridor to Pickle Lake or by a north-south corridor to the Nipigon or Marathon areas.

Recommended Plan:

According to the IRRP report [3], the preferred option under the High Scenario, with or without the potential connection of the Ring of Fire, is the following wires plan.

- Install a new 230 kV transmission line to Longlac TS from either from the Nipigon area or from the Marathon (or Terrance Bay) area;
- Install a new 230 kV switching station to connect the new line to the existing circuits M23L-M24L;
- Install a new 230/115 kV auto-transformer at Longlac TS;

- Install required reactive compensation for voltage control and short-circuit level requirements at the mine; and
- Install a new 115 kV Line from Longlac TS to Manitouwadge TS to supply all the pumping stations in the area, possibly in the second phase.

Advancing the plan for the new transmission line and transformer, in order to meet the timelines of the Geraldton mine and the Beardemore mine developments, is an alternative to the upgrade of circuit A4L described under the Medium Scenario above. During outages of the new line or transformer, the new mines and industrial loads need to be interrupted to maintain the loading on circuit A4L below its LMC.

The above plan will improve the reliability for the customers served from Longlac TS by maintaining their supply through the new transmission line and transformer during outages of circuit A4L.

6.3 West of Thunder Bay Sub-Region

This sub-region, as described in the IRRP report [4], consists of four main sub-systems, Moose Lake, Fort Frances, Kenora and Dryden. The West of Thunder Bay Sub-Region is also a source of supply to the North of Dryden sub-region (through the Dryden 115 kV system) and therefore the needs and recommendations from the North of Dryden IRRP (described in the previous sections) were considered in the West of Thunder Bay IRRP.

Similar to the other sub-regions described above, because of the uncertainty in the development plans and connection options, the IRRP has considered low, medium (or reference) and high load growth scenarios in the West of Thunder Bay sub-region and has identified near/mid/long-term needs and recommendations for each scenario.

The low load growth scenario has forecasted a peak demand of close to 240 MW in 2017 (with the startup of a new mine near Rainy River) which will remain fairly flat until 2034.

In the medium load growth scenario, involving new mines and industrial load (pumping stations of the pipeline conversion project), the load forecast increases from 252 MW in 2017 to 345 MW in 2034.

In the high load growth scenario, involving additional mines, the load forecast increases from 305 MW in 2017 to 551 MW in 2034.

6.3.1 Dryden Needs and Plans

The Dryden 115 kV sub-system can provide up to 240 MW of continuous supply to the Dryden and North of Dryden Sub-Region. Under the low and medium (reference) load growth scenarios, this LMC is sufficient to meet the demand of this sub-system.

Under the high load growth scenario, additional capacity of 50 MW will be required on the 115 kV system at Dryden by the mid-2020s. This scenario considers high growth in the North of Dryden Sub-Region, and assumes that all load on circuit E1Cwill be supplied by the proposed 230 kV line to Pickle Lake. The IRRP identified one option for meeting the need of the 115 kV system to install a third autotransformer at Dryden TS. A recommended plan has not been finalized at this time given the long lead time and uncertainty associated with potential developments in the area. The next cycle of Regional Planning will reassess the need.

6.3.2 Kenora Needs and Plans

The transformer station supplying the City of Kenora and surrounding areas ("Kenora MTS") can supply 25 MW. This transformer station currently supplies up to 20 MW. Since the increase in the residential and commercial load in the Kenora area is forecast to be modest over the planning period, the remaining 5 MW margin will be adequate for the Kenora area.

The IRRP has identified that an industrial customer, currently supplied by a local generating station is considering pursuing an alternative supply arrangement from Kenora MTS. Furthermore, potential developments at the former Abitibi mill site may also require additional transformer station capacity in the Kenora area. The magnitude and timing of these developments remains uncertain and is not expected to have major regional implications. No actions were recommended in the IRRP to address the need at this time.

6.3.3 Moose Lake Needs and Plans

The Moose Lake 115 kV sub-system has sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.3.4 Fort Frances Needs and Plans

The Fort Frances 115 kV sub-system was found to have sufficient supply capacity to meet demand in the planning horizon under each load growth scenario. Therefore, no actions were recommended in the IRRP at this time.

6.4 Thunder Bay Sub-Region

The IRRP for the Thunder Bay sub-region [5] considered low, medium and high load growth scenarios and identified near/mid/long-term needs and recommendations for each scenario. The assessments of this sub-region have assumed that the most impactful scenario in the Greenstone sub-system will materialize, resulting in 60 MW supply need from the Thunder Bay sub-region (i.e. on circuit A4L in case it would be upgraded).

The low load growth scenario has forecast the peak demand of close to 325 MW in 2015 will decline to about 300 MW by 2035 as a result of continuing decline in the pulp and paper sector and without new mining or industrial developments in Thunder Bay.

In the medium load growth scenario, involving new mines and industrial load (one pumping station of the Energy East gas-to-oil pipeline development supplied from the Thunder Bay transmission system) and no change in the pulp and paper sector, the load is forecasted to increase to 400 MW in 2035. This is comparable to the sub-region's historic peak demand in 2006/2007.

In the high load growth scenario, involving additional transmission connected mining developments north of Thunder Bay; the load is forecasted to increase to 415 MW by the end of planning period.

In addition to the potential long-term wires options for medium/high growth scenarios described below, the IRRP for Thunder Bay sub-region identified the near-term need for upgrading the thermal rating of circuit R2LB between Lakehead TS and Birch TS to that of the companion circuit R1LB. This work has been completed.

6.4.1 Long-Term Needs and Plans

Port Arthur TS - Transformation Capacity

The long-term load forecast indicates that the demand from the customers supplied by Port Arthur TS will exceed the station's current capacity by 2033, and additional station capacity will be required if this load growth materializes.

Currently, the low voltage equipment at Port Arthur TS are limiting the station capacity to 55 MW. The station transformers provide up to 59 MW of capacity.

Wires Option:

The low voltage equipment, which are limiting the station capacity are nearing end-of-life and are planned to be replaced and upgraded in mid-term. This upgrade would bring the station capacity up to 59 MW, sufficient to meet the need beyond 2035. No additional plan is required at this time and load at Port Arthur TS will be monitored and supply options will be assessed in the next cycle of Regional Planning.

Lakehead TS and Birch TS - Transformation Capacity

Currently the Thunder Bay 115 kV system can accommodate approximately 150 MW of additional load growth. This capacity is sufficient under the low and medium load growth scenarios in the long-term.

Under the High growth scenario, and assuming the most impactful Greenstone sub-system scenario (60 MW, as described above), the Thunder Bay system would require additional supply capacity of approximately 20 MW by 2030.

The Thunder Bay IRRP indicates that a firm plan to increase the LMC of the Thunder Bay 115 kV system is not required at this time, as the large margin remaining on the system provides significant lead time for the Working Group to monitor demand growth and study options. The IRRP report explored various wires and non-wires options as potential long term solutions to increase the LMC of the system, however no action beyond monitoring is recommended at this time.

The wires options discussed in the Thunder Bay IRRP are described below:

1. Installing a third 230/115 kV 250 MVA autotransformer at Lakehead TS to increase the LMC of Lakehead TS by approximately 240 MW.

2. A new 230 kV line from Lakehead TS to Birch TS and a 230 kV 250 MVA autotransformer at Birch TS to create a supply point for the southern part of Thunder Bay, with a supply capacity of 240 MW. The new 230 kV line would require a new Right-of-Way and would take 5 years or longer to build.

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7. CONCLUSIONS AND NEXT STEPS

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

This section provides a summary of the Needs and Plans for the Northwest Region as identified in this RIP.

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

North of Dryden Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
1	Circuits E1C and E4D Capacity	A 230 kV transmission line from Dryden/Ignace area to Pickle Lake	Medium[1]	Near-term	Recommended in IRRP. Development has started.
2	Circuits E4D and E2R Capacity	Upgrade of transmission lines E2R and E4D, and additional voltage support	All Scenarios	Near-term	Recommended in IRRP. The need has not materialized.
3		A 115 kV or 230 kV transmission line from Dryden to Ear Falls	High	Long-term	Proposed in IRRP. Not needed in the planning horizon, assuming Projects 1 and 2 proceed.

Greenstone-Marathon Sub-Region Wires Plans

No.	Need	Wires Options	Load Growth	Term	Status
4	Circuit A4L Capacity	Upgrade of sections of transmission line A4L, and dynamic voltage support devices at Geraldton	Medium[2]	Near-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Geraldton mine.
5		Upgrade of other sections of transmission line A4L	Medium[2]	Mid-term	Recommended in IRRP. Subject to the plans and timelines for connection of a new Beardmore mine.
6	Capacity for Pipeline Project and Ring of Fire	A 230 kV transmission line from Nipigon or Terrace Bay to Geraldton, and voltage support devices	High[2]	Mid/Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of pipeline loads and mines.
7		A 115 kV transmission line from Manitouwadge to Geraldton, and voltage support devices	High[2]	Long-term	Recommended in IRRP. Subject to the plans and timelines for connection of additional pipeline loads.

West of Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
8	Dryden 115 kV System Capacity	A 230/115 kV auto-transformer in Dryden area	High	Mid-term	Proposed in IRRP. Next planning cycle will reassess the need.

Thunder Bay Sub-Region Wires Plans					
No.	**Need**	**Wires Options**	**Load Growth**	**Term**	**Status**
9	Thunder Bay 115 kV System Capacity	A 230/115 kV auto-transformer in Thunder Bay area	High	Long-term	Proposed in IRRP. Next planning cycle will reassess the need.
10	Port Arthur TS Transformation Capacity	Upgrade of Low-Voltage equipment at Port Arthur TS	All Scenarios	Long-term	Proposed in IRRP. LV equipment are planned for End-of-Life replacement in mid-term. Next planning cycle will reassess the need.

8. REFERENCES

[1]. Northwest Region Scoping Assessment (SA) Outcome Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final_Northwest_Scoping_Process_Outcome_Report.pdf

[2]. North of Dryden Sub-Region Integrated Regional Resource Plan (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/North_of_Dryden/North-Dryden-Report-2015-01-27.pdf

[3]. Greenstone-Marathon Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Greenstone_Marathon/2016-Greenstone-Marathon-IRRP-Report.pdf

[4]. West of Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
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[5]. Thunder Bay Sub-Region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Thunder-Bay-IRRP.pdf

[6]. 2014 Draft Remote Community Connection Plan
http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Remote_Community/OPA-technical-report-2014-08-21.pdf

Appendix A. Stations in the Northwest Ontario Region

Sub Region	Station	Voltage (kV)	Supply Circuits
North of Dryden	Ear Falls TS	115/44	M3E, E4D, E1C, E2R
	Red Lake TS	115/44	E2R
	Cat Lake MTS	115/25	E1C
	Crow River DS	115/25	E1C
	Perrault Falls DS	115/12.5	E4D
	Slate Falls DS	115/24.9	E1C
Greenstone-Marathon	Longlac TS	115/44	A4L
	Manitouwadge TS	115/44	M2W
	Marathon TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
	Beardmore DS #2	115/25	A4L
	Jellicoe DS #3	115/12.5	A4L
	Manitouwadge DS #1	115/12.5	M2W
	Marathon DS	115/25	T1M
	Pic DS	115/25	M2W
	Schreiber Winnipeg DS	115/12.5	A5A
	White River DS	115/25	M2W
West of Thunder Bay	Barwick TS	115/44	K6F
	Dryden TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
	Fort Frances TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
	Kenora TS	230/115	K24F, K7K, K21W, K23D, K22W
	Mackenzie TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
	Moose Lake TS	115/44	A3M, M1S, M2D, B6M
	Fort Frances MTS	115/12.47	F1B
	Kenora MTS	115/12.5	15M1
	Agimak DS	115/25	29M1
	Burleigh DS	115/12.5	F1B
	Clearwater Bay DS	115/25	SK1
	Eton DS	115/12.48	K3D
	Keewatin DS	115/12.5	SK1
	Margach DS	115/25	K6F
	Minaki DS	115/25	K4W
	Nestor Falls DS	115/13.2	K6F
	Sam Lake DS	115/26.4	K3D
	Sapawe DS	115/12.5	B6M
	Shabaqua DS	115/12.5	B6M
	Sioux Narrows DS	115/12.5	K6F
	Valora DS	115/25	29M1
	Vermilion Bay DS	115/12.5	K3D
Thunder Bay	Birch TS	115/28.4	Q9B, P7B, Q8B, Q5B, R2LB, P3B, Q4B, R1LB, B6M
	Fort William TS	115/25	Q5B, Q4B
	Lakehead TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
	Port Arthur TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
	Murillo DS	115/26.40	B6M
	Nipigon DS	115/4.16	57M1
	Red Rock DS	115/12.5	56M1

Appendix B. Transmission Lines in the Northwest Ontario Region

Circuit(s)	Location	Voltage (kV)
D26A	Mackenzie x Dryden	230
F25A	Mackenzie x Fort Frances	230
K23D	Dryden x TCPL Vermill Bay x Kenora	230
K24F	Fort Frances x Kenora	230
N93A	Mackenzie x Marmion Lake x Atikokan	230
K21W, K22W	Kenora x Whiteshell (Manitoba Hydro)	230
A21L, A22L	Mackenzie x Lakehead	230
M23L, M24L	Marathon x Lakehead	230
15M1	Kenora x Rabbit Lake	115
29M1	Ignace x Camp Lake x Valora x Mattabi	115
A3M	Mackenzie x Moose Lake	115
B6M	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	115
D5D	Dryden x Domtar Dryden	115
F1B	Fort Frances x Burleigh	115
F3M	Fort Frances x Internat Fls (Minnesota Power)	115
K2M	Kenora x Norman	115
K3D	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	115
K4W	White Dog x Minaki x Rabbit Lake	115
K6F	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	115
K7K	Kenora x Weyerhaeuser Ken x Rabbit Lake	115
M1S	Moose Lake x Valerie Falls x Mill Creek	115
M2D	Moose Lake x Ignace x Dryden	115
SK1	Rabbit Lake x Keewatin x Forgie	115
W3C	White Dog x Caribou Falls	115
56M1	Nipignon x Red Rock	115
57M1	Reserve x Nipignon	115
A6P	Alexander x Port Arthur	115
L3P, L4P	Lakehead x Port Arthur	115
P3B, P7B	Port Arthur x Birch	115
P5M	Port Arthur x Conmee	115
Q4B, Q5B, Q8B, Q9B	Thunder Bay x Birch	115
R1LB, R2LB	Lakehead x Pine Portage x Birch	115
S1C	Silver Falls x Lac Des Iles x Conmee	115
A1B	Aguasabon x Terrace Bay	115
A4L	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	115
A5A	Alexander x Minnova x Schreiber x Aguasabon	115
C1A, C2A, C3A	Alexander x Cameron Falls	115
GA1	Upper White River x Lower White River	115
M2W	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	115
R9A	Alexander x Pine Portage	115
E1C	Ear Falls x Selco x Slate Falls x Cat Lake x Crow River x Musselwhite	115
E2R	Ear Falls x Balmer x Red Lake	115
E4D	Ear Falls x Scout Lake x Dryden	115
M3E	Manitou Falls x Ear Falls	115
T1M	Terrace Bay x Marathon	115

Appendix C. Distributors in the Northwest Ontario Region

Distributor Name	Station Name	Connection
ATIKOKAN HYDRO INC.	Moose Lake TS	Tx
FORT FRANCES POWER CORPORATION	Fort Frances MTS	Tx
HYDRO ONE NETWORKS INC.	Agimak DS	Tx
	Aguasabon GS	Tx
	Barwick TS	Tx
	Beardmore DS #2	Tx
	Burleigh DS	Tx
	Cat Lake MTS	Tx
	Clearwater Bay DS	Tx
	Crow River DS	Tx
	Dryden TS	Tx
	Ear Falls DS	Tx
	Ear Falls TS	Tx
	Eton DS	Tx
	Fort Frances TS	Tx
	H2O Pwr SturgFls CGS	Tx
	Jellicoe DS #3	Tx
	Keewatin DS	Tx
	Kenora DS	Tx
	Longlac TS	Tx
	Manitouwadge DS #1	Tx
	Manitouwadge TS	Tx
	Marathon DS	Tx
	Margach DS	Tx
	Minaki DS	Tx
	Murillo DS	Tx
	Nestor Falls DS	Tx
	Nipigon DS	Tx
	Perrault Falls DS	Tx
	Pic DS	Tx
	Port Arthur TS #1	Tx
	Red Lake TS	Tx
	Red Rock DS	Tx
	Sam Lake DS	Tx
	Sapawe DS	Tx
	Schreiber Winnipg DS	Tx
	Shabaqua DS	Tx
	Sioux Narrows DS	Tx
	Slate Falls DS	Tx
	Valora DS	Tx
	Vermilion Bay DS	Tx
	White River DS	Tx
	Whitedog Falls GS	Tx
	Whitedog DS	Tx
KENORA HYDRO ELECTRIC CORPORATION	Kenora MTS	Tx
SIOUX LOOKOUT HYDRO INC.	Sam Lake DS	Dx
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	Birch TS	Tx
	Fort William TS	Tx
	Port Arthur TS #1	Tx

Appendix D. Northwest Ontario Stations Non Coincident Load Forecast (2016-2025)

Table D-1 Stations Non Coincident Net Load Forecast (MW)

	Station LDCs
	Atikokan Hydro
	Fort Frances Power Corp
	Kenora Hydro
	Thunder Bay Hydro
	Hydro One Distribution

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Moose Lake TS*	Non Coincidental Gross						6.10	6.16	6.22	6.28	6.35	6.38	6.41	6.44	6.48	6.51
		CDM						0.04	0.07	0.12	0.17	0.21	0.24	0.28	0.31	0.33	0.37
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.50	4.30	4.53	4.93	6.06	6.06	6.09	6.10	6.11	6.14	6.13	6.13	6.13	6.14	6.13
West of Thunder Bay	*Fort Frances MTS*	Non Coincidental Gross						17.10	17.02	16.93	17.10	17.27	17.45	17.62	17.80	17.97	18.15
		CDM						0.11	0.18	0.32	0.46	0.56	0.66	0.76	0.85	0.92	1.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	16.93	16.29	17.17	17.92	16.79	16.99	16.83	16.61	16.64	16.70	16.78	16.85	16.95	17.05	17.11
West of Thunder Bay	*Fort Frances TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	15.60	16.37	16.73	16.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Barwick TS*	Non Coincidental Gross						17.07	17.07	17.29	17.56	17.69	17.81	17.93	18.04	18.19	18.33
		CDM						0.11	0.19	0.32	0.47	0.58	0.68	0.78	0.86	0.93	1.04
		DG						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Non Coincidental Net					14.00	15.96	15.88	15.96	16.08	16.11	16.13	16.15	16.18	16.25	16.28
West of Thunder Bay	*Kenora MTS*	Non Coincidental Gross						21.45	21.66	21.88	22.10	22.10	22.32	22.32	22.54	22.76	22.99
		CDM						0.14	0.24	0.41	0.59	0.72	0.85	0.97	1.07	1.17	1.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	20.49	20.77	21.27	21.62	20.57	21.30	21.41	21.46	21.49	21.37	21.46	21.34	21.45	21.58	21.66
Thunder Bay	*Birch TS*	Non Coincidental Gross						77.88	78.54	78.80	79.31	79.81	80.32	80.55	81.34	81.96	82.52
		CDM						0.51	0.85	1.48	2.13	2.60	3.06	3.50	3.87	4.21	4.70
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Non Coincidental Net	70.48	70.02	86.01	87.04	74.01	77.33	77.64	77.28	77.14	77.17	77.22	77.01	77.43	77.71	77.77

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thunder Bay	*Fort Williams TS*	Non Coincidental Gross						77.90	78.14	80.46	81.23	83.61	87.49	91.88	91.11	89.64	89.29
		CDM						0.51	0.85	1.51	2.18	2.73	3.33	3.99	4.33	4.60	5.09
		DG						4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45	4.45
		Non Coincidental Net	74.99	73.18	80.22	80.81	79.20	72.94	72.84	74.50	74.59	76.43	79.70	83.44	82.33	80.59	79.76
Thunder Bay	*Port Arthur TS#1*	Non Coincidental Gross						37.00	37.40	37.90	38.50	39.10	39.60	40.20	40.90	41.50	42.20
		CDM						0.24	0.41	0.71	1.03	1.27	1.51	1.74	1.94	2.13	2.40
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	34.92	35.73	35.36	39.98	30.70	36.74	36.98	37.18	37.45	37.81	38.08	38.44	38.94	39.36	39.78
Thunder Bay	*Port Arthur TS #1*	Non Coincidental Gross						8.54	8.65	8.77	8.80	8.94	9.10	9.19	9.28	9.36	9.44
		CDM						0.06	0.09	0.16	0.24	0.29	0.35	0.40	0.44	0.48	0.54
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.12	7.48	8.52	8.52	7.90	8.49	8.56	8.60	8.56	8.65	8.76	8.79	8.84	8.88	8.90
West of Thunder Bay	*Agimak DS*	Non Coincidental Gross						3.32	3.33	3.39	3.46	3.50	3.53	3.57	3.60	3.65	3.69
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.19	0.21
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.96	3.04	3.24	3.70	4.30	3.30	3.30	3.33	3.36	3.38	3.40	3.41	3.43	3.46	3.48
Greenstone-Marathon	*Beardmore DS #2*	Non Coincidental Gross						1.23	1.23	1.25	1.28	1.29	1.30	1.31	1.33	1.34	1.36
		CDM						0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.08
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.19	1.30	1.21	1.17	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West of Thunder Bay	*Burleigh DS*	Non Coincidental Gross						4.12	4.12	4.18	4.24	4.27	4.30	4.33	4.35	4.39	4.42
		CDM						0.03	0.04	0.08	0.11	0.14	0.16	0.19	0.21	0.23	0.25
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.63	3.80	4.10	4.05	3.70	4.09	4.08	4.10	4.13	4.13	4.14	4.14	4.14	4.16	4.17
North of Dryden	*Cat Lake MTS*	Non Coincidental Gross						0.82	0.83	0.85	0.86	0.88	0.89	0.90	0.91	0.92	0.94
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.79	0.69	0.80	0.72	0.74	0.82	0.82	0.83	0.84	0.85	0.85	0.86	0.87	0.88	0.88
West of Thunder Bay	*Clearwater Bay DS*	Non Coincidental Gross						5.47	5.47	5.54	5.61	5.65	5.68	5.71	5.74	5.78	5.83
		CDM						0.04	0.06	0.10	0.15	0.18	0.22	0.25	0.27	0.30	0.33
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.66	4.94	5.38	5.32	4.50	5.43	5.41	5.43	5.46	5.47	5.47	5.46	5.47	5.49	5.49
West of Thunder Bay	*Crilly DS*	Non Coincidental Gross						2.17	2.21	2.25	2.29	2.33	2.36	2.40	2.43	2.46	2.49
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.02	1.98	2.02	1.99	2.05	2.15	2.19	2.21	2.23	2.25	2.27	2.29	2.32	2.33	2.35

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North of Dryden	*Crow River DS*	Non Coincidental Gross						2.70	2.70	2.74	2.79	2.81	2.84	2.86	2.88	2.90	2.93
		CDM						0.02	0.03	0.05	0.07	0.09	0.11	0.12	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.89	2.52	2.64	2.58	2.12	2.68	2.68	2.69	2.72	2.72	2.73	2.73	2.74	2.75	2.76
West of Thunder Bay	*Dryden TS*	Non Coincidental Gross						21.14	21.33	21.80	22.31	22.65	22.99	23.31	23.63	24.02	24.41
		CDM						0.14	0.23	0.41	0.60	0.74	0.88	1.01	1.12	1.23	1.39
		DG						0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
		Non Coincidental Net	18.66	19.07	20.21	19.94	19.61	20.59	20.69	20.99	21.31	21.51	21.71	21.89	22.10	22.38	22.62
North of Dryden	*Ear Falls DS*	Non Coincidental Gross						4.29	4.32	4.34	4.37	4.39	4.42	4.44	4.46	4.49	4.51
		CDM						0.03	0.05	0.08	0.12	0.14	0.17	0.19	0.21	0.23	0.26
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.43	2.46	2.74	4.23	4.55	4.26	4.27	4.26	4.25	4.25	4.25	4.25	4.25	4.26	4.25
West of Thunder Bay	*Eton DS*	Non Coincidental Gross						5.04	5.04	5.10	5.17	5.21	5.24	5.27	5.30	5.34	5.38
		CDM						0.03	0.05	0.10	0.14	0.17	0.20	0.23	0.25	0.27	0.31
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.06	4.16	4.00	3.97	3.74	5.00	4.98	5.00	5.03	5.03	5.03	5.04	5.04	5.06	5.07
Greenstone-Marathon	*Jellicoe DS #3*	Non Coincidental Gross						0.47	0.47	0.48	0.49	0.49	0.50	0.50	0.50	0.51	0.51
		CDM						0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.48	0.47	0.46	0.45	0.33	0.47	0.47	0.47	0.48	0.48	0.48	0.48	0.48	0.48	0.48
West of Thunder Bay	*Kenora DS*	Non Coincidental Gross						6.88	6.88	6.97	7.10	7.17	7.24	7.30	7.37	7.44	7.51
		CDM						0.05	0.07	0.13	0.19	0.23	0.28	0.32	0.35	0.38	0.43
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	11.44	12.50	6.73	6.67	5.93	6.83	6.80	6.84	6.90	6.93	6.96	6.98	7.02	7.06	7.08
West of Thunder Bay	*Keewatin DS*	Non Coincidental Gross						5.55	5.55	5.62	5.73	5.79	5.84	5.89	5.95	6.00	6.06
		CDM						0.04	0.06	0.11	0.15	0.19	0.22	0.26	0.28	0.31	0.35
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net		5.29	5.43	5.41	4.62	5.51	5.49	5.52	5.57	5.60	5.62	5.64	5.66	5.70	5.72
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	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
Greenstone-Marathon	*Longlac TS*	Non Coincidental Gross						12.79	13.00	18.00	18.19	18.38	18.57	18.76	18.96	19.15	19.35
		CDM						0.08	0.14	0.34	0.49	0.60	0.71	0.81	0.90	0.98	1.10
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	9.80	10.78	12.66	12.60	11.94	12.70	12.86	17.66	17.70	17.78	17.86	17.95	18.06	18.17	18.25

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Manitouwadge DS #1*	Non Coincidental Gross						1.56	1.56	1.59	1.61	0.00	0.00	0.00	0.00	0.00	0.00
		CDM						0.01	0.02	0.03	0.04	0.00	0.00	0.00	0.00	0.00	0.00
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.86	1.36	1.54	1.34	1.29	1.55	1.55	1.56	1.56	0.00	0.00	0.00	0.00	0.00	0.00
Greenstone-Marathon	*Manitouwadge TS*	Non Coincidental Gross						11.07	11.10	11.28	11.48	13.21	13.33	13.44	13.55	13.69	13.83
		CDM						0.07	0.12	0.21	0.31	0.43	0.51	0.58	0.64	0.70	0.79
		DG						7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84	7.84
		Non Coincidental Net	9.48	10.37	10.79	9.66	9.05	3.15	3.14	3.23	3.33	4.94	4.98	5.02	5.06	5.15	5.20
Greenstone-Marathon	*Marathon DS*	Non Coincidental Gross						11.16	11.21	11.42	11.64	11.78	11.91	12.03	12.16	12.31	12.47
		CDM						0.07	0.12	0.21	0.31	0.38	0.45	0.52	0.58	0.63	0.71
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	7.22	8.08	10.71	10.57	7.56	11.08	11.09	11.20	11.33	11.39	11.45	11.51	11.58	11.68	11.76
West of Thunder Bay	*Margach DS*	Non Coincidental Gross						9.60	9.60	9.73	9.88	9.95	10.01	10.07	10.12	10.21	10.29
		CDM						0.06	0.10	0.18	0.27	0.32	0.38	0.44	0.48	0.52	0.59
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	8.77	9.38	9.44	9.37	8.82	9.53	9.50	9.55	9.61	9.62	9.63	9.63	9.64	9.68	9.70
West of Thunder Bay	*Minaki DS*	Non Coincidental Gross						0.99	0.99	1.00	1.02	1.02	1.03	1.03	1.04	1.05	1.06
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.94	1.06	0.97	0.93	1.00	0.98	0.98	0.98	0.99	0.99	0.99	0.99	0.99	0.99	1.00
Thunder Bay	*Murillo DS*	Non Coincidental Gross						19.37	19.61	19.88	19.95	20.27	20.64	20.84	21.03	21.21	21.39
		CDM						0.13	0.21	0.37	0.54	0.66	0.79	0.90	1.00	1.09	1.22
		DG						0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.12	0.12
		Non Coincidental Net	12.12	12.93	12.43	11.34	15.35	19.22	19.37	19.48	19.39	19.59	19.83	19.91	20.01	20.00	20.05
West of Thunder Bay	*Nestor Falls DS*	Non Coincidental Gross						3.36	3.36	3.41	3.46	3.48	3.50	3.52	3.54	3.56	3.59
		CDM						0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.17	0.18	0.20
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.22	3.32	3.33	3.29	3.05	3.34	3.33	3.34	3.36	3.36	3.37	3.36	3.37	3.38	3.39
Thunder Bay	*Nipigon DS*	Non Coincidental Gross						2.21	2.24	2.27	2.29	2.33	2.38	2.41	2.44	2.47	2.50
		CDM						0.01	0.02	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.32	2.19	2.31	2.23	2.17	2.19	2.21	2.23	2.23	2.26	2.29	2.31	2.32	2.34	2.36
North of Dryden	*Perrault Falls DS*	Non Coincidental Gross						0.79	0.80	0.81	0.83	0.83	0.84	0.85	0.86	0.87	0.88
		CDM						0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.89	0.91	0.78	0.86	0.86	0.79	0.79	0.79	0.80	0.81	0.81	0.81	0.82	0.82	0.83

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Greenstone-Marathon	*Pic DS*	Non Coincidental Gross						6.57	6.58	6.67	6.78	6.84	6.89	6.94	6.98	7.05	7.11
		CDM						0.04	0.07	0.12	0.18	0.22	0.26	0.30	0.33	0.36	0.41
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.96	6.94	6.37	6.50	6.38	6.52	6.50	6.55	6.60	6.61	6.62	6.63	6.65	6.68	6.71
North of Dryden	*Red Lake TS*	Non Coincidental Gross						26.58	26.81	27.04	27.27	27.41	27.64	27.88	28.12	28.36	28.61
		CDM						0.18	0.29	0.51	0.73	0.89	1.05	1.21	1.34	1.46	1.63
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	45.06	47.55	48.55	49.17	50.28	26.40	26.52	26.53	26.54	26.51	26.59	26.67	26.78	26.91	26.98
Thunder Bay	*Red Rock DS*	Non Coincidental Gross						4.01	4.02	4.04	4.02	4.06	4.09	4.10	4.10	4.11	4.11
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.21	0.23
		DG						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.23	0.23
		Non Coincidental Net	3.97	3.87	4.08	4.09	4.02	3.95	3.94	3.93	3.88	3.88	3.90	3.88	3.87	3.67	3.64
West of Thunder Bay	*Sam Lake DS*	Non Coincidental Gross						23.97	24.05	24.44	24.88	25.12	25.36	25.57	25.79	26.07	26.36
		CDM						0.16	0.26	0.46	0.67	0.82	0.97	1.11	1.23	1.34	1.50
		DG						0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	19.80	22.25	23.23	23.00	23.42	23.80	23.78	23.98	24.20	24.30	24.38	24.46	24.56	24.73	24.85
West of Thunder Bay	*Sapawe DS*	Non Coincidental Gross						0.95	0.95	0.97	0.98	0.99	1.00	1.01	1.01	1.02	1.03
		CDM						0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.95	0.80	0.94	0.92	2.61	0.95	0.94	0.95	0.96	0.96	0.96	0.96	0.97	0.97	0.97
Greenstone-Marathon	*Schreiber Winnipg DS*	Non Coincidental Gross						5.19	5.20	5.29	5.38	5.43	5.48	5.52	5.57	5.63	5.69
		CDM						0.03	0.06	0.10	0.14	0.18	0.21	0.24	0.26	0.29	0.32
		DG						0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Non Coincidental Net	4.47	5.21	5.19	5.07	5.32	5.15	5.15	5.19	5.22	5.24	5.26	5.27	5.29	5.33	5.35
West of Thunder Bay	*Shabaqua DS*	Non Coincidental Gross						2.80	2.81	2.85	2.89	2.92	2.94	2.96	2.98	3.01	3.04
		CDM						0.02	0.03	0.05	0.08	0.10	0.11	0.13	0.14	0.15	0.17
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.64	2.83	2.83	2.81	2.74	2.78	2.77	2.79	2.81	2.82	2.83	2.83	2.84	2.85	2.86
West of Thunder Bay	*Sioux Narrows DS*	Non Coincidental Gross						4.49	4.49	4.55	4.62	4.65	4.68	4.71	4.73	4.77	4.81
		CDM						0.03	0.05	0.09	0.12	0.15	0.18	0.20	0.23	0.25	0.27
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	4.09	4.25	4.37	4.34	4.22	4.46	4.44	4.46	4.49	4.50	4.50	4.50	4.51	4.53	4.54
North of Dryden	*Slate Falls DS*	Non Coincidental Gross						0.64	0.64	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.70
		CDM						0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.56	0.63	0.62	0.61	0.61	0.64	0.63	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.66

IRRP	Transformer Station Name	Customer Data (MW)	Peak Load (MW)														
			Historical Data					Near Term Forecast					Medium Term Forecast Provided			Medium Term Forecast Est.	
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
West of Thunder Bay	*Valora DS*	Non Coincidental Gross						0.77	0.78	0.79	0.81	0.83	0.84	0.85	0.86	0.88	0.89
		CDM						0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.05
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	0.64	0.70	0.74	0.73	0.69	0.77	0.77	0.78	0.79	0.80	0.81	0.81	0.82	0.83	0.84
West of Thunder Bay	*Vermilion Bay DS*	Non Coincidental Gross						3.95	3.97	4.01	4.06	4.09	4.12	4.15	4.18	4.21	4.25
		CDM						0.03	0.04	0.08	0.11	0.13	0.16	0.18	0.20	0.22	0.24
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	2.22	2.36	2.37	2.43	2.10	3.93	3.92	3.94	3.95	3.96	3.96	3.97	3.98	3.99	4.00
West of Thunder Bay	*Whitedog DS*	Non Coincidental Gross						2.37	2.39	2.41	2.44	2.46	2.49	2.51	2.54	2.56	2.59
		CDM						0.02	0.03	0.05	0.07	0.08	0.09	0.11	0.12	0.13	0.15
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	1.97	2.19	2.30	2.40	2.31	2.35	2.36	2.37	2.37	2.38	2.39	2.40	2.42	2.43	2.44
Greenstone-Marathon	*White River DS*	Non Coincidental Gross						7.02	7.06	7.18	7.32	7.41	7.49	7.56	7.64	7.73	7.83
		CDM						0.05	0.08	0.13	0.20	0.24	0.29	0.33	0.36	0.40	0.45
		DG						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Non Coincidental Net	3.20	3.20	6.80	6.74	6.44	6.98	6.98	7.05	7.13	7.16	7.20	7.23	7.28	7.34	7.38

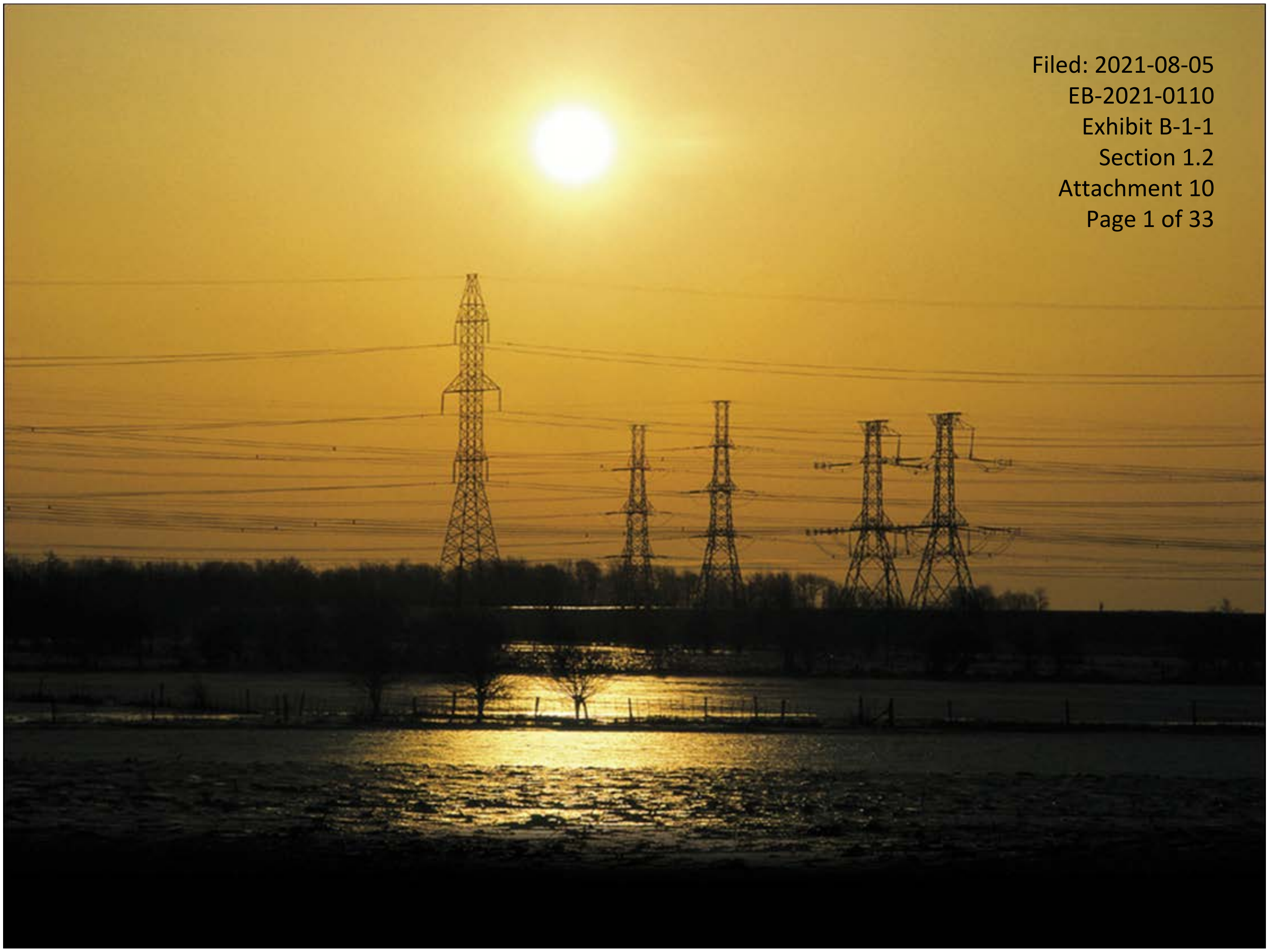
Appendix E. Past Sustainment Activities in Northwest Ontario

Station	I/S Date	Asset Class
ALEXANDER SS	8-Dec-16	Breaker: SF6_115 kV
BIRCH TS	3-Dec-15	Transformer: Step-down_115 kV
DRYDEN TS	29-Aug-16	Breaker: SF6_115 kV
	14-Jul-16	Breaker: SF6_115 kV
	20-Oct-16	Breaker: SF6_115 kV
	10-Nov-16	Breaker: SF6_115 kV
	29-May-16	Breaker: SF6_115 kV
	23-Jul-14	Breaker: SF6_13.8 kV
	4-Sep-14	Breaker: SF6_13.8 kV
	29-Aug-16	Switch: Air Break_115 kV
	29-Aug-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	14-Jul-16	Switch: Air Break_115 kV
	31-Aug-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	10-Nov-16	Switch: Air Break_115 kV
	20-Oct-16	Switch: Air Break_115 kV
	29-May-16	Switch: Air Break_115 kV
	1-Nov-16	Switch: Air Break_115 kV
	23-Jul-14	Switch: Air Break_13.8 kV
	4-Sep-14	Switch: Air Break_ 13.8 kV
FORT FRANCES TS	23-Nov-10	Breaker: SF6_13.8 kV
	2-Sep-10	Breaker: SF6_13.8 kV
	2-Oct-13	Switch: Air Break_115 kV
	27-Nov-15	Switch: Air Break_230 kV
	2-Oct-13	Switch: Ground_115 kV
	27-Nov-15	Switch: Ground_230 kV
	2-Sep-10	Switch: Air Break_ 13.8 kV
	2-Oct-16	Switch: Air Break_115 kV
	12-Sep-14	Switch: Ground_ 44 kV
	23-Nov-10	Switch: Air Break_ 13.8 kV
LAKEHEAD TS	27-Sep-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	14-Dec-11	Breaker: SF6_115 kV
	1-Dec-09	Breaker: SF6_13.8 kV
	4-Apr-12	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Ground_ 13.8 kV
	16-Nov-09	Switch: Air Break_ 13.8 kV
	21-Oct-09	Switch: Ground_ 13.8 kV
	21-Oct-09	Switch: Air Break_ 13.8 kV
	12-Sep-16	Transformer: Autotransformer_230 kV

Station	I/S Date	Asset Class
KENORA TS	15-Jul-2009	Breaker: SF6_13.8 kV
	29-May-2015	Switch: Air Break_230 kV
	29-May-2015	Switch: Ground_230 kV
	26-Feb-2013	Switch: Air Break_230 kV
	15-Jul-2009	Switch: Air Break_ 13.8 kV
MACKENZIE TS	17-Jun-2010	Breaker: SF6_13.8 kV
MANITOUWADGE TS	2-Jul-2016	Breaker: SF6_27.6 kV
	10-Jul-2016	Switch: Air Break_ 44 kV
	9-Jul-2016	Transformer: Step-down_115 kV
MARATHON TS	25-May-2009	Breaker: SF6_230 kV
	26-Mar-2014	Breaker: SF6_13.8 kV
	18-Dec-2013	Breaker: SF6_13.8 kV
	23-Dec-2016	Switch: Air Break_230 kV
	23-Dec-2016	Switch: Ground_230 kV
	26-Mar-2014	Switch: Air Break_ 13.8 kV
	18-Dec-2013	Switch: Air Break_ 13.8 kV
MOOSELAKE TS	8-Sep-2014	Breaker: SF6_115 kV
	31-Jul-2014	Breaker: SF6_115 kV
	29-May-2014	Breaker: SF6_115 kV
	8-Sep-2014	Breaker: SF6_115 kV
	11-Jul-2014	Breaker: SF6_115 kV
PORT ARTHUR TS #1	11-Aug-2015	Switch: Air Break_115 kV
	25-Nov-2009	Switch: Air Break_115 kV
	11-Nov-2009	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Air Break_115 kV
	20-Nov-2009	Switch: Air Break_115 kV
	6-Nov-2009	Switch: Air Break_115 kV
	22-Jun-2015	Switch: Air Break_115 kV
	2-Jun-2015	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Air Break_115 kV
	21-Sep-2012	Switch: Ground_115 kV
RABBIT LAKE SS	16-Dec-2011	Breaker: SF6_115 kV
	10-Nov-2011	Breaker: SF6_115 kV
	22-Oct-2011	Switch: Air Break_115 kV
	25-Nov-2016	Switch: Air Break_115 kV
	15-Nov-2016	Switch: Ground_115 kV
	23-Oct-2011	Switch: Air Break_115 kV

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
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
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
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



Windsor-Essex

REGIONAL INFRASTRUCTURE PLAN

March 18, 2020

hydro one

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Prepared and supported by:

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

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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 WINDSOR-ESSEX REGION.

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

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

This RIP is the final phase of the second cycle of Windsor-Essex regional planning process, which follows the completion of the Windsor-Essex Integrated Regional Resource Plan ("IRRP") in September 2019 and the Windsor-Essex Region Needs Assessment ("NA") in October 2017. This RIP provides a consolidated summary of the needs and recommended plans for Windsor-Essex Region in the near-term (up to 5 years) and the mid-term (5-10 years).

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

- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): two 27.6 kV feeder breakers have been replaced.
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- 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 2019)
- Leamington TS expansion: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)

- Kingsville TS transformers replacement (in progress, I/S 2022): Transformers T2 and T4 have been replaced with 50/83 MVA T6 in 2018. Transformers T1 and T3 replacement is underway.
- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (expected I/S 2024).

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 Windsor-Essex Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate ($M)
1	Supply capacity need to Kingsville- Leamington area	• Build new switching station at Leamington Junction (Lakeshore TS), and new DESN station (South Middle Road TS) • Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS	2022-2025	$295M
2	Lauzon TS T5/T6 transformers end-of-life and station capacity	• Replace Lauzon TS T5 & T6 transformers replacement with larger 75/125 MVA units	2024	$34M
3	Kent TS station capacity	• Install new feeder positions to supply load growth at Kent TS • Further evaluate the plan for a new DESN south of Chatham as part of the Chatham-Lambton-Sarnia regional planning process	-	-
4	Belle River TS station capacity	• Monitor load growth and re-evaluate the need in the next regional planning cycle	-	-

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.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE WINDSOR-ESSEX REGION BETWEEN 2020 AND 2030.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Hydro One, E.L.K. Energy Inc., Entegrus Powerlines Inc., EnWin Utilities Ltd., Essex Powerlines Corporation, 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 Windsor-Essex Region is comprised of the area southwest of the Municipality of Chatham-Kent. It includes the City of Windsor, Town of LaSalle, Town of Amherstburg, Town of Tecumseh, Town of Essex, Town of Lakeshore, Town of Kingsville, Municipality of Leamington, Township of Pelee, and the western portion of the Municipality of Chatham-Kent.

Electrical supply to the region is provided by seventeen 230 kV and 115 kV step-down transformer stations ("TS"). The map of the region is shown in Figure 1-1 below.

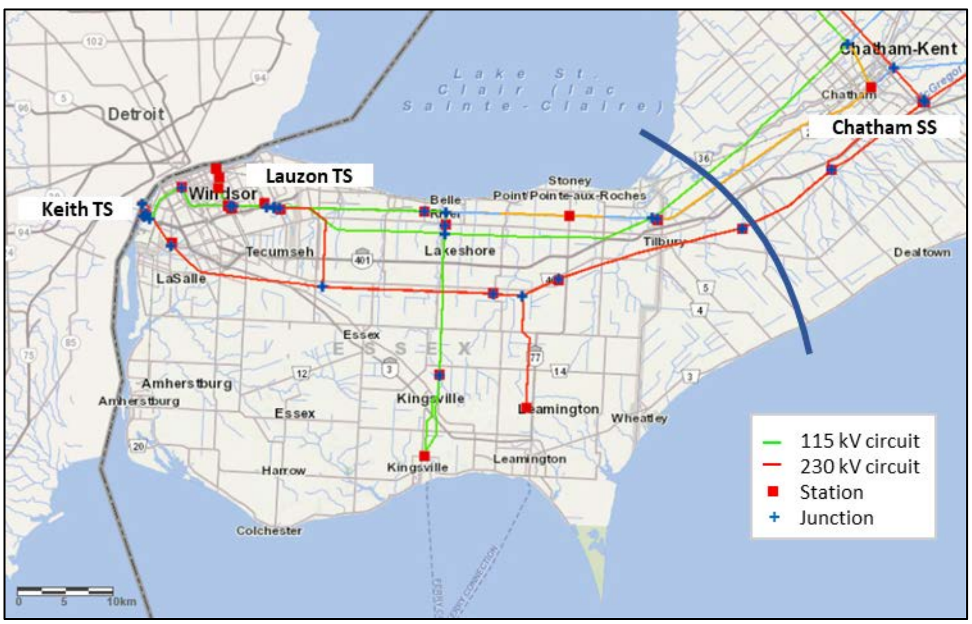


Figure 1-1: Windsor-Essex Region Map

1.1 Objectives and Scope

The 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;

- 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/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, 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 near to mid-term planning horizon (i.e., within the next 10 year period);
- 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 is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

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

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

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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

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

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

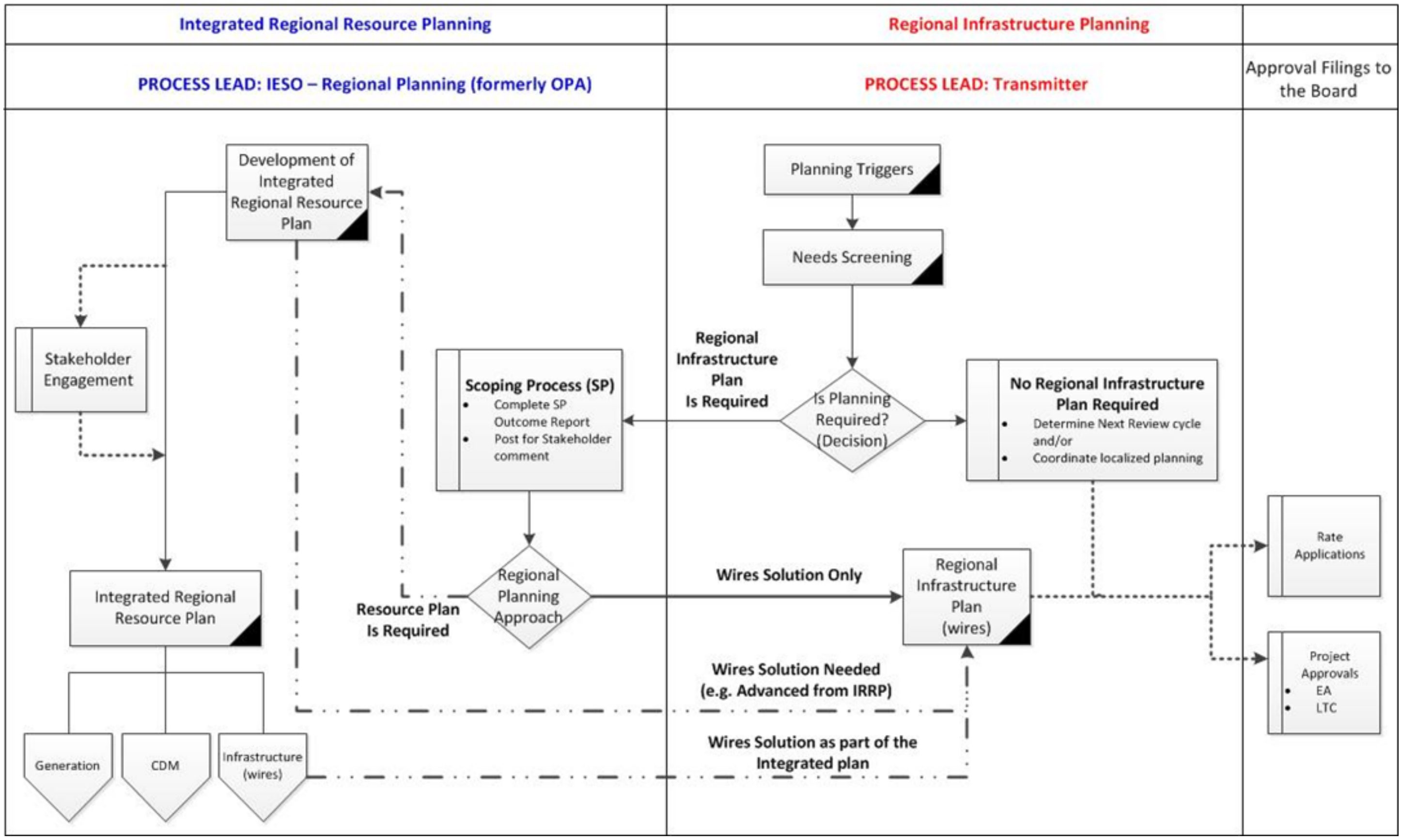


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

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

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

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

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

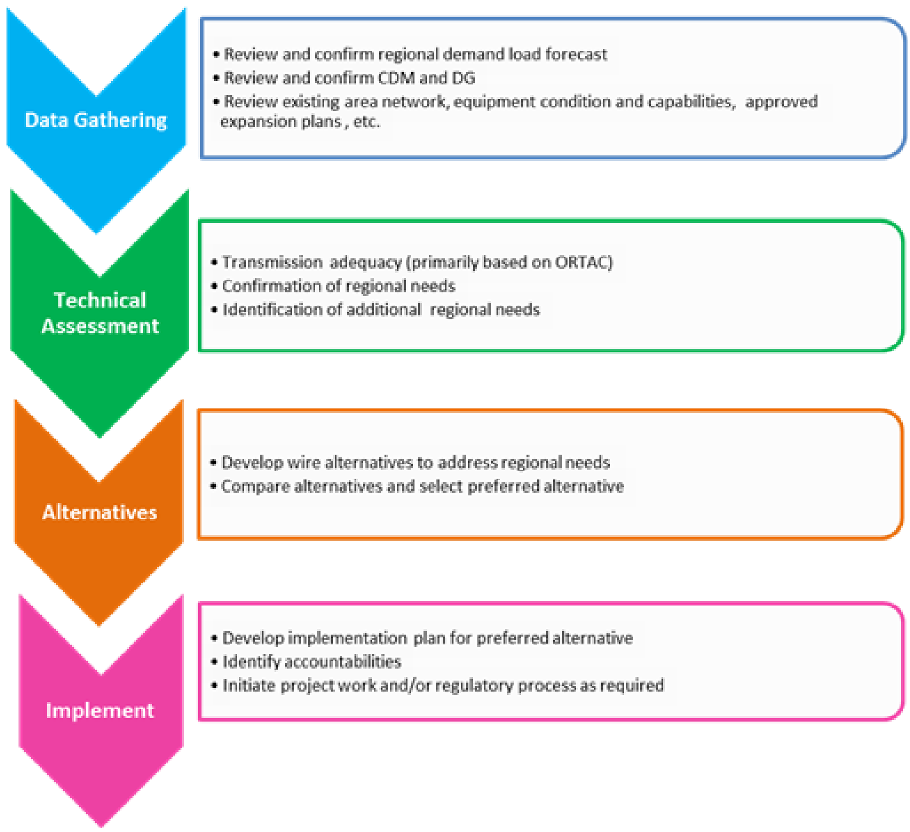


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE WINDSOR-ESSEX REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY CANADA-UNITED STATES (MICHIGAN) BORDER TO THE WEST AND THE MUNICIPALITY OF CHATHAM-KENT TO THE EAST. IT IS THE SOUTHERNMOST REGION OF ONTARIO.

The main transmission corridor in the region connects with the rest of the Hydro One system at Chatham Switching Station ("SS") and connects the Ontario transmission system with the Michigan transmission system at Keith TS.

The region's 115 kV network connects to the 230 kV transmission system at Keith TS and Lauzon TS via two autotransformers in each station. Fourteen 115 kV step-down transformer stations ("TS") and three 230 kV TS's serve the electrical load in the region through the 115 kV and 230 kV transmission network, as shown in Figure 3-1. Leamington TS is a new transformer station serving demand in the Kingsville-Leamington area, and came into service in 2017. Installation of a new second DESN at Leamington TS was completed in 2019.

There are 13 customer-owned generating plants in the region, connecting at the 230 kV and 115 kV levels with a combined contract capacity of 1,574 MW. Table 3-1 lists the region's transmission connected generations.

Table 3-1: Transmission Connected Generations

Station Name	Technology	Connection Point	Contract Capacity (MW)
Brighton Beach Power Station	Combined Cycle	Keith TS	541.25
West Windsor Power	Combined Cycle	J2N (Keith TS)	122.78
TransAlta Windsor Essex Cogeneration	CHP	Z1E	72.28
East Windsor Cogeneration	CHP	E8F/E9F	84
Gosfield Wind Project	Wind	K2Z	50.6
Pointe Aux Roches Wind	Wind	K6Z	48.6
Comber East (C24Z) Wind Project	Wind	C24Z	82.8
Comber West (C23Z) Wind Project	Wind	C23Z	82.8
KEPA Port Alma Wind Farm (I and II)	Wind	C24Z	200.6
RWEC Dillon Wind Farm	Wind	C23Z	78
Belle River Wind	Wind	C23Z	99.8
Romney Wind Farm	Wind	C21J	60
Windsor Solar	Solar	Z1E	50

The Windsor-Essex Region summer coincident peak demand in 2019 was about 1032 MW, adjusted to extreme weather. The region is served by five Local Distribution Companies ("LDC"): E.L.K. Energy Inc., Entegrus Powerlines Inc., EnWin Utilities Ltd., Essex Powerlines Corporation, and Hydro One Distribution. EnWin and Hydro One Distribution are directly connected to the transmission system, while three other LDCs have low voltage connections.

A single line diagram showing the electrical facilities in Windsor-Essex Region is provided in Figure 3-1.

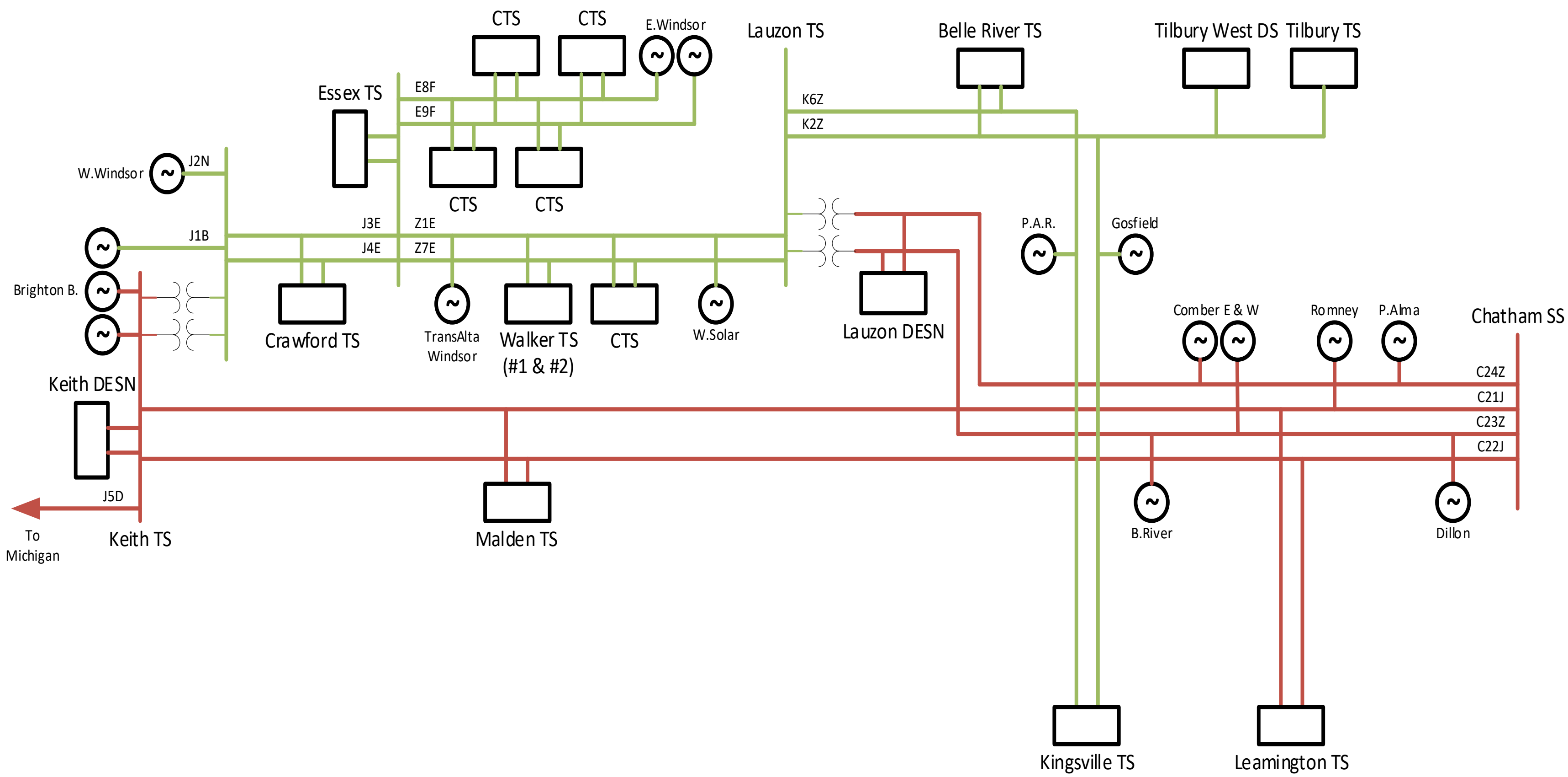


Figure 3-1: Single Line Diagram of Windsor-Essex Region's Existing Transmission System

4 TRANSMISSION FACILITIES 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 WINDSOR-ESSEX REGION.

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

- Malden TS transformers replacement (I/S 2011): T1 and T2 were replaced in 2010 and 2011, respectively.
- Walker TS #1: Reactor installation for short circuit mitigation (I/S 2011).
- Kingsville TS: Reactor installation for short circuit mitigation (I/S 2011).
- Keith TS: Reactor installation for short circuit mitigation (I/S 2012).
- Lauzon TS breakers replacement (I/S 2012): Three breakers were replaced (SC2Q, SC3E, and SC4J).
- Keith TS DESN transformers replacement (I/S 2013): T23 and T22 were replaced in 2008 and 2013, respectively.
- Keith TS breakers replacement (I/S 2015): Six breakers were replaced (SC11K, SC11SC, SC1B, T11P, T12P, and SC2Y).
- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): two 27.6 kV feeder breakers have been replaced.
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- 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 2019)
- Leamington TS expansion: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)
- Kingsville TS transformers replacement (in progress, I/S 2022): Transformers T2 and T4 have been replaced with 50/83 MVA T6 in 2018. Transformers T1 and T3 replacement is underway.
- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (planned I/S 2024)

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Windsor-Essex Region is anticipated to grow at an average rate of 1.5% over the next ten years. The Windsor-Essex Region has been historically a summer-peaking region. With the new development in the greenhouse sector particularly in the Kingsville-Leamington area, the region peak demand has gradually shifted to the winter season. Figure 5-1 shows the updated Windsor-Essex Region's summer non-coincident and coincident peak load forecast for the 2020-2030 study period.

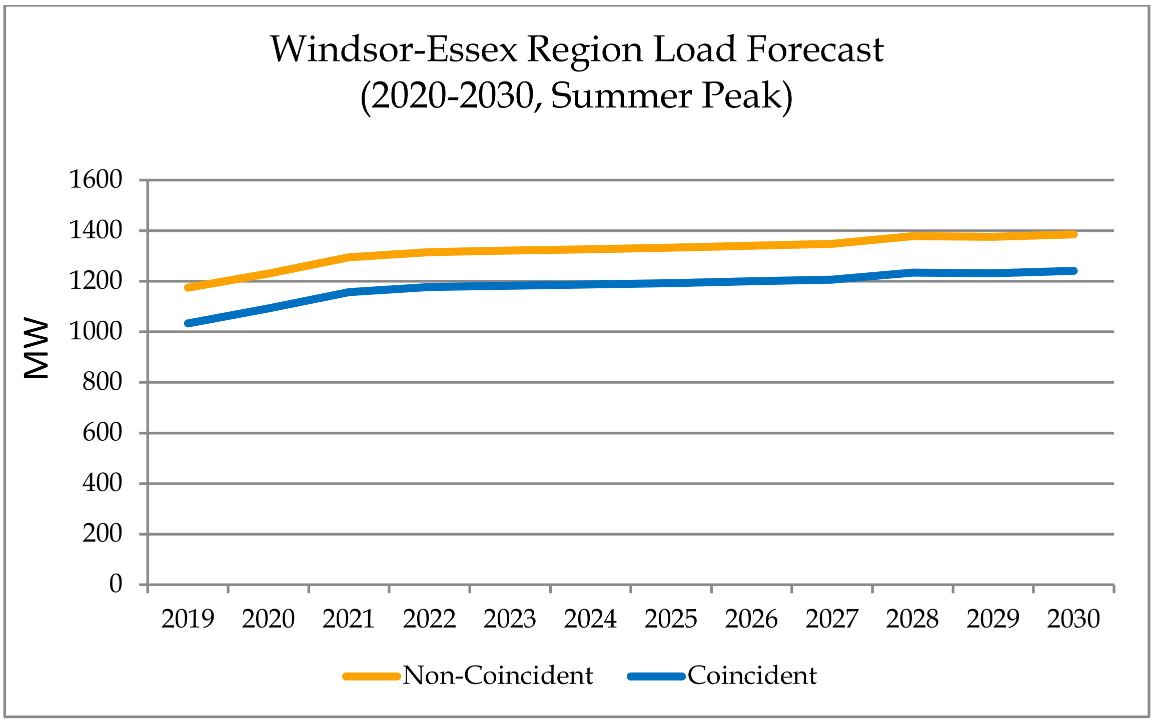


Figure 5-1: Windsor-Essex Region Load Forecast (Summer Peak)

The load forecast shows that the Region peak summer load increases from 1093 MW in 2020 to 1241 MW by 2030. The corresponding non-coincident summer peak loads increase from 1230 MW to about 1385 MW over the same period. The non-coincident and coincident net load forecasts for the individual stations in the Windsor-Essex Region are given in Appendix D, Table D-1 and Table E-1. Specifically for Kingsville TS and Leamington TS, based on their load characteristics, the annual peak of the stations occurs in the winter, thus for the two stations, the winter load forecast is also provided in Table D-2 and E-2 (for non-coincident and coincident forecast, respectively).

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2020-2030.

- Load forecast includes the contribution from the distributed generation (DG) and conservation, and demand management (CDM) program, as provided by the 2019 Windsor-Essex IRRP (i.e., net load forecast).
- All facilities identified in Section 4 and that are planned to be placed in-service within the study period are assumed 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 WINDSOR-ESSEX REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the Windsor-Essex Region and plans to address these needs for the study period of 2020-2030. Table 6.1 provides a summary of the needs and the corresponding sub-sections where recommendation and plans are discussed.

Table 6-1: Identified Near and Mid-Term Needs in Windsor-Essex Region

Section	Facilities	Need	Timing
6.1	• New Switching Station ("Lakeshore TS") • DESNs ("South Middle Road TS") • New 2-circuit 230 kV transmission line (Chatham SS x Lakeshore TS)	Supply capacity to Kingsville-Leamington area load	2023
6.2	Lauzon TS	Step-down transformers T6/T8 end-of-life and T5/T6 station capacity	2024
		Step-down transformers T5/T7 and autotransformers T1/T2 end-of-life	2029
	Lauzon 115 kV Subsystem (i.e., stations radially supplied from Lauzon TS via K2Z/K6Z)	Load meeting capability due to voltage change violations	Today
6.3	Kent TS	Station capacity	2025
6.4	Belle River TS	Station capacity	2028

6.1 Supply Capacity to Kingsville-Leamington Area Load

6.1.1 Description

In the first cycle of regional planning for the Windsor-Essex Region, the Study Team recommended the Supply to Essex County Transmission Reinforcement (SECTR) project to supply the unprecedented load growth in the Kingsville-Leamington area driven by greenhouse development. The SECTR project included 13 km extension of existing 230 kV double-circuits C21J/C22J south to Leamington, and a new Leamington TS DESN, adding 200 MW of supply capacity in the Kingsville-Leamington area. The SECTR project was placed in service late 2017.

The added supply was fully allocated by the time SECTR project was in-service. The continuing significant load growth in the Kingsville – Leamington and the associated load forecast indicated that changes would be required in the recommended plan as set out in the first cycle RIP of December 2015. This situation triggered the second cycle of regional planning for the Windsor – Essex region, with the Needs Assessment completed in October 2017.

To meet the growing electricity demand in the area, Hydro One proceeded to build the second DESN at Leamington TS. This expansion of Leamington TS, placed in service in late 2019, doubles the station capacity to 400 MW. Again, the rapidly growing demand in Kingsville-Leamington area exceeded the expanded station capacity – the existing connection applications in total are about 100 MW over the expanded station capacity. The magnitude of the electricity demand in this area not only exceeded station capacity, but also exceeded load meeting capacity of the transmission system. As consequences of this increasing demand, station capacity need, upstream transmission need, and load security need in this area have been identified by the Study Team. Until the transmission system is sufficiently upgraded, the system inadequacy would be managed with Special Protection Systems.

6.1.2 Alternatives and Recommendation

During the IRRP process, the Study Team has assessed the potential of non-wires alternatives including demand response, energy efficiency, and local generation to meet the supply capacity need in the Kingsville-Leamington area.

The Study Team recommends building a new switching station at Leamington JCT and new DESNs to meet the requirements of forecast load growth in the Kingsville – Leamington area. The team also recommends building a new 2 – circuit 230 kV line between Chatham SS and the new station at Leamington Junction.

Recommended Stations Project and Current Status

Hydro One has commenced a project to build a switching station in the vicinity of the existing Leamington Junction in the Town of Lakeshore in Essex County. All the 230 kV circuits C21J, C22J, C23Z and C24Z at this junction will be terminated at this station with full switching. The new station, to be known as Lakeshore Transformer Station, will have provision for additional development in the future. A second station will be built in close proximity to Lakeshore TS for the establishment of two new DESNs. This new station will be known as South Middle Road Transformer Station. Both stations will be located in the same Hydro One property in the Town of Lakeshore (Figure 6-1).

Each of the two DESNs at South Middle Road TS will consist of 2 x 75/100/125 MVA, 230/27.6 – 27.6 kV power transformers, twelve LV feeder positions and 2 LV capacitor banks, plus required switchgear.

Hydro One has completed necessary engagement activities and Class Environmental Assessment work for the establishment of the two stations. Hydro One obtained EA approval for the stations with the submission of the final Environmental Study Report to the Ministry of the Environment, Conservation and Parks, in January 2020. Construction is planned to commence in Q3 2020 for both Lakeshore TS and the first of the two DESNs at South Middle Road TS, and both facilities are planned to be in service in Q2 2022.

The second DESN at South Middle Road TS is planned to be in service in Q3 2025.

<u>Recommended Line Project and Current Status</u>

Hydro One is in the planning stages of the project to build a 2 x 230 kV line, about 49 km, between Chatham SS and Lakeshore TS. Engagement activities and Class Environmental Assessment studies are planned to commence in January 2020. EA approval and the OEB "Leave to construct" approval for the new line are expected in 2021 and 2022, respectively. The line is planned to be placed in service in Q4 2025.

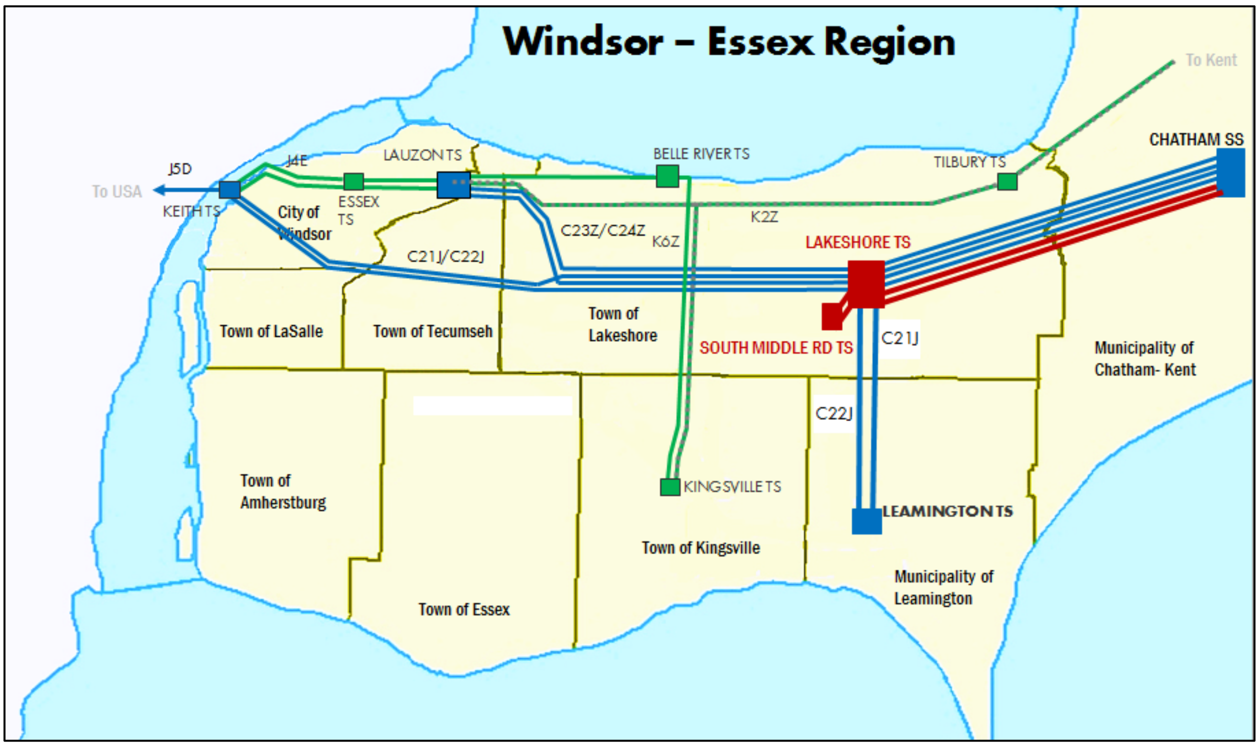


Figure 6-1: Planned Lakeshore TS, South Middle Road TS and Chatham SS x Lakeshore TS Line

6.2 Lauzon TS Transformers End-of-Life & Lauzon 115 kV Subsystem Supply Capacity Need

6.2.1 Description

Lauzon TS is located in the eastern part of the City of Windsor, and includes 230/115 kV autotransformation facility (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 C23Z/C24Z, and 115 kV circuits Z1E/Z7E and K2Z/K6Z.

All of the Lauzon TS autotransformers and step-down transformers are reaching their end-of-life within the next 10 years. The T6 and T8 transformers are expected to reach their end-of-life by 2024, while the rest of the units (T1, T2, T5, and T7) are expected to reach their end-of-life by 2029. Figure 6-2 shows the overview of the station and the surrounding area.

Figure 6-2: Lauzon TS

Over the next 10 years, the combined station summer peak load is expected to remain fairly constant at approximately 220 MW. The T5/T6 DESN supplies approximately 130 MW of load, and the T7/T8 DESN supplies 90 MW of load. Considering each DESN is rated approximately 100 MW, a station capacity need has also been identified at the T5/T6 DESN level as well at the combined station level.

In addition, there is an existing supply capacity need in the Lauzon 115 kV subsystem, as shown in Figure 6-3, which includes stations supplied by the 115 kV K2Z/K6Z (i.e., Kingsville TS, Belle River TS, and Tilbury West DS). This need arises due to voltage change violations of ORTAC following certain contingencies. This need is being evaluated in-detail through a separate study, to be provided as an addendum to the 2019 Windsor-Essex IRRP, expected for completion in Q3 2020.

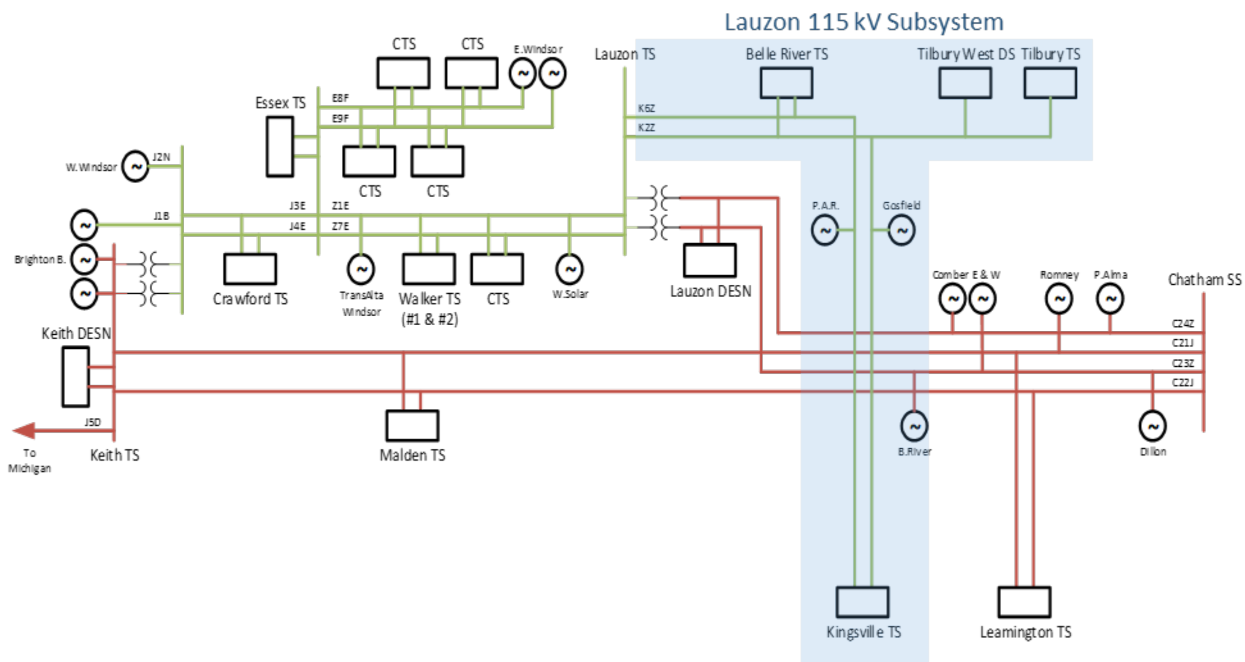


Figure 6-3: Lauzon 115 kV Subsystem

6.2.2 Alternatives and Recommendation

The following alternatives are considered to address the above end-of-life and station capacity needs:

1. **Maintain Status Quo:** This alternative was considered and rejected as it does not address the station capacity and risk of failure due to asset condition and would result in increased maintenance cost and reduce supply reliability for customers.
2. **Like-for-Like Replacement:** This alternative was considered and rejected as it does not address the station capacity need.
3. **Load Balancing between two DESNs:** Load balancing between two DESNs can be achieved through distribution feeders' re-configuration. This alternative was considered and rejected as the load forecast shows demand at Lauzon TS exceeds 200 MW in the whole study period.
4. **Distribution Load Transfer to Nearby Stations:** This alternative is not feasible as there are no sufficient capability to transfer the excess load to nearby stations.
5. **Replace and Upgrade the End-of-Life Transformers T5/T6:** This option will address the station capacity need and the T5/T6 end-of-life need.

The Study Team recommends Hydro One proceed with Alternative 5 – to replace the 50/83 MVA T5/T6 with 75/125 MVA units, with expected in-service date of 2024. The strategy of T1/T2 and T7/T8 replacement will be determined after the Lauzon 115 kV subsystem study is completed (expected Q3 2020).

6.3 Kent TS Station Capacity Need

6.3.1 Description

Kent TS is part of the Chatham-Lambton-Sarnia Region, and at the inter-regional boundary with the Windsor-Essex Region. Kent TS is located approximately 6 km to the northwest of Chatham SS, and is electrically connected to 230 kV double circuits L28C/L29C between Chatham SS and Lambton TS. Kent TS consists of two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4). The T1/T2 DESN is rated 153 MVA of capacity in summer; while the T3/T4 DESN is rated 58.7 MVA. Based on historical peak loading, and a request for load allocation, Entegrus was allocated 38 MW of incremental load at the T1/T2 DESN. Hydro One is currently coordinating with Entegrus to connect two new feeder positions at the T1/T2 DESN.

Figure 6-4 below shows the map and transmission system around Kent TS.

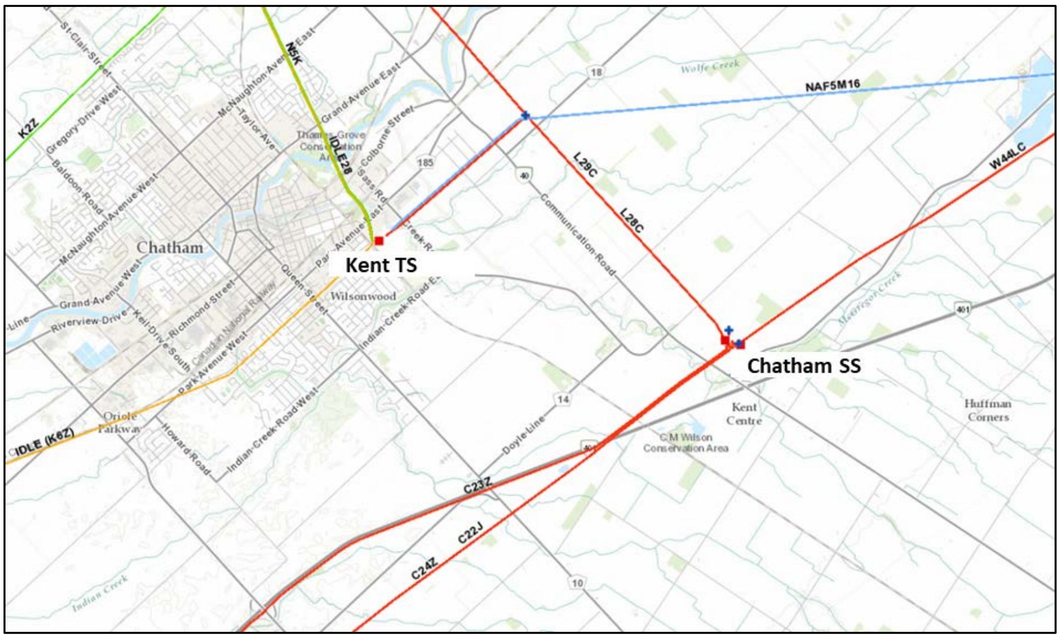


Figure 6-4: Kent TS Map

While Kent TS is part of the Chatham-Lambton-Sarnia Region, and not in the Windsor-Essex Region, there was an urgent capacity need identified by the LDCs in the region. There is a 55 MW load connection anticipated at Kent TS, and in addition, the load forecast predicts that the existing load will increase by 12.5 MW in the next five years. In 2020, the station capacity at Kent TS is expected to be fully utilized; and there will be an incremental capacity need of 30-40 MW over the next ten years.

6.3.2 Alternatives and Recommendation

The Study Team has evaluated the potential of upsizing Kent TS transformers and/or adding new DESN transformers at the station to provide the additional station capacity. Assessments concluded that those options were not feasible because long feeders would be required to connect the new load (located South of Chatham) to Kent TS, which would incur significant costs, higher losses along with challenges with station egress and feeder routing. Accordingly, the Study Team has determined that the recommended location for a new DESN is south of Chatham.

However, several transmission planning assessments are currently underway, including the Dresden area study which will be followed by regional planning for the Chatham-Kent-Lambton-Sarnia Region to be triggered in Q1/Q2 2020. In light of the fact that load forecasts for Chatham have shifted out the capacity need, the Study Team recommends that the plan for the new DESN South of Chatham to be further evaluated as part of the upcoming Chatham-Kent-Lambton-Sarnia regional planning process.

6.4 Belle River TS Station Capacity Need

6.4.1 Description

The existing Belle River TS comprises a 115 kV/27.6 kV DESN (T1/T2). It is supplied by two 115 kV circuits K2Z and K6Z. The station capacity is approximately 54 MW. The summer peak of its serving area is currently 45 MW. According to the load forecast in the study period, Belle River TS is expected to have moderate load growth. The station capacity is expected to be exceeded as early as in 2028.

6.4.2 Alternatives and Recommendation

1. **Maintain Status Quo:** Do nothing, and monitor if the forecasted load growth materializes.
2. **Non-wires Alternatives:** The provincial energy-efficiency initiatives could relieve the future capacity need at Belle River TS and keep the station loading below the station capacity.
3. **Wires Alternatives:** The wire alternatives to this need include upgrading the existing transformers to higher rating units, or transferring some of Belle River TS load to nearby stations through distribution load transfer.

The Study Team recommends Alternative 1, that no further investment is required at this time due to the amount of lead time available. Hydro One and relevant LDCs will continue monitoring the load growth at Belle River TS and re-evaluate the station capacity need in the next planning cycle.

7 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE WINDSOR-ESSEX REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 7-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 7-1: Recommended Plans in Windsor-Essex Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate ($M)
1	Supply capacity need to Kingsville- Leamington area	• Build new switching station at Leamington Junction (Lakeshore TS), and new DESN station (South Middle Road TS) • Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS	2022-2025	$295M
2	Lauzon TS T5/T6 transformers end-of-life and station capacity	Replace Lauzon TS T5 & T6 transformers replacement with larger 75/125 MVA units	2024	$34M
3	Kent TS station capacity	• Install new feeder positions to supply load growth at Kent TS • Further evaluate plan for the new DESN south of Chatham as part of the Chatham-Lambton-Sarnia regional planning process	-	-
4	Belle River TS station capacity	Monitor load growth and re-evaluate the need in the next regional planning cycle	-	-

The Study Team recommends that Hydro One to continue with the implementation of infrastructure investments listed in Table 7-1 while keeping the Study Team apprised of project status.

8 REFERENCES

[1] **Windsor-Essex Regional Infrastructure Plan (2015)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/RIP%20Report%20Windsor-Essex.pdf

[2] **Windsor-Essex Needs Assessment (2017)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs%20Assessment_Windsor-Essex_Final.pdf

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

[4] **Windsor-Essex Integrated Regional Resource Plan (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor_Essex_IRRP_Report_20190903.pdf?la=en

[5] **Windsor-Essex Integrated Regional Resource Plan – Appendices (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor_Essex_IRRP_Appendices_20190903.pdf?la=en

APPENDIX A. STATIONS IN THE WINDSOR-ESSEX REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Keith TS T1	115/27.6	Keith TS 115 kV Bus
Keith TS T22/T23	230/27.6	Keith TS 230 kV Bus
Leamington TS T1/T2	230/27.6	C21J/C22J
Leamington TS T3/T4	230/27.6	C21J/C22J
Malden TS T1/T2	230/27.6	C21J/C22J
Lauzon TS T5/T6	230/27.6	C23Z/C24Z
Lauzon TS T7/T8	230/27.6	C23Z/C24Z
Belle River TS T1/T2	115/27.6	K2Z/K6Z
Kingsville TS T1//T3/T6	115/27.6	K2Z/K6Z
Tilbury West DS	115/27.6	K2Z
Tilbury TS T1	115/27.6	K2Z
Crawford TS T3/T4	115/27.6	J3E/J4E
Essex TS T5/T6	115/27.6	Essex TS 115 kV Bus
Walker TS #1 T3/T4	115/27.6	Z1E/Z7E
Walker MTS #2	115/27.6	Z1E/Z7E
Ford Essex CTS	115/13.8	Z1E/Z7E
Chrysler WAP MTS	115/27.6	E8F/E9F
Ford Annex MTS	115/13.8	E8F/E9F
Ford Windsor MTS	115/27.6	E8F/E9F
G.M. Windsor MTS	115/27.6	E8F/E9F

APPENDIX B. TRANSMISSION LINES IN THE WINDSOR-ESSEX REGION

Location	Circuit Designations	Voltage (kV)
Chatham x Keith	C21J, C22J	230
Chatham x Lauzon	C23Z, C24Z	230
Keith x Essex	J3E, J4E	115
Lauzon x Essex	Z1E, Z7E	115
Essex x East Windsor CGS	E8F, E9F	115
Lauzon x Kingsville	K2Z, K6Z	115
Keith x Michigan Tie	J5D	115

APPENDIX C. DISTRIBUTORS IN THE WINDSOR-ESSEX REGION

Distributor Name	Station Name	Connection Type
E.L.K. Energy Inc.	Belle River TS	Dx
	Kingsville TS	Dx
	Lauzon TS	Dx
Entegrus Powerlines Inc.	Kingsville TS	Dx
	Leamington TS	Dx
	Tilbury West DS	Dx
EnWin Utilities Ltd.	Crawford TS	Tx
	Essex TS	Tx
	Keith TS	Tx
	Lauzon TS	Tx
	Malden TS	Tx
	Walker TS #1	Tx
	Walker MTS #2	Tx
	Chrysler WAP MTS	Tx
	Ford Annex MTS	Tx
	Ford Essex CTS	Tx
	Ford Windsor MTS	Tx
	G.M. Windsor MTS	Tx
Essex Powerlines Corp.	Keith TS	Dx
	Lauzon TS	Dx
	Leamington TS	Dx
	Malden TS	Dx
Hydro One Networks Inc. (Distribution)	Belle River TS	Tx
	Kingsville TS	Tx
	Lauzon TS	Tx
	Tilbury West DS	Tx
	Tilbury TS	Tx
	Keith TS	Tx
	Malden TS	Tx
	Leamington TS	Tx

APPENDIX D. WINDSOR-ESSEX REGION NON-COINCIDENT LOAD FORECAST

Table D-1: Windsor-Essex Non-Coincident (Summer) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Keith TS	142	104	88	87	87	86	86	85	85	85	85	85	85
Lauzon T5/T6	101	124	128	130	131	132	133	134	135	136	138	139	140
Lauzon T7/T8	103	87	88	87	88	88	89	89	89	89	90	90	90
Leamington T3/T4	183	121	120	122	123	123	123	124	125	126	127	127	128
Leamington T1/T2	183	4	68	125	139	139	139	139	140	140	140	144	145
Malden TS	183	134	134	134	135	135	135	134	135	136	137	137	137
115 kV													
Belle River TS	54	47	48	49	49	50	51	52	53	54	55	56	57
Crawford TS	92	81	82	82	83	84	85	86	87	88	88	89	90
Essex TS	107	89	90	90	91	92	93	93	94	95	95	96	97
Industrial Customer #1	59	34	34	35	35	35	35	35	35	35	35	35	35
Industrial Customer #2	39	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer #3	39	10	10	10	10	10	10	10	10	10	10	10	10
Industrial Customer #4	59	16	16	16	16	17	17	17	17	17	17	17	17
Industrial Customer #5	39	24	24	24	24	24	24	25	25	25	25	25	26
Kingsville TS	104	87	86	85	85	85	85	85	84	84	105	92	93
Tilbury TS	7	0	0	0	0	0	0	0	0	0	0	0	0
Tilbury West DS	31	19	19	20	20	20	20	20	20	21	21	21	22
Walker MTS #2	89	115	116	117	118	119	119	120	121	122	123	124	125
Walker TS #1	90	71	72	73	74	74	75	76	77	77	78	79	80

* Station LTR is based on 90% power factor

** Non-coincident station peak, adjusted to extreme weather

Table D-2: Kingsville TS and Leamington TS Non-Coincident (Winter) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Leamington T3/T4	195	109	166	181	181	181	180	180	181	180	181	217	226
Leamington T1/T2	195	3	61	114	127	127	127	127	127	128	128	146	152
115 kV													
Kingsville TS	116	102	116	116	116	116	116	116	116	115	115	128	131

APPENDIX E. WINDSOR-ESSEX REGION COINCIDENT LOAD FORECAST

Table E-1: Windsor-Essex Coincident (Summer) Net Load Forecast

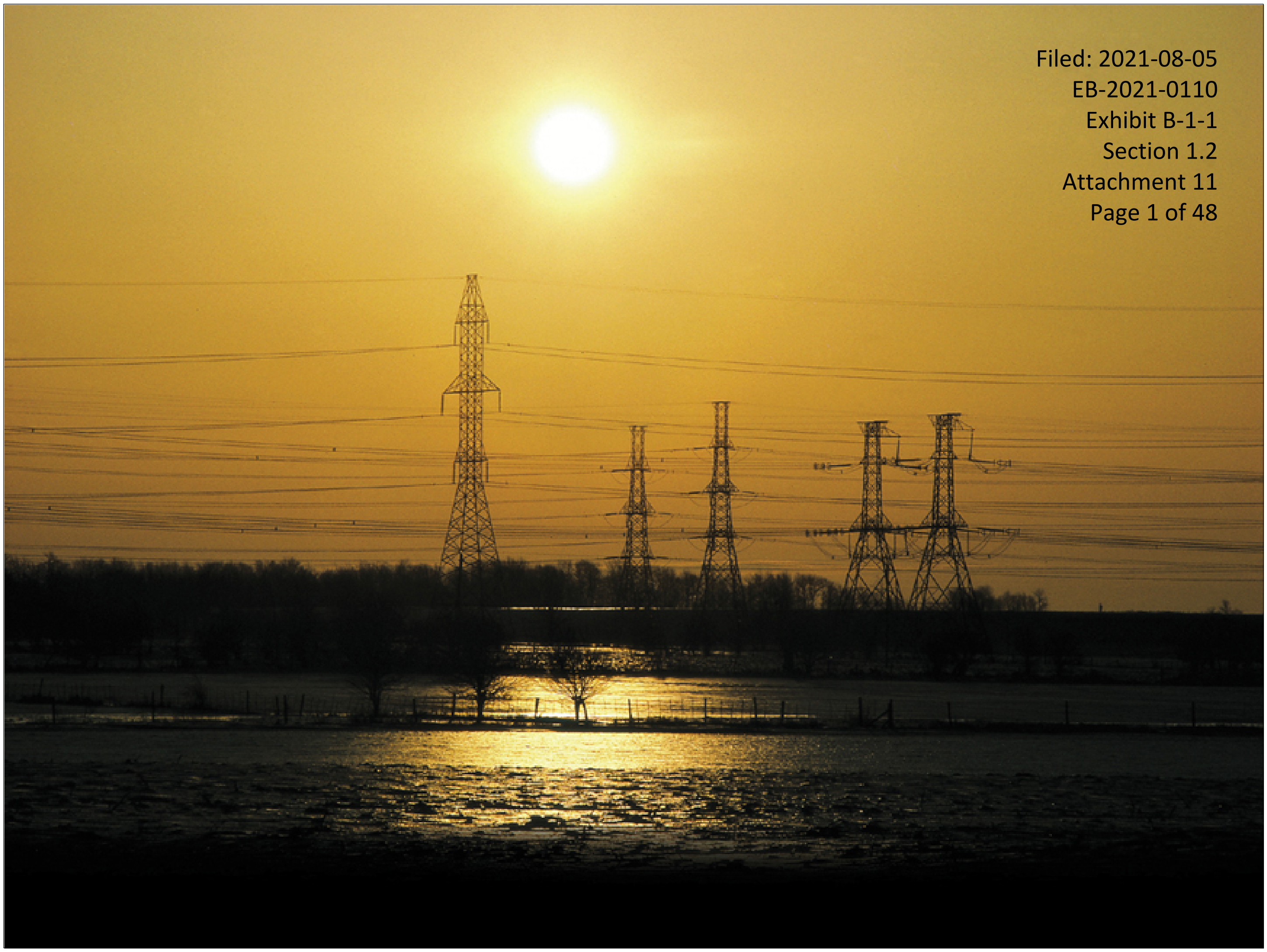
Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Keith TS	142	69	59	58	58	58	57	57	57	57	57	57	57
Lauzon T5/T6	101	121	125	126	127	128	129	130	131	133	134	135	136
Lauzon T7/T8	103	84	85	85	85	86	86	86	87	87	87	87	88
Leamington T3/T4	183	121	120	122	123	123	123	124	125	126	127	127	128
Leamington T1/T2	183	4	68	125	139	139	139	139	140	140	140	144	145
Malden TS	183	128	128	128	129	129	129	129	129	130	131	131	131
115 kV													
Belle River TS	54	44	45	46	47	48	49	49	50	51	52	53	54
Crawford TS	92	72	73	74	75	75	76	77	78	78	79	80	81
Essex TS	107	86	86	87	88	88	89	90	90	91	92	93	93
Industrial Customer #1	59	32	33	33	33	33	33	33	33	33	33	33	34
Industrial Customer #2	39	7	7	7	7	7	7	7	7	7	7	7	7
Industrial Customer #3	39	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer #4	59	4	4	4	4	4	4	4	4	4	4	4	4
Industrial Customer #5	39	15	15	15	15	15	15	15	16	16	16	16	16
Kingsville TS	104	82	81	80	80	80	80	80	79	79	99	87	87
Tilbury TS	7	0	0	0	0	0	0	0	0	0	0	0	0
Tilbury West DS	31	18	19	19	19	19	19	19	20	20	20	20	21
Walker MTS #2	89	76	77	77	78	79	79	80	81	81	82	82	83
Walker TS #1	90	61	61	62	62	63	64	64	65	66	66	67	68

* Station LTR is based on 90% power factor

** Coincident station peak, adjusted to extreme weather

Table E-2: Kingsville TS and Leamington TS Coincident (Winter) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Leamington T3/T4	195	109	166	181	181	181	180	180	181	180	181	217	226
Leamington T1/T2	195	3	61	114	127	127	127	127	127	128	128	146	152
115 kV													
Kingsville TS	116	87	99	99	99	99	99	99	98	98	98	109	112



London Area

REGIONAL INFRASTRUCTURE PLAN

August 25th, 2017

hydro one

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

With support from:

Organizations
Independent Electricity System Operator
Entegrus Inc.
Erie Thames Power Lines Corporation
London Hydro Inc.
St. Thomas Energy Inc.
Tillsonburg Hydro Inc.
Hydro One Networks Inc. (Distribution)

DISCLAIMER

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

The preferred solution(s) that have been identified in this report may be 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 NETWORKS INC. ("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 DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE LONDON AREA REGION.

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

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Entegrus Inc.
- Erie Thames Power Lines Corporation
- London Hydro Inc.
- St. Thomas Energy Inc.
- Tillsonburg Hydro Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the London Area Region which consists of the Strathroy Sub-Region, Greater London Sub-Region, Woodstock Sub-Region, Aylmer-Tillsonburg Sub-Region, and the St. Thomas Sub-Region. It follows the completion of the London Area Region's Needs Assessment ("NA") in April 2015, the London Area Region Scoping Assessment ("SA") in August 2015, the Strathroy TS Transformer Capacity Local Plan ("LP") in September 2016, the Greater London Sub-Region Integrated Regional Resource Plan ("IRRP") in January 2017, and the Woodstock Sub-Region Restoration Local Plan ("LP") in May 2017.

This RIP provides a consolidated summary of needs and recommended plans for the entire London Area Region. Needs which are to be addressed include:

- Load restoration in Woodstock Sub-Region
- Load restoration in Greater London Sub-Region
- Voltage constraints, thermal constrains and delivery point performance in Aylmer-Tillsonburg Sub-Region

The major infrastructure investments planned for the region over the near and mid-term, as identified in the regional planning process are given below.

No.	Project	I/S Date	Estimated Cost[1]
1	Distribution System Upgrades in the Greater London Sub-Region	2023	$1.8-4M ($180/kW)
2	Wonderland TS Reinvestment: Replace transformer T5	2022	$15-20M

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. 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.

[1] Costs presented are preliminary estimate and may change resulting from clarification of scope and through detailed cost estimating.

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1. INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Independent Electricity System Operator, Entegrus Inc., Erie Thames Power Lines Corporation, London Hydro Inc., St. Thomas Energy Inc., Tillsonburg Hydro Inc., and Hydro One Networks Inc. (Distribution) in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The London Area is located in South Western Ontario and includes all or part of the following Counties, and Cities: Oxford County, Middlesex County, Elgin County, Norfolk County, the City of Woodstock, the City of London, and the City of St. Thomas. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

The region also includes the following First Nations: Chippewas of the Thames, Oneida Nation of the Thames, and Munsee-Delaware Nation.

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fifteen Hydro One step-down TS's, four direct transmission connected load customers and three transmission connected generators in the London Area. The distribution system consists of voltage levels 27.6 kV and 4.16kV.The boundaries of the Region are shown in Figure 1-1 below.

Within the current regional planning cycle, four regional assessments have been conducted for the London Area Region. The findings of these studies are an input to the RIP and the studies are as follows:

1. IESO's Greater London Sub-Region Integrated Regional Resource Plan – January, 2017
2. Hydro One's Woodstock Sub-Region Restoration Local Plan - May, 2017
3. Hydro One's Strathroy TS Transformer Capacity Local Plan – September, 2016
4. Hydro One's London Area Region Needs Assessment Report – April, 2015

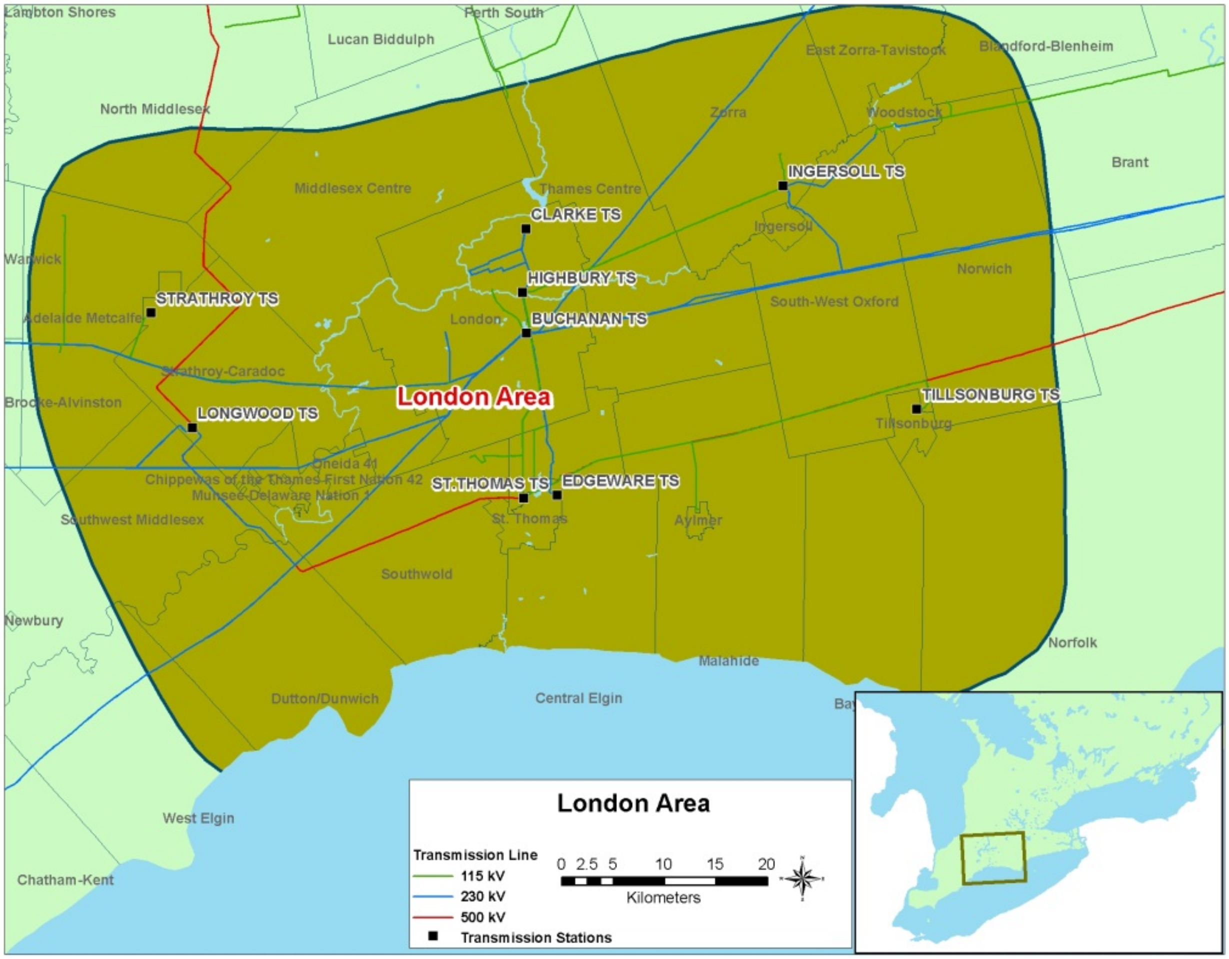


Figure 1-1 London Area Region

1.1 Scope and Objectives

This RIP report examines the needs in the London Area Region and its objectives are to:

- Confirm supply needs identified in previous planning phases;
- 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 plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Greater London Sub-Region IRRP

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. 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.

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 major High Voltage transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs
- Section 7 describes the needs and provides 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 performed 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 evaluates supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115kV and 230kV 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 Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, and needs are local in nature, an assessment is undertaken for any necessary investments directly by the LDCs (or customers) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited to investments in wires (transmission or distribution) solutions c) do not require upstream transmission investments d) do not require plan level stakeholder engagement and e) do not require other approvals such as Leave to Construct (S92) approval or Environmental Approval.

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. If there are needs that do not require regional coordination, the Working Group can recommend them to be undertaken as part of the LP approach discussed above. Otherwise, the approach is to complete either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-

[2] Also referred to as Needs Screening.

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 ("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 the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

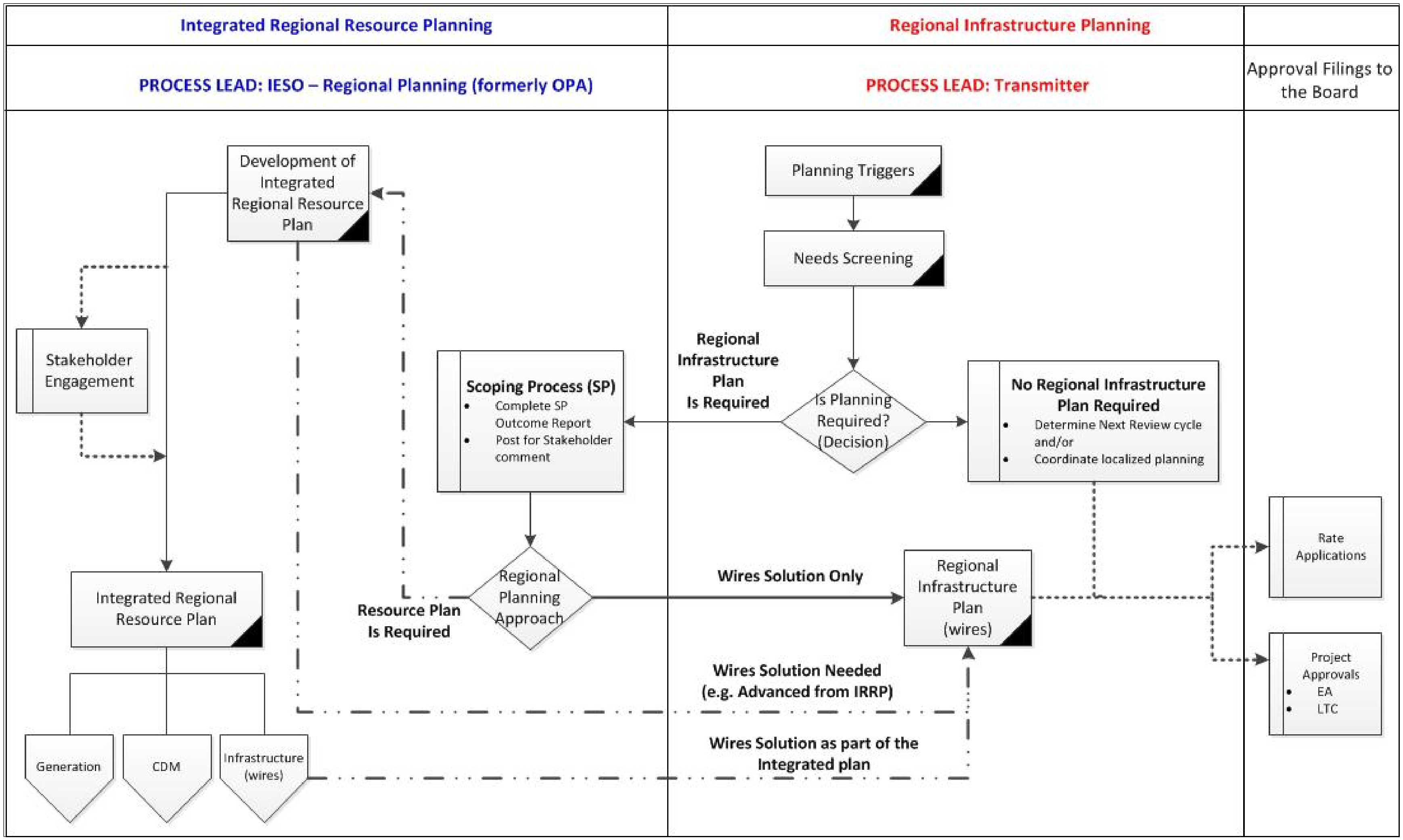


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Working Group to reconfirm or update the information as required:

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation ("DG") or CDM 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.

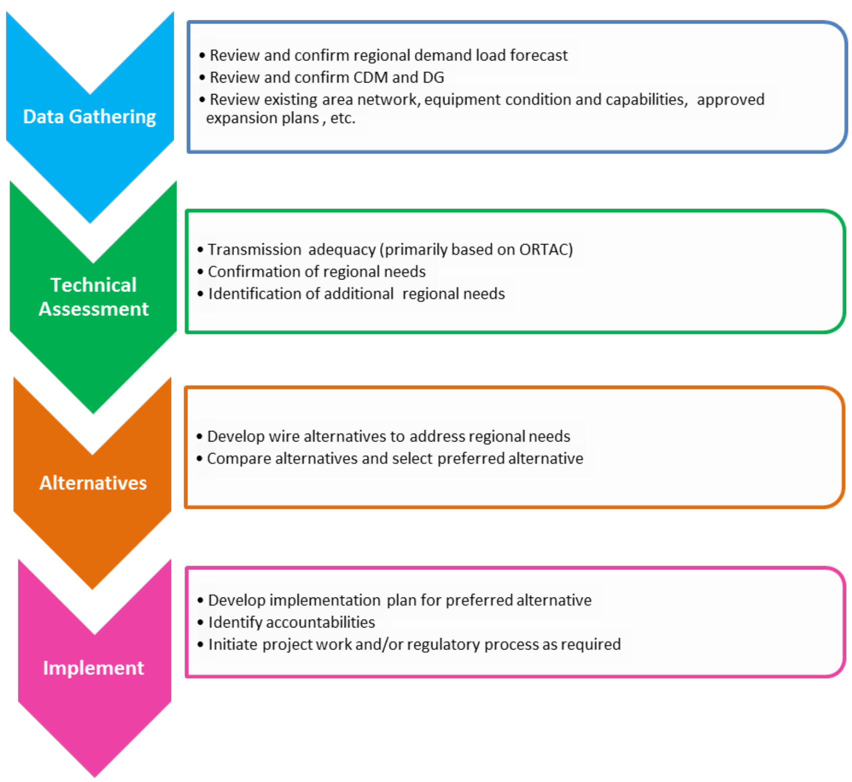


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE LONDON AREA IS LOCATED IN SOUTH WESTERN ONTARIO AND INCLUDES ALL OR PART OF OXFORD COUNTY, MIDDLESEX COUNTY, ELGIN COUNTY, NORFOLK COUNTY, THE CITY OF WOODSTOCK, THE CITY OF LONDON, AND THE CITY OF ST. THOMAS. THE REGION ALSO INCLUDES THE FOLLOWING FIRST NATIONS: CHIPPEWAS OF THE THAMES, ONEIDA NATION OF THE THAMES, AND MUNSEE-DELAWARE NATION. LONDON AREA REGION IS DIVIDED INTO FIVE SUB-REGIONS: STATHROY SUB-REGION, GREATER LONDON SUB-REGION, WOODSTOCK SUB-REGION, AYLMER-TILLSONBURG SUB-REGION, AND THE ST. THOMAS SUB-REGION.

Electrical supply to the London Area Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fifteen Hydro One step-down TS', four direct transmission connected load customers and three transmission connected generators. The region is summer-peaking and has a peak demand of approximately 1,250 MW including direct transmission connected customers. A map of the London Area Region (highlighting the sub-regions) and a single line diagram of the transmission system are shown in Figure 3-1 and Figure 3.2.

Table 3-1 Sub-Region Details

Sub-Region	Station Name (DESN)	Voltage Level (kV)	Supply Circuits	Connected Customers
Strathroy Sub-Region	Strathroy TS (T7/T8)	230/27.6	W2S, S2N	• Hydro One Distribution • Entegrus
	Longwood TS (T13/T14)	230/27.6	L24L, L26L	• Hydro One Distribution
Greater London Sub-Region	Talbot TS (T1/T2, T3/T4)	230/27.6	W36, W37	• London Hydro • Hydro One Distribution
	Clark TS (T3/T4)	230/27.6	W36, W37	
	Wonderland TS (T5/T6)	230/27.6	N21W, N22W	
	Buchanan TS (T13/T14)	230/27.6	W42L, W43L	
	Nelson TS (T1/T2)	115/13.8	W5N, W6NL	
	Highbury TS (T3/T4)	115/27.6	W6NL, W9L	
Woodstock Sub-Region	Ingersoll TS (T5/T6)	230/27.6	M31W, M32W	• Hydro One Distribution • Erie Thames Powerlines
	Woodstock TS (T1/T2)	115/27.6	K7, K12	
	Commerceway TS (T1/T2)	115/27.6	K7, K12	
Aylmer Sub-Region	Aylmer TS (T2/T3)	115/27.6	WT1A, W8T, T11T	• Hydro One Distribution, • Erie Thames Powerlines • Tillsonburg Hydro
	Tillsonburg TS (T1/T3)	115/27.6	WT1T, W8T, T11T	
St.Thomas Sub-Region	St. Thomas TS	115/27.6kV	W3T, W4T, T11T	Station is planned for decommissioning, no remaining customers connected.
	Edgeware TS	230/27.6kV	W45LS, W44LC	• Hydro One Distribution • St. Thomas Energy • London Hydro

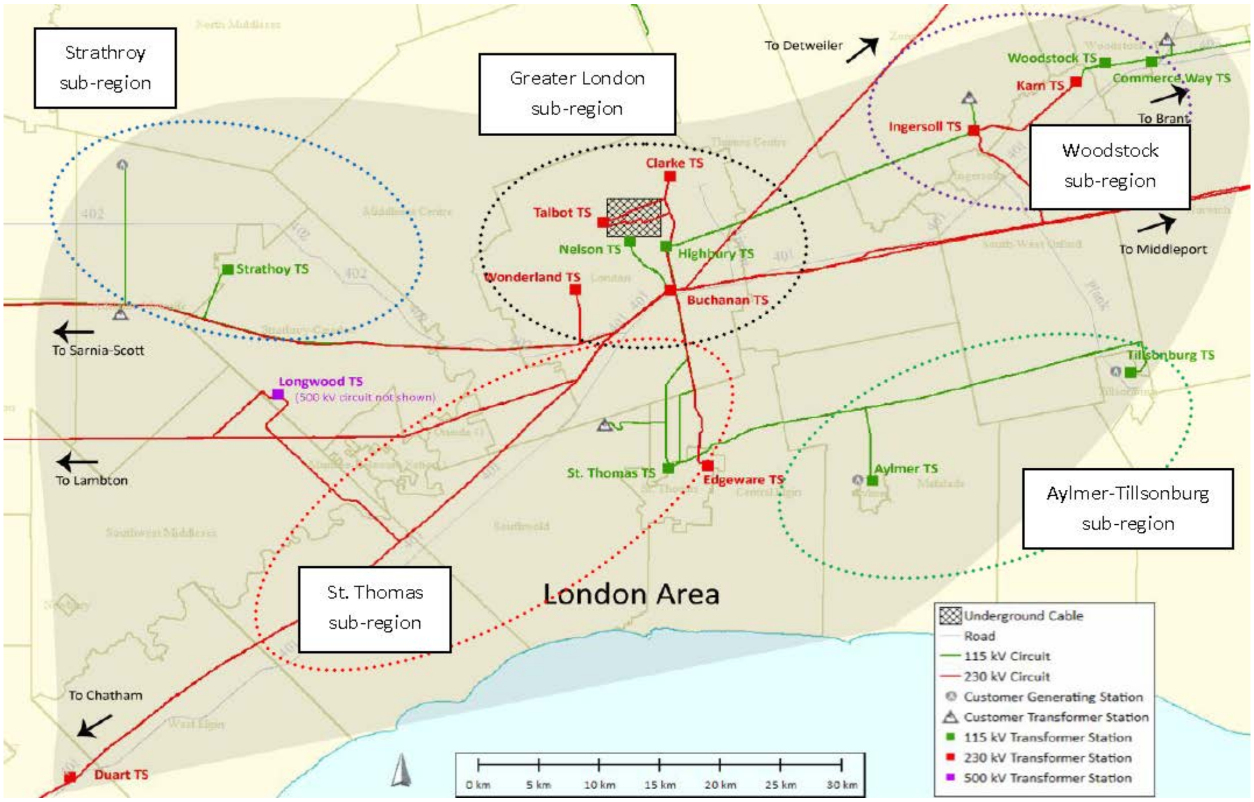
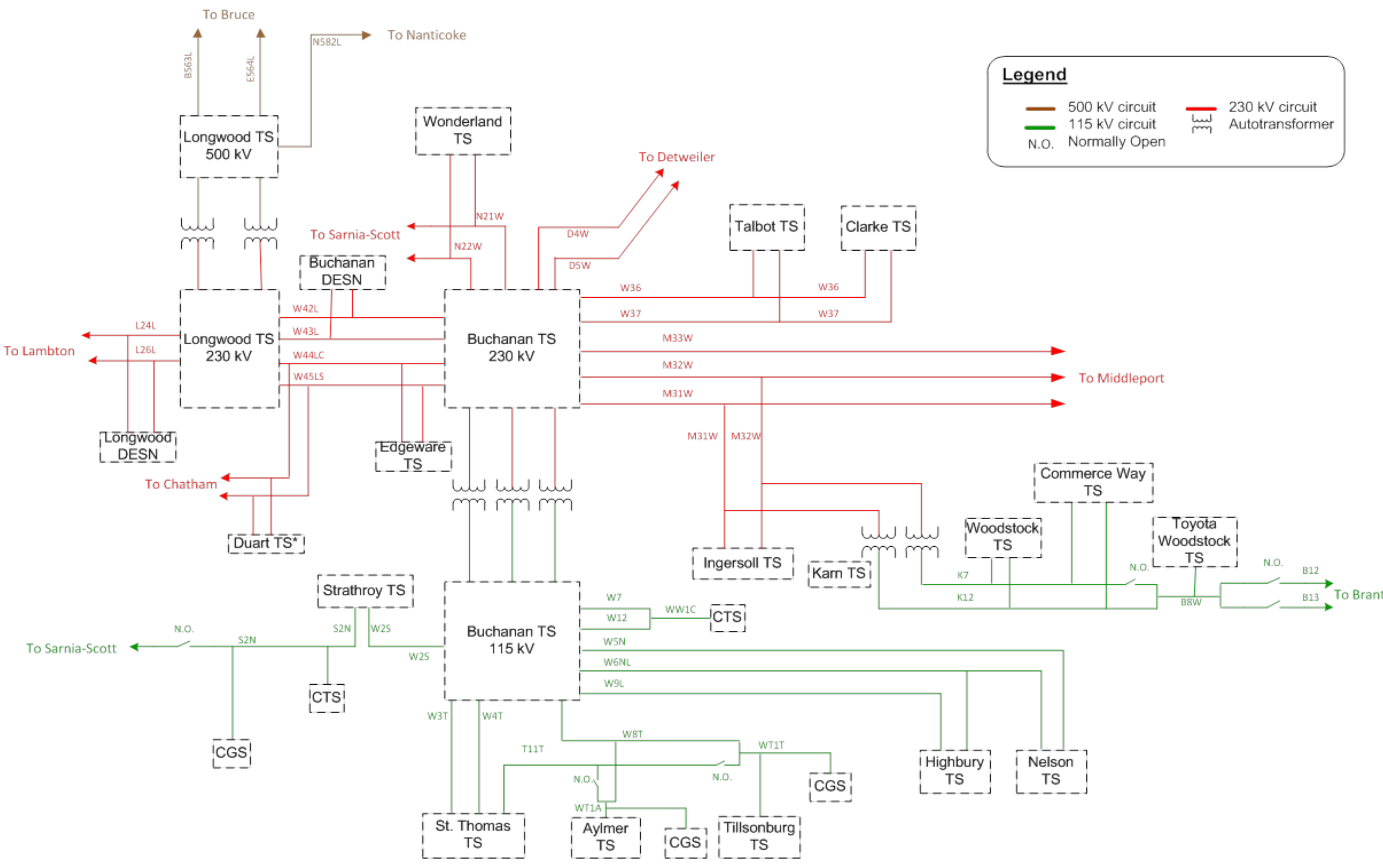


Figure 3-1 London Area Region – Supply Areas



* Part of Chatham-Kent/Sarnia/Lambtion Regional Planning, shown here for completeness

Figure 3-2 London Area Region Single Line Diagram

4. TRANSMISSION PROJECTS COMPLETED 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 LONDON AREA REGION.

A brief listing of the major projects completed over the last 10 years is given below:

- Talbot TS Expansion (2007) – Expansion of the existing Talbot TS and construction of a second 50/83 MVA 230/27.6 kV transformer station to alleviate load from existing transformer stations in the area, which were loaded beyond its capacity and provide additional capacity for the load growth in the London area.
- Highbury TS Transformer Replacement (2009) – Like-for-like replacement of 50/83 MVA 115/27.6 kV transformer T4 that was over 60 years old and nearing end-of-life.
- Commerce Way TS (2010) – Construction of a new 50/83 MVA 115/27.6 kV Commerce Way transformer station to alleviate load from Woodstock TS, which was loaded beyond its capacity and provide additional capacity for the load growth in the Woodstock area.
- Strathroy TS Transformer Replacement (2012) – Like-for-like replacement of 25/42 MVA 115/27.6 kV transformer T2 due to failure.
- Ingersoll TS Transformer Replacement (2012) – 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.
- Woodstock TS Transformer Replacement (2014) – Like-for-like replacement of 50/83 MVA 115/27.6 kV transformers T1 & T2 that were approximately 50 years old and were nearing end-of-life.

The following development projects are expected to be placed in-service within the next 10 years:

1. **Aylmer TS**: is located in Southwestern Ontario and is comprised of two 11/15 MVA, 110-28 kV transformers (T2 & T3) and two 27.6 kV feeder breaker positions M1, M2. The station is supplied by a single 115kV line WT1A and it supplies Erie Thames Powerlines Corp. and Hydro One Distribution at 27.6 kV.

   The deteriorating asset condition of a significant portion of station equipment, including transformers (T2 & T3) and LV switchyard, qualifies it as a candidate for a complete station rebuild. To address the urgent need, the existing station will be replaced with a new DESN with two 25/33/42 MVA transformers. The replacement work also includes all 28kV LV switching facilities, the addition of two new feeder positions, and an upgrade to associated protection and control systems.

   This project is currently under execution and planned to be completed before end of 2017.

2. **Strathroy TS**: is located in Middlesex County in Southwestern Ontario and is comprised of two 25/33/42 MVA 110-28 kV transformers (T1 & T2) and four 27.6 kV feeder breaker positions. Strathroy TS supplies Entegrus Powerlines Inc. and Hydro One Distribution at 27.6 kV.

   Due to deteriorating asset condition, Hydro One has planned to replace the T1 transformer with similar type 42MVA transformer, replace all LV switching facilities, and upgrade associated protection and control facilities and AC/DC station ancillary infrastructure.

   This project is currently under execution and planned to be completed in 2017.

3. **Nelson TS**: is located in the City of London in Southwestern Ontario and is comprised of two DESN stations (the "T1/T2 DESN" and the "T3/T4 DESN") which are both supplied from the 115 kV circuits W5N and W6NL. The T1/T2 DESN consists of two 18/27/33 MVA, 115/ 13.8 kV transformers with two LV yards (outdoor and indoor), and the T3/T4 DESN consists of two 60/80/100 MVA, 115/ 13.8 kV transformers with two LV yards (both indoor). The T1/T2 DESN supplies about 17 MW of 13.8kV load in the London downtown area and the T3/T4 DESN supplies approximately 31 MW of 13.8 kV load, also in the London downtown area.

   The deteriorating asset condition of a significant portion of station equipment, including transformers (T1 & T2) and LV switchyard, qualifies it as a candidate for a complete station rebuild. In addition, London Hydro has requested that Hydro One rebuild the LV at 27.6kV rather than at 13.8kV so that the station can be integrated into London Hydro's 27.6kV distribution system to provide load support. As a result, Hydro one is building a new station within the existing Nelson TS yard. The new station will consist of two new 115/27.6 kV, 50/83 MVA DESNs and new LV switchyard with 8 feeder positions and 2 capacitor bank positions. All associated protection and control systems and station ancillary infrastructure will be upgraded. The work will also involve decommissioning of the existing DESN substation consisting of T1 and T2 transformers and the 13.8kV air insulated outdoor switchyard.

   This project is currently under execution and planned to be completed in 2018.

5. FORECAST AND STUDY ASSUMPTIONS

THE FORECASTS REFLECT THE EXPECTED PEAK DEMAND AT EACH STATION UNDER EXTREME WEATHER CONDITIONS, BASED ON FACTORS SUCH AS POPULATION, HOUSEHOLD AND ECONOMIC GROWTH, CONSISTENT WITH MUNICIPAL PLANNING ASSUMPTIONS.

5.1 Historical Demand

The London Area regional peak load has been relatively constant over the past 5 years (approximate decline of -0.4%).

5.2 Contribution of CDM and DG

In developing the planning forecast, the following process was used to assess the London Region:

- First, "gross demand" is established. Gross demand reflects the forecast developed and provided by the area LDCs and is influenced by a number of factors such as economic, household and population growth.
- Second, "net demand" is derived by reducing the gross demand by expected savings from improved building codes and equipment standards, customer response to time-of-use pricing, projected province-wide CDM programs, committed and forecast DG . This information is provided by the IESO.

5.3 Gross and Net Demand Forecast

Prior to the RIP's kick-off, the Working Group was asked to confirm the load forecasts for all stations in the Region provided for previous assessments. The RIP's load forecast was updated according the revised load forecasts provided by the LDCs.

The load in the London Area Region including CDM targets and DG contributions is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). The growth rate varies across the region but an overall coincident net load forecast in the region is illustrated in Figure 5-1. 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 B and C.

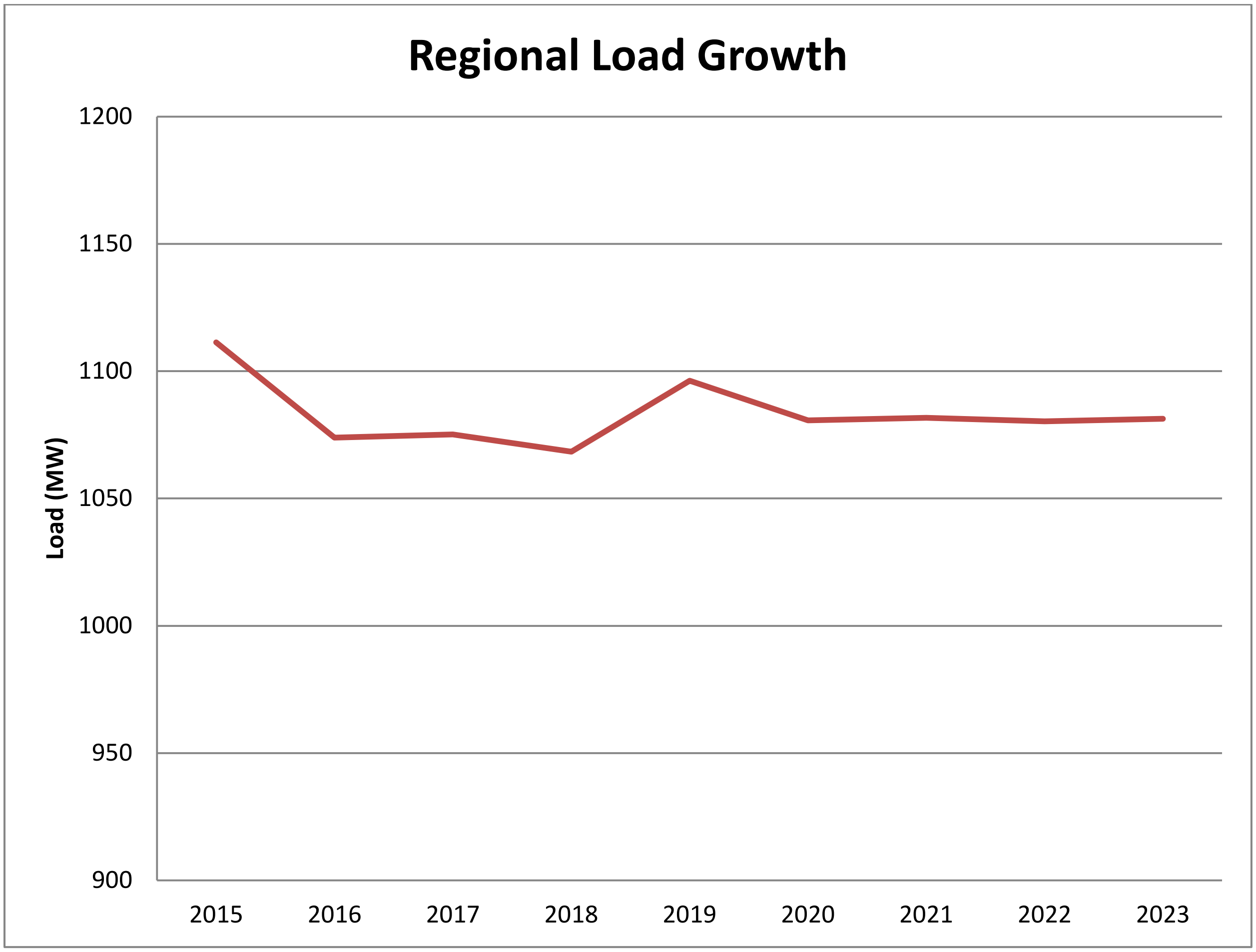


Figure 5-1 London Area Region Coincident Net Load Forecast

5.4 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2023.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE LONDON AREA 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 London Area Region. The findings of these studies are an input to the RIP and the studies are as follows:

1. IESO's Greater London Sub-Region Integrated Regional Resource Plan – January, 2017[1]
2. Hydro One's Woodstock Sub-Region Restoration Local Plan - May, 2017[2]
3. Hydro One's Strathroy TS Transformer Capacity Local Plan – September, 2016[3]
4. Hydro One's London Area Region Needs Assessment Report – April, 2015[4]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the London Area Region assuming the new Nelson TS DESN will be in-service by the end of 2018, and the new Aylmer TS DESN will be in-service by the end of 2017. Further detailed description and status of plans to meet these needs is provided in Section 7.

6.1 Transmission Line Facilities

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. The main features of the electrical supply system in the London Area are as follows:

- Longwood TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Buchanan TS and Karn TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Fifteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerceway TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Nelson TS, Strathroy TS, St. Thomas TS, Talbot TS, Tillsonburg TS, Wonderland TS, and Woodstock TS.
- Four Customer Transformer Stations (CTS) are supplied in the London Area: Ford Talbotville CTS, Enbridge Keyser CTS, Lafarge Woodstock CTS, and Toyota Woodstock CTS.
- There are 3 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
- Erie Shores Wind Farm GS is a 99 MW wind farm connected to 115kV circuit near Tillsonburg TS
- Silver Creek GS is a 10 MW solar generator connected to 115kV circuit near Aylmer TS

The 500kV system is part of the bulk system planning conducted by the IESO and is not studied as part of this RIP

Table 6-1 provides 230 kV and 115 kV circuit network that supplies to the London Area.

Table 6-1 230 kV and 115 kV circuits network in the London Area

Voltage	Circuit Designations	Location
230 kV	N21W, N22W	Scott TS to Buchanan TS
	W42L, W43L	Longwood TS to Buchanan TS
	W44LC	Longwood TS to Chatham TS to Buchanan TS
	W45LS	Longwood TS to Spence SS to Buchanan TS
	W36, W37	Buchanan TS to Talbot TS
	D4W, D5W	Buchanan TS to Detweiler TS
	M31W, M32W	Buchanan TS to Ingersoll TS to Middleport TS
	M33W	Buchanan TS to Brantford TS
115 kV	W2S	Buchanan TS to Strathroy TS
	W5N	Buchanan TS to Nelson TS
	W6NL	Buchanan TS to Highbury TS to Nelson TS
	W9L	Buchanan TS to Highbury TS
	W7, W12 WW1C W8T T11T WT1T W3T, W4T WT1A K7, K12	Buchanan TS to CTS Buchanan TS to CTS Buchanan TS to Cranberry JCT Erie Shore Wind Farm JCT to Tillsonburg TS Buchanan TS to St. Thomas TS Aylmer TS to Lyons JCT Karn TS to Commerce Way TS

The 115 kV circuit W8T from Buchanan TS to Edgeware JCT exceeds its planning rating under pre-contingency conditions in the near term based on the gross load forecast. Such thermal overload is deferred to the medium term based on the net load forecast. The transmission line constraint is further described in section 7.2.2 of this report. The remaining 115 kV and 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single element in the area.

6.2 Step-Down Transformation Facilities

There are a total of fifteen step-down transmission connected transformer stations in the London Area Region. The stations have been grouped based on the geographical area and supply configuration. The station loading and the associated station capacity and the need date in each sub-region is provided in Table 6-3 below. The findings of the transformation capacity assessment are as follows:

- As confirmed in the "Strathroy TS Transformer Capacity Local Plan (LP)", based on the limited time rating ("LTR") of the station, the transformation capacity is adequate in Strathroy Sub-Region over the study period.
- As confirmed in the "Greater London Sub-Region Integrated Regional Resource Plan (IRRP)", based on the LTR of the stations, the transformation capacity is adequate in Greater London Sub-Region over the study period.
- Based on the LTR of the load stations, the transformation capacity is adequate in Woodstock Sub-Region, Aylmer-Tillsonburg Sub-Region and the St. Thomas Sub-Region over the study period.

Table 6-2 Transformation Capacities in the Sub-Regions

Sub-Region	Station	LTR (MW)	2015 Non Coincident Peak (MW)	Need Date
Strathroy Sub-Region	Strathroy TS	50	45	-[3]
	Longwood TS	128	33	-[3]
Greater London Sub-Region	Talbot TS	290	268	-[3]
	Clark TS	110	106	-[3]
	Wonderland TS	99	109[4]	-[3]
	Buchanan TS	183	143	-[3]
	Nelson TS	105[5]	23	-[3]
	Highbury TS	114	93	-[3]
Woodstock Sub-Region	Ingersoll TS	167	75	-[3]
	Woodstock TS	87	56	-[3]
	Commerceway TS	112	33	-[3]
Aylmer Sub-Region	Aylmer TS	55[6]	21	-[3]
	Tillsonburg TS	109	88	-[3]
St.Thomas Sub-Region	St.Thomas TS	50	0	-[3]
	Edgeware TS	191	113	-[3]

[3] Adequate over the study period

[4] Peak loading at Wonderland TS is forecasted to reduce to within its 10-day LTR rating by 2017

[5] Nelson TS LTR reflects the Station Rebuild Project under execution - planned to be completed in 2018

[6] Aylmer TS LTR reflects the Transformer Replacement Project under execution - planned to be completed in 2017

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

6.3 System Reliability and Load Restoration

In case of incidents 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.

In the London Area Region it is expected that all loads can be restored within the ORTAC load restoration requirements with exception of:

- Loss of M31W/M32W – Woodstock Sub-Region
- Loss of W36/W37 or W42L/W43L – Greater London Sub-Region

The load restoration constraints are further described in section 7.1 of this report.

6.4 Voltage

Under pre-contingency conditions with all facilities in service, ORTAC provides requirements for acceptable system voltages. The table below indicates the maximum and minimum voltages generally applicable. These values are obtained from Chapter 4 of the IESO "Market Rules" and CSA standards for distribution voltages below 50 kV.

Table 6-3 Pre-Contingency Voltage Limits

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Low Voltage Bus
Maximum Continuous (kV)	550	250	127*	106%
Minimum Continuous (kV)	490	220	113	98%

*Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 115 kV system can be as high as 132 kV.

With all planned facilities in service pre-contingency, ORTAC provides requirements for system voltage changes in the period immediately following a contingency as indicated in Table 6-4.

Table 6-4 Post-Contingency Voltage Change Limits

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Low Voltage Bus		
				44	27.6	13.8
% voltage change **before** tap changer action	10%	10%	10%	10%		
% voltage change **after** tap changer action	10%	10%	10%	5%		
AND within the range						
Maximum* (kV)	550	250	127	112% of nominal		
Minimum* (kV)	470	207	108	88% of nominal		

*The maximum and minimum voltage ranges are applicable following a contingency. After the system is re-dispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages.

The Aylmer-Tillsonburg Sub-Region is normally supplied by a single 115 kV transmission circuit W8T which is approximately 60 km in length. The Sub-Region has a total peak demand of 106 MW and is expected to grow to 122 MW by year 2023. During planned or forced outages the interrupted load in the Sub-Region can be transferred to the backup 115 kV circuit T11T.

Under pre-contingency conditions and with Erie Shores Wind Farm unavailable, the voltage at Tillsonburg TS 115 kV bus does not meet ORTAC criteria (113 kV) under existing peak load conditions and may reach as low as 100 kV. The transformer ULTCs at Tillsonburg TS is however maintaining the LV bus voltage above ORTAC criteria of 27 kV (98% of nominal voltage). Study results indicate that the LV voltage cannot be maintained at desirable levels when the load in the Aylmer-Tillsonburg Sub-Region exceeds 115 MW. Based on the latest load forecasts, this loading level may be reached as early as 2019.

The voltage constraint is further described in section 7.2.1 of this report.

6.5 Customer Delivery Point Performance

In accordance with Section 2.5 of the Transmission System Code, Hydro One Networks Inc. (Networks) is required to develop performance standards at the customer delivery point level, consistent with system wide standards that reflect:

- typical transmission-system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- historical performance at the customer delivery point level;
- acceptable bands of performance at the customer delivery point level for the transmission system configurations; geographic area, load, and capacity levels; and

- defined triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, exemptions from such standards, and study triggers and results.

The Customer Delivery Point Performance Standards and triggers are based on the size of load being served (as measured in megawatts by a delivery point's total average station load) are provided in Table 6-4 below.

Table 6-4 Customer Delivery Point Performance Standards

Performance Measure	Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		**15-40 MW**		**40-80 MW**		**>80 MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/year)	4.1	**9.0**	1.1	**3.5**	0.5	**1.5**	0.3	**1.0**
DP Interruption Duration (min/year)	89	**360**	22	**140**	11	**55**	5	**25**

The minimum standards of performance are to be used as triggers by Networks to initiate technical and financial evaluations with affected customers. These bands are to:

- accommodate normal year-to-year delivery point performance variations;
- limit the number of delivery points that are to be considered "performance outliers" to a manageable/affordable level;
- deliver a level of reliability that is commensurate with customer value i.e. the larger the load, the greater the level of reliability provided; and
- direct/focus efforts for reliability improvements at the "worst" performing delivery points.

The customer delivery points serving THI and HONI distribution at Tillsonburg TS is not meeting CDPPS requirements with regards to frequency of interruptions. This customer delivery point has averaged approximately 3.3 interruptions per year over the past 10 years, doubling the performance target of 1.5.

The Customer Delivery Point Performance need is further described in section 7.2.3 of this report.

6.6 End-of-Life Equipment Replacements

Recent condition assessment of Wonderland TS has revealed that one of the existing power transformers at the station (T5) is in poor condition and must be replaced in the near-term. The facility was originally built in the 1960s and its assets are degrading in condition and require replacement by 2022. The existing 230/28kV T6 power transformer was replaced in 2004 due to failure. The existing 230/28 kV T5 power transformer will be replaced with a similar unit (230kV-28kV 83 MVA) to match the ratings of transformer T6. After the transformer replacement is completed, the LTR of Wonderland TS is expected to increase to approximately 114MW.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES THE ELECTRICAL INFRASTRUCTURE NEEDS, POSSIBLE WIRES ALTERNATIVES AND SUMMARIZES THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS IN THE LONDON AREA REGION

The needs listed in Table 7-1 include needs previously identified in the IRRP for the Greater London Sub-Region and the NA and LP's for the Strathroy, Woodstock, Aylmer-Tillsonburg and St. Thomas Sub-Regions.

The near-term needs include needs that arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

Table 7-1 Identified Near-Term Needs in London Region

<table>
<tr><th>Sub-Region</th><th>Type</th><th>Section</th><th>Needs</th><th>Timing</th></tr>
<tr><td>Woodstock Sub-Region</td><td rowspan="2">Load Restoration</td><td>7.1.1</td><td>Loss of M31W/M32W</td><td>No action required at this time</td></tr>
<tr><td>Greater London Sub-Region</td><td>7.1.2</td><td>Loss of W36/W37 or W42L/W43L</td><td>Now</td></tr>
<tr><td rowspan="3">Aylmer-Tillsonburg Sub-Region</td><td>Voltage Constraint</td><td>7.2.1</td><td>Voltage at Tillsonburg TS below ORTAC criteria</td><td>Now</td></tr>
<tr><td>Thermal Constraint</td><td>7.2.2</td><td>Thermal constraint on 115kV line W8T</td><td>Now</td></tr>
<tr><td>Delivery Point Performance</td><td>7.2.3</td><td>Poor delivery point performance at Tillsonburg TS</td><td>Now</td></tr>
</table>

7.1 Load Restoration

7.1.1 Woodstock Sub-Region: Loss of M31W/M32W

Description

The Woodstock Sub-Region load restoration need was identified in the NA and LP reports and further assessment was recommended to address the supply shortfall during peak load periods. Previous assessments indicated that in case of loss of two transmission elements (M31W/M32W), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria.

Recommended Plan and Current Status

A local planning report[7] was completed to develop a plan to address the load restoration need identified in the Sub-Region. The report concluded the following:

For Woodstock Sub-Region, the critical line section is M31W/M32W tap between Salford Junction and Ingersoll Junction. Should a contingency on this line section occur, all of the sub-region's load, which amounted to 188 MW in 2016, would be interrupted by configuration.

Under such emergency conditions, depending on system performance and availability of switching facilities, all or a portion of a load station could be restored by transferring load to neighbouring unaffected supply. Hydro One Distribution estimated that 10 MW of load at Ingersoll TS could be transferred to Highbury TS. Another 8 MW could be transferred from Commerce Way TS to Tillsonburg TS on the feeder level. On the transmission side, the supply from Brant TS will be able to restore about 20 MW of load in the Woodstock Sub-Region.

These measures can be deployed remotely to manage and mitigate the impact of the loss of two transmission elements within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crews from the nearest staffed centre in London Area will be dispatched to install temporary fixes on the transmission system such as building an emergency by-pass.

The Working Group is recommending that no further action is required at this time.

7.1.2 Greater London Sub-Region: Loss of W36/W37 or W24L/W43L

The Greater London Sub-Region load restoration need was identified in the NA and IRRP reports and further assessment was recommended to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (W36/W37 or W42L/W43L), the load interrupted with the current circuit configuration during peak periods may exceed load restoration criteria.

W36/W37 – Clarke TS and Talbot TS

Description

Clarke TS and Talbot TS are supplied by 230 kV transmission circuits W36/W37 and have a total peak demand of 370 MW. Following the loss of both W36 and W37, supply to Clarke TS and Talbot TS would be interrupted.

[7] Woodstock Restoration Local Planning Report – May 30, 2017

Under such emergency conditions, London Hydro can currently restore up to 55 MW of interrupted load through distribution system transfers within 30 minutes and up to 105 MW within four hours. The interrupted load would be transferred to Wonderland TS, Buchanan TS and Highbury TS during such events. As part of the rebuild of Nelson TS in 2018, the station's LV bus will be converted from 13.8 kV to 27.6 kV. After the conversion, Nelson TS will be able to provide additional backup capacity to support meeting the ORTAC timelines in the event of a double circuit outage. With the new 27.6 kV Nelson TS, a total of 95 MW of load can be restored within 30 minutes, and 150 MW of load within four hours. This reduces the 30 minute shortfall to 25 MW and the four hour shortfall to 71 MW in 2019.

Recommended Plan and Current Status

The Greater London Sub-Region IRRP [8] developed a plan to address the load restoration need identified in the Sub-Region. The report concluded the following:

Currently, London Hydro has 28 distribution feeders in total that emanate from Clarke TS and Talbot TS. Only half of these feeders are presently interconnected to other non-Clarke and non-Talbot feeders (i.e., Highbury, Buchanan, and Wonderland TS feeders). Installing approximately 10 additional automated switching devices in strategic locations on the distribution feeders could provide an additional 25 MW of load transfer capability within 30 minutes for Clarke TS and Talbot TS load. These switching devices are estimated to cost approximately $0.6 million.

An additional 10-15 MW of load restoration support for longer-term relief (more than 30 minutes) could be provided by extending the 14 existing Clarke and Talbot feeders to connect with feeders from non-connected neighboring stations. For example, a 3.7 km Talbot feeder line extension to connect to a Wonderland feeder at an approximate cost of $1.2 million could provide support to 10-15 MW of load for the Clarke TS and Talbot TS load pockets.

For a unit cost of $180/kW, the Working Group is recommending the implementation of automated switching devices and feeder extensions on the Distribution System as the most cost effective method to substantially mitigate the restoration shortfall in this area.

These solutions would also maximize the use of existing distribution infrastructure and provide flexibility to London Hydro to manage load between different stations in its service territory.

It is important to note that the feeder capacity margins are not static and will reduce as the 20-year projected load growth at the transformer stations materializes. Hence, the amount of load that can be restored using the distribution system in the event of a double element loss of supply to Clarke TS and Talbot TS will reduce over time. Consequently, part of the recommendation is that London Hydro continues to monitor load growth and relevant feeder limits in its service territory. The Working Group recommends the actions described below to meet the restoration need identified for the Greater London

[8] Greater London Sub-Region, Integrated Regional Resource Plan – January 20, 2017

Sub-region. Successful implementation of this plan will substantially address the restoration need in this sub-region for the next decade.

W42L/W43L – Buchanan TS

In case of loss of theW42L/W43L transmission lines, the load supplied from Buchanan TS which reaches slightly over 150 MW would be interrupted by configuration.

Under such emergency conditions, London Hydro can transfer any interrupted load in excess of 150 MW to adjacent stations within the service area. These measures to manage and mitigate the impact of the equipment loss can be deployed within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crews from the nearest staffed centre in London area will be dispatched to install temporary fixes on the transmission system such as building an emergency by-pass.

The Working Group is recommending that no further action is required at this time.

7.2 Aylmer-Tillsonburg Sub-Region: Voltage/Thermal Constraint & Delivery Point Performance

The Aylmer-Tillsonburg Sub-Region is primarily supplied by a single 115 kV transmission circuit W8T. The Sub-Region has a total peak demand of 106 MW and is expected to grow to 122 MW by year 2023. During planned or forced outages the interrupted load in the Sub-Region can be transferred to the backup 115 kV circuit T11T. The Tillsonburg TS voltage constraint and the W8T thermal constraint need was identified in the NA report and further assessment was recommended to address these needs. Following the NA report, the Working Group further identified Delivery Point Performance needs at Tillsonburg TS. These needs are assessed as part of this RIP.

7.2.1 Voltage Constraint

The voltage constraint observed on the 115 kV bus at Tillsonburg TS results from having a long 65 km 115 kV single circuit supply, a large 90 MW Tillsonburg TS load at the end of the transmission line, and a lack of reactive power support at the station to compensate. To mitigate the voltage constraints at Tillsonburg TS, the Working Group considered the following options.

Installation of Shunt Capacitors at Tillsonburg TS

One method to mitigate the voltage constraints at Tillsonburg TS is to provide reactive power compensation at the station. Installation of shunt capacitor banks (2 x 21 Mvar) on the 27.6 kV bus at Tillsonburg TS provides the necessary reactive compensation to meet the ORTAC voltage criteria (113 kV) for the peak load forecast over the study period of 89 MW at Tillsonburg TS. Further, the shunt capacitors are capable of supporting future load growth beyond the study period up to 109 MW – equal to the LTR rating of Tillsonburg TS. These shunt capacitor banks are estimated to cost approximately $8 million.

Installation of Switching at Buchanan TS and Reconfiguration of 115 kV Circuits

Another method to mitigate the voltage constraints at Tillsonburg TS is to reconfigure the 115 kV circuits supplying the Aylmer-Tillsonburg Sub-Region. A single line diagram of the Aylmer-Tillsonburg Sub-Region after the decommissioning of St. Thomas TS is shown in Figure 7-1.

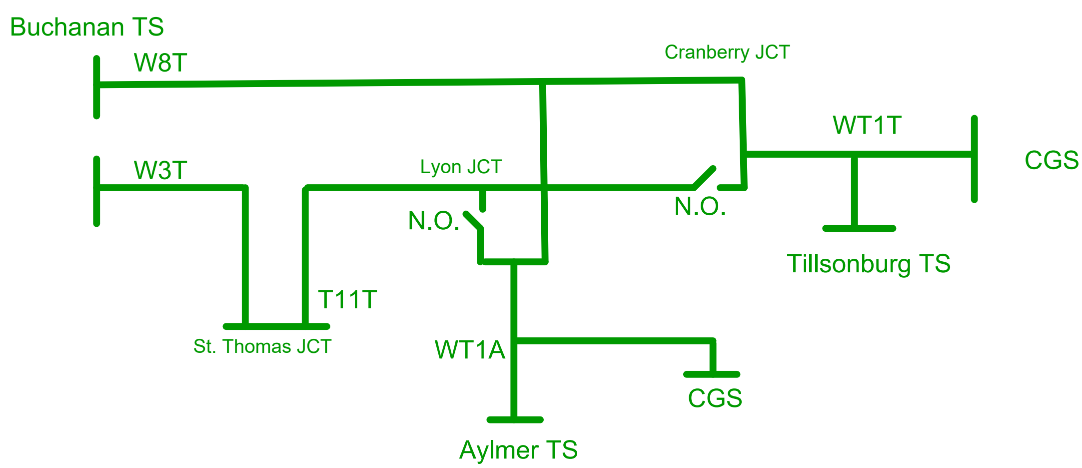


Figure 7-1 Existing Single Line Diagram of Aylmer-Tillsonburg Sub-Region

Aylmer TS and Tillsonburg TS are normally supplied by 115 kV circuit W8T. Reconfiguring the system so that Aylmer TS and Tillsonburg TS are normally supplied by both W8T and T11T reduces the system impedance and improves the voltages in the area. The reconfiguration of the 115 kV system requires installing new switches at Buchanan TS to tie 115 kV circuits W8T and W3T. The "normally open" switches at Lyon JCT and Cranberry JCT will be changed to "normally closed". Lastly the protection relaying at Buchanan TS will require upgrades/modification. A single line diagram of the Aylmer-Tillsonburg Sub-Region after the reconfiguration is shown in Figure 7-2.

The voltages at the Tillsonburg TS 115 kV bus after the reconfiguration improve to 113 kV, meeting the ORTAC voltage criteria for the peak load forecast over the study period. Any further load growth beyond the peak load forecast of 89 MW at Tillsonburg TS will cause the voltage at Tillsonburg TS 115 kV bus to fall below the ORTAC voltage criteria of 113 kV. Similar to the current situation, the transformer ULTCs at Tillsonburg TS can maintain the LV bus voltage above the ORTAC criteria of 27 kV (98% of nominal voltage) for load growth up to 109 MW – equal to the LTR rating of Tillsonburg TS. Reconfiguration of the 115 kV system is estimated to cost approximately $4 million.

While the reconfiguration of the 115 kV system mitigates the voltage constraint need over the study period, it potentially worsens the customer delivery point performance of Tillsonburg Hydro and Hydro One Distribution at Tillsonburg TS. Frequency of outages is expected to increase slightly resulting from higher exposure to lightning and wind events. In addition, restoration times are expected to increase slightly due to the incremental switching requirements.

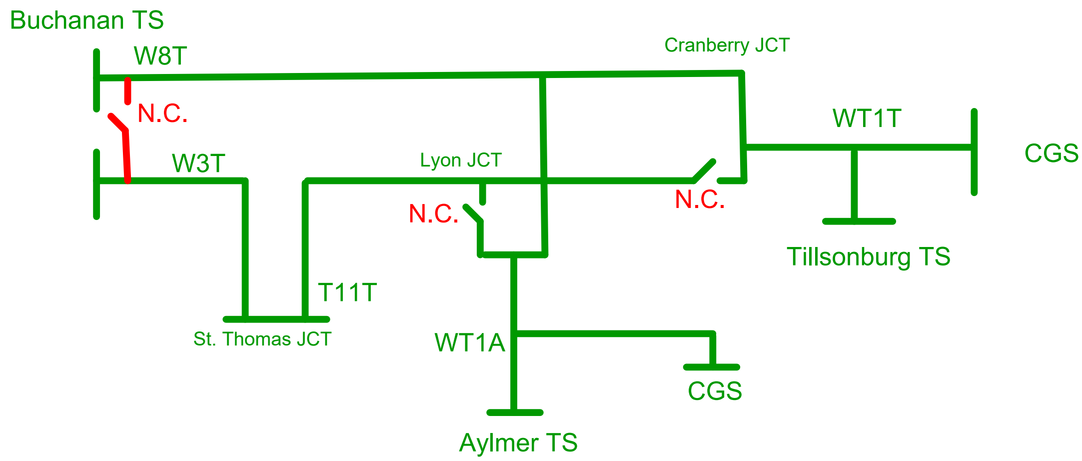


Figure 7-2 Single Line Diagram of Aylmer-Tillsonburg Sub-Region after Reconfiguration

7.2.2 Thermal Constraint

Thermal constraints are observed on a section of line approximately 1.5 km long on 115 kV circuit W8T between Buchanan TS and Edgeware JCT. Under pre-contingency conditions, the thermal loading on this section line reaches 140% of its planning rating of 590A based on the peak load forecast over the study period. Implementing either one of the options in section 7.2.1 to mitigate the voltage constraint at Tillsonburg TS substantially improves the thermal loading on this section line.

Reconfiguring the 115 kV system in the Aylmer-Tillsonburg Sub-Region and installing new switches at Buchanan TS to mitigate the voltage constraint at Tillsonburg TS also mitigates the thermal constraint on circuit W8T.

Installing capacitor banks at Tillsonburg TS reduces the loading on this section of W8T to 106% of its planning rating. As a result, upgrading this section of line would be required to increase the planning to rating to address the thermal overload based on the peak load forecast over the study period. Thirteen poles are required to be replaced at an estimated cost of $1.5 million. This will raise the planning rating of the line to match the other sections of circuit W8T.

A thermal constraint on a section of line approximately 1.5 km long on 115 kV circuit WT1T between Cranberry JCT and Tillsonburg TS was previously identified in the NA report. Tillsonburg Hydro has since provided a revised load forecast and there is no longer an overloading in this section of line.

7.2.3 Customer Delivery Point Performance

The Tillsonburg TS customer delivery point performance need was identified by the Working Group after the NA report was completed. Historical values indicated that the frequency of outages to Tillsonburg Hydro and Hydro One Distribution fall below the standards per Hydro One's "Customer Delivery Point Performance Standard" which is approved by the OEB.

The vast majority of interruptions to Tillsonburg Hydro and Hydro One Distribution at Tillsonburg TS results from having only one normal transmission supply to Tillsonburg TS. One method which substantially improves customer delivery point performance is to provide a second transmission circuit to supply Tillsonburg TS. In most situations, a second supply is normally cost prohibitive. Tillsonburg TS however is in a situation where there is an existing backup 115 kV circuit T11T within 3.5 km of the station. A second transmission supply to Tillsonburg TS would require extending 115kV circuit T11T from Cranberry JCT to Tillsonburg TS, HV bus work at Tillsonburg TS and protection relaying modifications and upgrades at Buchanan TS. Providing a second transmission supply to Tillsonburg TS is estimated to cost approximately $16 million.

7.2.4 Aylmer-Tillsonburg Sub-Region Recommended Plan

The Working Group examined various options to address the voltage, thermal and customer delivery point performance needs of the Sub-Region. The needs, options and alternatives are summarized in Tables 7-2, 7-3 and 7-4 respectively.

Table 7-2 Aylmer-Tillsonburg Sub-Region Needs

Need ID	Needs	Timing
I	Voltage constraint at Tillsonburg TS	Existing
II	Thermal constraint on W8T (Buchannan X Edgeware JCT)	Existing
III	Customer Delivery Point Performance below standards at Tillsonburg TS	Existing

Table 7-3 Aylmer-Tillsonburg Sub-Region Need Mitigation Options

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Installation of Shunt Capacitors at Tillsonburg TS	HONI	2021	$8M	I
2	Installation of Switching at Buchanan TS and Reconfiguration of 115 kV Circuits	HONI	2019	$4M	I & II
3	W8T Circuit Upgrade	HONI	2021	$1.5M	II
4	Second transmission circuit supply to Tillsonburg TS	THI & HONI	2021	$16M	II & III

After further assessing the needs in Aylmer-Tillsonburg Sub-Region, the Working Group proposed a number of different options to mitigate the voltage, thermal and customer delivery point performance needs. Due to the complexity of the projects examined, it was determined that further assessment to clarify scope and specifically the cost details is needed. As such, the Working Group recommends Hydro One to pursue Budgetary Cost Estimates in order to obtain the necessary information to properly analyze the cost and benefits of each alternative.

Hydro One plans to obtain Budgetary Cost Estimates for the alternatives proposed and provide back the results to the Working Group by Q4 2018 in order to continue the planning activities for the Sub-Region.

Table 7-4 Aylmer-Tillsonburg Sub-Region Alternatives

Alternatives	Benefits/	Total Cost
I	Proceed with Projects I, III and IV -Resolves all three needs in the sub-region	$25.5M
II	Proceed with Project II -Resolves need I & II of the sub-region -Increase in the frequency interruptions at Tillsonburg TS -Lengthens restoration time (slightly) during forced outages -During planned or forced outages to W8T or T11T, switches at Buchanan, Lyon JCT and Cranberry JCT will be opened negating the voltage support effects	$4M
III	Proceed with Projects I and III -Resolves needs I & II in the sub-region	$9.5M

7.3 Long Term Regional Plan

As discussed in Section 5, the electricity demand in the London Area Region is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). Load growth over the long term period is expected to be moderate (up to 1.5%) from 2027 to 2037. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the London Area Region have been identified at this time. If new needs emerge due to a change in load forecast or any other reason, a new regional planning cycle will be initiated ahead of the 5-year planning cycle.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE LONDON AREA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

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

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

Need ID	Needs	Timing
I	Woodstock Sub-Region load restoration	Now
II	Greater London Sub-Region load restoration	Now
III	Voltage constraint at Tillsonburg TS	Now
IV	Thermal constraint on W8T	Now
V	Poor delivery point performance at Tillsonburg TS	Now
VI	EOL Asset – Wonderland TS transformer T5	2022

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

Table 8-2 Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

#	Project	Lead Responsibility	I/S Date	Estimated Cost[9]	Mitigated Need ID
1	Distribution System Upgrades in the Greater London Sub-Region	London Hydro Inc.	2023	$1.8-4M ($180/kW)	II
2	Wonderland TS Reinvestment: Replace transformer T5	Hydro One Transmission	2022	$15-20M	VI

Woodstock Sub-Region load restoration need (Need ID I) was assessed by the Working Group during Local Planning and "status quo/do nothing" course of action has been recommended. Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

[9] Costs presented are preliminary estimate and may change resulting from clarification of scope and through detailed cost estimating.

Greater London Sub-Region load restoration need (Need ID II) was further assessed during Integrated Regional Resource Planning and the Working Group is recommending the implementation of automated switching devices and feeder extensions on the Distribution System as the most cost effective method to substantially mitigate the restoration shortfall in this area.

Due to the various needs of the Aylmer-Tillsonburg Sub-Region and the complexity of the options proposed, the Working Group is recommending Budgetary Cost Estimates be completed in order to obtain the necessary information to properly analyze the cost and benefits of each alternative.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. 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

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[3]. Hydro One, “Needs Screening Report, London Area Region. April 1, 2015.
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[4]. “Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario”. May 17, 2013.
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http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

APPENDICES

Appendix A: Stations in the London Area Region

Station Name	Voltage Level	Supply Circuits
Strathroy TS	230/27.6kV	W2S, S2N
Talbot TS	230/27.6kV	W36, W37
Clark TS	230/27.6kV	W36, W37
Wonderland TS	230/27.6kV	N21W, N22W
Buchanan TS	230/27.6kV	W42L, W43L
Nelson TS	115/27.6kV[10]	W5N, W6NL
Longwood TS	230/27.6kV	L24L, L26L
Highbury TS	115/27.6kV	W6NL, W9L
Ingersoll TS	230/27.6kV	M31W, M32W
Woodstock TS	115/27.6kV	K7, K12
Commerceway TS	115/27.6kV	K7, K12
Aylmer TS	115/27.6kV	W8T, T11T, WT1A
Tillsonburg TS	115/27.6kV	W8T, T11T, WT1T
St. Thomas TS	115/27.6kV	W3T, W4T, T11T
Edgeware TS	230/27.6kV	W45LS, W44LC

[10] As part of the Nelson TS rebuild planned to be completed by year end 2018, the low voltage bus is being converted from 13.8 kV to 27.6 kV

Appendix B: Non-Coincident Load Forecast 2016-2025

*Gross Load Forecast - Median Weather

Transformer Station Name	LDC/Customer	DESN ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)		
					2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Aylmer TS	Hydro One	*T2/T3*	*18.4*	Gross Peak Load				7	7	7	7	7	7	7	7
	Erie Thames			Gross Peak Load				15	19	19	26	27	27	27	28
				DG				0	0	0	0	0	0	0	0
				CDM				0	1	1	1	2	2	2	2
				Net Load Forecast	21	21	21	21	25	25	32	32	32	33	33
Buchanan TS	Hydro One	*T13/T14*	*183*	Gross Peak Load				10	11	11	11	11	11	11	11
	London Hydro			Gross Peak Load				127	144	146	145	147	148	150	151
				DG				1	1	1	1	1	1	1	1
				CDM				2	4	5	6	8	8	9	10
				Net Load Forecast	147	149	143	134	150	151	149	149	150	151	151
Clark TS	Hydro One	*T3/T4*	*110*	Gross Peak Load				14	14	14	14	14	14	15	15
	London Hydro			Gross Peak Load				95	96	97	98	99	93	94	95
				DG				2	3	3	3	3	3	3	3
				CDM				2	2	3	4	5	6	7	7
				Net Load Forecast	107	111	106	105	106	106	106	106	99	100	101
Commerceway TS	Hydro One	*T1/T2*	*112*	Gross Peak Load				38	34	34	34	34	34	34	34
				DG				0	0	0	0	0	0	0	0
								0	0	0	0	0	0	0	0
				CDM				1	1	1	1	2	2	2	2
				Net Load Forecast	42	33	33	37	33	33	32	32	32	32	32
Edgeware TS	Hydro One	*T1/T2*	*191*	Gross Peak Load				57	57	57	58	59	59	60	60
	London Hydro			Gross Peak Load				1	1	1	1	1	1	1	1
	St. Thomas			Gross Peak Load				52	52	52	52	53	53	53	53
				DG				1	1	1	1	1	1	1	1
				CDM				2	2	3	5	6	7	7	8
				Net Load Forecast	116	97	98	106	106	106	105	105	105	105	105

Transformer Station Name	LDC/Customer	DESN ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)		
					2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Highbury TS	Hydro One	*T3/T4*	*114*	Gross Peak Load				6	7	7	7	7	7	7	7
	London Hydro			Gross Peak Load				88	88	89	83	84	91	92	93
				DG				4	4	4	4	4	4	4	4
				CDM				2	2	3	4	5	6	6	7
				Net Load Forecast	92	93	93	88	88	89	82	82	88	88	89
Ingersoll TS	Hydro One	*T5/T6*	*167*	Gross Peak Load				38	38	38	38	38	38	38	38
	Erie Thames			Gross Peak Load				39	40	40	40	40	40	40	40
				DG				6	6	6	6	6	6	6	6
				CDM				1	2	2	3	4	5	5	6
				Net Load Forecast	76	74	75	70	70	69	68	67	67	67	66
Longwood TS	Hydro One	*T13/T14*	*128*	Gross Peak Load				33	33	34	34	35	36	36	37
				DG				0	0	0	0	0	0	0	0
				CDM				1	1	1	1	2	2	2	3
				Net Load Forecast	39	32	30	32	32	32	33	33	33	34	34
Nelson TS	London Hydro	*T1/T2*	*105*	Gross Peak Load				16	17	15	52	58	59	60	61
				DG				0	0	0	0	15	15	15	15
				CDM				1	1	1	2	2	2	2	2
				Net Load Forecast	45	42	23	16	16	14	50	42	42	43	44
St Thomas TS	St. Thomas	*T3/T4*	*50*	Gross Peak Load				0	0	0	0	0	0	0	0
				DG				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
				Net Load Forecast	5	1	1	0	0	0	0	0	0	0	0

Transformer Station Name	LDC/Customer	DESN ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)		
					2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Strathroy TS	Hydro One	*T1/T2*	*50*	Gross Peak Load				15	15	15	16	16	16	16	16
	Entegrus			Gross Peak Load				33	34	34	34	35	35	35	36
				DG				1	1	1	1	1	1	1	1
				CDM				1	1	1	2	3	3	3	4
				Net Load Forecast	44	45	45	46	46	47	46	46	47	47	47
Talbot TS	London Hydro	*T1/T2/T3 /T4*	*290*	Gross Peak Load				273	277	282	258	254	256	263	265
				DG				0	0	0	0	0	0	0	0
				CDM				5	7	10	13	14	15	17	18
				Net Load Forecast	242	247	268	268	270	272	245	240	241	246	247
Tillsonburg TS	Hydro One	*T1/T3*	*109*	Gross Peak Load				50	50	51	51	52	53	53	54
	Tillsonburg Hydro			Gross Peak Load				37	38	39	40	41	41	42	42
				DG				0	0	0	0	0	0	0	0
				CDM				2	2	2	4	5	6	6	7
				Net Load Forecast	94	81	88	85	86	87	88	88	89	89	89
Wonderland TS	Hydro One	*T5/T6*	*99*	Gross Peak Load				9	9	9	9	9	9	9	9
	London Hydro			Gross Peak Load				104	90	92	90	92	94	90	92
				DG				1	1	1	1	1	1	1	1
				CDM				2	2	3	4	5	5	6	7
				Net Load Forecast	109	109	109	110	96	97	94	95	97	92	93
Woodstock TS	Hydro One	*T1/T2*	*87*	Gross Peak Load				68	68	68	69	69	69	69	70
				DG				3	3	3	3	3	3	3	3
				CDM				1	1	2	3	4	4	4	5
				Net Load Forecast	62	55	56	64	64	64	63	62	62	62	62

Appendix C: Coincident Load Forecast 2016-2025

Station	Historical MW	Near Term Forecast (MW)					Medium Term Forecast (MW)		
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Aylmer TS	18	18	20	21	22	23	25	27	28
Buchanan TS	126	125	127	129	131	133	135	138	141
Clark TS	96	92	92	91	90	89	88	87	88
Commerceway TS	25	24	23	23	22	21	21	20	20
Edgeware TS	105	103	103	103	102	102	102	102	102
Highbury TS	77	72	72	72	72	71	71	71	71
Ingersoll TS	70	63	63	62	61	60	60	60	59
Longwood TS	31	30	30	31	31	31	31	31	32
Nelson TS	16	16	16	14	50	42	42	43	44
St Thomas TS	0	0	0	0	0	0	0	0	0
Talbot TS	267	261	257	253	249	247	245	242	240
Tillsonburg TS	91	91	92	92	92	92	93	94	95
Wonderland TS	103	98	97	94	92	89	88	85	83
Woodstock TS	58	54	54	54	53	53	53	52	52

Appendix D: 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

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Peterborough to Kingston Region

Regional Infrastructure Plan ("RIP")

July 8th, 2016

Kingston Hydro
Hydro One Networks Inc. (Distribution)

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County.

The Needs Assessment ("NA") report for the Peterborough to Kingston region was completed in February, 2015 (see attached). The report concluded that there were only two needs in the region and that they should be addressed as follows:

a) Transformation capacity relief for Gardiner TS T1/T2 DESN1: to be addressed by a Local Plan ("LP").
b) Loading constraints on circuit Q6S: to be addressed by Bulk System Planning and not as part of Regional Planning.

An LP was undertaken by Hydro One Networks Inc. (Transmitter), Hydro One Networks Inc. (Distribution) and Kingston Hydro to address the transformation capacity relief for Gardiner TS T1/T2 DESN1 . The LP recommended re-distributing the load at Gardiner TS by transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2. The estimated cost of this project is approximately $1.5M. An LP report was prepared and published by the Working Group for the Peterborough to Kingston region in October, 2015 (also attached).

There are no other major development projects planned for the Peterborough to Kingston Region over the near and mid-term

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the ("RIP") for the Sudbury/Algoma Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2014) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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NEEDS ASSESSMENT REPORT

Region: Peterborough to Kingston

Revision: Final
Date: February 10, 2015

Prepared by: Peterborough to Kingston Region Study Team

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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 Needs Assessment 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 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"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Peterborough to Kingston Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	December 12, 2014	**END DATE**	Feb 10, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Peterborough to Kingston Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This NA included a study of transmission system connection facilities capability, which covers station and line loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Peterborough to Kingston Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.
- Under high Transfer East of Cherrywood and low water conditions in the east, P15C may be loaded near its continuous rating under pre-contingency conditions. This issue will be further assessed by the IESO as part of bulk system planning.

C. 115kV Transmission Lines

- With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S may reach its LTE ratings in the near term based on the gross load forecast. The net load in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.
- The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.
- With the loss of 230 kV circuits P15C and C27P and expected load additional loading in Renfrew area in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue will be further assessed by the IESO as part of bulk system planning.

D. 230 kV and 115 kV Connection Facilities

- Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast with planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted load over the study period. It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region. Based on the gross 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.

For the loss of two elements, the load interrupted by configuration may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, the load interrupted by configuration does not exceed 150 MW. No action is required at this time.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace major equipment do not affect the needs identified.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that

- “localized” wires only solutions be developed in the near-term to adequately and efficiently address the needs associated with transformation capacity relief for Gardiner TS T1/T2 DESN1 as indicated above through planning between Hydro One Networks Inc. and the impacted distributors. See Section 7 for further details, and
- IESO to assess loading constraints on circuit Q6S for the loss of two elements, and P15C under high transfers as part of their bulk system planning

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Peterborough to Kingston Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Peterborough to Kingston Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the Peterborough to Kingston Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the IESO.

Table 1: Study Team Participants for Peterborough to Kingston Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
3.	Independent Electricity System Operator ("IESO")
4.	Kingston Hydro Corporation ("Kingston Hydro")
5.	Peterborough Distribution Inc. ("Peterborough Distribution")
6.	Veridian Connections Inc. ("Veridian")
7.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the Peterborough to Kingston Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the Peterborough to Kingston Region over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station and line thermal capacity and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Peterborough to Kingston Region Description and Connection Configuration

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The boundaries of the Peterborough to Kingston Region are shown below in Figure 1.

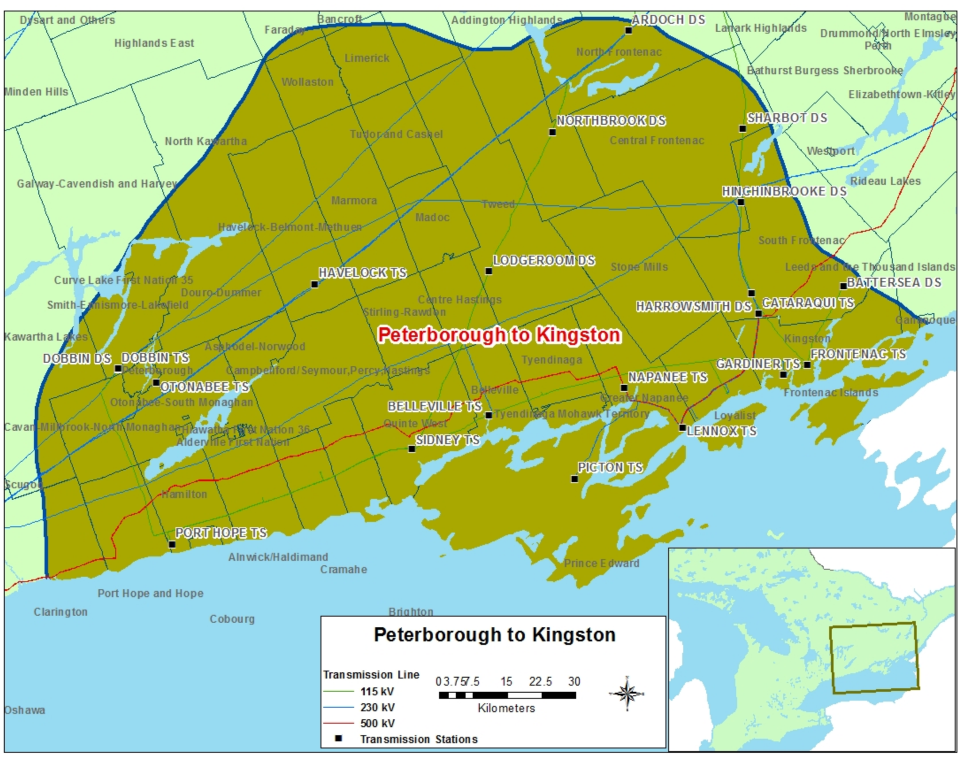

Figure 1: Peterborough to Kingston Region Map

Electrical supply to the Peterborough to Kingston Region is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Lennox Transformer Station (TS) and 230/115 kV autotransformers at Cataraqui TS and Dobbin TS. There are ten Hydro One step-down TS's, eight high voltage distribution stations (HVDS), and five other direct transmission connected load customers in the Region. The distribution system consists of voltage levels 44 kV, 27.6 kV, 12.5 kV, 8.32kV, and 4.16kV. The main generation facility in the Region is the 2000 MW Lennox Generation Station (GS) connected to Lennox TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. 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: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Belleville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.

- There are 3 existing Transmission connected generating stations in the Region as follows:
    - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS

- A 910 MW gas-fired plant (Napanee GS) is expected to connect to Lennox TS at the 500kV level in 2018.

- Up to 535 MW of additional transmission connected renewable generation could be in service in the Region by the year 2023.

- There are a network of 230 kV and 115 kV circuits that provide supply to the Region, as shown in Table 2 below:

Table 2: Transmission Lines in Peterborough to Kingston Region

Voltage	Circuit Designations	Location
230 kV	X1H, X2H, X3H, X4H	Hinchinbrooke SS to Lennox TS
	X21, X22	Picton TS to Lennox TS
	H23B	Belleville TS to Hinchinbrooke SS
	H27H	Hinchinbrooke SS to Havelock TS
	X1P	Dobbin TS to Chenaux TS
	C27P	Dobbin TS to Chat Falls GS
	H24C, H26C	Cherrywood TS to Havelock TS
	C28C	Cherrywood TS to Chat Falls GS
	P15C	Cherrywood TS to Dobbin TS
	B23C	Cherrywood TS to Belleville TS
115 kV	P3S, P4S	Dobbin TS to Sidney TS
	Q6S	Cataraqui TS to Sidney TS
	B1S	Barrett Chute TS to Sidney TS
	Q3K	Cataraqui TS to Frontenac TS
	B5QK	Cataraqui TS to Frontenac TS to Barrett Chute TS

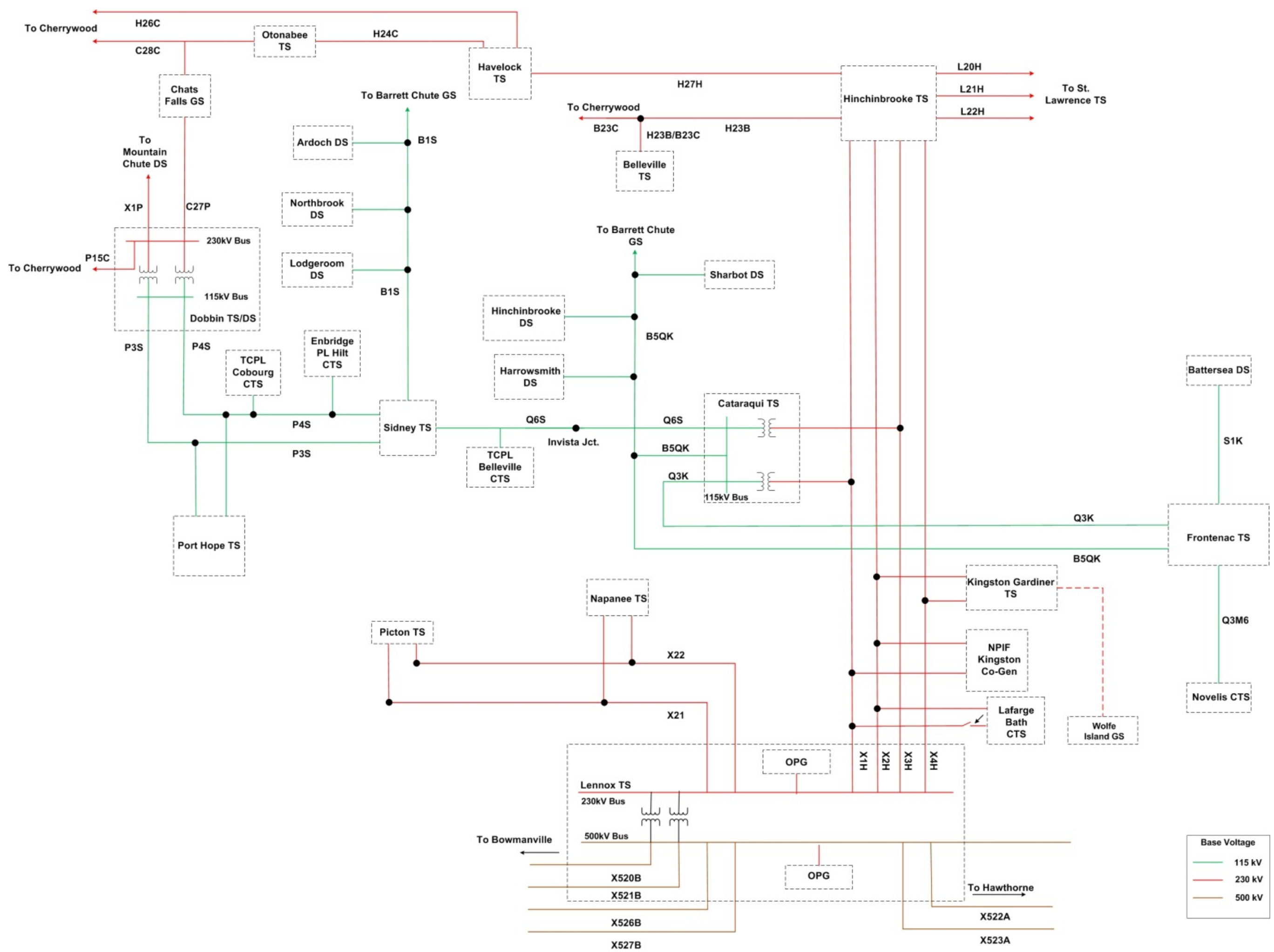

Figure 2: Single Line Diagram – Peterborough to Kingston Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
    1. Historical 2013 regional coincident peak load and station non-coincident peak load
    2. List of existing reliability and operational issues
    3. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load, and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Gross Load Forecast

As per the data provided by the study team, the gross load in the Peterborough to Kingston Region is expected to grow at an average rate of approximately 0.4% annually from 2014-2023.

4.2 Net Load Forecast

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. The net load is expected to decrease at an average rate of approximately 0.6% annually from 2014-2023.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region consists of both winter and summer peaking stations. Therefore, this assessment is based on both winter and summer peak loads, as appropriate.

2. Forecast loads are provided by the Region's LDCs. LaFarge Canada had provided a load forecast for LaFarge Canada CTS. Load data was not received by the other industrial customers in the region (Enbridge Pipeline Inc, TransCanada Pipeline Ltd.). For these stations, the load was assumed to be consistent with historical loads.

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 summer/winter peak load as a reference point.

4. The 2013 summer/winter peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

5. Accounting for (2), (3), (4) above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG is analyzed to determine if needs can be deferred.

   A coincident version of the gross and net load forecast was used to assess the transformer capacity needs (section 6.1.1), 230 kV transmission line needs (section 6.1.2), 115 kV transmission line needs (6.1.3) and system reliability operation and restoration needs (6.2).

   A non-coincident version of the gross and net load forecast was used to assess the station capacity as presented in section 6.1.4.

   A coincident peak load forecast and a non-coincident peak load forecast were produced for each gross load and net load forecasts.

6. Review impact of any on-going and/or planned development projects in the Region during the study period.

7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.

8. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed 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 or winter 10-Day Limited Time Rating (LTR), as appropriate.

9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer or winter 10-Day LTR, as appropriate.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) (Section 4.2) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC (Section 7.2) criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Peterborough to Kingston Region.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Dobbin TS and Cataraqui TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 230 kV Transmission Lines

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high Transfer East of Cherrywood and low water conditions in Eastern Ontario, the 230 kV circuit P15C may be loaded near its continuous rating under pre-contingency conditions. This issue should be further assessed by the IESO as part of bulk system planning.

6.1.3 115kV Transmission Lines

With the loss of 230 kV circuit P15C, the 115 kV circuit Q6S from Invista Jct to Sidney TS may reach its LTE rating in the near term based on the gross load forecast. The net load forecast in the area is forecasted to decrease from 2014-2023 with the inclusion of DG and CDM. No action is required at this time and the capacity need will be reviewed in the next planning cycle.

With the loss of 230 kV circuits P15C and C27P and expected additional loading in the Renfrew region in 2018, the circuit Q6S may be loaded beyond its LTE rating. This issue should be further assessed by the IESO as part of bulk system planning.

The remaining 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region.

6.1.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs and HVDSs in the Region using either the summer or winter station peak load forecasts as appropriate that were provided by the study team. The results are as follows:

Gardiner TS

Gardiner TS T1/T2 DESN1 (summer peaking station) is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the planned CDM targets and DG contributions, the station capacity for Gardiner TS T1/T2 DESN1 is adequate to meet the net forecasted demand over the study period.

It should be noted that Gardiner TS T3/T4 DESN2 is lightly loaded. Hydro One transmission will undertake an assessment of the need for load transfers as a local planning initiative and work with LDCs to develop a plan to balance load between the two DESNs

All the other TSs and HVDSs in the Region are forecasted to remain within their normal supply capacity during the study period. Therefore, no action is required at this time and the capacity needs will be reviewed in the next planning cycle.

6.2 System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region.

Based on the gross 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.

For the loss of circuits X2H and X4H, the load interrupted by configuration at Gardiner TS may exceed 150 MW based on the gross coincident load forecast. However, based on the net coincident load forecast, which accounts for CDM and DG, the load interrupted by configuration does not exceed 150 MW. Therefore, no action is required at this time and this will be reviewed in the next planning cycle.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables.

During the study period:

- Replacement (like-for-like) of both transformers (T1 and T2) at Gardiner TS DESN1 is scheduled in 2020. The replacement plan does not affect the results of this NA study.

- Replacement of two autotransformers, T2 and T5 (78 MVA and 115 MVA respectively), at Dobbin TS with a single 150/250 MVA autotransformer is scheduled in 2019. The third autotransformer (T1) will remain the same. The replacement plan does not affect the results of this NA study.

- There are no significant lines sustainment plans that will affect the results of this NA study.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that no further coordinated regional planning is required.

Rather the study team recommends the following to address the identified needs:

a) Hydro One transmission will lead the assessment and develop a local plan ("Gardiner TS Load Balancing") with the relevant LDCs to balance load between the two DESNs at Gardiner TS; and,

b) IESO to assess and develop a plan for the contingencies associated with circuit Q6S for the loss of two elements and loading constraints on circuit P15C under high transfers within the context of a bulk planning study for the area.

8 NEXT STEPS

Hydro One Transmission and impacted LDCs will address the recommendation in Section 7a and develop a local plan.

IESO to initiate a bulk planning study for the area.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
IESO	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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GARDINER TS LOAD BALANCING

Region: Peterborough to Kingston

Revision: FINAL
Date: October 7, 2015

Prepared by: "Peterborough to Kingston" Region Local Planning Study Team

Peterborough to Kingston Region Local Planning Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Kingston Hydro (Embedded LDC)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Peterborough to Kingston Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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 Local Planning 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 Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning 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 Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Peterborough to Kingston (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	April 10, 2015	**END DATE**	October 7, 2015

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the Peterborough to Kingston Region. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

2. LOCAL NEED ADDRESSED IN THIS REPORT

The Needs Assessment (NA) report for the Peterborough to Kingston Region indicated that Gardiner TS T1/T2 DESN1 is forecasted to exceed its normal supply capacity in the near term. Gardiner TS T3/T4 DESN2 is lightly loaded. The local need addressed in this report will be how to best alleviate the station capacity issue at Gardiner TS T1/T2 DESN1.

3. ALTERNATIVES CONSIDERED

The alternatives considered were:

1) Transfer load from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN
2) Do Nothing

4. PREFERRED ALTERNATIVE

Transferring load from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 is the preferred alternative as it addresses the station capacity issue at Gardiner TS T1/T2 DESN1. Transferring some of the existing load at Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 is the most straight forward and cost effective option.

5. RECOMMENDATIONS

Hydro One Distribution will proceed with a detailed estimate for the load transfer work at Gardiner TS. The detailed estimate for the load transfer work is expected to be completed mid-2016. The expected in-service date for this work is end of 2018.

Table of Contents

1 Introduction

The Needs Assessment (NA) for the Peterborough to Kingston Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 Regions is complete and will be initiated for Group 3 Regions later this year. The Peterborough to Kingston Region belongs to Group 2. The NA for this Region was triggered on December 12, 2014 and was completed on Feb 10, 2015. The NA for the Peterborough to Kingston Region was prepared jointly by the study team, including Local Distribution Companies (LDC), Independent Electric System Operator (IESO), Ontario Power Authority (merged with IESO as of January 2015 and herein referred to as IESO), and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Peterborough to Kingston Region over the next ten years (2014 to 2023) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

This report was prepared by the Peterborough to Kingston Region LP study team (Table 1) and led by the transmitter, Hydro One Networks Inc. (Hydro One). The report captures the results of the assessment based on information provided by LDCs and Hydro One.

Table 1: Study Team Participants for Peterborough to Kingston Region

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Kingston Hydro (Embedded LDC)

2 Regional Description

The Peterborough to Kingston Region includes Frontenac County, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. Please refer to the NA Report for further details. The Peterborough to Kingston Region and its approximate boundaries are shown in Figure 1. The facilities in the Region are depicted in the single line diagram shown in Figure 2.

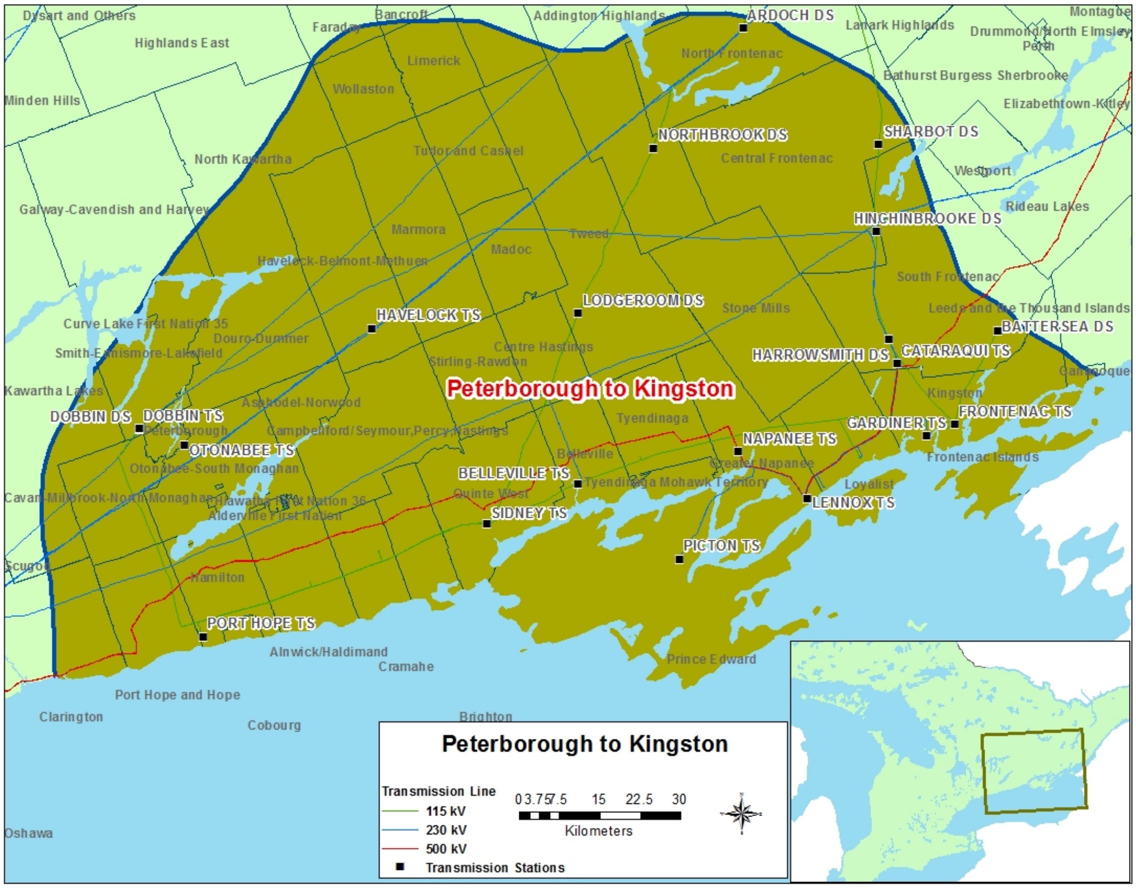


Figure 1: Peterborough to Kingston Region Map

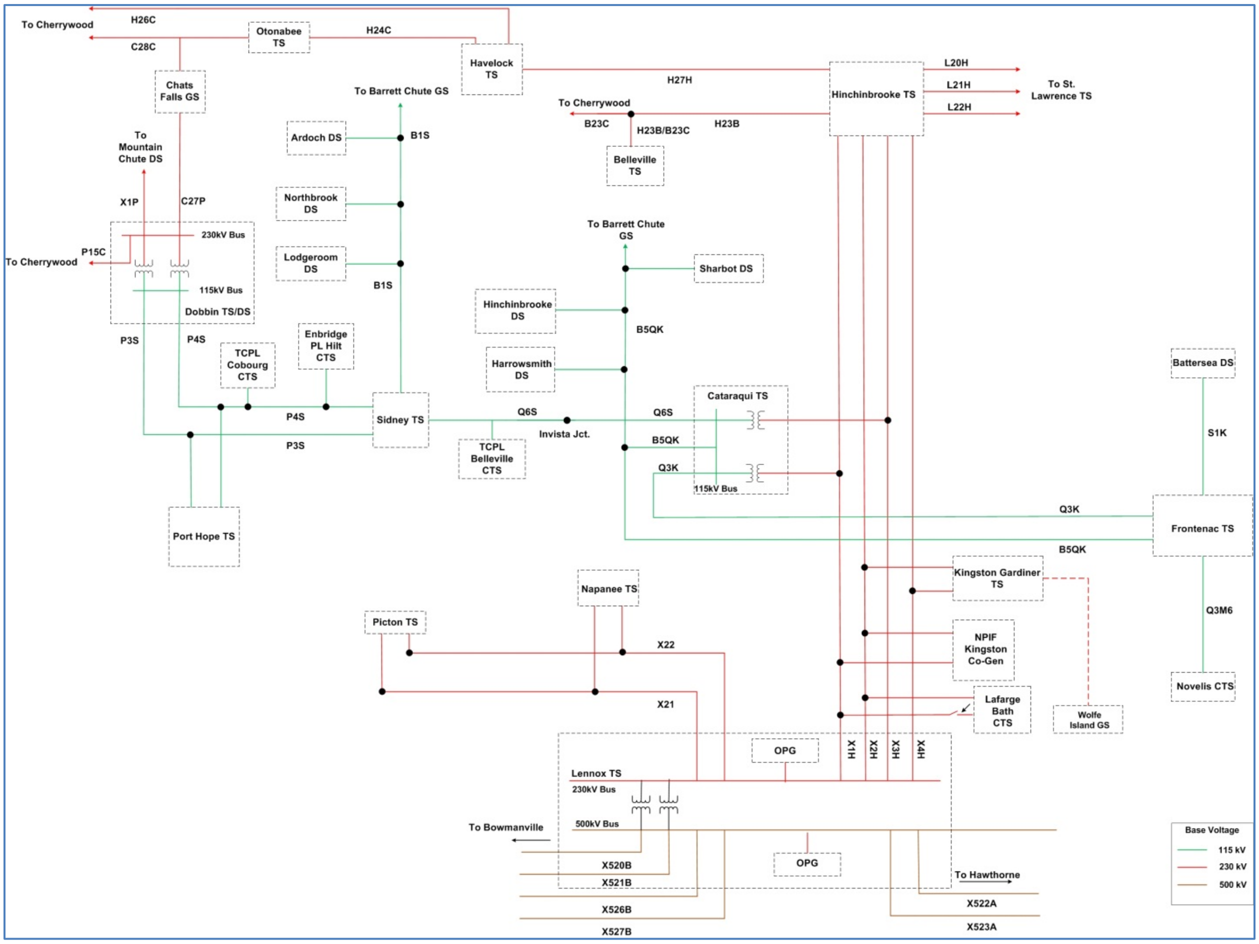


Figure 2: **Single Line Diagram – Peterborough to Kingston Region**

3 Peterborough to Kingston Region Needs

As an outcome of the NA process, the study team identified a need to address the normal supply capacity at Gardiner TS T1/T2 DESN1. Since this need can be clearly addressed by a straightforward wires solution, the study team agreed that it should be further planned directly by the impacted LDC and the transmitter through the LP process and that further coordinated regional planning was not required. Hydro One with the impacted LDCs further undertook planning assessments to develop options and recommend a wires only solution(s). Gardiner TS (230/44 kV)

3.1 Gardiner TS (230/44kV)

Gardiner TS T1/T2 DESN1 is forecasted to exceed its normal supply capacity from 2014 to 2023 based on the gross load forecast (approximately 112% and 117% of Summer 10-Day LTR in 2014 and 2023 respectively). However, based on the net load forecast which takes planned CDM targets and DG contributions into consideration, this issue will be avoided. Nevertheless, the station will still be loaded at 100% of its thermal capacity at that time. The load forecast provided by LDCs and the CDM and DG forecast provided by the IESO are attached in Appendix A.

4 Options Considered

This section describes the options considered to address the local need described in section 3.1.

4.1 Gardiner TS Load Balancing

Prior to the regional planning process, Hydro One Distribution had already planned on re-distributing the load at Gardiner TS by transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2. This would alleviate the loading concerns at Gardiner TS T1/T2 DESN1 for this study period. The preliminary budgetary cost estimate for this project is about $1.5M.

4.2 Do Nothing

Do nothing is not a viable option since it could result in the violation of transformer ratings at Gardiner TS T1/T2 DESN1, which is not acceptable.

5 Recommendation

The study team agreed that transferring one feeder from Gardiner TS T1/T2 DESN1 to Gardiner TS T3/T4 DESN2 would relieve the thermal loading at Gardiner TS T1/T2 DESN1. This is a cost effective solution that will ensure that any additional load growth during the study period at Gardiner TS can be accommodated without exceeding the station thermal limit. Hydro One Distribution will be proceeding with the development of a plan to transfer the load along with a cost estimate for the work by the end of 2015. The expected in-service date for this feeder load transfer is end of 2018.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

iii) Peterborough to Kingston Region Needs Assessment Report

Appendix A: Load Forecast for Peterborough to Kingston Region

Table A1: Gross Load Forecast (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2
Battersea DS T1/T2	9.4	9.4	9.4	9.4	9.3	9.2	9.1	9.1	9.0	9.0
Belleville TS T1/T2	141.5	131.7	131.4	131.1	130.8	129.8	128.7	128.6	128.3	128.0
Dobbin DS T1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Dobbin DS T2	6.3	6.2	6.2	6.2	6.2	6.2	6.1	6.1	6.1	6.1
Dobbin TS T3/T4	83.5	83.2	83.0	83.0	82.7	81.6	80.5	80.3	79.9	79.5
Frontenac TS T3/T4	100.8	101.5	102.3	103.3	104.0	103.8	103.6	104.4	105.0	105.5
Gardiner TS T1/T2	125.3	124.9	124.8	125.2	124.8	122.9	121.2	120.9	120.4	119.8
Gardiner TS T3/T4	15.8	15.8	15.9	15.9	16.0	15.8	15.7	15.7	15.7	15.7
Harrowsmith DS T1	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.4
Harrowsmith DS T2	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.3	9.4
Havelock TS T1/T2	63.5	63.3	63.2	63.2	63.1	62.4	61.8	61.7	61.5	61.3
Hinchinbrooke DS T1	6.5	6.5	6.5	6.5	6.5	6.4	6.4	6.3	6.3	6.3
Lodgeroom DS T1	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3
Lodgeroom DS T2	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1
Napanee TS T1/T2	55.1	52.6	52.5	53.1	53.3	53.0	52.7	53.1	53.4	53.6
Northbrook DS T1	6.8	6.8	6.8	6.8	6.8	6.8	6.7	6.7	6.7	6.6
Otonabee TS T1/T2	43.6	43.4	43.1	43.1	42.9	42.4	41.9	41.7	41.5	41.3
Otonabee TS T1/T2	84.3	83.8	83.4	83.4	83.0	81.8	80.8	80.5	80.0	79.6
Picton TS T1/T2	54.6	46.4	46.6	47.0	47.2	46.8	46.4	46.7	46.8	46.9
Port Hope TS T1/T2	53.1	49.7	49.3	49.4	49.4	48.9	48.5	48.5	48.4	48.3
Port Hope TS T3/T4	64.1	63.4	63.2	63.2	63.0	62.1	61.3	61.1	60.9	60.6
Sharbot DS T1	4.3	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.2
Sidney TS T1/T2	64.1	63.9	63.8	64.0	63.9	63.1	62.4	62.4	62.2	62.1
LaFarge Canada CTS	21.0	21.0	21.0	22.0	17.0	17.0	17.0	17.0	17.0	17.0
Enbridge PL Hilt CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TCPL Cobourg CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
TCPL Belleville CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

Table A2: Net Load Forecast (MW)

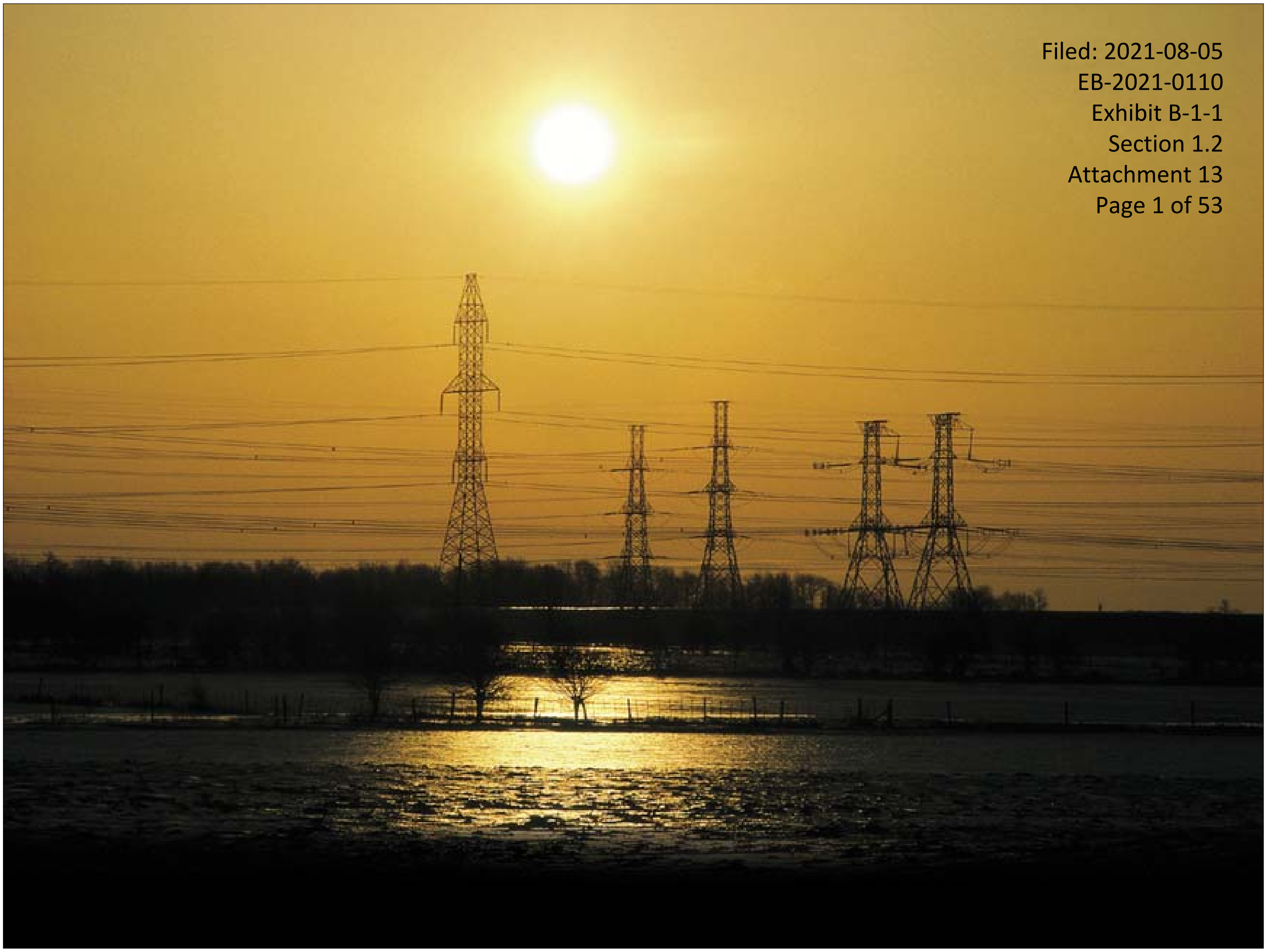
Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Battersea DS T1/T2	10.0	10.0	10.1	10.1	10.1	10.1	10.2	10.2	10.2	10.2
Belleville TS T1/T2	148.9	149.3	149.6	149.9	150.3	150.6	150.9	151.3	151.6	152.0
Dobbin DS T1	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2
Dobbin DS T2	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.6	6.6	6.6
Dobbin TS T3/T4	84.3	84.6	84.9	85.3	85.6	85.9	86.2	86.5	86.8	87.1
Frontenac TS T3/T4	106.2	107.6	108.9	110.3	111.7	113.0	114.4	115.8	117.2	118.5
Gardiner TS T1/T2	140.5	141.3	142.2	143.1	143.7	144.3	144.9	145.5	146.1	146.7
Gardiner TS T3/T4	16.0	16.1	16.2	16.4	16.5	16.6	16.8	16.9	17.1	17.2
Harrowsmith DS T1	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4
Harrowsmith DS T2	9.0	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4
Havelock TS T1/T2	64.0	64.2	64.4	64.6	64.9	65.1	65.3	65.5	65.7	66.0
Hinchinbrooke DS T1	6.6	6.6	6.6	6.7	6.7	6.7	6.7	6.7	6.8	6.8
Lodgeroom DS T1	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4
Lodgeroom DS T2	5.1	5.1	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Napanee TS T1/T2	71.1	72.0	72.8	73.6	74.4	75.2	76.0	76.9	77.7	78.5
Northbrook DS T1	6.9	6.9	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.2
Otonabee TS T1/T2	45.5	45.6	45.7	45.8	45.9	46.0	46.1	46.1	46.2	46.3
Otonabee TS T1/T2	88.0	88.2	88.3	88.5	88.6	88.8	88.9	89.0	89.2	89.3
Picton TS T1/T2	55.1	55.7	56.3	56.9	57.5	58.2	58.8	59.4	60.0	60.6
Port Hope TS T1/T2	53.7	54.0	54.3	54.5	54.8	55.1	55.4	55.7	56.0	56.3
Port Hope TS T3/T4	64.7	65.0	65.3	65.5	65.8	66.1	66.4	66.6	66.9	67.2
Sharbot DS T1	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5
Sidney TS T1/T2	77.3	77.7	78.0	78.3	78.7	79.0	79.3	79.7	80.0	80.3
LaFarge Canada CTS	21.0	21.0	21.0	22.0	17.0	17.0	17.0	17.0	17.0	17.0
Enbridge PL Hilt CTS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TCPL Cobourg CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
TCPL Belleville CTS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

Table A3: Conservation Demand Management (Percent of Gross Load)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
C&S	0.0%	0.2%	0.5%	0.6%	1.1%	1.6%	1.9%	2.3%	2.5%	2.6%
TOU	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
EE programs	0.5%	0.8%	1.0%	1.1%	1.3%	2.1%	3.1%	3.2%	3.6%	4.2%
Total	1%	1%	2%	2%	3%	4%	5%	6%	6%	7%

Table A4: Distributed Generation (MW)

Transformer Station	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ardoch DS T1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Battersea DS T1/T2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Belleville TS T1/T2	6.7	16.2	16.2	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Dobbin DS T1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dobbin DS T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Frontenac TS T3/T4	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Gardiner TS T1/T2	13.8	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Lodgeroom DS T1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lodgeroom DS T2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Napanee TS T1/T2	15.5	18.3	18.7	18.7	18.9	18.9	18.9	18.9	18.9	18.9
Otonabee TS T1/T2	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Otonabee TS T1/T2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Picton TS T1/T2	0.0	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Port Hope TS T1/T2	0.2	3.5	3.9	3.7	4.0	4.0	4.0	4.0	4.0	4.0
Port Hope TS T3/T4	0.0	0.46	0.52	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sidney TS T1/T2	12.7	12.	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7



South Georgian Bay/Muskoka

REGIONAL INFRASTRUCTURE PLAN

August 18th, 2017

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

With support from:

Company
Independent Electricity System Operator
Alectra Utilities Corporation (formerly PowerStream Inc.)
Hydro One Networks Inc. (Distribution)
InnPower Corporation
Orangeville Hydro Ltd.
Veridian Connections Inc.

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address near and mid-term needs identified in previous planning phases and also 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.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE STUDY TEAM 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 OF THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

The participants of the RIP Study Team included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator
- Alectra Utilities (formerly PowerStream Inc.)
- Hydro One Networks Inc. (Distribution)
- InnPower Corporation
- Orangeville Hydro Ltd.
- Veridian Connections Inc.

This RIP is the final phase of the OEB's mandated regional planning process for the South Georgian Bay/Muskoka Region. It follows the completion of Integrated Regional Resource Plans ("IRRP") for Barrie/Innisfil and Parry Sound/Muskoka Sub-Regions on December 16, 2016.

This RIP provides a consolidated summary of the needs and recommended plans for the South Georgian Bay/Muskoka Region which includes the Barrie/Innisfil and Muskoka/Parry Sound Sub-Regions. The major transmission and distribution infrastructure investments planned for the South Georgian Bay/Muskoka Region over the near and mid-term, as identified in the various phases of the regional planning process are given in the Table below.

No.	Project	I/S Date	Cost ($ Million)
1	Replacement of 115-44kV transformers (T1 and T2) at Barrie TS, uprating 115kV circuits to 230kV, adding additional feeders to Barrie DESN	2020/2021	$84
2	Replacement of 230-44kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS	2020/2021	$17
3	Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)	2021	$5-7
4	Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS*	2020	$7
5	Replacement of 230/44 kV transformers at Parry Sound TS*	2021	$20
6	Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS	2024/2025	$33

* Replacement of transformers at Parry Sound TS would eliminate the need to build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS

A load transfer from Barrie TS to Midhurst TS that is planned for 2019 will address the near-term capacity need at Barrie TS and will defer the capacity need of the upgraded Barrie TS to 2031.

A cost-benefit/responsibility analysis will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system, which will be completed by the end of 2017.

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can also be started earlier.

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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. ("Hydro One") and documents the results of the study with input and consultation with Hydro One Distribution, Alectra Utilities (formerly PowerStream Inc.) ("Alectra"), Veridian Connections Inc. ("Veridian"), Innisfil Hydro Distribution Systems Ltd ("InnPower"), Orangeville Hydro Ltd ("Orangeville Hydro") and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The South Georgian Bay/Muskoka region consists of the area roughly bordered by the Municipality of West Nipissing to the northwest, Algonquin Provincial Park to the northeast, Peterborough County and Hastings County to the southeast, Lake Scugog, York and Peel Regions to the south, Wellington County to the southwest and the Municipality of Grey Highlands to the west. Figure 1-1, on the following page, shows the boundaries of the South Georgian Bay/Muskoka Region.

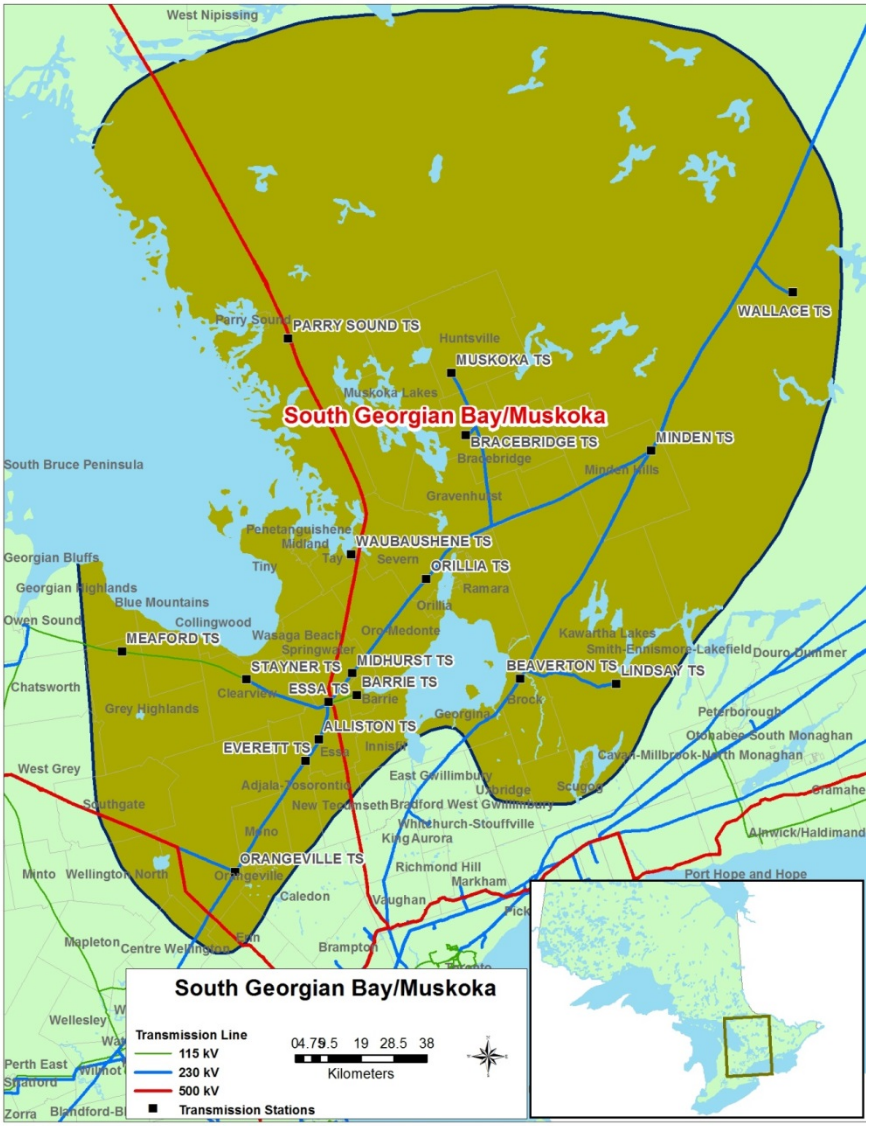

Figure 1-1 South Georgian Bay/Muskoka Region

1.1 Scope and Objectives

This RIP report examines the needs in the South Georgian Bay/Muskoka Region. Its objectives are to:

- Identify new needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and/or distribution facilities 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 Region's 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 plans to address near and mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Barrie-Innisfil and Parry Sound/Muskoka sub-region IRRPs.

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can also be started earlier.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the regional characteristics
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs
- Section 7 describes the needs and provides 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 performed 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 115kV and 230kV 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 or comprehensive planning is required an assessment is undertaken for any necessary investments directly by the LDCs (or customers) and the transmitter through a Local Plan ("LP"). 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. If there are needs that do not require regional coordination, the Study Team can recommend them to be undertaken as part of the LP approach discussed above. Otherwise, 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 is identified in the NA phase, it is possible that different approaches 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

[1] Also referred to as Needs Screening.

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 ("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 the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeline provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project-specific level will be conducted as part of the project approval requirement.

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

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

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

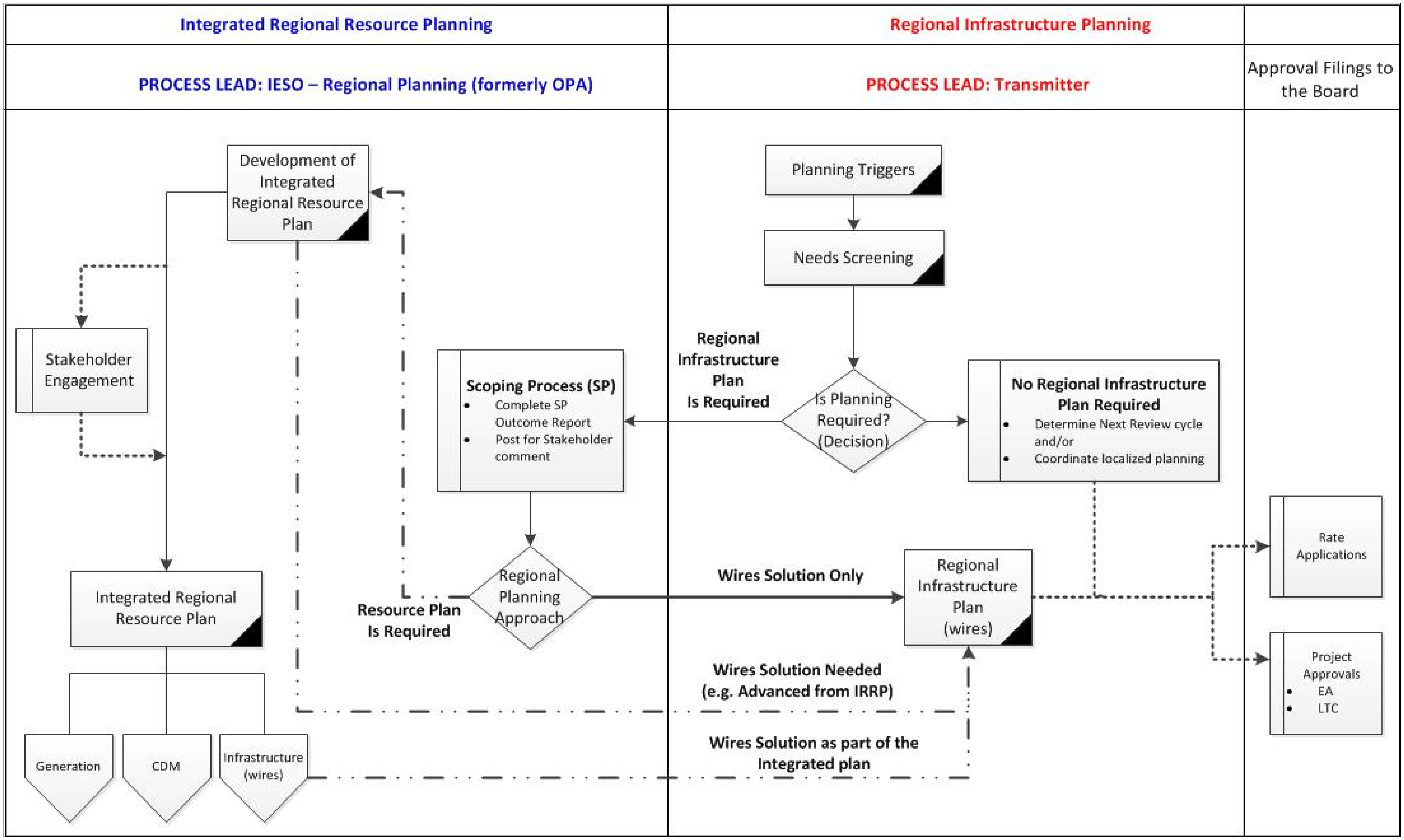

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. **Data Gathering:** The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Study Team to reconfirm or update the information as required:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation ("DG") or CDM 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.

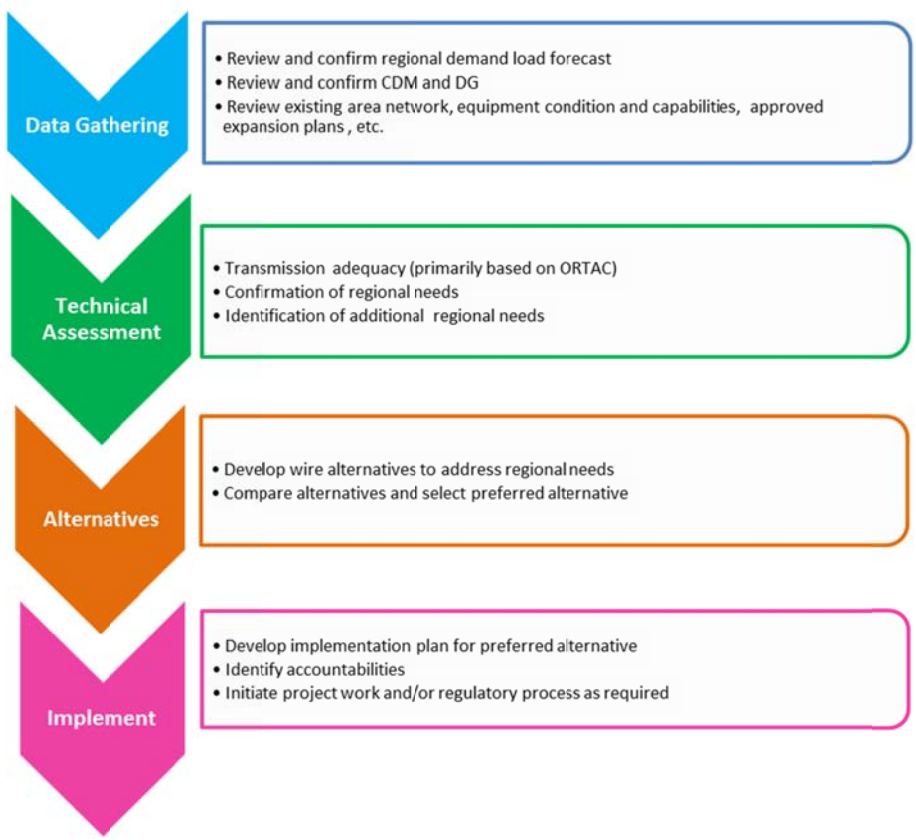

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE 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 2015 WINTER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1,350 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

There are sixteen Hydro One-owned 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 March 2013 South Georgian Bay/Muskoka Region 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. An IRRP was undertaken for each sub-region. A map of the South Georgian Bay/Muskoka Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Barrie/Innisfil 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.

3.2 Parry Sound/Muskoka Sub-Region

This 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, and Minden TS, and transmission circuits M6E/M7E and E26/E27.

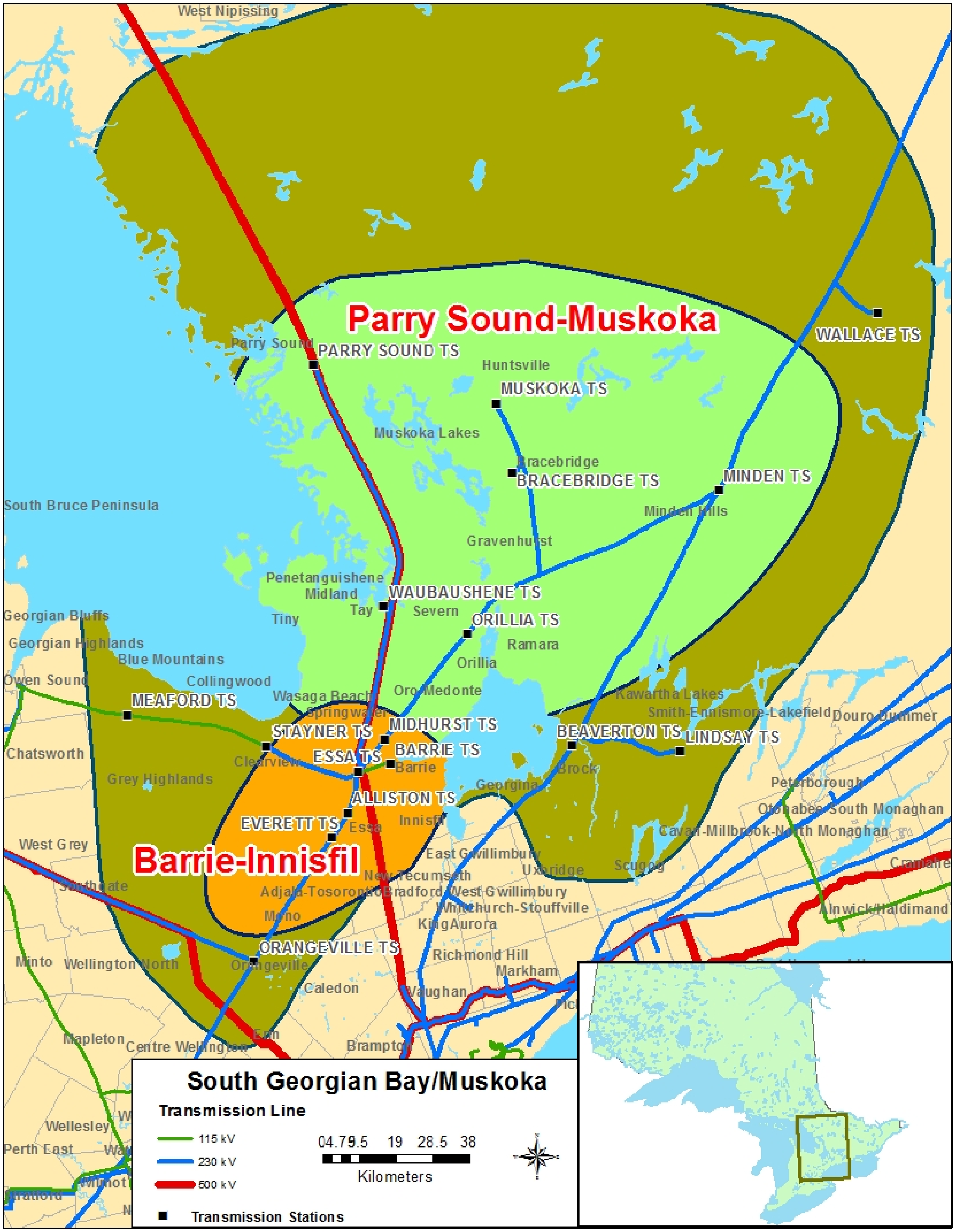

Figure 3-1 South Georgian Bay/Muskoka – Supply Areas

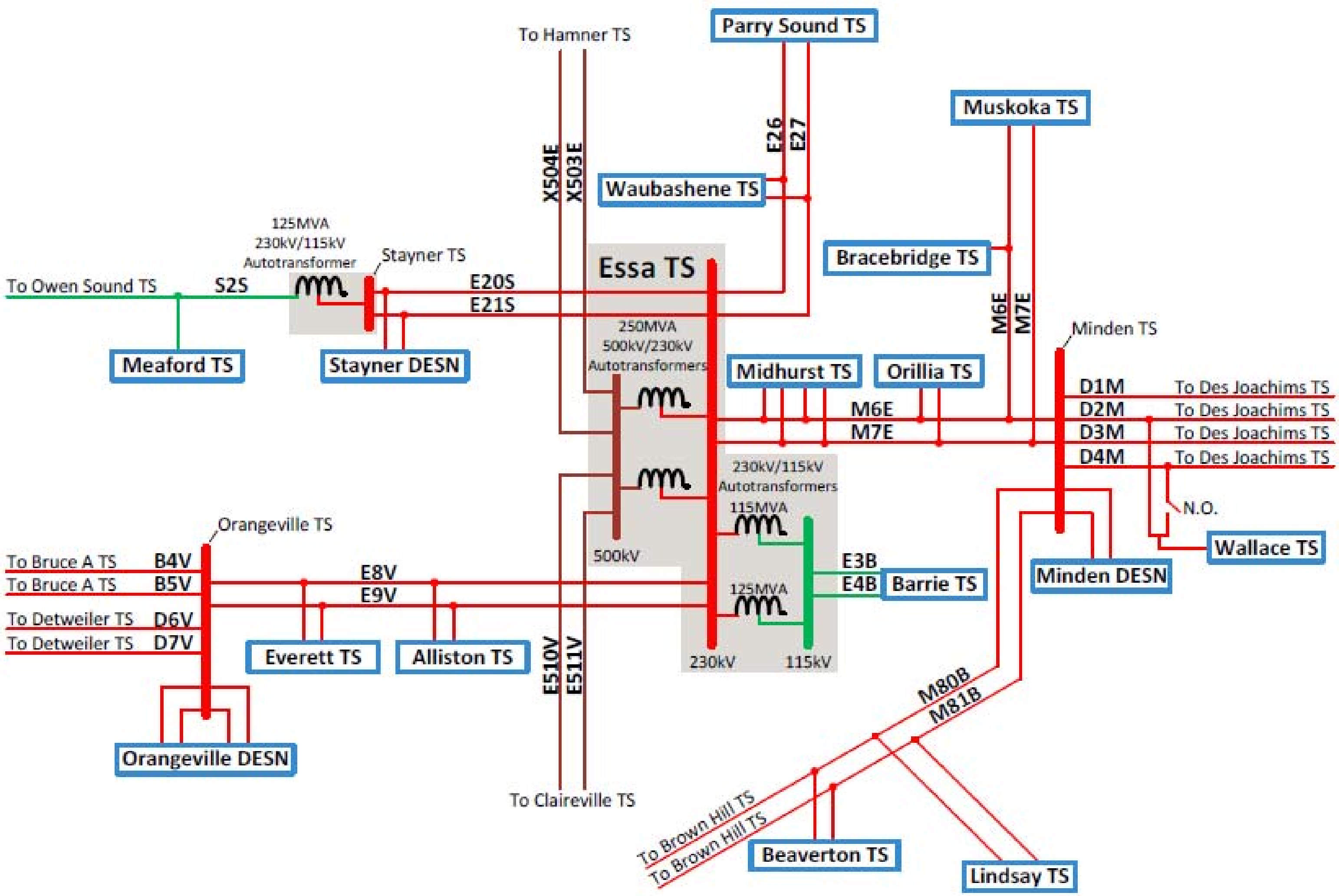

Figure 3-2 South Georgian Bay/Muskoka Region Single Line Diagram (Current)

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

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR HAVE BEEN INITIATED, AIMED AT IMPROVING THE SUPPLY TO THE SOUTH GEORGIAN BAY/MUSKOKA REGION.

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

- Everett TS (2007) – Construction of new 50/85 MVA 230/44 kV Everett transformer station to alleviate load from Alliston TS, which was loaded beyond its capacity, and provide additional capacity for the load growth in the South Georgian Bay area.

- South Georgian Bay Transmission Reinforcement (2009) – Replacement of 27 km of 115 kV single circuit (S2E) between Essa TS and Stayner TS with a 230 kV double circuit (E20S/E21S) to improve supply reliability and prevent excessive post-contingency voltage decline. Replacement of two 50/83 MVA 115/44 kV step-down transformers at Stayner TS with two 75/125 MVA 230/44 kV transformers to provide additional capacity for the load growth in the South Georgian Bay area.

- Essa TS Shunt Capacitor Bank (2010) – Installation of one (1) 230 kV 245 MVAr shunt capacitor bank to address the need for added voltage support to increase the transfer capability of power from north to south and accommodate committed generation facilities north and west of Sudbury.

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44 kV 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (2 banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and improve the power quality for customers.

- Meaford TS Transformer Replacement (2015) – Like-for-like replacement of 25/42 MVA 115/44 kV transformers that were over 60 years old and nearing end-of-life.

The following development projects are expected to be placed in-service within the next 5-10 years:

- Barrie TS (2020/2021) – Hydro One is working with IESO, Alectra Utilities, InnPower, and Hydro One Distribution to replace the aging infrastructure while also addressing the growth related needs. The plan entails uprating 115kV lines E3B/E4B to 230kV, upgrading existing DESN transformer from 115/44 kV, 55/92 MVA to 230/44 kV, 75/125 MVA, increasing the number of feeders at Barrie TS, and removing the two 230/115 KV auto-transformers and 115 kV switchyard at Essa TS.

- Minden TS (2020-2021) – A recent station assessment has identified that power transformers T1 and T2, protection and control equipment, and select 44kV switchyard assets are degrading in condition and require replacement. Work involves replacing existing T1 & T2 three-phase power transformers with standard size three-phase power transformers, and upgrading and replacing the 44kV switchyard components.

- Orangeville (2024-2025) End-of-life transformers T1 and T2 (non-standard) will be replaced with two standard three-phase transformers sized 215.5-28 kV, 50/66.7/83.3 MVA units and T3 and T4 will be replaced with standard 215.5-44 kV, 75/100/125 MVA units. To standardize the configuration, the T1/T2 switchyard will be reconfigured as a single 230-28 kV switchyard and the two existing 44 kV feeders, M45 and M46, will be relocated and supplied from the T3/T4 DESN. Associated end-of-life protection, control and telecom assets and station service equipment is also planned for replacement.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the South Georgian Bay/Muskoka Region is expected to increase at an annual rate of approximately 1.17 % between 2016 and 2034. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The winter and summer, gross and net non-coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

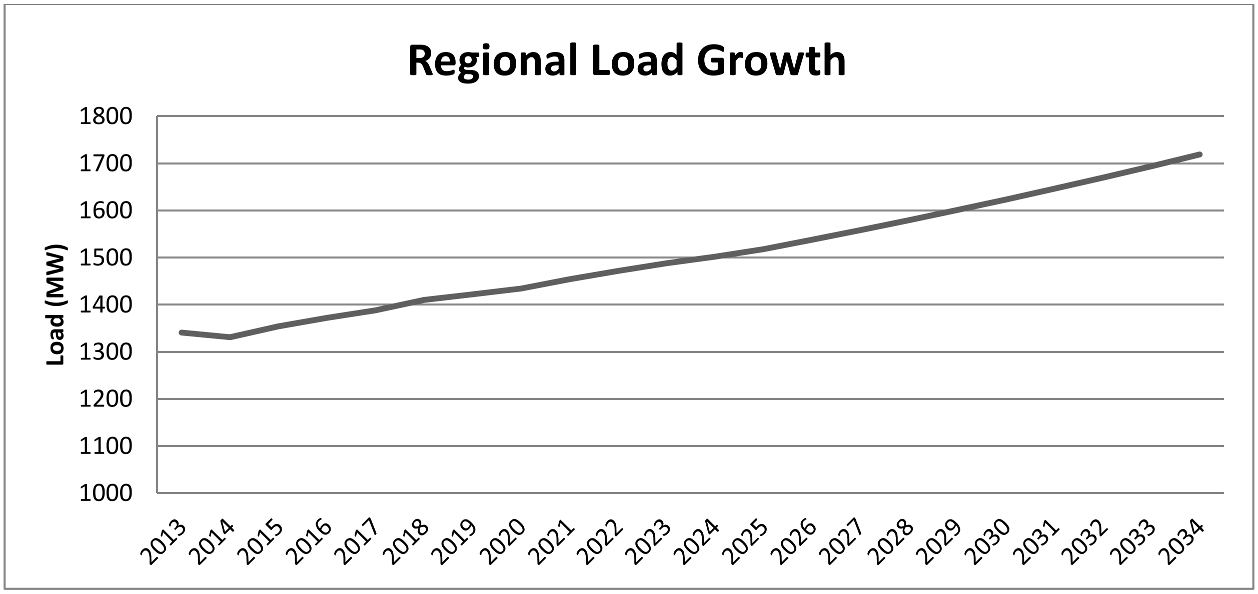

Figure 5-1 South Georgian Bay/Muskoka Region Winter Coincident Net Load Forecast

Prior to the RIP's kick-off, the Study Team was asked to confirm the load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for South Georgian Bay/Muskoka Region did not have a significant revision compared to the IRRP's load forecast.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2014 – 2034.
- The Region is winter peaking, however five out of sixteen stations in the Region are summer peaking (Alliston TS, Barrie TS, Everett TS, Midhurst TS and Orangeville TS T1/T2 DESN). Therefore, this assessment is based on both winter and summer peak loads, as appropriate.
- "Barrie Area Transmission Upgrade project" to be completed by the end of 2020.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-

voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.[2] Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR") or the winter 10-Day LTR depending on what season the station peaks.

- Barrie TS is forecasted to experience the highest average yearly growth rate of any TS in the study area over the 20 year planning period for all growth scenarios.

[2] These power factor assumptions differ from those in the IRRP, which assumes a 90% lagging power factor for all stations. This results in differences in need dates for station capacity when comparing the IRRP and the RIP.

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION 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, six regional assessments have been conducted for the South Georgian Bay/Muskoka Region. The findings of these studies are an input to the RIP:

1. South Georgian Bay/Muskoka Region Needs Assessment Report – March 3, 2015 [2]
2. South Georgian Bay/Muskoka Region Scoping Assessment Report – June 22, 2015 [3]
3. Local Planning Report – Orangeville TS End of life (“EOL”) Replacement – May 27, 2016 [4]
4. Barrie/Innisfil Sub-Region IRRP – Dec. 16, 2016 [5]
5. Parry Sound/Muskoka Sub-Region IRRP – Dec. 16, 2016 [6]

The NA, IRRP, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the South Georgian Bay/Muskoka Region assuming Essa/Barrie and E3B/E4B upgrade to be completed by 2020/2021, Minden DESN transformer replacement and 44kV upgrade to be completed by November 2020/2021, and Orangeville transformer replacement and station reconfiguration to be completed by October 2024/2025.

Sections 6.1-6.3 present the results of this review and Table 6-1 lists the Region’s near, mid and long-term needs identified in both the IRRP and RIP phases.

Table 6-1 Near, Mid and Long-Term Needs in the South Georgian Bay/Muskoka Region

Type	Section	Needs	Timing
Station Capacity	7.1	Barrie TS (existing 115/44kV configuration)	Today
	7.2	Barrie TS (future 230/44kV configuration)	2031[3]
	7.7	Everett TS	2027
	7.3	Parry Sound TS	Today
	7.7	Waubaushene TS	2027[4]
Transmission line capacity	7.1	E3B/E4B forecasted to exceed their Load Meeting Capability (LMC)	2019
Load Restoration	7.4	Load Restoration for loss of double-circuit M6E/M7E	Today
Load Security	7.7	Load Security for M6E/M7E – load growth may exceed its 600 MW LMC	Early 2030s
Outage Duration and Frequency	7.5	44kV Parry Sound/Muskoka Sub-Region experience below average performance w.r.t frequency and duration of outages	Today
Distribution Feeder Capacity	7.6	The one Barrie TS feeder that is designated to InnPower will exceed its normal operating rating	2020
End of Life	7.8	Minden TS (two transformers and associated ancillary equipment)	2020/2021
	7.9	Orangeville TS (All four transformers)	2024/2025
	7.3	Parry Sound TS (one transformer, T2)[5]	2021

6.1 115kV and 230kV Transmission Facilities

The South Georgian Bay/Muskoka Region is comprised of mostly 230kV circuits, M6E/M7E, E8V/E9V E26/E27, E20S/E21S, D1M/D2M/D3M/D4M, M80B/M81B, and one pair of 115kV circuits E3B/E34B, supplying the Barrie/Innisfil and Parry Sound/Muskoka Sub-Regions and other areas outside the two sub-regions. Refer to Figure 3-2 for existing facilities in the Region.

3 The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

4 The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

5 Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition.

Bulk system planning is being conducted by the IESO and is also informed by government policy such as the Long-Term Energy Plan (LTEP). The next LTEP is expected to be issued in 2017. Any outcomes impacting planning decisions will be later updated in this regional planning report.

6.2 Barrie/Innisfil Sub-Region's Step-Down Transformer Station Facilities

There are four step-down transformer stations in the Barrie/Innisfil Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Barrie/Innisfil Sub-Region

Station	DESN	Voltage Transformation
Alliston TS	T2/T3/T4	230/44kV
Barrie TS	T1/T2	115/44kV
Everett TS	T1/T2	230/44kV
Midhurst TS	T1/T2	230/44kV

Based on the LTR of these transformer stations, additional transformation capacity is required at Barrie TS (115/44kV) since the station exceeded its LTR in 2015. This will be addressed by the proposed replacement and upgrade of Barrie TS and circuits E3B/E4B (see details in Section 7.1). In 2031, the upgraded Barrie TS is forecasted to reach its capacity.[6] Since this is a long-term capacity need, it will be monitored and investigated further in the next cycle of the Regional Planning Process. The upgrade of Barrie TS will also address the InnPower distribution feeder capacity need that arises in 2020 – see Section 7.6 for more information.

Everett TS is expected to reach its LTR in approximately ten years. The station's LTR of 86 MW is presently limited by the tap ratio setting of the low voltage current transformers (CT). As the capacity need date approaches, the tap ratio will be increased and the capacity of the station will increase to the LTR of the transformers. The solution to address this capacity need is further described in Section 7.7.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-3.

[6] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

Table 6-3 Transformation Capacities in the Barrie Innisfil Sub-Region

Station	LTR (MW)	2016 Summer Peak (MW)	Relief Required By
Alliston TS (T2)	100	118	-
Alliston TS (T3/T4)	101		-
Barrie TS (T1/T2)	109	102	Immediately
Barrie TS (uprated)	161.5[7]	102	The uprated Barrie TS will exceed its capacity by 2031
Everett TS (T1/T2)	86	70	2027
Midhurst TS (T1/T2)	163	105	-
Midhurst TS (T3/T4)	150	106	-

6.3 Parry Sound/Muskoka Sub-Region's Step-Down Transformer Station Facilities

There are five step-down transformer stations in the Parry Sound/Muskoka Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Parry Sound Muskoka Sub-Region

Station	DESN	Voltage Transformation
Bracebridge TS	T1	230/44kV
Muskoka TS	T1/T2	230/44kV
Orillia TS	T1/T2	230/44kV
Parry Sound TS	T1/T2	230/44kV
Waubaushene TS	T5/T6	230/44kV

Under peak conditions in winters between 2013 and 2016, Parry Sound TS transformers supplied up to 6 MW over their LTR. Although the 2017 winter station peak only reached 44 MW (8 below LTR), the immediate addition of 44 kV capacity is required to provide relief to Parry Sound TS. Two alternatives to address this need are discussed further in Section 7.3.

Waubaushene TS is expected to exceed its LTR of 105 MW by 2027[8]. Plans to mitigate loading problems in Waubaushene TS are discussed in Section 7.7 as long-term needs.

[7] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[8] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

Muskoka TS, Orillia TS and Bracebridge TS are adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Parry Sound/Muskoka Sub-Region

Station	LTR (MW)	2017 Winter Peak (MW)	Relief Required By
Bracebridge TS (T1)	84	11	-
Muskoka TS (T1/T2)	198	145	-
Orillia TS (T1/T2)	177	115	-
Parry Sound TS (T1/T2)	52	44	Immediately
Waubaushene TS (T5/T6)	104[9]	81	2027

The winter and summer non-coincident load forecasts for all stations in the Region are given in Appendix C and Appendix D, respectively.

6.4 Areas outside of Sub-region

The table below lists the seven transformer stations that are outside of the Sub-regions

Table 6-6 Transformation Capacities in the Areas outside of Sub-Region

Station	DESN	Voltage Transformation
Beaverton TS	T3/T4	230/44kV
Lindsay TS	T1/T2	230/44kV
Meaford TS	T1/T2	115/44kV
Minden TS	T1/T2	230/44kV
Orangeville TS	T1/T2	230/44/27.6kV
Orangeville TS	T3/T4	230/44kV
Stayner TS	T3/T4	230/44kV
Wallace TS	T3/T4	230/44kV

[9] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacitor banks have a 90% power factor and stations with low-voltage capacitor banks have a 95% power factor. Since Waubaushene TS has low voltage capacitor banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP..

Table 6-7 Transformation Capacities in the Areas outside of Sub-Region

Station	LTR (MW)	2017 Winter Peak (MW)	Relief Required By
Beaverton TS	213	72.2	-
Lindsay TS	183	76.6	-
Meaford TS	58	31.7	-
Minden TS	58	50.6	-
Orangeville TS (T1/T2) 27.6 kV	110	32	-
Orangeville TS (T1/T2) 44 kV	56	21	-
Orangeville TS (T3/T4)	118	71	-
Stayner TS	203	124.5	-
Wallace TS	54	33.3	-

Based on peak load conditions, all the transformers are within their respective LTRs.

End-of-Life Equipment Replacements

Recent station assessments have identified near-term end-of-life needs at Orangeville TS and Minden TS, and a recent condition assessment of Parry Sound TS has revealed that one of the existing power transformers at the station is in a very poor condition and must be replaced in the near-term.

- The Minden TS facility was originally built in 1950. Its assets are degrading in condition and require replacement in 2020-2021. Existing 230/44 kV T1 and T2 three-phase power transformers and associated ancillary equipment will be upgraded with the smallest available standard size 230/44 kV three-phase power transformers. As a result, the rating of transformers will increase from 25/33/42 to 50/66.7/83.3 MVA. See Section 7.8 for more information.

- Switchyards at Orangeville TS were placed in-service in 1960s and several of the assets are at the end of their useful lives including all four transformers (T1, T2, T3, and T4). In addition, the existing 210-44-28 kV winding configuration on T1 and T2 is non-standard which introduces challenges with maintenance, spare parts and future replacement strategies. The existing switchyard supplied by T1/T2 consists of 28kV feeders, plus additional two 44kV feeders.

  After reviewing different alternatives, the preferred solution is to replace T1/T2 with standard three-phase 215.5-28kV transformers, while T3 and T4 will be replaced with standard 215.5-44kV units. The existing 44kV feeders in the T1/T2 DESN will be relocated to the T3/T4 DESN. Due to this modification, the T3/T4 rating will change from 50/67/83 to 75/100/125 MVA, while the T1/T2 rating will change from 75/100/125 to 50/66.7/83.3 MVA. See Section 7.9 for more information.

- Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition which has triggered a station assessment which will be undertaken by Hydro One's Station Sustainment team in 2017. The team will assess all of the Parry Sound TS equipment to determine when the various components need to be replaced in order to avoid end-of-life failures. See Section 7.3 for more information.

It is worth noting that there are potential bulk power system elements that are also at the end of their useful lives. These include 230 kV transmission lines D1M/D2M, E8V/E9V, and M6E/M7E. IESO will lead the bulk power system studies for these lines in coordination with Hydro One.

7. REGIONAL PLANS

THIS SECTION DISCUSSES THE NEEDS, WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES SOLUTION FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS IN THE SOUTH GEORGIAN BAY/MUSKOKA REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRPS FOR THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS.

The near-term needs arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Barrie/Innisfil Sub-Region

Description

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.

Over the next 10 years, the load in this Sub-Region is forecasted to increase at a rate of approximately 2.5% annually.

Based on the net forecasts (DG and CDM incorporated) in the Sub-Region, adequate transformation capacity is available at Midhurst TS and Alliston TS to maintain reliable supply to meet the demand over the near and mid-term period.

Barrie TS is a summer-peaking station and currently exceeds its normal supply capacity based on both gross and net summer demand. Circuits E3B/E4B that supply radially to Barrie only are also approaching their LMC, which they are expected to exceed by 2019.

Everett TS has a long term need which is discussed in Section 7.7.

Recommended Plan and Current Status

During the regional planning process, the Study Team considered multiple alternatives to address the transformation capacity and end-of-life needs in this Sub-Region.

The 44 kV switchyard at Barrie TS was placed in-service in 1962 and the assets are in degraded condition and are in need of replacement. Previous assessments have suggested the replacement of aged and degraded infrastructure, including both transformer banks, low voltage switchgear, capacitor banks and associated ancillary equipment. Loading on the Barrie TS T1/T2 yard has steadily increased since 2013 and has reached a point where it is encroaching on the LTR rating of the transformer banks, and limiting further connections downstream from the station.

Since Barrie TS currently exceeds its supply capacity, the like-for-like option would not result in any increase in capacity. Instead it was proposed to remove T1/T2 (230/115kV) at Essa TS and replace T1/T2 (55/95MVA, 115/44kV) at Barrie TS with one pair of transformers T1/T2 (75/125MVA, 230/44kV) at Barrie TS, along with uprating circuits E3B/E4B from 115kV to 230 kV. This would increase the Barrie DESN capacity by 50MW, and increase the LMC of E3B/E4B as well.

The Study Team recommended to rebuild and uprate Barrie TS as the best solution to meet the transformation capacity need in the Sub-Region. Hydro One is currently developing this plan, called the 'Barrie Area Transmission Upgrade project'. Class Environmental Assessment (EA) is in progress for this project. Since circuits E3B and E4B are 9km in length, an OEB Section 92 approval is required for this project. It will be initiated once the engineering estimate is completed for this project by early 2018.

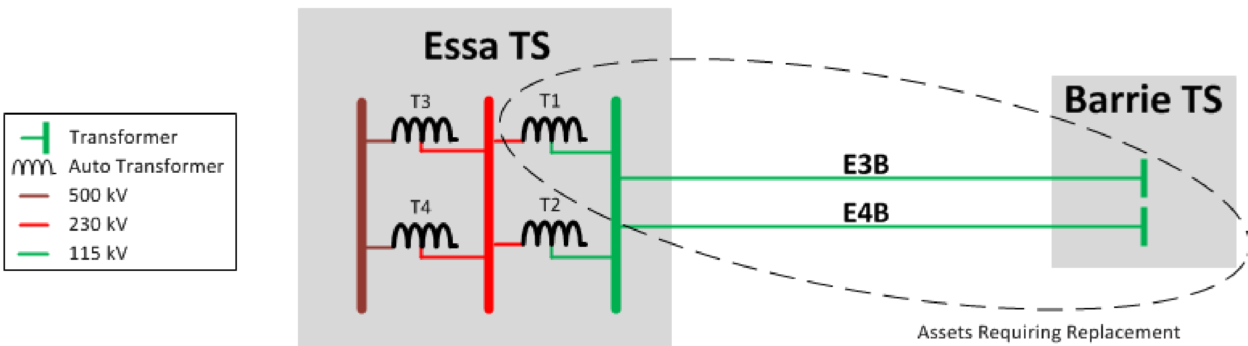

Figure 7-1 Current Arrangement of Essa TS, Barrie TS, and Circuits E3B/E4B

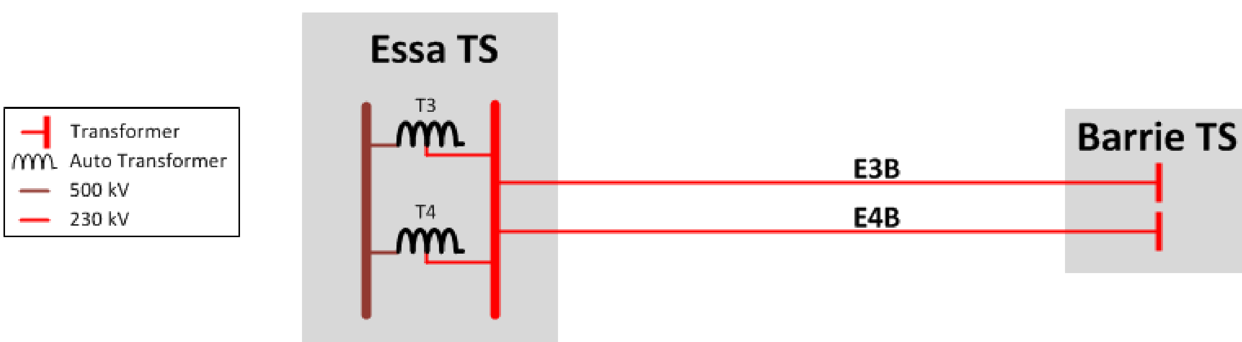

Figure 7-2 New Configuration of Essa/Barrie Supply to Barrie DESN

The total cost of this project is estimated to be $84M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection arrangements as defined above, and feeder egress to the distribution risers outside of the station.

7.2 Transformation Capacity Need at Uprated Barrie TS

Description

Over the 20 year planning period, Barrie TS will experience the biggest growth out of all the transformer stations, which is influenced by the recent continued development of data centers in the City Of Barrie, and greenfield residential development in the annexed lands in south Barrie, in addition to the proposed industrial and commercial development at Innisfil Heights near Highway 400. With the forecast data collected, it is determined that the uprated Barrie TS will exceed its LTR by 2031.

Proposed Alternatives and Recommended Plan

One of the alternatives to accommodate load growth in Barrie/Innisfil Sub-Region, is to build a new 230 kV station via the idle Hydro One right-of-way, a corridor currently being utilized by the existing 13M3 feeder, which could provide an additional 150MW capacity.

The additional feeders that are being built by Alectra will facilitate the transfer of up to 27 MW of load from Barrie TS to Midhurst TS by 2019 and will defer a capacity need at the upgraded Barrie TS to 2031. This need will be monitored and investigated further in the next cycle of the Regional Planning Process. Long-term options beyond 2026 are discussed in Section 7.7.

7.3 Increase Transformation Capacity in Parry Sound/Muskoka Sub-Region

Description

The load forecast reflects an annual growth of 0.82 % in Parry Sound/Muskoka area throughout the study period.

Based on historical demand data and the station's net demand forecast, Parry Sound TS T1/T2 has already exceeded its respective normal supply capacity and will continue to do so over the study period. Parry Sound TS is a winter peaking station with a winter LTR of 52 MW. It had exceeded its LTR by as much as 6 MW in the winters of 2013 to 2016, however the 2017 winter peak was 8 MW below the LTR.

Waubaushene TS is expected to be loaded beyond its winter LTR (104.5 MW) by 2026-27. Recommended plans for addressing this need are discussed in Section 7.7. Although the summer peak is not expected to exceed the summer LTR over the study period based on the net demand forecast, historical summer peak demand (2015/2016) at Waubaushene TS was approaching the summer LTR. The

Study Team will continue to monitor the summer and winter demand closely and explore opportunities to manage the peak demand growth at Waubaushene TS.

Therefore, based on the current load forecasts, additional transformation capacity relief is required for both Parry Sound TS and Waubaushene TS to accommodate the load growth and improve reliability in this sub-region.

Recommended Plan and Current Status

There are two options that have been proposed to address the capacity need at Parry Sound TS: a) Distribution load transfer and b) upsize transformers at Parry Sound TS.

Option a) To accommodate the load growth at Parry Sound TS, 6 MW of Parry Sound's load can be transferred over to Muskoka TS. For this load transfer to take place, Hydro One Distribution will need to seek approval to construct a new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS, which would cost approximately $7M and would be in service by 2020. This option will address the near term supply needs at Parry Sound TS.

Option b) Hydro One has identified that Parry Sound TS (T1/T2) transformer T2 is in poor condition and must be replaced in the near-term. The second transformer is also identified to be reaching the end of its useful life over the next 5-10 years. As a result, Hydro One is planning to replace T2 which is a non-standard 25/42 MVA, 230/44 kV transformer with a 50/83 MVA unit which is currently the smallest standard size transformer at this voltage level. In addition, Hydro One will also consider advancing the replacement of the companion transformer, T1, since it will be much more efficient and economical to replace both transformers at the same time. The additional cost to replace T1 is approximately $8M. This would address the near- and long-term capacity need at Parry Sound TS; eliminate the need to spend $7M on the 44 kV sub-transmission line; and provide better reliability for customers. The advancement cost of replacing T1 is approximately $2M. The new transformers at Parry Sound TS would be expected in service by 2021.

Since the peak demand growth is relatively slow in this area, conservation and local demand management and distributed generation can be used in the meantime to defer capacity-related upgrades at these stations. Results from the Parry Sound/Muskoka Local Achievable Potential ("LAP") study can help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage electricity demand growth in the area.

Going forward, the Study Team will need to assess the cost-benefit of the various options to address supply capacity needs at Parry Sound TS and to determine whether it would be cost-effective to advance the replacement of the companion transformer, T1, at Parry Sound TS at this time. The decision related to the end of life replacement of the transformers at Parry Sound TS will need to be made by mid-2018 so that the transformers can come into service by early 2021.

With the future increased station capacity at Parry Sound TS, the long-term capacity need at Waubaushene TS could be addressed via permanent load transfers since transfer capability already exists between the two stations.

7.4 Parry Sound/Muskoka Load Restoration Assessment

Description

The Parry Sound/Muskoka load restoration need was identified in the Parry Sound/Muskoka Sub-Region IRRP report, which indicated that for the loss of two transmission elements (M7E/M6E transmission lines) the load interrupted with current circuit configuration during peak periods will exceed load restoration criteria.

M6E/M7E transmission lines currently supply 465 MW of peak demand. In the event of a double circuit outage, all customers on this double circuit will be interrupted for more than 30 minutes. As per ORTAC criteria, this constitutes a violation unless 215 MW of peak load can be restored within 30 minutes for a M76/M7E outage during a peak demand period.

Proposed Alternatives and Recommended Plan

In collaboration with the Study Team, a recommendation for the load restoration was identified in the Region. One of the alternatives considered was resupplying load from the 44 kV system. However, this will only supply about 20-30 MW.

The Study Team is recommending that an investment in motorized disconnect switches (MDS) should be made, which can be used to isolate sections of the transmission lines within 30 minutes. These switches would be installed at the Orillia TS junction. Another alternate solution was installing breakers on the line instead of motorized switches, since breakers can immediately isolate a section faulted line.

Breakers would be useful if the loading on the double circuit was more than 600 MW, however given the uncertainty of future load growth and the cost of breakers which are 3-4 times more expensive than motorized switches, the Study Team recommended to proceed with the installation of two 230 kV motorized switches at Orillia TS. The switches will be in service by 2021 at a cost of $5-7M.

In the event of a double M6E/M7E outage, with the motorized disconnect switches installed, at least 50% of the load on this double circuit supply can be restored within 30 minutes, meeting the ORTAC 30 minute load restoration criteria.

IESO has issued a hand-off letter to Hydro One to initiate the development work for the installation of motorized disconnect switches at Orillia TS. The development work is currently underway, in the budgetary estimating phase.

7.5 Outage Duration And Frequency in Parry Sound/Muskoka Sub-Region

Description

Load in the Parry Sound/Muskoka Sub-Region is supplied via:

- Local generation resources;
- 230 kV transmission system;
- 44 kV sub-transmission and low-voltage distribution system.

Customers supplied by Muskoka TS and Parry Sound TS in this sub-region experience more frequent and prolonged outages, almost double the provincial performance, which can impede economic development. Most of the incidents occur on the 44kV sub-transmission system due to longer feeder length as compared to the average length of feeders in the rest of the province. Longer lines increase exposure to tree contact and require additional time for repair crews to identify and isolate faulted sections.

Recommended Plan and Current Status

Hydro One Distribution currently has a number of on-going maintenance and outage mitigation initiatives. These are listed below:

- Vegetation Management Program
- Line Patrols
- Mid-cycle Hazard Tree Program
- Distribution Management System and Grid Modernization

In addition, Hydro One Distribution will assess other options as well and provide an update to the communities and LACs on plans to improve the 44 kV system by the end of 2017.

Another option to mitigate outages on the 44 kV is to build new distribution lines from Bracebridge TS, and transfer some load over to Bracebridge TS, since currently the industrial load demand at that station has been decreasing over the last several years.

Cost-Benefit/Responsibility will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the 44 kV sub-transmission system, which will be completed by the end of 2017.

7.6 Distribution Feeder Capacity to Supply InnPower

Description

Currently six feeders in Barrie TS are used to supply Alectra, and one feeder supplies InnPower. From the forecast provided, the Study Team concluded in the IRRP that InnPower will exceed its load capacity of

25 MW, which its existing feeder can supply, by 2020. An additional feeder will be required for InnPower starting 2020.

Recommended Plan and Current Status

The uprated Barrie TS will include eight feeders, as opposed to the current seven feeders that exist today. This additional feeder can be used in addition to the existing InnPower dedicated feeder to supply InnPower load.

7.7 Long Term Regional Plan

As discussed in Section 5, the electricity demand in South Georgian Bay/Muskoka Region is forecasted to grow at 1.46% annually over the next 10 years, and at a slightly lower average rate of 1.17% from 2016-2034. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1% annually from year 2024 to 2034 in the Parry Sound/Muskoka Sub-Region, while 1.9% in the Barrie/Innisfil Sub-Region. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

Parry Sound/Muskoka

Currently the Muskoka-Orillia 230kV subsystem supplies up to 454 MW. Based on electricity demand growth, Muskoka-Orillia is not expected to exceed its LMC of 600 MW until early 2030.

The following options will be revisited in the next regional planning cycle:

- Upgrade the transmission lines in the area, thus increasing M6E/M7E LMC.
- Connect a 20 MW generation on the Muskoka-Orillia 230 kV system
- Results from the Parry Sound/Muskoka LAP study can help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage electricity demand growth in the area.

Electricity demand forecast is expected to exceed Waubaushene TS system's capability by 2026-27. To manage this long term growth, 4MW load can be transferred from Waubaushene TS to Orillia TS. More transfer capability between Waubaushene TS and Midhurst TS will be available upon completion of 'Barrie Area Transmission Upgrade' project. With the potential increase of the capacity at Parry Sound TS, there will be capability to transfer additional load from Waubaushene TS to Parry Sound TS.

Barrie/Innisfil

Barrie/Innisfil sub region is the area supplied by Midhurst TS, Barrie TS, Alliston TS, and Everett TS. The planning load forecast projects that load will exceed the aggregate capacity of these transformers by

2033. Due to the uncertainty of long term forecasts, IESO will monitor the area and an annual update to the Study Team on demand, conservation and DG trends.

Everett TS is forecasted to exceed its LTR (86.4 MW) by 2026. This LTR is currently limited by the CT ratio. Hydro One is now able to update CT ratio whenever desired which would increase the LTR. The new LTR may defer the capacity need at Everett TS beyond the study period.

In the Barrie area, load is expected to exceed the area's LMC (Midhurst TS and Barrie TS capacity) by 2031. Alectra Utilities and InnPower will undertake a LAP study to address the long term needs for Barrie TS service area to determine the conservation and demand management potential in the area beyond the conservation values already accounted for in the planning forecast.

Metrolinx is planning to electrify the Barrie GO train lines and has approached Hydro One, requesting 40-50MW of capacity. The new 230kV circuits from Essa TS to Barrie TS would provide adequate capacity and tapping positions for Metrolinx's substation, however the supply capacity at Essa TS may present some limitations. Therefore the Metrolinx project is being closely monitored by the IESO and Study Team.

7.8 Minden TS End of Life Assets

Description

The Minden T1/T2 yard is a unique DESN which transforms voltages from 230 kV to 44 kV and facilitates load delivery to the Minden area via four (4) feeders supplying the Hydro One distribution system. This station was built in the 1950s and is primarily composed of older equipment. The T1 and T2 transformers are each rated at 25/42 MVA and are non-standard as per the current standards. Non-standard and obsolete equipment introduces complexities in repairing failures and difficulties in finding and installing spare equipment. The transformers are currently beyond their expected service life and their condition is deteriorating and leak risk is increasing. Furthermore, due to the station's unique configuration, an outage on the high voltage bus or a transformer will cause load loss, which does not occur in a standard DESN layout.

Alternatives and Recommended Plan

The following alternatives were considered to address the end of life situation at Minden TS:

- Maintain Status Quo ("do nothing"): This alternative was considered and rejected as it does not address the risk of failure due to aging equipment and would result in increased maintenance expenses and reduced supply reliability for customers.
- Like-for-Like replacement of assets: This alternative would require the purchase and installation of custom, non-standard, 25/42 MVA transformers and associated equipment which is not justifiable based on the load forecast and would cost more than the smallest standard 230/44 kV transformers which are 50/83 MVA.

- Replace transformers with standard 50/83 MVA units and reconfigure switchyard: This alternative will include replacing the existing transformers with 50/83 MVA units and reconfiguring part of the switchyard to meet standard DESN layout and improve supply reliability to customers.

The preferred alternative is for Hydro One to replace the existing transformers with standard 50/83 MVA units and reconfigure the switchyard to allow it to operate the way a standard DESN should. The new equipment is expected to have a service life of over 50 years and will be able to supply the forecasted load growth in the Minden area. This option allows for easy installation of spare equipment in case failures occur and the improved reliability will improve the customer satisfaction in the area. This refurbishment project is currently planned to be completed in 2020-2021 at a cost of $17 million.

7.9 Orangeville TS End of Life Assets

Description

Orangeville TS is a transmission station that provides 230 kV switching as well as transformation of 230 kV to 44 kV and 27.6 kV. Orangeville TS serves as the supply for Hydro One Distribution and Orangeville Hydro customers in and around the town of Orangeville via two DESN switchyards, T1/T2 (27.6 and 44 kV) and T3/T4 (44 kV). The 27.6 kV and 44 kV switchyards were placed in-service in 1969 and many assets are in a degraded condition and in need of replacement. Previous assessments have identified that all four transformers T1, T2, T3, and T4 and associated equipment are candidates for replacement. In addition, the existing 210-44-28 kV winding configuration on T1 and T2 is non-standard, which introduces challenges with maintenance, sparing and future replacement strategies.

In recent discussions, Orangeville Hydro expressed its intent to further increase its use of the 27.6 kV feeders supplied from Orangeville TS. Consequently, Orangeville Hydro intends to reduce the number of customers and stations connected to the 44 kV feeders M3 and M5.

Alternatives and Recommended Plan

The following alternatives were considered to address the end of life issue at Orangeville TS:

- Maintain Status Quo (“do nothing”): This alternative was considered and rejected as it does not address the risk of failure due to aging equipment and would result in increased maintenance expenses and reduced supply reliability for customers.
- Like-for-Like replacement of assets: This alternative would require the purchase and installation of custom, non-standard, transformers and associated equipment which is not justifiable based on the cost of custom equipment, Orangeville Hydro’s supply voltage plans, and Hydro One’s effort to standardize non-standard station configurations.
- Replace transformers with standard units and reconfigure 27.6 kV and 44 kV switchyards: This alternative aims to replace the existing T1/T2 transformers with standard units, standardize the configuration of the T1/T2 switchyard by converting it to a typical 230/27.6 kV DESN, replace

the aging T3/T4 230/44 kV transformers to maintain overall 44 kV capacity, and relocate 44 kV feeders to the new T3/T4 DESN.

The preferred alternative is for Hydro One to replace the 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. Hydro One will also replace the existing T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate the additional capacity required by the relocation of the two 44 kV feeders. This alternative will address the need to replace end-of-life transformers T1/T2/T3/T4 and associated equipment as well as associated end-of-life protection, control and telecom assets. It will allow Hydro One to standardize the DESN layout, simplify equipment maintenance and installation in case of a failure, and reliably supply the forecasted demand for the area. This refurbishment project is currently planned to be completed in 2024-2025 at a cost of $33 million.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

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

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

Need ID	Needs	Timing
I	Additional transformation capacity for 115kV Barrie TS	Today
II	Additional transformation capacity for the uprated 230kV Barrie TS	Long-term[10]
III	Additional transformation capacity for Parry Sound TS	Today
IV	Transmission Line Capacity for E3B/E4B	2019
V	Load restoration for loss of M6E/M7E	Today
VI	Mitigate frequency and duration of outages on the 44kV Parry Sound/Muskoka sub-region	Today
VII	Additional feeder position for InnPower supplied from Barrie TS	2020
VIII	Additional capacity required for Barrie/Innisfil Sub-Region and Barrie sub-area	Long-term
IX	Additional transformation capacity for Waubaushene TS	Long-term[11]
X	Additional transformation capacity for Everett TS	Long-term
XI	LMC and Load Security for M6E/M7E	Long-term

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

[10] The LTR for the upgraded Barrie TS has been updated since the 2016 Barrie/Innisfil IRRP due to change in the planning LTR factor and changes in power factor assumptions. An increase of approximately 10.75 MW for the summer 10-day LTR (2.25 MW from the LTR factor change and 8.5 MW from the differing power factor assumptions) resulted in a deferral of the need date from 2026 (as indicated in the IRRP) to 2031 in the RIP report. As well, the IRRP forecast included an extreme weather correction which also contributes to the difference in need date.

[11] The LTR for Waubaushene TS has been updated since the 2016 PSM IRRP due to changes in power factor assumptions. For the 2016 PSM IRRP, it was assumed that all transformer stations have a 90% power factor. For the SGBM RIP, it was assumed that stations without low voltage capacity banks have a 90% power factor and stations with low-voltage capacity banks have a 95% power factor. Since Waubaushene TS has low voltage capacity banks, the power factor was changed from 90% to 95% in the SGBM RIP, resulting in a higher LTR and a later need date as compared to the findings in the 2016 PSM IRRP.

Table 8-2 Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

Project	Lead Responsibility	I/S Date	Cost	Need Mitigated
Replacement of 115/44 kV transformers (T1 and T2) at Barrie TS, uprating 115 kV circuits E3B/E4B to 230 kV, adding additional feeder to Barrie DESN	Hydro One	2020	$84M	I, IV, VII
Replacement of 230/44 kV transformers (T1 and T2) and possible rebuild of low voltage switchyard at Minden TS	Hydro One	2020-2021	$17M	End-of-Life
Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)	Hydro One	2021	$5-7M	V
Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS*	Hydro One	2020	$7M	III
Replacement of 230/44 kV transformers at Parry Sound TS*	Hydro One	2021	$20M	End-of-Life, III
Replacement of Orangeville TS transformers and associated low voltage equipment, and reconfiguration of low voltage switchyards	Hydro One	2024-2025	$33M	End-of-Life

* Replacement of transformers at Parry Sound TS would eliminate the need to build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS

For the Need III, Parry Sound/Muskoka Local Achievable Potential (“LAP”) study will be initiated shortly to help the Study Team better understand cost and feasibility of using distributed energy resources and local demand management options to manage the electricity demand growth in the area. Furthermore, the Study Team will need to assess the cost-benefits of the various options to address supply capacity needs at Parry Sound TS and to determine whether it would be cost-effective to advance the replacement of the companion transformers at Parry Sound TS at this time. The decision related to the end of life replacement of the transformers at Parry Sound TS will need to be made by mid-2018 so that the transformers can come into service by early 2020s.

For Need VI, cost-benefit/responsibility analysis will be considered by Hydro One Distribution, Lakeland Power and Veridian Connections to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system, which will be completed by the end of 2017.

Barrie/Innisfil Sub-Region and Barrie sub-area needs (Need VIII) has been reviewed in this Regional Planning cycle and “status quo/do nothing” course of action has been recommended for the time being, while the IESO and the Study Team will continue to monitor load growth in the area and determine the conservation and demand management potential in the area.

As described in Section 7.7, no investment is required at this time to address the long-term needs II, IX, X, and XI. Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. 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

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APPENDICES

Appendix A: Stations in the South Georgian Bay-Muskoka Region

Station (DESN)	Voltage Level	Supply Circuits
Everett TS (T1/T2)	230/44kV	E8V/E9V
Alliston TS (T2/T3/T4)	230/44kV	E8V/E9V
Midhurst TS (T1/T2)	230/44kV	M6E/M7E
Barrie TS (T1/T2)	120/44kV	E3B/E4B
Essa TS (T1/T2)	230/120kV	Essa TS 230kV supply
Parry Sound TS (T1/T2)	230/44kV	E26/E27
Waubaushene TS (T5/T6)	230/44kV	E26/E27
Muskoka TS (T1/T2)	230/44kV	M6E/M7E
Bracebridge TS (T1)	230/44kV	M6E
Orillia TS (T1/T2)	230/44kV	M6E/M7E
Beaverton TS T3/T4	230/44kV	M80B/M81B
Lindsay TS T1/T2	230/44kV	M80B/M81B
Minden TS T1/T2	230/44kV	Minden TS 230kV supply
Orangeville TS T3/T4	230/44kV	Orangeville TS 230kV supply
Orangeville TS T1/T2	230/44/28kV	Orangeville TS 230kV supply
Stayner TS T3/T4	230/44kV	Stayner TS
Wallace TS T3/T4	230/44kV	D2M/D4M
Meaford TS T1/T2	115/44kV	S2S

Appendix B: Transmission Lines in the South Georgian Bay Muskoka Region

Location	Circuit Designation	Voltage Level
Essa TS to Parry Sound/Waubaushene TS	E26/E27	230kV
Essa TS to Midhurst/Orillia/Muskoka TS	M6E/M7E	230kV
Essa TS to Alliston/Everett/Orangeville TS	E8V/E9V	230kV
Essa TS to Barrie TS	E3B/E4B	115kV
Essa TS to Stayner TS	E20S/E21S	230kV
Stayner TS to Meaford TS	S2S	115kV
Minden TS to DesJoachims TS	D1M/D2M/D3M/D4M	230kV
Minden TS to Lindsay/Beaverton TS	M80B/M81B	230kV

Appendix C: Non-Coincident Winter Load Forecast 2014-2034

Note: 2014 values in grey are actuals from IRRP

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS (T2)	Non Coincidental Gross		28.7	29.1	29.5	29.7	30.2	30.7	31.2	31.5	31.8	32.1	32.4	32.7	33.1	33.4	33.7	34.1	34.4	34.8	35.1	35.5	35.8
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.6	0.8	1.3	1.7	1.8	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.8	4.0	4.0	4.1	4.1
S: 100	DG (MW)		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	0.0	0.0	0.0	0.0	0.0	0.0
W: 115	Non Coincidental Net	28.6	28.5	28.7	28.9	29.1	29.4	29.4	29.5	29.7	29.7	29.8	29.9	30.1	30.2	30.3	30.4	30.5	30.6	30.8	31.1	31.4	31.7
Alliston TS (T3/T4)	Non Coincidental Gross		60.1	68.5	71.4	74.4	77.4	80.3	82.9	85.6	88.3	90.9	91.9	93.8	95.7	97.7	99.7	101.6	103.5	105.4	106.5	108.4	110.2
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.3	4.5	5.0	5.7	6.5	7.1	7.7	8.3	9.1	9.8	10.6	11.4	12.1	12.2	12.4	12.6
S: 112	DG (MW)		0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077	0.077
W: 128	Non Coincidental Net	60.8	59.6	67.5	70.0	72.7	75.2	76.9	78.3	80.5	82.5	84.4	84.7	86.1	87.3	88.5	89.8	91.0	92.1	93.2	94.2	95.9	97.5
Barrie TS	Non Coincidental Gross		96.3	99.1	102.6	107.1	113.5	120.6	128.6	136.7	144.8	153.0	157.6	162.3	167.2	172.2	177.4	182.7	188.2	193.8	199.6	205.6	211.8
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.3	3.1	4.9	6.9	8.0	9.4	10.9	12.2	13.3	14.5	16.0	17.4	19.0	20.7	22.2	22.9	23.6	24.3
S: 115	DG (MW)		0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
W: 128	Non Coincidental Net	94.0	95.6	97.7	100.6	104.8	110.4	115.6	121.6	128.6	135.4	142.1	145.4	149.0	152.7	156.2	159.9	163.7	167.5	171.5	176.7	182.0	187.5
Beaverton TS	Non Coincidental Gross		96.6	97.6	98.6	98.9	100.1	101.3	102.6	103.3	103.9	104.5	105.34	106.18	107.03	107.88	108.75	109.62	110.49	111.38	112.27	113.17	114.07
LTR (MVA)	CDM (MW)		0.7	1.3	1.9	2.1	2.7	4.1	5.5	6.1	6.7	7.4	8.1	8.7	9.3	10.0	10.7	11.4	12.1	12.8	12.9	13.0	13.1
S: 204	DG (MW)		1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655	1.655
W: 224	Non Coincidental Net	92.7	94.2	94.6	95.1	95.1	95.7	95.5	95.4	95.6	95.5	95.4	95.6	95.8	96.1	96.2	96.4	96.6	96.7	96.9	97.7	98.5	99.3
Bracebridge TS	Non Coincidental Gross		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	0.0	0.0	0.0	0.0	0.0	0.0
LTR (MVA)	CDM (MW)		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	0.0	0.0	0.0	0.0	0.0	0.0
S: 93	DG (MW)		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	0.0	0.0	0.0	0.0	0.0	0.0
W: 93	Non Coincidental Net	20.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Everett TS	Non Coincidental Gross			61.2	62.4	64.4	65.6	67.5	69.2	70.9	73.4	75.1	77.4	79.7	82.1	84.5	87.1	89.7	92.4	95.1	98.0	100.9	104.0
LTR (MVA)	CDM (MW)			0.8	1.2	1.4	1.8	2.8	3.7	4.2	4.7	5.3	6.0	6.5	7.1	7.9	8.6	9.3	10.1	10.9	11.2	11.6	11.9
S: 96	DG (MW)			0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
W: 96	Non Coincidental Net	54.7	0.0	60.4	61.2	63.0	63.8	64.7	65.4	66.7	68.6	69.7	71.4	73.1	74.9	76.6	78.5	80.3	82.2	84.2	86.7	89.3	92.0
Lindsay TS	Non Coincidental Gross		91.6	93.3	94.3	94.6	95.9	97.5	98.9	99.9	100.9	101.8	102.8	103.8	104.9	105.9	107.0	108.1	109.1	110.2	111.3	112.5	113.6
LTR (MVA)	CDM (MW)		0.7	1.3	1.8	2.0	2.6	4.0	5.3	5.9	6.5	7.2	7.9	8.5	9.1	9.9	10.5	11.2	12.0	12.6	12.8	12.9	13.0
S: 169	DG (MW)		1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634	1.634
W: 193	Non Coincidental Net	89.2	89.3	90.4	90.9	90.9	91.6	91.9	91.9	92.4	92.7	92.9	93.2	93.7	94.2	94.4	94.8	95.2	95.5	96.0	96.9	97.9	98.9
Meaford TS	Non Coincidental Gross		29.9	30.4	30.9	31.1	31.7	32.2	32.8	33.2	33.6	34.0	34.4	34.8	35.2	35.7	36.1	36.5	37.0	37.4	37.9	38.3	38.8
LTR (MVA)	CDM (MW)		0.2	0.4	0.6	0.7	0.9	1.3	1.8	1.9	2.2	2.4	2.7	2.8	3.1	3.3	3.6	3.8	4.1	4.3	4.3	4.4	4.4
S: 54	DG (MW)		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
W: 61	Non Coincidental Net	29.7	29.7	30.0	30.3	30.4	30.8	30.9	31.0	31.2	31.4	31.6	31.8	32.0	32.2	32.3	32.5	32.7	32.9	33.1	33.5	33.9	34.3
Midhurst TS (T1/T2)	Non Coincidental Gross			108.0	110.7	113.0	115.8	119.2	131.0	133.4	136.3	139.2	141.5	144.3	147.2	149.7	154.6	157.5	160.5	163.4	166.3	169.2	172.1
LTR (MVA)	CDM (MW)			0.5	1.2	1.6	2.4	3.1	3.6	4.5	5.5	6.4	7.4	8.6	9.8	10.9	12.1	13.2	14.7	16.0	16.2	16.3	16.5
S: 172	DG (MW)			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	0.0	0.0	0.0	0.0	0.0
W: 194	Non Coincidental Net	101.6	105.5	107.5	109.5	111.4	113.4	116.0	127.3	128.9	130.8	132.8	134.0	135.8	137.4	138.7	142.5	144.3	145.8	147.4	150.1	152.9	155.6
Midhurst TS (T3/T4)	Non Coincidental Gross			65.5	67.7	69.9	72.6	75.4	88.6	90.8	93.5	96.3	98.5	101.2	104.0	106.2	106.9	109.6	112.3	115.0	117.7	120.4	123.1
LTR (MVA)	CDM (MW)			0.3	0.7	1.0	1.6	2.3	2.6	3.2	4.0	4.7	5.6	6.5	7.6	8.7	9.5	10.4	11.7	12.8	13.1	13.2	13.5
S: 166	DG (MW)			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	0.0	0.0	0.0	0.0	0.0
W: 192	Non Coincidental Net	75.0	63.3	65.2	67.0	68.9	71.0	73.1	86.0	87.6	89.5	91.6	92.8	94.7	96.4	97.5	97.5	99.3	100.6	102.2	104.6	107.2	109.7
Minden TS	Non Coincidental Gross			58.8	59.5	59.8	60.3	61.2	62.0	62.5	62.9	63.3	63.7	64.1	64.5	64.9	65.4	65.8	66.2	66.6	67.0	67.4	67.8
LTR (MVA)	CDM (MW)			0.2	0.4	0.5	0.7	0.9	1.0	1.2	1.4	1.5	1.6	1.8	2.0	2.1	2.3	2.5	2.7	2.8	2.8	2.8	2.8
S: 59	DG (MW)			1.630	1.630	1.630	1.630	1.630	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770	1.770
W: 64	Non Coincidental Net	55.0	56.3	57.0	57.5	57.6	58.0	58.7	59.2	59.5	59.8	60.0	60.3	60.5	60.8	61.0	61.3	61.6	61.7	62.0	62.4	62.8	63.2

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Muskoka TS	Non Coincidental Gross			160.6	163.0	164.7	166.9	169.8	172.7	175.0	177.2	179.4	181.6	183.9	186.2	188.7	191.2	193.7	196.0	198.5	201.0	203.5	205.9
LTR (MVA)	CDM (MW)			0.5	1.1	1.5	2.2	2.9	3.4	4.1	4.8	5.3	5.9	6.6	7.1	7.7	8.2	8.8	9.5	10.0	10.0	10.0	9.9
S: 154	DG (MW)			3.360	3.360	3.360	3.360	5.060	5.110	5.110	5.110	5.110	5.110	5.110	5.110	5.110	4.600	4.600	2.080	2.080	2.080	2.080	1.970
W: 175	Non Coincidental Net	165.0	167.4	156.7	158.5	159.9	161.3	161.9	164.2	165.8	167.3	169.0	170.6	172.2	174.0	175.9	178.4	180.3	184.4	186.4	188.9	191.4	194.1
Orangeville TS	Non Coincidental Gross		51.4	51.9	53.1	54.2	55.4	56.6	57.8	59.0	60.0	61.0	62.1	63.2	64.4	65.5	66.7	67.9	69.1	70.4	71.6	72.9	74.2
(T1/T2 - 27.6kV)	CDM (MW)		0.4	0.7	1.0	1.2	1.5	2.3	3.1	3.5	3.9	4.3	4.8	5.2	5.6	6.1	6.6	7.1	7.6	8.1	8.2	8.4	8.5
LTR (MVA)	DG (MW)		3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154
S: 104 W:122	Non Coincidental Net	49.3	47.9	48.1	48.9	49.9	50.7	51.1	51.5	52.4	53.0	53.5	54.2	54.9	55.6	56.3	57.0	57.7	58.4	59.1	60.3	61.4	62.6
Orangeville TS	Non Coincidental Gross		23.4	23.9	24.3	24.6	25.1	25.6	26.1	26.6	27.0	27.4	27.8	28.2	28.7	29.1	29.5	30.0	30.4	30.9	31.3	31.8	32.3
(T1/T2 - 44kV)	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.0	1.4	1.6	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.6	3.6	3.7
LTR (MVA)	DG (MW)		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	0.0	0.0	0.0	0.0	0.0	0.0
S: 53 W: 63	Non Coincidental Net	24.0	23.2	23.6	23.8	24.1	24.4	24.6	24.7	25.0	25.3	25.5	25.7	25.9	26.2	26.4	26.6	26.8	27.1	27.3	27.7	28.1	28.6
Orangeville TS (T3/T4)	Non Coincidental Gross		86.2	87.7	89.3	90.3	92.2	94.1	96.1	97.6	99.1	100.5	101.9	103.3	104.8	106.2	107.7	109.2	110.8	112.3	113.9	115.5	117.1
LTR (MVA)	CDM (MW)		0.6	1.2	1.7	1.9	2.5	3.8	5.2	5.7	6.4	7.1	7.9	8.4	9.1	9.9	10.6	11.4	12.2	12.9	13.1	13.3	13.4
S: 106	DG (MW)		2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.058
W: 124	Non Coincidental Net	82.6	83.5	84.5	85.5	86.3	87.6	88.2	88.9	89.8	90.6	91.3	92.0	92.8	93.6	94.3	95.1	95.8	96.6	97.4	98.8	100.2	101.6
Orillia TS	Non Coincidental Gross			127.0	128.9	131.1	133.5	136.0	138.3	139.8	141.6	143.2	144.8	146.4	148.2	149.9	151.7	153.4	155.2	156.9	158.6	160.4	162.1
LTR (MVA)	CDM (MW)			0.6	1.2	1.6	2.3	3.0	3.4	4.1	4.8	5.3	6.0	6.7	7.4	8.2	8.8	9.5	10.4	11.1	11.2	11.2	11.1
S: 165	DG (MW)			3.690	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	4.230	0.540	0.540	0.540	0.540	0.540
W: 186	Non Coincidental Net	122.4	118.3	122.7	123.5	125.3	127.0	128.8	130.6	131.5	132.6	133.6	134.6	135.5	136.5	137.5	138.7	139.7	144.2	145.2	146.9	148.7	150.5
Parry Sound TS	Non Coincidental Gross			61.2	62.1	62.7	63.4	64.5	65.5	66.3	67.1	67.9	68.6	69.4	70.2	71.1	71.9	72.8	73.6	74.5	75.3	76.2	77.1
LTR (MVA)	CDM (MW)			0.2	0.5	0.7	1.0	1.2	1.5	1.7	1.9	2.1	2.3	2.6	2.7	2.9	3.1	3.3	3.6	3.8	3.8	3.8	3.8
S: 52	DG (MW)			0.410	0.410	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	0.650	0.650	0.650	0.650	0.650
W: 57	Non Coincidental Net	57.5	60.5	60.6	61.2	61.6	62.0	62.8	63.7	64.2	64.7	65.3	65.9	66.4	67.1	67.7	68.4	69.1	70.0	70.7	71.5	72.4	73.3
Stayner TS	Non Coincidental Gross		139.4	140.6	141.9	142.2	143.8	145.6	147.3	148.3	149.3	150.2	151.1	152.0	152.9	153.8	154.8	155.7	156.6	157.6	158.5	159.5	160.4
LTR (MVA)	CDM (MW)		1.0	1.9	2.7	3.1	3.9	6.0	8.0	8.7	9.6	10.7	11.7	12.4	13.2	14.3	15.2	16.2	17.2	18.1	18.2	18.3	18.4
S: 191	DG (MW)		18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864	18.864
W: 214	Non Coincidental Net	138.3	119.5	119.9	120.3	120.3	121.0	120.8	120.5	120.7	120.8	120.7	120.6	120.7	120.8	120.7	120.7	120.6	120.6	120.6	121.5	122.3	123.1
Wallace TS	Non Coincidental Gross		40.0	40.6	41.1	41.2	41.8	42.4	42.9	43.3	43.6	43.9	44.2	44.5	44.8	45.1	45.5	45.8	46.1	46.4	46.7	47.1	47.4
LTR (MVA)	CDM (MW)		0.3	0.5	0.8	0.9	1.1	1.7	2.3	2.5	2.8	3.1	3.4	3.6	3.9	4.2	4.5	4.8	5.1	5.3	5.4	5.4	5.4
S: 55	DG (MW)		3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871	3.871
W: 60	Non Coincidental Net	39.3	35.8	36.2	36.4	36.4	36.8	36.8	36.7	36.9	36.9	36.9	36.9	37.0	37.1	37.1	37.1	37.1	37.2	37.2	37.5	37.8	38.1
Waubaushene TS	Non Coincidental Gross			99.2	99.2	100.2	101.1	102.5	103.8	104.6	105.6	106.6	107.5	108.5	109.3	110.3	111.3	112.2	113.2	114.2	115.0	115.9	116.8
LTR (MVA)	CDM (MW)			0.2	0.5	0.8	1.1	1.5	1.9	2.3	2.9	3.4	3.9	4.5	5.0	5.5	5.9	6.3	6.8	7.2	7.2	7.2	7.2
S: 100	DG (MW)			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	0.0	0.0	0.0	0.0	0.0
W: 110	Non Coincidental Net	94.1	95.9	99.0	98.7	99.5	100.0	101.0	101.9	102.3	102.8	103.2	103.6	104.0	104.3	104.8	105.4	105.9	106.5	107.0	107.8	108.7	109.6

Appendix D: Non-Coincident Summer Load Forecast 2014-2034

Note: 2014 values in grey are actuals from IRRP

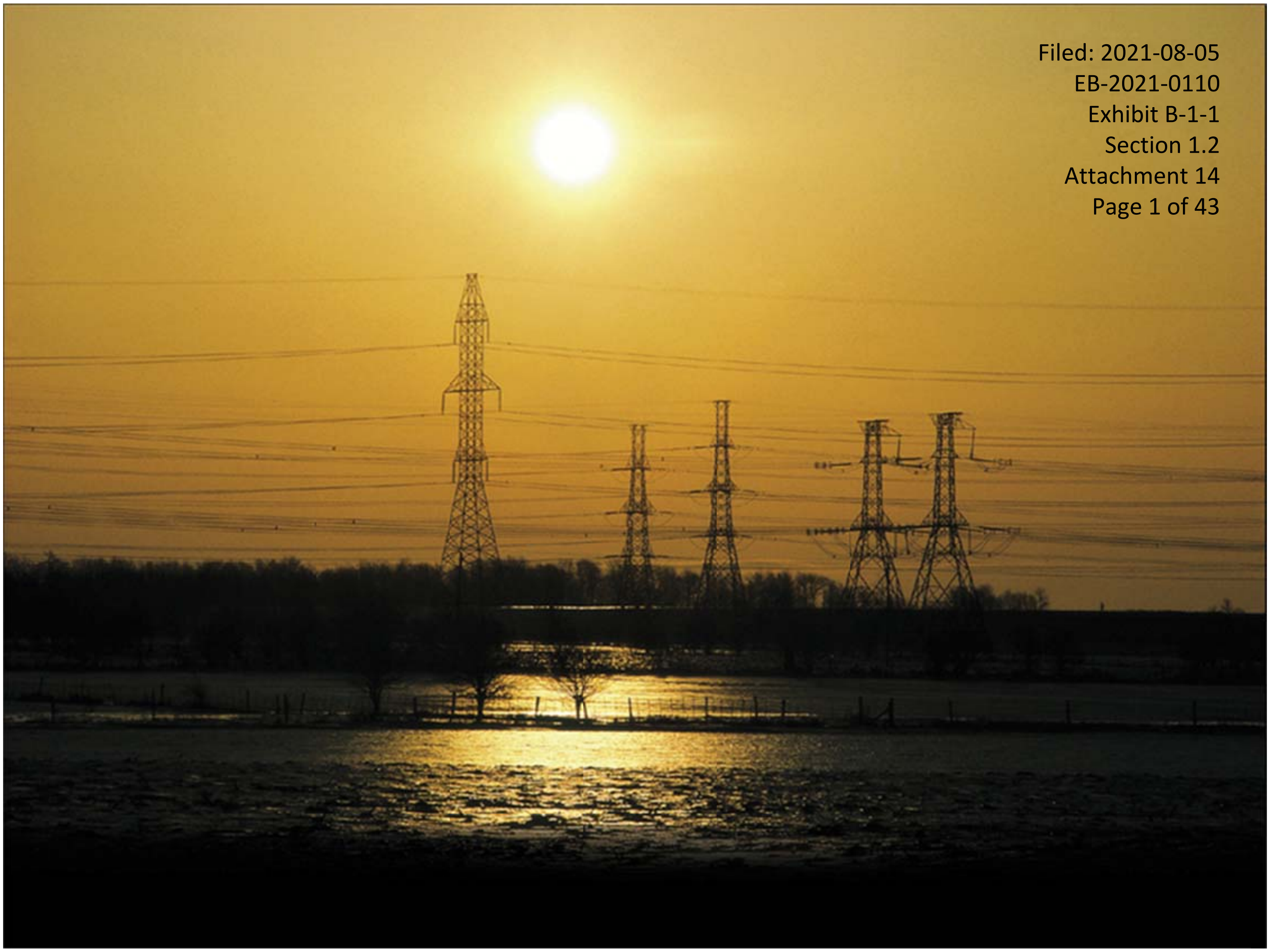
Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS (T2)	Gross			38.9	42.1	45.4	48.6	51.9	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
LTR (MVA)	CDM (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S: 100	DG (MW)			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	0.0	0.0	0.0	0.0	0.0
W: 115	Net	28.6	33.2	38.9	42.1	45.4	48.6	51.9	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
Alliston TS (T3/T4)	Gross			56.8	59.0	61.3	66.0	71.0	73.5	76.1	78.3	80.6	82.4	84.3	86.1	88.1	90.0	91.8	93.7	95.5	97.4	99.2	101.0
LTR (MVA)	CDM (MW)			0.4	1.2	1.4	2.1	2.7	3.3	3.9	4.5	5.1	5.7	6.5	7.0	7.8	8.5	9.1	10.0	10.7	10.8	10.8	10.8
S: 112	DG (MW)			0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222	0.222
W: 128	Net	60.8	50.3	56.1	57.7	59.6	63.7	68.0	70.0	72.0	73.6	75.3	76.5	77.6	78.9	80.0	81.3	82.4	83.5	84.6	86.4	88.2	90.0
Barrie TS	Gross			107.4	112.5	116.1	124.4	132.1	140.3	147.7	155.7	163.2	169.6	176.9	184.0	191.1	196.7	203.1	210.4	214.4	219.4	225.4	230.3
LTR (MVA)	CDM (MW)			0.5	1.2	1.9	3.2	4.5	5.4	6.6	7.8	8.9	10.6	12.1	14.1	16.5	18.1	19.9	22.2	24.2	24.5	24.6	24.8
S: 115	DG (MW)			0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041
W: 128	Net	94.0	96.8	106.9	111.2	114.2	121.1	127.5	134.9	141.1	147.8	154.2	158.9	164.8	169.9	174.6	178.6	183.1	188.2	190.1	194.8	200.7	205.5
Beaverton TS	Gross		57.2	57.6	58.2	58.1	58.8	59.5	60.3	60.7	61.1	61.4	61.7	62.0	62.3	62.6	63.0	63.3	63.6	63.9	64.2	64.5	64.9
LTR (MVA)	CDM (MW)		0.4	0.8	1.1	1.2	1.6	2.4	3.3	3.6	3.9	4.4	4.8	5.1	5.4	5.8	6.2	6.6	7.0	7.3	7.4	7.4	7.4
S: 204	DG (MW)		12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411	12.411
W: 224	Net	92.7	44.4	44.4	44.7	44.4	44.8	44.7	44.6	44.7	44.7	44.6	44.5	44.5	44.5	44.4	44.3	44.3	44.2	44.2	44.4	44.7	45.0
Bracebridge TS	Gross			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	0.0	0.0	0.0	0.0	0.0
LTR (MVA)	CDM (MW)			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	0.0	0.0	0.0	0.0	0.0
S: 93	DG (MW)			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	0.0	0.0	0.0	0.0	0.0
W: 93	Net	20.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Everett TS	Gross		67.1	69.8	71.2	73.7	75.1	77.5	79.7	81.8	85.0	87.2	89.4	91.6	93.9	96.3	98.7	101.1	103.7	106.2	108.9	111.6	114.4
LTR (MVA)	CDM (MW)		0.5	0.9	1.4	1.6	2.1	3.2	4.3	4.8	5.5	6.2	6.9	7.5	8.1	9.0	9.7	10.5	11.4	12.2	12.5	12.8	13.1
S: 96	DG (MW)		0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211	0.211
W: 96	Net	54.7	66.4	68.7	69.6	71.9	72.8	74.1	75.2	76.8	79.3	80.8	82.3	83.9	85.6	87.1	88.7	90.4	92.1	93.8	96.2	98.6	101.1
Lindsay TS	Gross		74.3	75.4	76.2	76.1	77.1	78.5	79.7	80.5	81.2	82.0	82.7	83.5	84.2	85.0	85.8	86.5	87.3	88.1	88.9	89.7	90.5
LTR (MVA)	CDM (MW)		0.6	1.0	1.4	1.6	2.1	3.2	4.3	4.7	5.2	5.8	6.4	6.8	7.3	7.9	8.4	9.0	9.6	10.1	10.2	10.3	10.4
S: 169	DG (MW)		9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799	9.799
W: 193	Net	89.2	63.9	64.6	65.0	64.7	65.2	65.5	65.6	66.0	66.2	66.4	66.6	66.9	67.1	67.3	67.5	67.7	67.9	68.2	68.9	69.6	70.3
Meaford TS	Gross		25.5	25.9	26.2	26.4	26.8	27.3	27.8	28.2	28.5	28.9	29.2	29.5	29.8	30.1	30.4	30.7	31.0	31.3	31.6	31.9	32.2
LTR (MVA)	CDM (MW)		0.2	0.3	0.5	0.6	0.7	1.1	1.5	1.7	1.8	2.1	2.3	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.6	3.7	3.7
S: 54	DG (MW)		0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
W: 61	Net	29.7	25.3	25.5	25.7	25.8	26.1	26.2	26.3	26.5	26.6	26.8	26.9	27.1	27.2	27.3	27.4	27.5	27.6	27.7	28.0	28.3	28.5
Midhurst TS (T1/T2)	Gross			109.8	112.5	114.8	118.4	121.4	124.2	126.8	130.3	132.8	135.4	138.9	141.5	144.0	147.7	150.2	153.8	156.4	159.9	162.5	166.0
LTR (MVA)	CDM (MW)			0.7	1.6	2.2	3.3	4.4	5.1	6.1	7.3	8.3	9.5	10.9	12.1	13.4	14.7	15.8	17.5	18.7	19.0	19.1	19.4
S: 172	DG (MW)			2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786	2.786
W: 194	Net	101.6	99.9	106.3	108.1	109.8	112.3	114.2	116.4	117.9	120.2	121.7	123.1	125.3	126.6	127.9	130.2	131.7	133.5	134.9	138.1	140.5	143.8
Midhurst TS (T3/T4)	Gross			72.0	75.0	78.0	80.0	83.0	86.0	89.0	91.0	94.0	97.0	100.0	103.0	105.0	108.0	111.0	115.0	118.0	121.0	124.0	127.0
LTR (MVA)	CDM (MW)			0.2	0.6	0.9	1.6	2.3	2.6	3.3	4.4	5.4	6.6	7.8	9.3	10.8	12.1	13.5	15.5	17.2	17.5	17.6	17.9
S: 166	DG (MW)			0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031
W: 192	Net	75.0	65.0	71.7	74.3	77.1	78.4	80.7	83.4	85.6	86.6	88.6	90.4	92.2	93.6	94.2	95.8	97.4	99.5	100.8	103.5	106.3	109.0
Minden TS	Gross			25.4	25.6	25.8	26.0	26.4	26.8	27.0	27.2	27.4	27.5	27.7	27.9	28.1	28.3	28.5	28.7	28.9	29.0	29.2	29.4
LTR (MVA)	CDM (MW)			0.2	0.3	0.4	0.6	0.7	0.8	1.1	1.3	1.5	1.7	1.9	2.2	2.4	2.6	2.9	3.2	3.4	3.4	3.4	3.4
S: 59	DG (MW)			1.660	1.660	2.210	2.330	2.940	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.080	3.050
W: 64	Net	55.0	24.3	23.6	23.6	23.2	23.1	22.7	22.9	22.8	22.8	22.9	22.7	22.7	22.7	22.6	22.6	22.6	22.5	22.5	22.6	22.7	23.0

Station		2013 (Reference)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Muskoka TS	Gross			93.5	94.7	95.4	96.3	98.0	99.5	100.6	101.5	102.5	103.5	104.3	105.4	106.5	107.5	108.7	109.6	110.6	111.5	112.5	113.6
LTR (MVA)	CDM (MW)			0.7	1.4	1.9	2.8	3.6	4.3	5.1	6.0	6.7	7.4	8.2	8.9	9.6	10.2	11.0	12.0	12.6	12.6	12.6	12.4
S: 154	DG (MW)			7.970	8.070	8.290	8.620	13.400	13.450	13.450	13.450	13.450	13.450	13.450	13.450	13.450	12.940	12.940	10.420	10.410	10.410	8.150	5.810
W: 175	Net	165.0	97.2	84.9	85.2	85.2	84.9	81.0	81.8	82.0	82.1	82.4	82.7	82.6	83.1	83.5	84.3	84.8	87.2	87.6	88.5	91.8	95.4
Orangeville TS	Gross		53.1	56.1	57.4	58.4	59.5	60.8	62.1	63.2	64.2	65.2	66.2	67.2	68.2	69.2	70.2	71.3	72.4	73.4	74.5	75.7	76.8
(T1/T2 - 27.6kV)	CDM (MW)		0.4	0.8	1.1	1.3	1.6	2.5	3.4	3.7	4.1	4.6	5.1	5.5	5.9	6.4	6.9	7.4	7.9	8.4	8.6	8.7	8.8
LTR (MVA)	DG (MW)		1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519
S: 104 W: 122	Net	49.3	51.2	53.8	54.8	55.6	56.4	56.8	57.2	58.0	58.5	59.1	59.6	60.2	60.8	61.2	61.8	62.4	62.9	63.5	64.5	65.5	66.5
Orangeville TS	Gross		24.2	24.5	25.0	25.1	25.6	26.2	26.8	27.2	27.6	28.0	28.4	28.8	29.2	29.6	30.0	30.4	30.9	31.3	31.7	32.2	32.6
(T1/T2 - 44kV)	CDM (MW)		0.2	0.3	0.5	0.5	0.7	1.1	1.4	1.6	1.8	2.0	2.2	2.4	2.5	2.8	3.0	3.2	3.4	3.6	3.6	3.7	3.7
LTR (MVA)	DG (MW)		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
S: 53 W: 63	Net	24.0	24.0	24.2	24.5	24.6	24.9	25.1	25.3	25.6	25.8	26.0	26.2	26.4	26.7	26.8	27.1	27.3	27.5	27.7	28.1	28.5	28.9
Orangeville TS (T3/T4)	Gross		67.4	68.4	69.6	70.2	71.5	73.1	74.6	75.8	77.0	78.1	79.2	80.3	81.4	82.6	83.7	84.9	86.1	87.3	88.5	89.7	91.0
	CDM (MW)		0.5	0.9	1.3	1.5	2.0	3.0	4.0	4.4	5.0	5.5	6.1	6.6	7.1	7.7	8.2	8.8	9.4	10.0	10.2	10.3	10.4
LTR (MVA)	DG (MW)		1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.071
S 106 W: 124	Net	82.6	65.8	66.4	67.2	67.6	68.5	69.0	69.5	70.3	71.0	71.5	72.0	72.7	73.3	73.8	74.4	75.0	75.6	76.2	77.3	78.4	79.5
Orillia TS	Gross			99.8	101.2	103.2	105.2	107.2	109.0	110.3	111.6	112.9	114.2	115.4	116.8	118.1	119.6	120.9	122.2	123.7	125.0	126.4	127.7
LTR (MVA)	CDM (MW)			0.6	1.3	1.7	2.5	3.3	3.8	4.7	5.5	6.2	7.0	7.9	8.8	9.7	10.5	11.3	12.5	13.4	13.4	13.4	13.3
S: 165	DG (MW)			10.620	11.240	11.350	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	11.460	7.770	7.710	7.650	7.510	1.410
W: 186	Net	122.4	84.9	88.5	88.6	90.1	91.2	92.4	93.7	94.2	94.7	95.3	95.7	96.1	96.6	96.9	97.6	98.1	101.9	102.6	104.0	105.5	113.0
Parry Sound TS	Gross			31.3	31.8	32.1	32.5	33.0	33.6	34.0	34.4	34.8	35.1	35.6	36.0	36.4	36.9	37.3	37.8	38.2	38.7	39.1	39.6
LTR (MVA)	CDM (MW)			0.2	0.5	0.6	0.9	1.1	1.3	1.7	2.0	2.2	2.5	2.8	3.0	3.3	3.6	3.9	4.3	4.5	4.6	4.6	4.5
S: 52	DG (MW)			0.460	0.490	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	1.140	0.730	0.730	0.730	0.730	0.730
W: 57	Net	57.5	30.9	30.6	30.9	30.4	30.5	30.7	31.1	31.2	31.3	31.5	31.5	31.7	31.8	31.9	32.2	32.3	32.8	32.9	33.4	33.8	34.3
Stayner TS	Gross		104.6	105.2	106.1	105.9	106.9	108.3	109.7	110.5	111.2	111.9	112.6	113.2	113.9	114.6	115.3	116.0	116.7	117.4	118.1	118.8	119.5
LTR (MVA)	CDM (MW)		0.8	1.4	2.0	2.3	2.9	4.4	5.9	6.5	7.2	7.9	8.7	9.3	9.9	10.7	11.3	12.1	12.8	13.5	13.5	13.6	13.7
S: 191	DG (MW)		8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735	8.735
W: 214	Net	138.3	95.1	95.1	95.3	94.9	95.2	95.1	95.0	95.3	95.3	95.2	95.1	95.3	95.3	95.2	95.2	95.2	95.1	95.2	95.8	96.4	97.1
Wallace TS	Gross		36.0	36.4	36.8	36.9	37.3	37.8	38.4	38.7	39.0	39.3	39.6	39.9	40.1	40.4	40.7	41.0	41.3	41.6	41.8	42.1	42.4
LTR (MVA)	CDM (MW)		0.3	0.5	0.7	0.8	1.0	1.5	2.1	2.3	2.5	2.8	3.1	3.3	3.5	3.8	4.0	4.3	4.5	4.8	4.8	4.8	4.9
S: 55	DG (MW)		3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880	3.880
W: 60	Net	39.3	31.9	32.0	32.2	32.2	32.4	32.4	32.4	32.5	32.6	32.6	32.6	32.7	32.8	32.8	32.8	32.8	32.9	32.9	33.2	33.4	33.7
Waubaushene TS	Gross			75.1	75.5	76.1	76.9	77.7	78.5	79.2	80.8	81.5	82.1	82.7	83.4	84.0	84.7	85.4	86.1	87.8	88.3	88.9	89.5
LTR (MVA)	CDM (MW)			0.2	0.5	0.7	1.0	1.3	1.5	2.1	2.8	3.4	4.2	5.0	5.7	6.3	7.0	7.6	8.3	8.9	8.9	9.0	9.0
S: 100	DG (MW)			9.360	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.410	9.300	4.570	2.240
W: 110	Net	94.1	71.6	65.5	65.6	66.0	66.5	67.0	67.6	67.7	68.6	68.7	68.5	68.3	68.3	68.3	68.3	68.4	68.4	69.5	70.1	75.4	78.3

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



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.

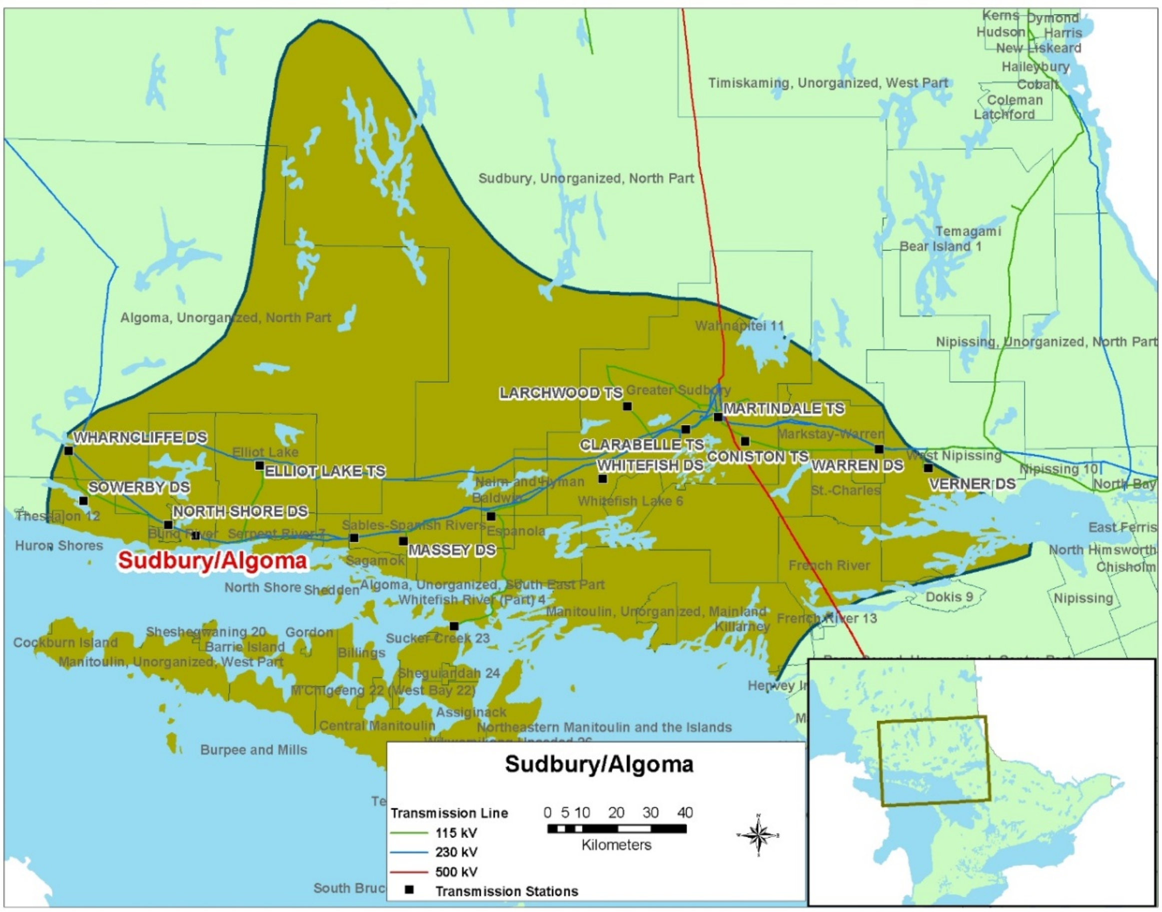

Figure 1-1: Sudbury/Algoma region

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.

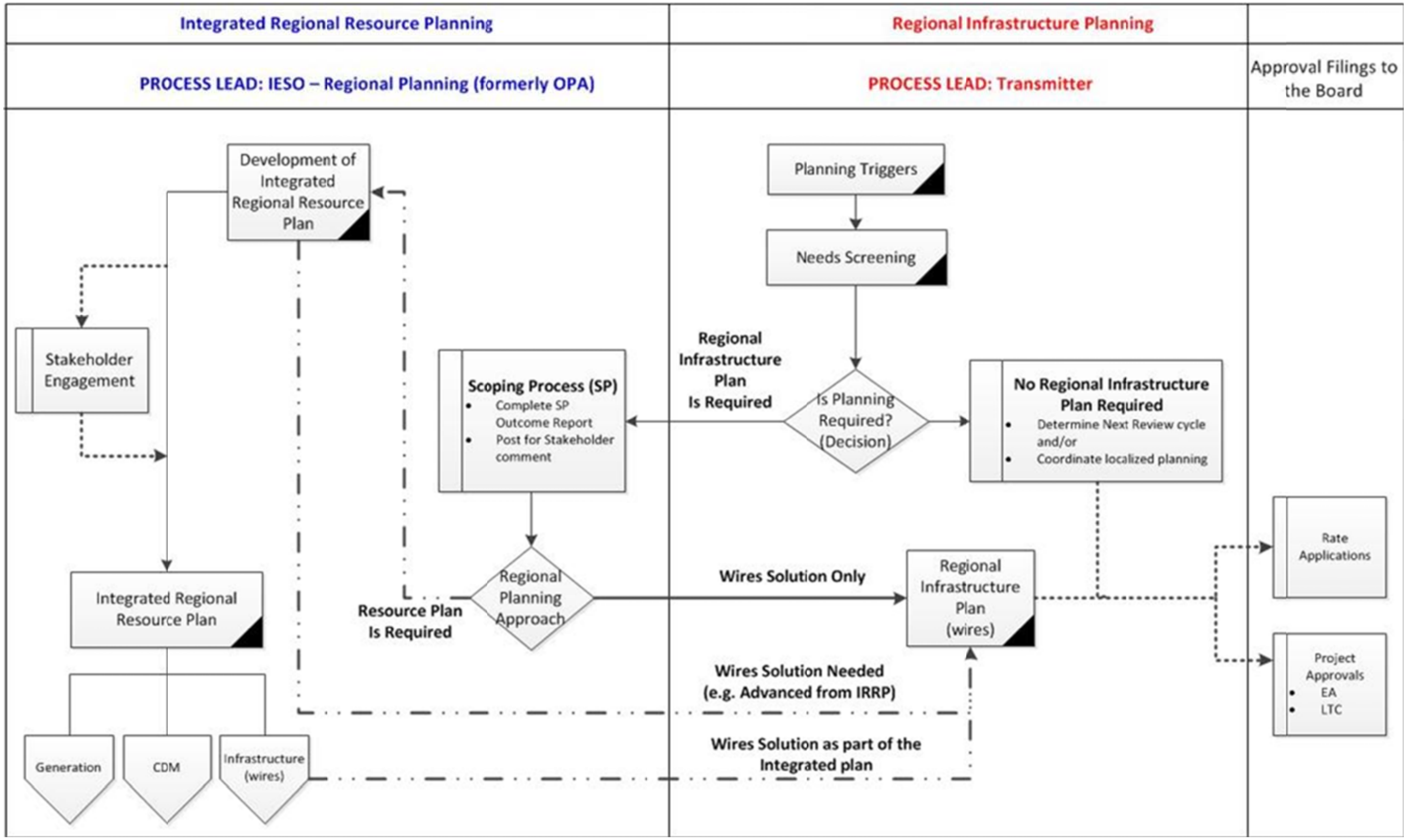

Figure 2-1: Regional Planning Process Flowchart

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.

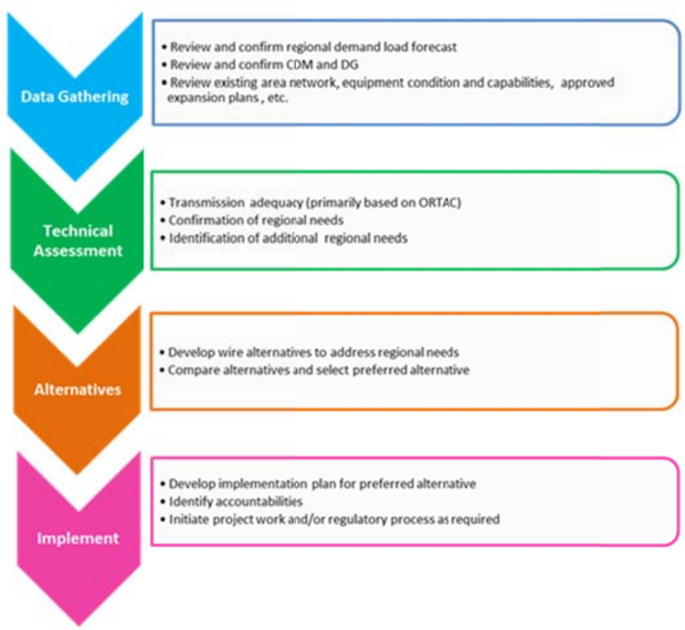

Figure 2-2: RIP Methodology

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

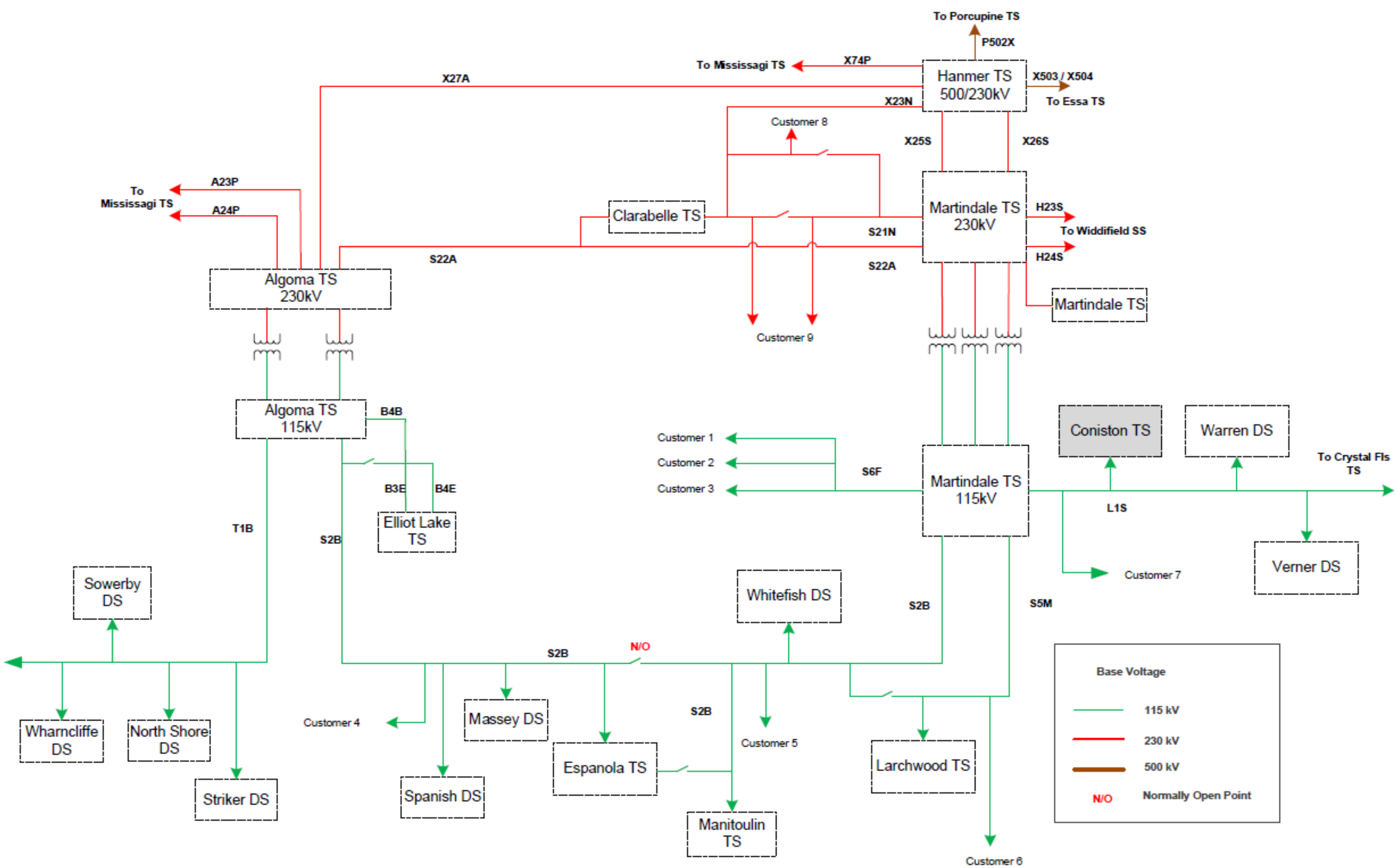

Figure 3-3: Single Line Diagram of Sudbury/Algoma Region

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	Customer Data	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)				
						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)				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
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	Customer Data	Historical Data (MW) 2019	WAN	WAE	Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment: Load Growth Factor	Near Term Forecast (MW) 2020	2021	2022	2023	2024	Medium Term Forecast (MW) 2025	2026	2027	2028	2029
						1	1.0158	1.0758											
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

Chatham-Kent/Lambton/Sarnia

Regional Infrastructure Plan

August 21, 2017

Prepared by Hydro One Networks Inc. (Lead Transmitter)

With support from:

Companies
Independent Electricity System Operator (IESO)
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Regional Infrastructure Plan ("RIP") was prepared for the purpose of developing an electricity infrastructure plan to address needs identified in the Chatham-Kent/Lambton-Sarnia Region. 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 members in the region.

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 input from the Region's Local Distribution Companies ("LDCs") and the IESO in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements. It summarizes investments in transmission facilities, distribution facilities, or both, recommended to meet the electricity infrastructure needs within the Chatham-Kent/Lambton/Sarnia Region.

The regional planning process for the Chatham-Kent/Lambton/Sarnia Region was initiated with a Needs Assessment in April 2016, which identified loading at Kent TS would exceed their transformer 10-day Limited Time Rating ("LTR") in 2016 based on the net load forecast. The Needs Assessment Study Team recommended Hydro One and relevant LDCs to develop a Local Plan to address this issue ("Kent TS T3 Capacity Limitation"). This Local Plan was completed in June 2017, and concluded that there is existing distribution transfer capability to ensure that the transformer T3 would not exceed its LTR.

The major sustainment projects planned for the region over the near and medium-term are given as below:

- Refurbishment of existing Wanstead TS is currently underway and is scheduled to be completed in 2018;
- Chatham SS component replacement, including a capacitor and the associated breaker, is planned to be completed by 2023;
- St. Andrews TS T3, T4 & switchyard refurbishment, planned to be completed by 2023;
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

In accordance with the regional planning process as mandated by the TSC and DSC, the next planning cycle will be started no later than 2020. However, should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle may commence earlier to address the need.

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1. INTRODUCTION

This Regional Infrastructure Plan ("RIP") summarizes all the regional planning activities undertaken in the Chatham-Kent/Lambton/Sarnia Region. It was prepared by Hydro One Networks Inc. ("Hydro One") as the lead transmitter in the region, and is supported by the representatives from Bluewater Power Distribution Corporation, Entegrus Inc., Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO"). This RIP is the final phase of the regional planning process for the region in accordance with the Ontario Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements.

1.1 Background and Scope

In accordance with the TSC and DSC amendments in August 2013, the regional planning process for the Chatham-Kent/Lambton/Sarnia Region began with Needs Assessment in April 2016 and was completed in June 2016.

Based on the findings, the Needs Assessment Study Team agreed that Scoping Assessment was not required for this region at the time. The only need identified, thermal overloading of transformer T3 at Kent TS, was to be addressed between Hydro One (transmitter) and relevant LDCs through Local Planning process which was completed in June 2017.

Being the final phase of the regional planning process, the scope of this RIP includes a comprehensive summary of the needs and relevant wire plans to address near and medium-term needs (2015-2025) identified in previous planning phases.

2. REGIONAL DESCRIPTION

The Chatham-Kent/Lambton/Sarnia Region, as shown in Figure 2-1, 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 region's summer coincident peak load was about 710 MW in 2016.

Figure 2-1 Map of Chatham-Kent/Lambton/Sarnia Region

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, and W44LC/W45LS) towards Buchanan TS. This region also contains a number of interconnections with neighboring Michigan State (B3N, L4D, and L51D). Figure 2-2 shows Hydro One transmission and transmission-connected customers' assets in the Chatham-Kent/Lambton/Sarnia Region.

Large gas-fired generators in the region include: Greenfield Energy Centre CGS, TransAlta Sarnia CGS, St. Clair Power CGS, and Greenfield South Power Corporation (GSPC). Lists of transmission lines, stations, and distributors (LDCs) in the region are provided in Appendix A, B, and C, respectively.

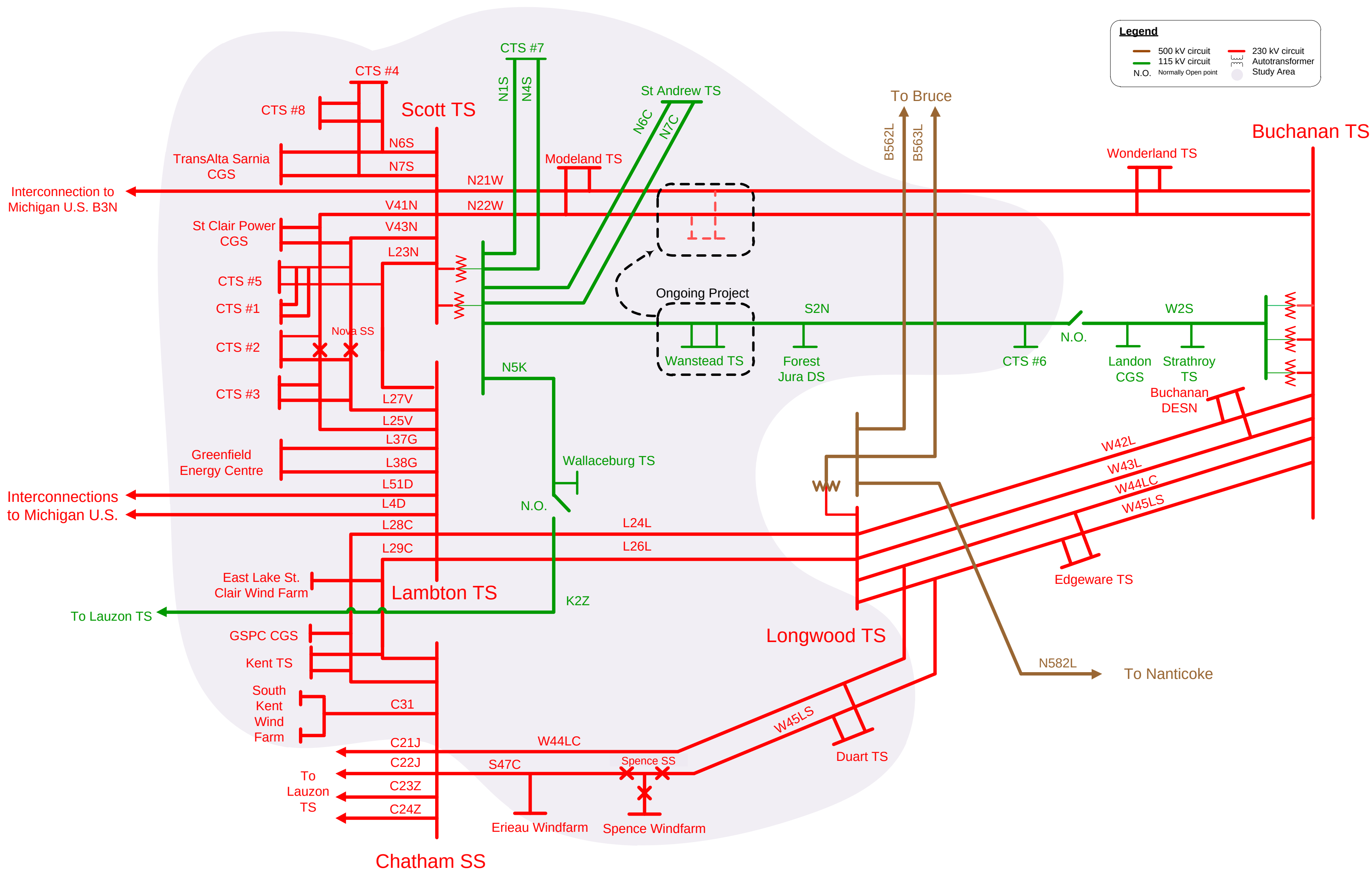


Figure 2-2 Single Line Diagram of Chatham-Kent/Lambton/Sarnia Region

3. NEEDS ASSESSMENT RESULTS

3.1 Load Forecast

During the Needs Assessment phase, LDCs in the region provided gross load forecasts for Hydro One's step-down transformer stations and assumed 2015 historical extreme weather-corrected summer peak loads as reference points. As for transmission connected industrial customers, 2014 historical load levels were assumed throughout the study period.

Based on data provided by the Study Team, the summer gross coincident load in the region is expected to grow at an average rate of approximately 1.3% annually over the next 10 year period. Factoring in the contributions of conservation and demand management and distributed generation, the summer net coincident load in the region is expected to grow at an average rate of approximately 0.2% annually.

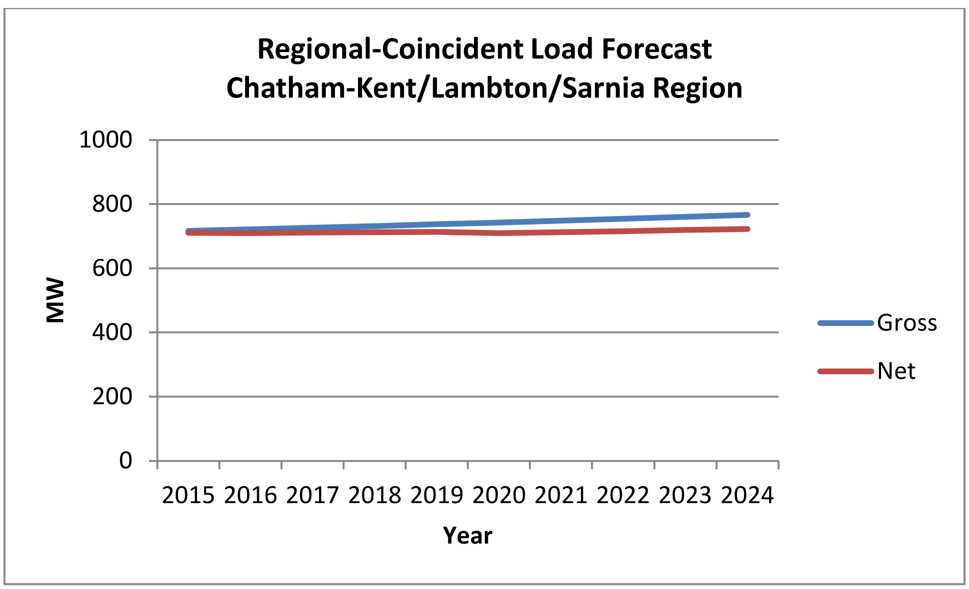


Figure 3-1 Regional load forecast during Needs Assessment

Further load forecast details are provided in Appendix D.

3.2 Major Transmission Projects Completed or Underway

Over the last 10 years, a number of major transmission projects, shown below, have been completed by Hydro One aimed to maintain or improve the reliability and adequacy of supply in the Chatham-Kent/Lambton/Sarnia Region:

- Lambton to Longwood 230kV L24L/L26L Circuit Reconductoring
- New Transformer Station Duart TS

In addition, as part of Hydro One's transmission rates application (EB-2016-0160), existing Wanstead TS has been identified as reaching end-of-life. Effort is underway to convert Wanstead TS from 115 kV to 230 kV and connecting to 230 kV circuits N21W/N22W. The target in-service date is Q4 2018.

3.3 Regional Needs

The results from the Needs Assessment for the region are summarized below:

Table 3-1 Regional Needs

No.	Needs	Description
1	Kent TS Capacity	Loading at Kent TS is expected to exceed the transformer 10-day limited time rating (LTR) in 2016 based on the net load forecast.
2	End-of-Life equipment at St. Andrews TS, Scott TS, and Chatham SS	During the study period, plans to replace end of life equipment at St. Andrews TS, Scott TS, and Chatham SS[1] are identified.

4. RECOMMENDED PLANS

This section provides a consolidated summary of the regional infrastructure plans for addressing needs in the Chatham-Kent/Lambton/Sarnia Region.

4.1 Kent TS Transformation Capacity

Based on the information available at the time of Chatham-Kent/Lambton/Sarnia Region Needs Assessment, it was identified that transformer T3 at Kent TS will be overloaded for the loss of its companion transformer T4. Subsequently, local planning team consists of Hydro One and impacted LDCs had undertaken further investigations and determined there is a sufficient transfer capability on the distribution system to offload Kent TS T3. Therefore, the local planning team agreed no further action is required at this time.

[1] The need to replace end-of-life equipment at Chatham SS was identified post completion of the 2016 Needs Assessment report.

4.2 Sustainment Plans

As part of Hydro One's transmitter license 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. Since the conclusion of Needs Assessment, additional sustainment projects have been planned for the region in the medium-term. Below is a list of Hydro One's major transmission sustainment projects in the Chatham-Kent/Lambton/Sarnia Region that are currently planned. Note that the project scopes and timelines are currently under development and may change accordingly.

- Chatham SS Component Replacement, mainly to replace capacitor SC21 and the associated breaker and is planned to be completed by 2023.
- St. Andrews TS T3, T4 & Switchyard Refurbishment, planned to be completed by 2023. The current scope includes both transformers and a breaker replacement.
- Sarnia Scott TS T5 & Component Replacement, which includes autotransformer T5, breaker, and other components, planned to be completed by 2024.

5. CONCLUSION AND NEXT STEPS

This Regional Infrastructure Plan (RIP) report summarizes the regional planning activities for the Chatham-Kent/Lambton/Sarnia Region and concludes the first regional planning cycle for the region.

As mandated by the OEB, next planning cycle will begin no later than 2020. Should there be a need that emerges due to change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

6. REFERENCES

[1] Needs Assessment Report, Chatham-Kent/Lambton/Sarnia Region. June 12, 2016. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf

[2] Local Planning Report – Kent TS Transformation Capacity, Chatham-Kent/Lambton/Sarnia Region. June, 2017. http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Kent%20TS%20Transformation%20Capacity%20Local%20Planning%20Report%20(Final).pdf

APPENDIX A: TRANSMISSION LINES IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No	Circuit Designation	Location	Voltage (kV)
1	N6S, N7S	Scott TS to TransAlta Sarnia CGS	230
2	V41N, V43N	Scott TS to Nova SS	230
3	L23N	Scott TS to Lambton TS	230
4	L25V, L27V	Lambton TS to Nova SS	230
5	L37G, L38G	Lambton TS to Greenfield Energy Centre CGS	230
6	L28C, L29C	Lambton TS to Chatham SS	230
7	C31	Chatham SS to South Kent Wind Farm CGS	230
8	W44LC	Buchanan TS to Longwood TS to Chatham SS	230
9	W45LS	Buchanan TS to Longwood TS to Spence SS	230
10	S47C	Spence SS to Chatham SS	230
11	L24L, L26L	Lambton TS to Longwood TS	230
12	N21W, N22W	Scott TS to Buchanan TS	230
13	N1S, N4S	Scott TS to CTS	115
14	N6C, N7C	Scott TS to St. Andrews TS	115
15	S2N	Scott TS to CTS	115
16	N5K	Scott TS to Wallaceburg TS	115
17	K2Z	Kent TS (115kV) to Lauzon TS	115

APPENDIX B: STATIONS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

No.	Station	Voltage (kV)	Supply Circuits
1	Scott TS	230/115	N/A
2	Lambton TS	230	N/A
3	Kent TS	115	L28C/L29C
4	Duart TS	230	W44LC, W45LS
5	Modeland TS	230	N21W, N22W
6	Wanstead TS	115 (existing) 230 (future)	S2N (existing) N21W/N22W (future)
7	St. Andrews TS	115	N6C, N7C
8	Wallaceburg TS	115	N5K
9	Forest Jura HVDS	115	S2N

Note: Customer-owned transformer stations are excluded

APPENDIX C: DISTRIBUTORS IN THE CHATHAM-KENT/LAMBTON/SARNIA REGION

Distributor Name	Station Name	Connection Type
Bluewater Power Distribution Corporation	Modeland TS	Tx
	St. Andrews TS	Tx
	Wanstead TS	Dx
Entegrus Inc.	Kent TS	Tx, Dx
	Wallaceburg TS	Dx
Hydro One Networks Inc. (Distribution)	Duart TS	Tx
	Forest Jura HVDS	Tx
	Kent TS	Tx
	Lambton TS	Tx
	Wallaceburg TS	Tx
	Wanstead TS	Tx

APPENDIX D: REGIONAL-COINCIDENT LOAD FORECAST (MW)

Coincidental Net Load (MW)

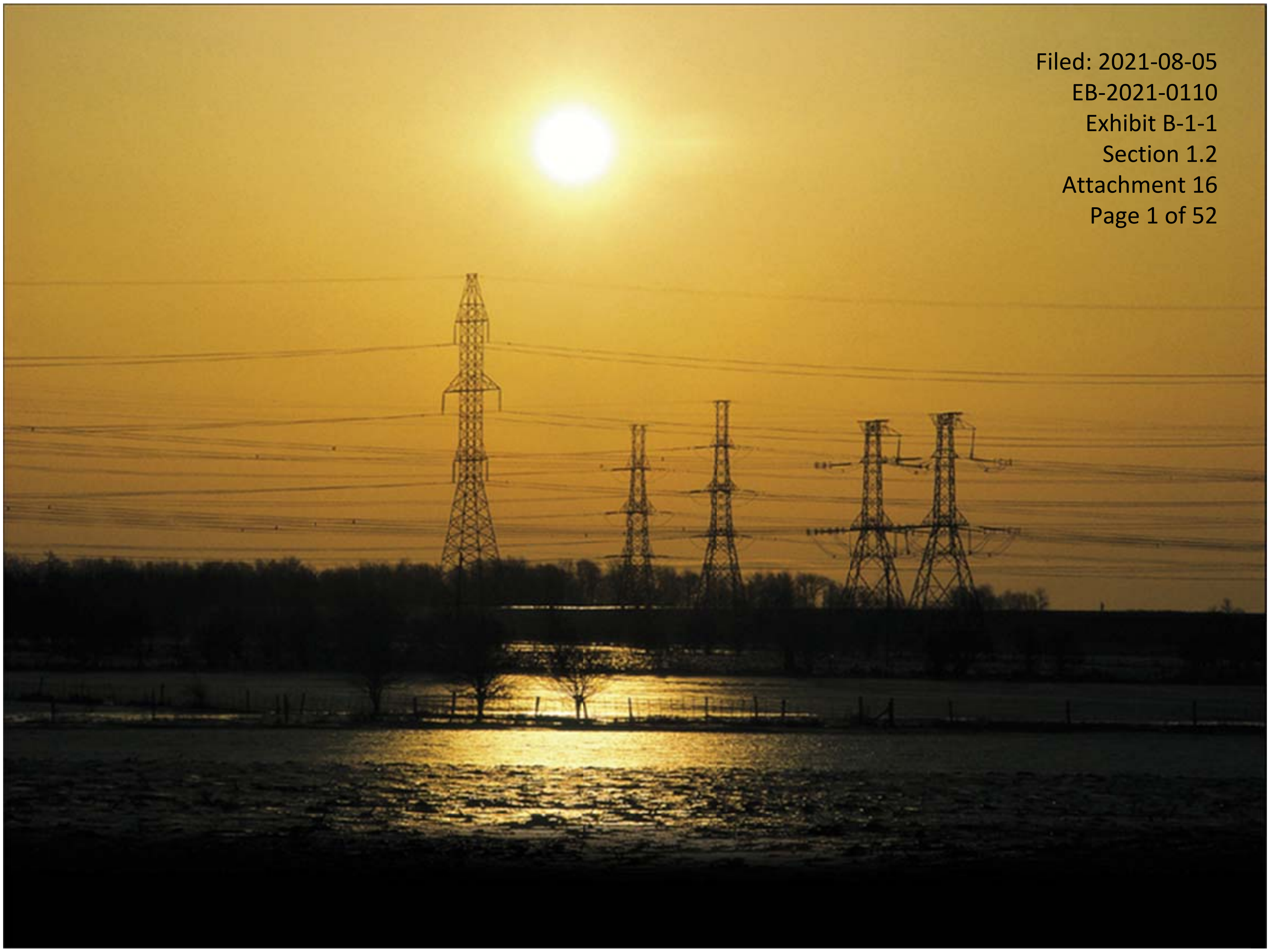
	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.5	14.5	14.4	14.5	14.5	14.6	14.7	14.8	15.0	15.1
Forest Jura DS	19.5	19.6	19.8	19.9	20.0	20.2	20.4	20.6	20.9	21.1
Kent TS T1/T2	69.8	70.0	71.1	72.0	72.9	74.0	75.3	76.6	78.1	79.5
Kent TS T3/T4	40.3	40.7	41.3	41.8	42.2	42.8	43.5	44.2	45.0	45.8
Lambton TS	61.7	61.6	61.8	61.7	61.6	61.7	61.9	62.2	62.5	62.8
Modeland TS	82.1	81.4	81.2	80.6	80.1	79.7	79.5	79.4	79.4	79.2
St. Andrews TS	63.0	62.3	61.8	61.1	60.5	60.0	59.6	59.3	59.0	58.7
Wallaceburg TS	27.0	26.8	27.2	27.6	27.9	23.2	23.7	24.2	24.8	25.3
Wanstead TS	28.1	28.2	28.5	28.6	28.8	29.0	29.3	29.6	30.0	30.3
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

Coincidental Gross Load (MW)

	Forecast (MW)									
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Duart TS	14.7	14.9	15.1	15.3	15.5	15.7	16.0	16.2	16.4	16.7
Forest Jura DS	19.7	20.0	20.4	20.7	21.1	21.4	21.8	22.2	22.6	22.9
Kent TS T1/T2	71.1	72.7	74.4	76.1	77.9	79.7	81.6	83.5	85.4	87.4
Kent TS T3/T4	40.8	41.7	42.6	43.6	44.6	45.5	46.6	47.6	48.7	49.8
Lambton TS	62.3	62.9	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.0
Modeland TS	82.9	83.3	83.6	84.0	84.3	84.7	85.0	85.3	85.7	86.0
St. Andrews TS	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6
Wallaceburg TS	27.7	28.3	29.0	29.7	30.3	31.0	31.8	32.5	33.3	34.0
Wanstead TS	28.7	29.2	29.7	30.1	30.6	31.1	31.6	32.2	32.7	33.2
CTS #1	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
CTS #2	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
CTS #3	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
CTS #4	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
CTS #5	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9	30.9
CTS #6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CTS #7	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9	53.9
CTS #8	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7

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
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
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council Inc.
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
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code



Greater Bruce - Huron

REGIONAL INFRASTRUCTURE PLAN

August 18, 2017

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Power Lines Inc.
Erie Thames Powerlines Corporation
Festival Hydro Inc.
Goderich Hydro - West Coast Huron Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

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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 GREATER BRUCE-HURON REGION.

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

- Hydro One Networks Inc. (Lead Transmitter)
- Entegrus Power Lines Inc.
- Erie Thames Powerlines Corporation
- Festival Hydro Inc.
- Goderich Hydro - West Coast Huron Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Wellington North Power Inc.
- Westario Power Inc.

This RIP is the final phase of the regional planning process for the Greater Bruce-Huron Region and provides a consolidated summary of needs and recommended plans for the Greater Bruce-Huron Region for the near-term (up to 5 years) and mid-term (5 to 10 years). No long term needs (10 to 20 years) have been identified.

Investments planned for the Greater Bruce-Huron 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	Improve L7S Customer Delivery Point Performance	Staged Plan 2017-2023	$154k - TBD
2	Accommodation for Connection Capacity Requests near Kincardine– Hydro One Network Inc. Distribution	TBD (customer dependent)	TBD

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 GREATER BRUCE-HURON 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., Erie Thames Powerlines Corporation, Festival Hydro Inc., Hydro One Distribution, the Independent Electricity System Operator ("IESO"), Wellington North Power Inc., Goderich Hydro - West Coast Huron Energy Inc. and Westario Power Inc. in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

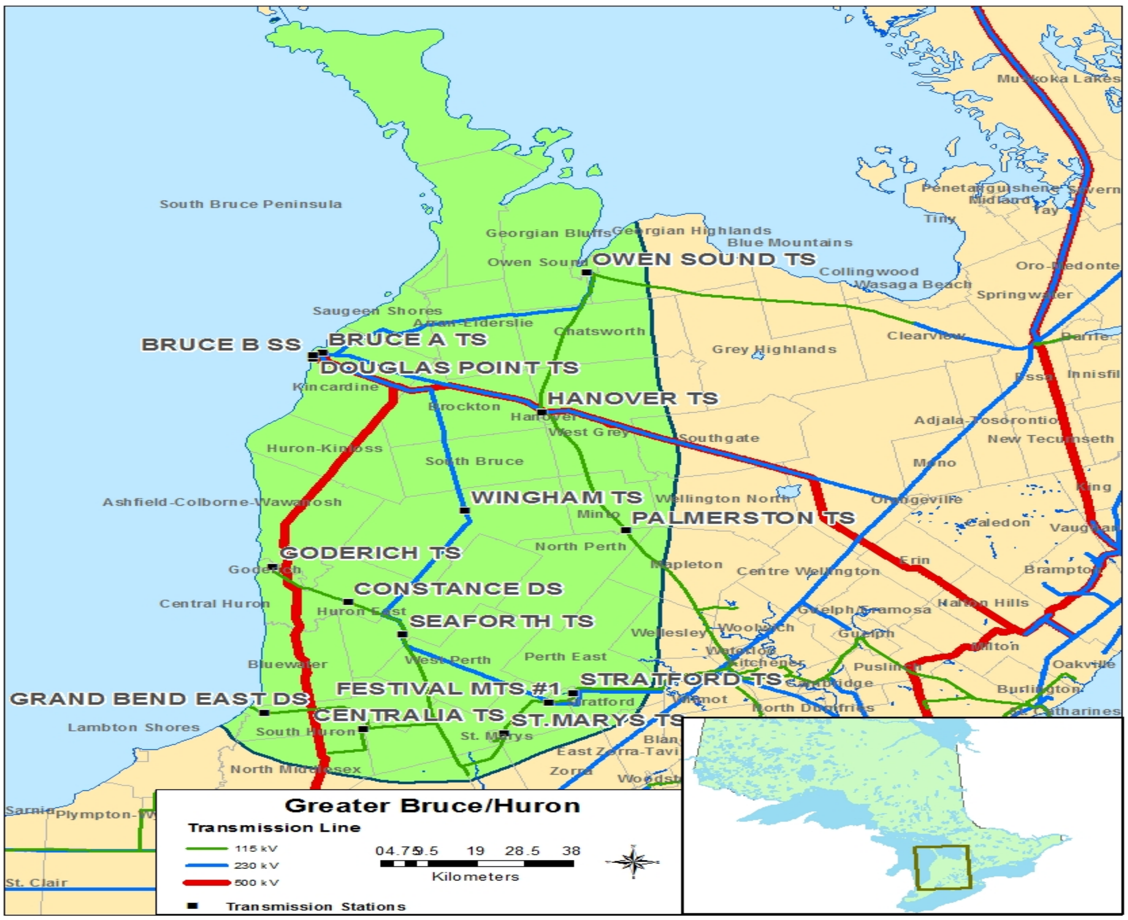

Figure 1-1 Greater Bruce-Huron Region

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. Electrical supply to the Region is provided from six 230 kV and twelve 115 kV step-down transformer stations. The boundaries of the Region are highlighted in Figure 1-1 above.

1.1 Objective and Scope

This RIP report examines the needs in the Greater Bruce-Huron 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 (2016-2025) identified in previous planning phases (Needs Assessment or Local Plan)
- Identification of any new needs over the 2016-2025 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[1] ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

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

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

The IRRP phase will generally assess infrastructure (wires) versus resource 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

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[1] Also referred to a Needs Screening

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 Greater Bruce-Huron 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 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.

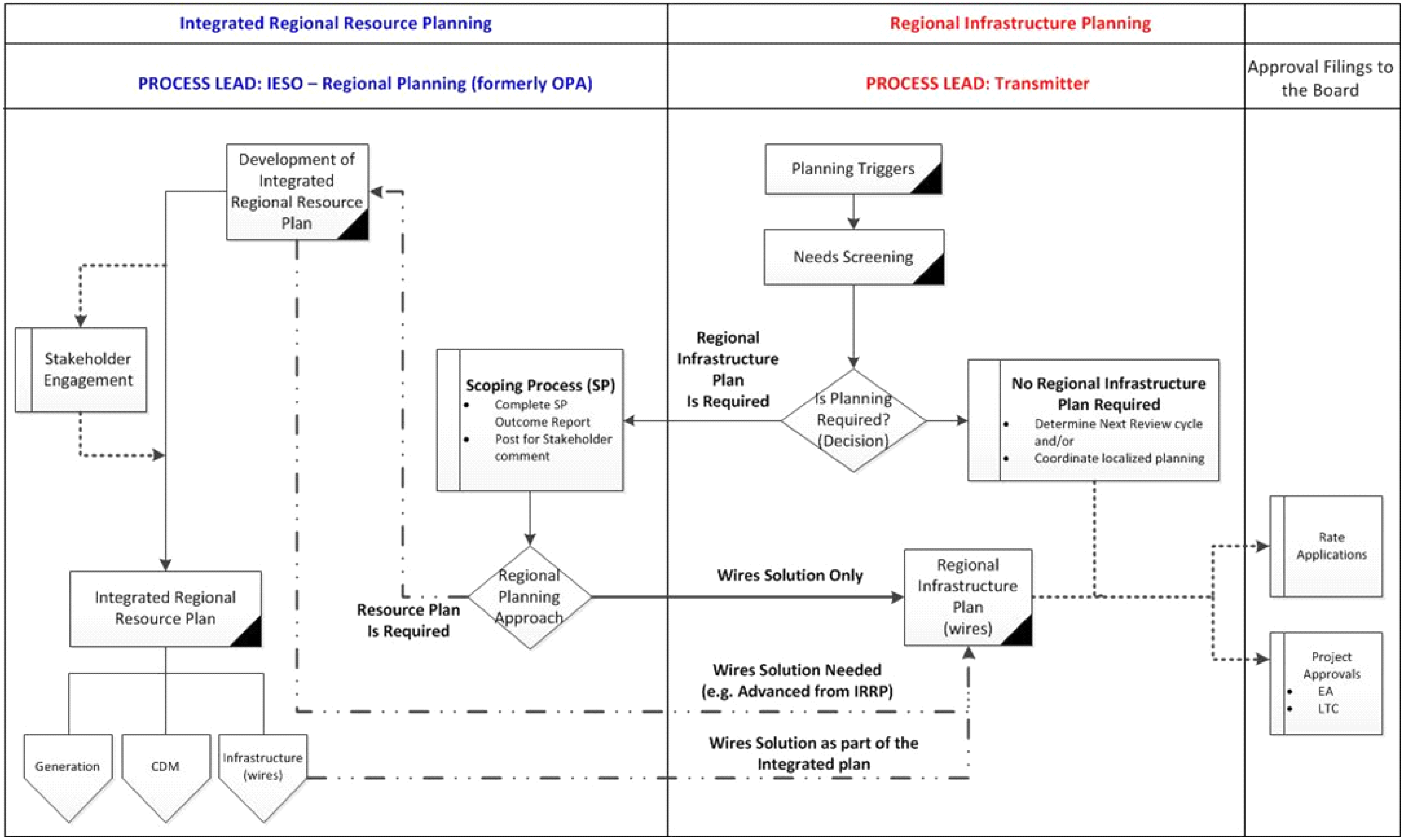

Figure 2-1 Regional Planning Process Flowchart

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 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.

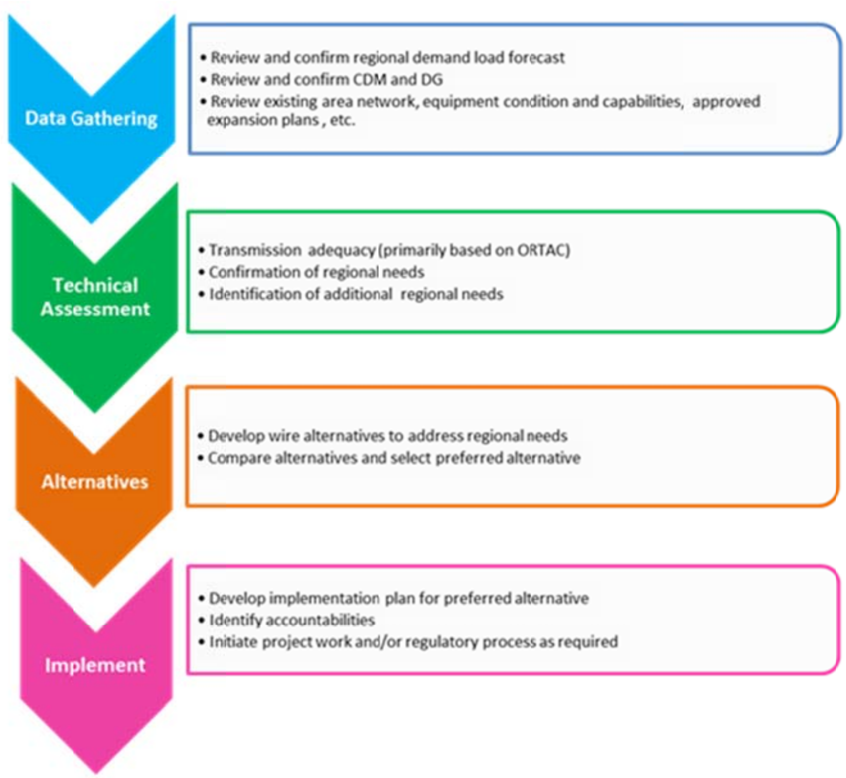

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER BRUCE-HURON REGION COMPRISES OF THE COUNTIES OF BRUCE, HURON, AND PERTH, AS WELL AS PORTIONS OF GREY, WELLINGTON, WATERLOO, OXFORD, AND MIDDLESEX COUNTIES AS SHOWN IN FIGURE 3-1.

Electricity supply for the 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. The 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 Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Within the Region, electricity is delivered to the end users of LDCs and directly-connected industrial customers by eleven Hydro One step-down transformation stations, as well as seven customer-owned transformer or distribution stations supplied directly from the transmission system. 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 Greater Bruce-Huron Region transmission system facilities is shown below in Figure 3-2.

Figure 3-1 Geographical Area of the Greater Bruce-Huron Region with Electrical Layout

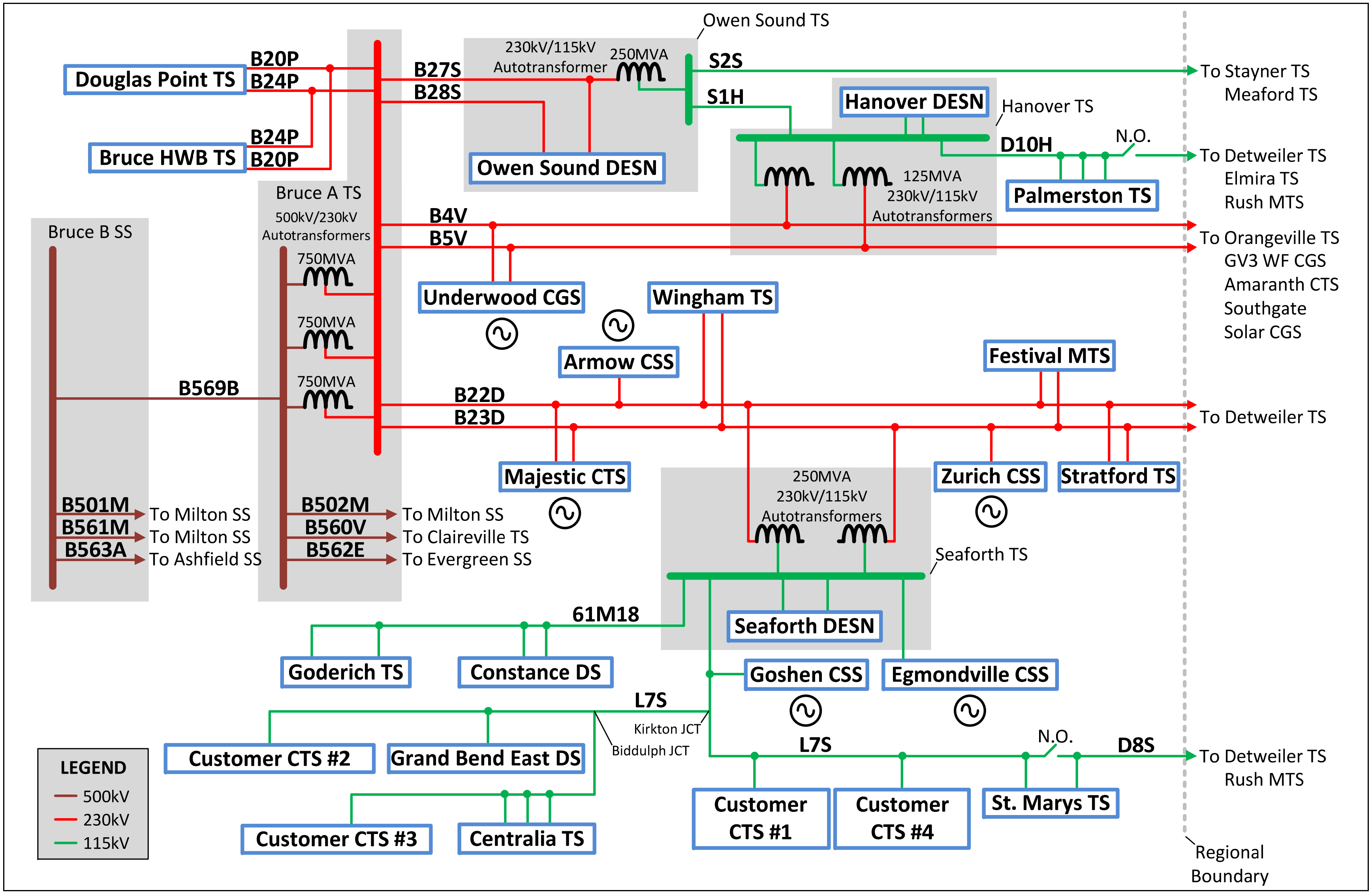

Figure 3-2 Greater Bruce-Huron Region Single Line Diagram

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 GREATER BRUCE-HURON 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 reactive and voltage support needs:

- a 230 kV shunt capacitor bank installed at Detweiler TS in 2007
- a 230 kV shunt capacitor bank installed at Orangeville TS in 2008

For bulk power system transfer needs:

- 500 kV double circuit line from the Bruce Nuclear Complex to Milton SS in 2011
- 230 kV Static Var Compensator (SVC) at Detweiler TS in 2011

For major station refurbishment needs based on asset condition assessment:

- Goderich TS in 2016

For renewable generation connection needs:

- 230 kV Melancthon Grey Wind Farm onto circuits B4V/B5V in 2006/2008
- 230 kV Ripley Wind Farm onto circuits B22D/B23D in 2007
- 230 kV Underwood Wind Farm onto circuits B4V/ B5V in 2008
- 230 kV Dufferin Wind Farm into Orangeville TS in 2014
- 500 kV Jericho/Adelaide/Bornish Wind Farms into Evergreen SS in 2014
- 230 kV Grand Valley 3 Wind Farm onto circuit B4V in 2015
- 115 kV Bluewater Wind Farm into Seaforth TS in 2015
- 115 kV Goshen Wind Farm onto circuit L7S in 2015
- 500 kV K2 Wind Farm into Ashfield SS in 2015
- 230 kV Grand Bend Wind Farm onto circuit B23D in 2016
- 230 kV Armow Wind Farm onto circuit B22D in 2016
- 230 kV Southgate Solar Farm onto circuit B4V in 2016

The following projects are underway:

- Centralia TS is currently undergoing major station refurbishment work with a projected in-service of 2018.
- Palmerston TS is currently undergoing major station refurbishment work with a projected in-service of 2018.
- Bruce A TS 230 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by 2019.
- Replacement of the Bruce Special Projection Scheme (BSPS) is currently underway with a projected in-service of 2018.
- Modification to the Bruce Reactor Switching Scheme (RSS) is currently underway with a projected in-service of 2018.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Bruce-Huron Region is forecast to increase annually between 2016 and 2025. The growth rate varies across the Region with most of the growth concentrated in the County of Bruce and more specifically in the Kincardine area. The Region's 2017 RIP load forecasts 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 1.4% annually from 2016-2025 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.3% from 2016-2025.

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 0.8% annually from 2016-2025 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 0.6% from 2016-2025.

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 winter coincident peak load is larger than its summer coincident peak load. Based on historical load and the non-coincident load forecasts, the Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors assessment for this Region was conducted for both summer and winter peak load.

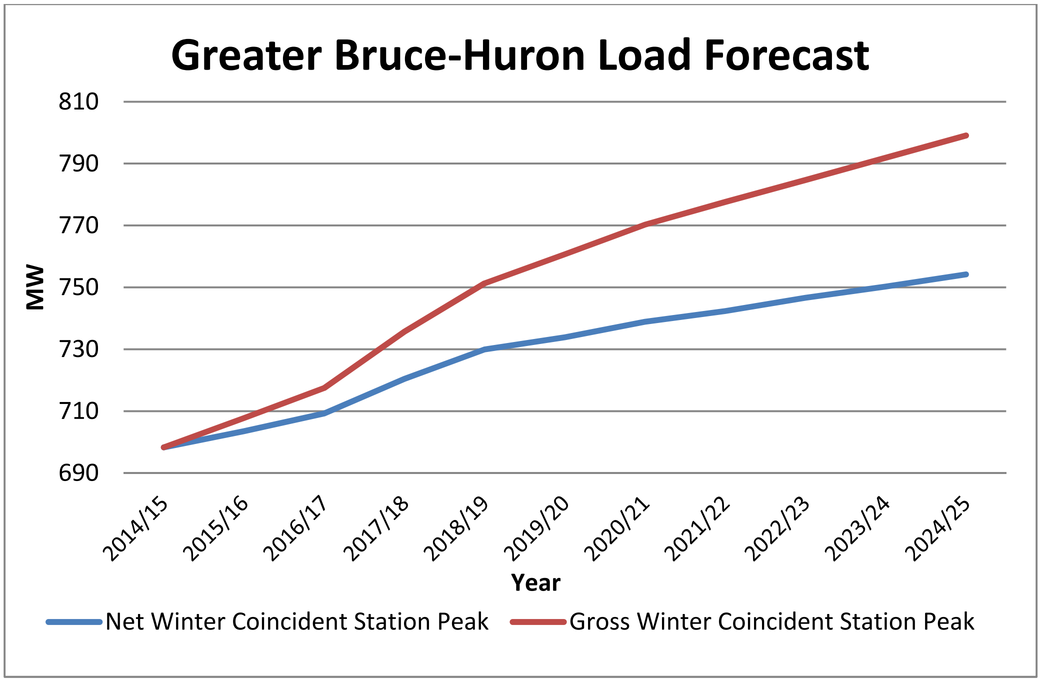

Figure 5-1 Greater Bruce-Huron Region Winter Extreme Weather Peak Forecast

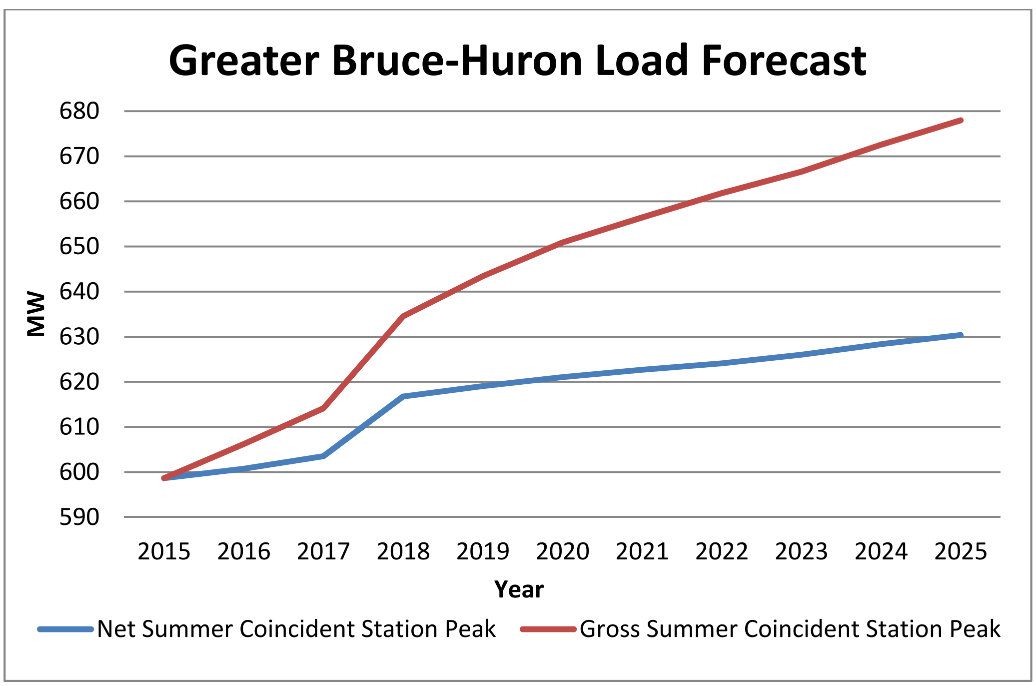

Figure 5-2 Greater Bruce-Huron Region Summer Extreme Weather Peak Forecast

5.2 Study Assumptions

The following assumptions are made in this report.

1) The study period for the RIP assessments is 2016-2025.

2) All planned facilities listed in Section 4 are assumed to be in-service.

3) The Region contains some stations that are summer peaking and others that are winter peaking. The assessment is therefore based on both summer and winter peak loads.

4) 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.

5) Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2016-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STEP-DOWN TRANFORMATION STATION FACILITIES SUPPLYING THE GREATER BRUCE-HURON REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle, five regional assessments have been conducted for the Greater Bruce-Huron Region. The findings of these studies are input to the RIP. The studies are:

1) Needs Assessment Report - Greater Bruce-Huron Region, May 2016
2) Local Planning Report - Low Power Factor at Wingham TS, October 2016
3) Local Planning Report - Circuit L7S Thermal Overload, November 2016
4) Local Planning Report - Low Power Factor at Bruce HWP B TS, May 2017
5) Customer Delivery Point Performance Review, 2016-2017

This RIP reviewed the loading on transmission lines and stations in the Greater Bruce-Huron Region based on the RIP load forecast. Sections 6.1-6.6 presents the results of this review and Table 6-1 lists the Region's needs identified in both the Needs Assessment and the RIP 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 Identified in the Needs Assessment Report [1]			
Transmission Circuit Capacity	6.3	Overload on sections of 115 kV single circuit line, L7S	2019 (based on gross load forecast)
			2025 (based on net load forecast)
Power Factor Review	6.5.2	Low power factor at Wingham TS	Immediate
		Low power factor at Bruce HWP B TS	Immediate
Customer Delivery Point Performance Review	6.5.1	Delivery points supplied from 115 kV circuits 61M18, L7S and D10H	Immediate
Additional Needs identified in RIP Phase			
Step-down Transformation Capacity	6.4	Hydro One Distribution (Kincardine area)	2019/2020

6.1 230 kV Transmission Facilities

Half of the 230 kV transmission circuits in the Greater Bruce-Huron 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 KWCG, Georgian Bay 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 (refer to Figure 3-2):

1) Bruce A TS to Orangeville TS 230kV transmission circuits B4V/B5V – supplies Hanover TS
2) Bruce A TS to Detweiler TS 230kV transmission circuits B22D/ B23D – supplies Wingham TS, Seaforth TS, Festival MTS #1, and Stratford TS
3) Bruce A TS to Owen Sound TS 230kV transmission circuits B27S/B28S – supplies Owen Sound TS
4) Bruce A TS to Douglas Point TS 230kV transmission circuits B20P/B24P – supplies Douglas Point TS and Bruce HWP B TS

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

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the Greater Bruce-Huron 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:

1) Three (3) 500/230kV autotransformers at Bruce A TS
2) Two (2) 230/115kV autotransformers at Seaforth TS
3) Two (2) 230/115kV autotransformers at Hanover TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the autotransformation supply capacity is adequate over the study period.

6.3 Supply Capacity of the 115 kV Network

The Greater Bruce-Huron Region contains four (4) single circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Hanover TS to Detweiler TS 115 kV transmission circuit D10H with Normally Open (N/O) point at Palmerston TS – supplies Palmerston TS & Elmira TS
2) Seaforth TS to Goderich TS 115 kV transmission circuit 61M18 – supplies Constance DS and Goderich TS
3) Seaforth TS to St. Marys TS 115 kV transmission circuit L7S – supplies Grand bend East DS, Lake Huron WTP CTS, Centralia TS, McGillivray R&BP CTS, Enbridge Bryanston CTS and St. Marys Cement CTS
4) Hanover TS to Owen Sound TS 115 kV transmission circuit S1H

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, except circuit L7S. Circuit L7S will exceed its thermal rating in 2019 based on gross load forecast, and in 2025 based on net load forecast.

6.4 Step-down Transformer Stations

There are 18 step-down transformer stations within the Greater Bruce-Huron Region. Fourteen supply electricity to LDCs and four are transmission-connected industrial customer stations. These stations are listed in Appendix C. Of the 18 stations, 3 of them are owned and operated by LDCs.

As part of both the Needs Assessment as well as this RIP, step-down transformation station capacity was reviewed. Since the May 2016 Needs Assessment, the load forecasts at Seaforth TS, Stratford TS and Douglas Point TS have been modified; refer to Appendix E for the analysis of these modifications. The analysis showed that the load forecasts at Seaforth TS and Stratford TS can still be accommodated. However, the load forecast modification at Douglas Point TS will result in its transformation capacity limit being exceeded towards the end of the study period, winter 2023/2024. This is due to a 15 MW request for capacity made since the May 2016 Needs Assessment.

Furthermore, since updating the RIP forecast there has been additional connection requests for 2.2 MW, 0.5 MW and 20 MW of capacity by 2019/2020 at Douglas Point TS. The 2.2 MW and 0.5 MW requests can be accommodated within the station's transformation capacity limits; however the 20 MW request would result in Douglas Point TS exceeding its transformation capacity within the near term (2019/2020) and cannot be fully accommodated at this time. Therefore additional step-down transformation capacity at/near Douglas Point TS is needed.

Based on the requirements of the customer requesting the 20 MW of connection capacity, three "need" scenarios have been developed:

Scenario 1 – If the customer requires all 20 MW of capacity immediately, the need for additional step-down transformation capacity is required in 2019/2020. Hydro One Transmission will work with Hydro One Distribution and the customer to develop a plan to meet the increased capacity requirement. All costs for the additional capacity will be allocated to the benefitting customer(s) as per the Transmission System Code.

Scenario 2 – If the customer accepts an offering to connect a portion of its load, the need for additional step-down transformation capacity is required in 2021 due to the inherent "organic" growth of load. In order to meet the need timeline, an expedited coordinated regional planning process will be undertaken by the IESO, Hydro One Transmission and Hydro One Distribution. Cost allocation for additional investment will depend on the solution to address the need.

Scenario 3 – If the customer elects not to proceed with its connection request, the need for additional step-down transformation capacity is require by 2023/2024. CDM would help to defer the need and therefore it is recommended to monitor load growth and re-evaluate the need in the next regional planning cycle.

6.5 Other Items Identified During Regional Planning

6.5.1 Customer Delivery Point Performance

The Needs Assessment section 6.2.5 identified that a performance review of several 115 kV customer delivery points be undertaken. A summary of the review is provided in Appendix F.

6.5.2 Low Power Factor Concerns

The Needs Assessment sections 6.2.3 identified two stations which historically have low power factor: Wingham TS and Bruce HWB TS.

6.6 Long-Term Regional Needs

A long-term, beyond 10 year, analysis was not deemed necessary by the Working Group for the Region at this time and therefore no long-term studies have been undertaken. If new long-term needs were to arise, there is sufficient time to assess them in the next planning cycle which can also be started earlier to make timely investment decisions.

7. REGIONAL PLANS

THIS SECTION SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS LISTED IN TABLE 6-1.

7.1 Transmission Circuit Capacity

7.1.1 Circuit L7S

L7S is a single 115 kV circuit transmission line operated radial from Seaforth TS to St. Marys TS. As per section 6.1.3 of the Needs Assessment, the circuit will reach its Load Meeting Capability ("LMC") in 2019 based on the gross load forecast and 2025 based on the net load forecast.

Recommended Plan and Current Status

To address the transmission circuit capacity needs for L7S, the Local Planning working group created a Development Plan which recommended monitoring load growth at stations supplied from circuit L7S. The Development Plan is detailed in the Local Planning report [3]. The Development Plan specified that when loading on L7S is expected to exceed its limits within a 3 year period, Hydro One Transmission will increase the thermal rating of the limiting spans of circuit L7S. The cost to increase the rating is currently estimated to be approximately $550 k. Strengthening L7S will be sufficient for supplying load connected to L7S load for the study period. Loading beyond the study period's forecast may then require additional voltage support. Capacity cost allocation will be as per the Transmission System Code.

Current Status of the Loading on Circuit L7S

The past winter (2016/2017) loading on circuit L7S was reviewed in accordance with the Development Plan. Winter peak coincident loading on the circuit was approximately 65% of the circuit capacity and did not trigger the need to increase the rating. Monitoring will continue after each peak load season, winter and summer.

7.2 Power Factor Review

7.2.1 Wingham TS

Power factor at Wingham TS is often low and does not meet IESO Market Rule requirements. As per section 6.2.3 of the Needs Assessment, the low power factor at Wingham TS is to be managed by the transmitter and affected LDCs.

Recommended Plan and Current Status

The power factor review conducted by the Local Planning working group, showed that the power factor of the load itself remains within Market Rule requirements. Further investigation revealed that the low power factor is due to the connected Distributed Generation (DG). The investigation is detailed in the Local Planning report [2]. The Local Plan recommends no mitigation is required at this time and to seek IESO's direction on power factor requirements with respect to DG.

Current Status of Power Factor with Respect to Distributed Generation

At this time, IESO does not recommend a Market Rule power factor amendment as the measured power factor is due to the connected DG and asks that a case by case review be conducted when the power factor consistently does not meet the Market Rule requirement.

7.2.2 Bruce HWP B TS

Power factor at Bruce HWP B TS is often low and does not meet IESO Market Rule requirements. As per section 6.2.3 of the Needs Assessment, the low power factor at Bruce HWP B TS is to be managed by the transmitter and the affected customer.

Recommended Plan

The power factor review conducted by the Local Planning working group, showed that while the power factor of the load occasionally (rather than often as previously identified) does not meet Market Rule requirements there is no negative effect at this time. The investigation is detailed in the Local Planning report [4]. The Local Plan recommends no mitigation is required at this time.

7.3 Customer Delivery Point Performance

7.3.1 Customers Supplied from Circuit 61M18

The performance of delivery points supplied from circuit 61M18, specifically Constance DS and Goderich TS were reviewed. The review is summarized in Appendix F, section F.1.

Recommended Plan and Current Status

To address delivery point performance to Constance DS and Goderich TS, it is recommended that Hydro One Transmission continue to rely on its line and station maintenance programs, as well as capital sustainment projects listed in section 4.0 and in Table 7-1 to improve the overall reliability.

Current Status of Sustainment Work associated 61M18 Delivery Points

The 17 remaining original 1959 structures on circuit 61M18 along with 11 other structures are schedule to be tested over the next 2 years. Those that are determined to be End-Of-Life (in poor condition), will then be replaced in the next 5 years. These replacements will occur under Hydro One's Line Sustainment programs.

7.3.2 Customers Supplied from Circuit L7S

The performance of delivery points supplied from circuit L7S, specifically Centralia TS, Grand Bend East DS, St. Marys TS and the 4 industrial customer connections, were reviewed. The review is summarized in Appendix F, section F.2.

Recommended Plan

To address delivery point performance, it is recommended that Hydro One Transmission undertake a staged approach. Stage 1 will entail a detailed field screening of the line for approximately $154 thousand in 2017. Based on findings from the field screening, work to reduce the frequency of interruptions due to adverse weather should be implemented in 2018 and 2019. Cost for improvements is unknown at this time as it is dependent on actual findings. Performance will then be monitored for 2-3 years to verify improvement. Stage 2 will be based on the monitored performance and may entail strategically installing 115 kV in-line remotely-operated switches on circuit L7S to reduce the duration of interruptions. Switches are currently estimated to cost between $1M to $4M depending on the number of switches and their location. Funding of the staged plan to be as per the OEB-approved Hydro One Customer Delivery Point Performance Standard [EB-2002-0424, updated February 7, 2008]. Capital contribution from customers is not anticipated at this time. If, however, capital contribution is required from customers such financial obligation will be determined using methodology set out in the Transmission System Code.

7.3.3 Customers Supplied from Circuit D10H

The performance of delivery points supplied solely from circuit D10H, specifically Palmerston TS and Elmira TS were reviewed. The review is summarized in Appendix F, section F.3.

Current Status

Consultations with customers supplied from D10H are expected to be undertaken in 2017. Additional assessment and/or infrastructure to adhere to the OEB-approved funding rules for customer delivery point reliability improvements. Improvements may entail installing 115 kV in-line remotely operated switches for approximately $1.5M. Funding of the staged plan to be as per the OEB-approved Hydro One Customer Delivery Point Performance Standard [EB-2002-0424, updated February 7, 2008]. Capital contribution might be required from customers and such financial obligation will be determined using methodology set out in the Transmission System Code.

7.4 Step-Down Transformation Capacity

7.4.1 Hydro One Distribution

The RIP load forecast in conjunction with more recent requests for step-down transformation capacity by Hydro One Distribution at Douglas Point TS indicates that additional step-down transformation capacity is needed.

Current Status

Hydro One Distribution is currently working with its customer to determine their connection capacity requirements, size and timeline. Once the customer's requirements are firm, one of the three "need" scenarios outlined in section 6.4 of this report will be undertaken.

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. There is currently no major line sustainment *projects* planned within the next 5 years. 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	General Description of Work	Planning In
Bruce A TS	• Replacement of 230 kV circuit breakers • Uprating of the station strain buses • Replacement of Protections and Control relay building	2019
	• Replacement of 500 kV circuit breakers and switches • Replacement of 2 autotransformers 500/230 kV • Upgrading of Protection and Control equipment	2025
Bruce B SS	• Replacement of 500 kV circuit breakers and switches	2021

[2] Scope and dates as of July 2017 and are subject to change

Centralia TS	• Replace existing 3 transformers with a typical 25/42 MVA 2 transformer arrangement • Replacement of 27.6 kV switchyard • Installation of new PCT Facilities	2019
Detweiler TS	• Replacement of AC and DC station service	2018
	• Replacement of T2 and T4 autotransformers and upgrade to spill containment • Replacement Protection and Control equipment	2021
Hanover TS	• Replacement of T1/T2 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems and CVT's *Additional scope of work currently under development*	2023
Palmerston TS	• Replace existing 3 transformers with a typical 50/83 MVA 2 transformer arrangement. • Replacement of low voltage switches • Replacement of Protection and Control systems with new PCT facilities • Upgrade to AC & DC station services	2019
Seaforth TS	• Replacement of 2 autotransformers 230/115 kV • Replacement of 2 step-down transformers 115/27.6 kV • Replacement of 230kV switches • Upgrade Protection and Control systems • Updated AC & DC station service	2023
Wingham TS	• Complete station refurbishment *Additional scope of work currently under development*	2022

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 GREATER BRUCE-HURON REGION.

Five near and mid-term needs were identified for the Greater Bruce-Huron Region. They are:

I. Transmission Circuit Capacity on L7S

II. Low power factor at Wingham TS

III. Low power factor at Bruce HWB TS

IV. Customer delivery point performance review on the 115 kV system

V. Step-down transformation capacity at Douglas Point TS

This RIP report addresses all five of these needs and has concluded that no regional plans for needs I, II and III are required at this time. Next Steps, Lead Responsibility, and Timeframes for implementing the regional plans needs IV and V 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	Improve 3L7S Delivery Point Performance	2 Stage Plan	Hydro One Transmission	2017-2023	$154k - TBD	IV
2	Accommodation for Connection Capacity Requests near Kincardine– Hydro One Network Inc. Distribution	Await Customer Direction	Hydro One Distribution	TBD	TBD	V

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, Greater Bruce-Huron Region", 6 May 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf

[2] Hydro One, "Local Planning Report – Low Power Factor at Wingham TS Assessment", 18 October 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Local%20Planning%20Report%20-%20Wingham%20TS%20Power%20Factor%20Assessment.pdf

[3] Hydro One, "Local Planning Report – L7S Thermal Overload", 14 November 2016. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Local%20Planning%20Report%20-%20L7S%20Thermal%20Overload.pdf

[4] Hydro One, "Local Planning Report – Low TS Power Factor at Bruce heavy Water B TS Assessment", 12 May 2017. http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Bruce%20HWB%20TS%20Power%20Factor%20Assessment%20-%20FINAL.PDF

APPENDIX A: STEP-DOWN TRANSFORMER STATIONS IN THE GREATER BRUCE-HURON REGION

Station	Voltage (kV)	Supply Circuits
Bruce HWP B TS	230 kV	B20P/B24P
Douglas Point TS	230 kV	B20P/B24P
Hanover TS	115 kV	B4V/B5V
Owen Sound TS	230 kV	B27S/B28S
Seaforth TS	115 kV	B22D/B23D
Stratford TS	230 kV	B22D/B23D
Wingham TS	230 kV	B22D/B23D
Festival MTS #1	230 kV	B22D/B23D
Palmerston TS	115 kV	D10H
Goderich TS	115 kV	61M18
Constance DS	115 kV	61M18
St. Marys TS	115 kV	L7S
Customer CTS #1	115 kV	L7S
Centralia TS	115 kV	L7S
Grand Bend East DS	115 kV	L7S
Customer CTS #2	115 kV	L7S
Customer CTS #3	115 kV	L7S
Customer CTS #4	115 kV	L7S

APPENDIX B: REGIONAL TRANSMISSION CIRCUITS IN THE GREATER BRUCE-HURON REGION

Location	Circuit Designation	Voltage (kV)
Bruce A TS - Orangeville TS	B4V/B5V	230 kV
Bruce A TS - Detweiler TS	B22D/ B23D	230 kV
Bruce A TS - Owen Sound TS	B27S/B28S	230 kV
Bruce A TS - Douglas Point TS	B20P/B24P	230 kV
Hanover TS – Palmerston TS	D10H-North	115 kV
Seaforth TS - Goderich TS	61M18	115 kV
Seaforth TS - St. Marys TS	L7S	115 kV
Owen Sound TS – Hanover TS	S1H	115 kV

APPENDIX C: DISTRIBUTORS IN THE GREATER BRUCE-HURON REGION

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc.	Constance	Tx
	Centralia TS	Dx
	Grand Bend East DS	Tx
	Douglas Point TS	Dx
	Goderich TS	Dx
	Hanover TS	Dx
	Owen Sound TS	Dx
	Palmerston TS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Wingham TS	Dx
Erie Thames Power Lines Corporation	Constance DS	Dx
Festival Hydro Inc.	Grand Bend East DS	Dx
	Seaforth TS	Dx
	Stratford TS	Dx
	Festival MTS #1	Tx
Lake Huron Primary Water Supply System	Lake Huron WTP CTS	Tx
Lake Huron Primary Water Supply System	McGillivray R&BP CTS	Tx
West Coast Huron Energy Inc.	Goderich TS	Tx
Enbridge Pipeline Inc.	Enbridge Bryanston CTS	Tx
St. Marys Cement Inc.	St. Marys Cement CTS	Tx

APPENDIX D: REGIONAL LOAD FORECAST (2016-2025)

Table D-1: Gross – Winter Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.87	33.40	33.77	34.25	34.87	35.48	35.93	36.36	36.77	37.19
Constance DS	17.68	17.76	17.79	17.87	18.01	18.16	18.26	18.35	18.46	18.57
Douglas Point TS*	73.44	74.42	83.75	92.21	93.41	94.66	95.80	96.95	98.14	99.39
Customer CTS #1	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.41	19.55	19.70	19.85	20.00	20.15	20.30	20.45	20.60	20.76
Goderich TS	36.35	36.50	36.59	36.73	36.92	37.11	37.25	37.37	37.49	37.61
Grand Bend East DS	14.22	14.36	14.43	14.55	14.72	14.89	15.00	15.09	15.19	15.28
Hanover TS	102.37	103.16	103.93	104.95	105.99	107.05	107.73	108.39	109.06	109.72
Customer CTS #2	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	61.92	62.92	63.88	65.12	66.22	67.44	68.42	69.41	70.41	71.40
Seaforth TS*	33.44	33.65	37.25	33.62	33.87	34.12	34.28	34.44	34.59	34.74
Customer CTS #4	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.64
St. Marys TS	23.74	25.04	25.17	25.31	25.50	25.69	25.84	25.98	26.12	26.25
Stratford TS*	80.14	80.81	81.39	85.46	86.20	86.93	87.56	88.18	88.79	89.41
Wingham TS	48.99	49.80	50.44	51.23	52.24	53.24	54.07	54.89	55.74	56.62
Bruce HWB TS	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

*Updated March 2017 for RIP

Table D-2: Gross – Summer Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.42	32.73	33.15	33.78	34.40	34.83	35.24	35.65	36.05	36.45
Constance DS	15.56	15.57	15.63	15.76	15.90	15.98	16.07	16.16	16.26	16.36
Douglas Point TS*	47.40	47.40	63.29	63.76	64.26	64.64	65.03	65.41	65.78	66.18
Customer CTS #1	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	25.03	25.22	25.41	25.60	25.79	25.98	26.18	26.37	26.57	26.77
Goderich TS	39.08	39.15	39.27	39.48	39.68	39.81	39.93	40.06	40.18	40.31
Grand Bend East DS	16.44	16.50	16.62	16.84	17.05	17.17	17.29	17.39	17.50	17.61
Hanover TS	76.71	76.94	77.62	78.60	79.25	79.71	80.12	80.53	80.93	81.32
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	97.58	98.48	99.75	101.70	103.59	104.89	106.11	107.31	108.48	109.63
Palmerston TS	53.07	53.79	54.90	56.36	57.68	58.81	59.97	61.19	62.43	63.75
Seaforth TS*	30.68	34.34	30.56	30.78	30.99	31.14	31.27	30.78	31.54	31.67
Customer CTS #4	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.31	25.42	25.57	25.75	25.94	26.09	26.24	26.38	26.52	26.66
Stratford TS*	78.09	78.59	82.38	83.14	83.91	84.52	85.11	85.70	86.29	86.88
Wingham TS	37.99	38.11	38.36	38.87	39.37	39.67	39.97	40.26	40.54	40.83
Bruce HWB TS	5.14	5.24	5.34	5.44	5.54	5.64	5.74	5.84	5.93	6.03

*Updated March 2017 for RIP

Table D-3: Gross – Winter Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	34.15	34.70	35.08	35.59	36.23	36.87	37.33	37.77	38.21	38.63
Constance DS	19.42	19.51	19.54	19.63	19.79	19.95	20.06	20.17	20.28	20.40
Douglas Point TS*	73.44	74.42	83.75	92.21	93.41	94.66	95.80	96.95	98.14	99.39
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	25.47	25.66	25.85	26.05	26.24	26.44	26.64	26.84	27.04	27.24
Goderich TS	41.61	41.78	41.88	42.04	42.26	42.48	42.63	42.77	42.91	43.05
Grand Bend East DS	14.75	14.89	14.97	15.09	15.27	15.45	15.56	15.66	15.75	15.85
Hanover TS	96.65**	97.40	98.12	99.09	100.07	101.06	101.71	102.33	102.97	103.58
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	68.03**	69.12	70.18	71.54	72.76	74.10	75.17	76.26	77.36	78.45
Seaforth TS*	34.75	34.96	38.70	34.92	35.19	35.44	35.62	35.78	35.93	36.09
Customer CTS #4	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	25.13	26.50	26.64	26.79	26.99	27.19	27.35	27.50	27.64	27.78
Stratford TS*	84.52	85.23	85.84	90.13	90.91	91.69	92.36	93.00	93.65	94.30
Wingham TS	57.98	58.94	59.70	60.63	61.82	63.01	63.98	64.96	65.96	67.00
Bruce HWB TS	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Updated March 2017 for RIP

**Load Transfer from Hanover TS to Palmerston TS

Table D-4: Gross – Summer Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	34.23	34.56	35.01	35.67	36.32	36.78	37.22	37.64	38.07	38.49
Constance DS	17.78	17.79	17.86	18.01	18.17	18.27	18.36	18.47	18.58	18.70
Douglas Point TS*	48.06	48.06	64.17	64.65	65.15	65.54	65.93	66.32	66.69	67.10
Customer CTS #1	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	28.11	28.32	28.53	28.74	28.96	29.18	29.39	29.61	29.84	30.06
Goderich TS	40.71	40.78	40.91	41.12	41.33	41.46	41.59	41.72	41.85	41.98
Grand Bend East DS	18.88	18.95	19.09	19.34	19.58	19.72	19.85	19.98	20.10	20.22
Hanover TS	75.61**	75.84	76.50	77.47	78.12	78.57	78.97	79.37	79.77	80.15
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	101.31	102.25	103.57	105.59	107.55	108.90	110.17	111.41	112.63	113.82
Palmerston TS	54.71**	55.45	56.60	58.10	59.46	60.63	61.82	63.07	64.36	65.72
Seaforth TS*	31.00	34.70	30.87	31.10	31.31	31.46	31.59	31.10	31.86	31.99
Customer CTS #4	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	26.05	26.17	26.31	26.51	26.70	26.86	27.01	27.16	27.30	27.44
Stratford TS*	88.42	88.99	93.28	94.15	95.01	95.70	96.38	97.05	97.71	98.37
Wingham TS	54.05	54.21	54.58	55.29	56.00	56.43	56.86	57.27	57.67	58.08
Bruce HWB TS	6.54	6.66	6.79	6.91	7.04	7.16	7.29	7.42	7.54	7.67

*Updated March 2017 for RIP

**Load Transfer from Hanover TS to Palmerston TS

Table D-5: Net – Winter Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.65	32.92	32.96	33.16	33.52	33.90	34.16	34.45	34.69	34.94
Constance DS	17.57	17.55	17.41	17.35	17.36	17.40	17.41	17.44	17.46	17.50
Douglas Point TS*	72.99	73.55	81.97	89.53	90.03	90.70	91.34	92.11	92.84	93.64
Customer CTS #1	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.29	19.33	19.29	19.27	19.28	19.31	19.36	19.43	19.49	19.56
Goderich TS	36.12	36.07	35.81	35.65	35.58	35.55	35.50	35.49	35.45	35.43
Grand Bend East DS	14.13	14.19	14.13	14.13	14.19	14.27	14.30	14.34	14.37	14.39
Hanover TS	101.72	101.94	101.69	101.76	102.01	102.42	102.56	102.84	103.02	103.23
Customer CTS #2	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	61.53	62.17	62.50	63.20	63.80	64.60	65.20	65.92	66.58	67.25
Seaforth TS*	33.24	33.26	36.45	32.63	32.64	32.68	32.68	32.72	32.71	32.72
Customer CTS #4	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.65
St. Marys TS	23.59	24.75	24.63	24.57	24.58	24.61	24.63	24.68	24.70	24.73
Stratford TS*	79.65	79.87	79.65	82.97	83.08	83.29	83.48	83.78	83.99	84.23
Wingham TS	48.70	49.23	49.38	49.75	50.36	51.02	51.55	52.16	52.73	53.35
Bruce HWB TS	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

*Updated March 2017 for RIP

Table D-6: Net – Summer Regional-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.04	31.57	31.62	31.89	32.20	32.42	32.61	32.85	33.05	33.25
Constance DS	15.45	15.35	15.23	15.20	15.20	15.19	15.18	15.20	15.22	15.24
Douglas Point TS*	47.00	46.67	61.64	61.45	61.39	61.39	61.38	61.49	61.50	61.58
Customer CTS #1	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.85	24.86	24.77	24.69	24.66	24.70	24.74	24.82	24.87	24.93
Goderich TS	38.70	38.50	38.18	37.98	37.84	37.74	37.63	37.59	37.50	37.43
Grand Bend East DS	16.32	16.27	16.20	16.24	16.31	16.33	16.33	16.37	16.38	16.40
Hanover TS	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.71	96.49	96.54	97.40	98.36	99.01	99.56	100.27	100.83	101.40
Palmerston TS	52.48	52.81	53.30	54.15	54.94	55.69	56.45	57.35	58.21	59.16
Seaforth TS*	30.39	33.79	29.72	29.62	29.57	29.53	29.48	28.89	29.45	29.42
Customer CTS #4	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.07	25.01	24.87	24.79	24.76	24.75	24.74	24.77	24.77	24.78
Stratford TS*	77.42	77.37	80.20	80.09	80.13	80.23	80.31	80.53	80.65	80.80
Wingham TS	37.72	37.57	37.40	37.49	37.65	37.71	37.76	37.88	37.94	38.03
Bruce HWB TS	5.06	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12

*Updated March 2017 for RIP

Table D-7: Net – Winter Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.93	34.20	34.24	34.46	34.82	35.23	35.50	35.79	36.05	36.31
Constance DS	18.62	18.61	18.45	18.39	18.40	18.44	18.45	18.48	18.51	18.55
Douglas Point TS*	72.99	73.55	81.97	89.53	90.03	90.70	91.34	92.11	92.84	93.64
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.83	23.87	23.82	23.80	23.81	23.84	23.90	24.00	24.07	24.16
Goderich TS	40.85	40.79	40.49	40.32	40.23	40.20	40.15	40.14	40.09	40.06
Grand Bend East DS	14.66	14.72	14.65	14.65	14.72	14.81	14.84	14.88	14.90	14.93
Hanover TS	102.77*	102.99	102.75	102.81	103.07	103.48	103.63	103.90	104.09	104.30
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	62.06*	62.70	63.04	63.75	64.36	65.15	65.77	66.49	67.16	67.83
Seaforth TS*	33.66	33.68	36.92	33.05	33.05	33.10	33.09	33.13	33.13	33.14
Customer CTS #4	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.97	26.19	26.07	26.01	26.01	26.04	26.07	26.12	26.14	26.17
Stratford TS*	83.99	84.23	84.00	87.49	87.61	87.83	88.03	88.34	88.57	88.83
Wingham TS	57.64	58.26	58.44	58.87	59.59	60.38	61.01	61.73	62.41	63.14
Bruce HWB TS	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Updated March 2017 for RIP

Table D-8: Net – Summer Non-Coincident Peak Load Forecast

Station	Forecast (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.84	33.38	33.43	33.72	34.04	34.27	34.47	34.72	34.93	35.15
Constance DS	17.66	17.54	17.41	17.37	17.38	17.36	17.35	17.38	17.39	17.42
Douglas Point TS	47.66	47.32	62.49	62.30	62.24	62.24	62.23	62.35	62.36	62.44
Customer CTS #1	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.91	27.92	27.81	27.73	27.69	27.74	27.77	27.87	27.93	28.00
Goderich TS	39.02	38.81	38.49	38.29	38.15	38.05	37.93	37.89	37.81	37.74
Grand Bend East DS	18.75	18.68	18.61	18.65	18.73	18.75	18.76	18.80	18.81	18.83
Hanover TS	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.41	100.21	100.26	101.16	102.15	102.82	103.40	104.13	104.72	105.31
Palmerston TS	52.80	53.13	53.63	54.48	55.27	56.03	56.79	57.70	58.57	59.52
Seaforth TS	30.39	33.79	29.72	29.62	29.57	29.53	29.48	28.89	29.45	29.42
Customer CTS #4	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.81	25.74	25.60	25.52	25.49	25.48	25.47	25.50	25.50	25.50
Stratford TS	86.73	86.68	89.84	89.72	89.77	89.88	89.97	90.21	90.35	90.52
Wingham TS	50.79	50.58	50.35	50.48	50.69	50.77	50.84	51.00	51.08	51.20
Bruce HWB TS	9.83	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95

*Updated March 2017 for RIP

APPENDIX E: RIP TRANSMISSION ADEQUACY ASSESSMENT

This table assesses the impact of the updated March 2017 RIP load forecast based on the original findings of the May 2016 Needs Assessment.

Change in Load Forecast	Seaforth TS			Stratford TS			Douglas Point TS		
		Coincident MW	Non-Coincident MW		Coincident MW	Non-Coincident MW		Coincident MW	Non-Coincident MW
Red font indicates an increase in forecasted load from the Needs Assessment.	summer: 2025 Gross	31.67	31.67	summer: 2025 Gross	86.88	98.37	summer: new 2025 Gross	66.18	67.1
	summer: 2025 Net	29.42	29.42	summer: 2025 Net	80.8	90.52	summer: new 2025 Net	61.58	62.44
	summer 10 Day LTR	39.3 MW		summer 10 Day LTR	104.4 MW		summer 10 Day LTR	87.5 MVA	
Green font indicates a reduction in forecasted load from the Needs Assessment.	winter: new 2025 Gross	34.74	36.09	winter: new 2025 Gross	89.41	94.3	winter: new 2025 Gross	99.39	99.39
	winter: new 2025 Net	32.72	33.14	winter: new 2025 Net	84.23	88.83	winter: new 2025 Net	93.64	93.64
	winter 10 Day LTR	49.9 MW		winter 10 Day LTR	115.7 MW		winter 10 Day LTR	98.8 MW	

	Seaforth TS	Stratford TS	Douglas Point TS
Historical Power Factor	N/A	N/A	N/A
Load Security	no negative impact	no negative impact	no negative impact
Load Restoration	no negative impact	no negative impact	no negative impact
Voltage Performance	no negative impact	no negative impact	no negative impact
CDPP	N/A	N/A	N/A
230/115 kV Autos	no negative impact	no negative impact	no negative impact
230 kV Lines	no negative impact	no negative impact	no negative impact
115 kV Lines	no negative impact	no negative impact	no negative impact
Step down Transformation Capacity	no negative impact	Study shows that there is a slight impact but loading remains within LTR and at least one LV cap must be in-service during summer loading by the end of the study period. This is similar to the Needs Assessment results.	Study shows that the gross winter forecast loading is at the LTR in winter 2023/2024. All summer forecasts show loading is within LTR for the study period.
Bulk System Performance	no negative impact	no negative impact	no negative impact

APPENDIX F: CUSTOMER DELIVERY POINT PERFORMANCE REVIEW

Based on the recommendations from the May 2016 Needs Assessment, 15 customer delivery points were reviewed in detail to assess their reliability performance. Reliability performance of a delivery point is a measure of the frequency of interruption and duration of interruption. The yearly frequency and yearly total duration of interruptions are compared against Hydro One performance standards filed with the OEB, [EB-2002-0424, updated February 7, 2008].

All 15 delivery points are supplied solely from single circuit 115 kV transmission lines and are grouped as follows:

Table F-1 - Customer Delivery Points

Single circuit 115 kV Transmission Line	Station	# of Customer Delivery Points
61M18	Goderich TS	2
	Constance DS	1
L7S	Centralia TS	2
	Grand Bend East DS	1
	St. Mary TS	1
	Industrial Customer # 1	1
	Industrial Customer # 2	1
	Industrial Customer # 3	1
	Industrial Customer # 4	1
D10H -North	Palmerston TS	2
D10H - South	Elmira TS	2

The reliability performance of the delivery points were studied in groups based on their connection point to the transmission system, specifically their 115 kV transmission line supply as shown in Table F-1.

The review of each delivery point included a 10 year review of interruptions between years 2006 and 2015. The interruptions were compared against each delivery points "Group" metrics as defined in the OEB filing as well as each delivery points "Individual Historical Performance" as defined in the OEB filing. Where the yearly performance did not meet either the Group or Individual standards for either frequency or duration of interruptions, Hydro One Transmission classified the delivery point as an "Outlier". Based on a delivery point's Outlier status, their reliability performance is reviewed. The summary of review is given below.

F.1 Delivery Points Supplied by Transmission Line 61M18

In the past, 2006-2010, Goderich TS was classified as a Group Outlier for both frequency and duration of interruption. Recently it is classified as a Group Outlier for duration only. These classifications are mainly due to past equipment failures at Seaforth TS and recently as a consequence of line 61M18 tied to line L7S while L7S experienced interruptions.

Constance DS is not classified as a Group Outlier; however it is occasionally classified as an Individual Outlier for duration of interruption. Although Constance DS is subject to the same line 61M18 interruptions as Goderich TS, it is typically not classified as a Group Outlier because it has less stringent performance metrics due to the smaller amount of load (MW) supplied from it.

The review showed that the root cause of interruptions is due to the performance of the transmission line 61M18 during adverse weather. When 61M18 is interrupted, all load connected to Constance DS and Goderich TS is left unsupplied. As line 61M18 is radial, there are not many options to resupply the load prior to repairing the line. Often building a temporary bypass can take longer than fixing the damaged equipment and the ability to transfer the load to other stations is limited due to the sparse topology of customer distribution systems. Overall, customers supplied from Constance DS and Goderich TS have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance compared to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line’s susceptibility to faults caused by external forces such as lightning and storms.

As upgrading the transmission supply to these stations is not economical for neither the customers nor Hydro One Transmission based on the OEB-approved funding rules for customer delivery point reliability improvement, it is recommended for Hydro One Transmission to continue to rely on its Line and Station maintenance and capital sustainment projects to improve the overall reliability performance to delivery points. Based on customer consultations, Goderich Hydro - West Coast Huron Energy Inc., Erie Thames Power and Hydro One Distribution have agreed to this approach and will continue to monitor performance.

F.2 Delivery Points Supplied by Transmission Line L7S

Centralia TS is classified as a Group Outlier for both frequency and duration of interruption. Recently in 2013 and 2014 is has also been classified as an Individual Outlier for duration of interruption.

Grand Bend East DS is classified as a Group Outlier for both frequency (occasionally) and duration (consistently) of interruption, as well as an Individual Outlier for duration.

All four industrial customer delivery points are occasionally classified at a Group Outlier for frequency of interruption; while one of them often is classified as a Group Outlier for duration of interruption. Over the past 3 years, the industrial customer delivery points have often been classified as Individual Outliers for duration.

The review showed that the root cause of interruptions is due to the performance of the transmission line L7S during adverse weather. When L7S is interrupted, all load connected to it is left unsupplied. As line L7S is radial, there are not many options to resupply the load prior to repairing the line. Often building a temporary bypass can take longer than fixing the damaged equipment and the ability to transfer the load to other stations is limited due to the sparse topology of customer distribution systems. Depending on prevailing system conditions, manual switching on the transmission system can be performed to resupply some L7S load from Detweiler TS via 115 kV circuit D8S. Overall, customers supplied from L7S have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance compared to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line's susceptibility to faults caused by external forces such as lightning and storms.

Due to the Individual Outlier classification of delivery points supplied from L7S it is recommended that a focused line assessment is undertaken. Although major upgrades to the transmission supply is not economical for neither the customers nor Hydro One Transmission based on the OEB-approved funding rules for customer delivery point reliability improvement, it remains the recommendation for Hydro One Transmission to improve the reliability of transmission line L7S. A two stage approach is prudent. Stage 1 will entail a detailed field screening of the line for approximately $154 k in 2017. Based on findings from the field screening, work to reduce the frequency of interruptions due to adverse weather should be implemented in 2018 and 2019. Cost for improvements is unknown at this time as it is dependent on actual findings. Performance will then be monitored for 2-3 years to verify improvement. It is expected that reduction to the frequency of interruptions will reduce the total duration of interruptions. Stage 2 will be based on the monitored performance and may entail strategically installing 115 kV in-line remotely-operated switches to reduce the duration of interruptions. Switches are currently estimated to cost between $1M to $4M depending on the number of switches and their location.

Based on customer consultations, Festival Hydro, Hydro One Distribution and the industrial customers have agreed to this approach.

F.3 Delivery Points Supplied by Transmission Line D10H

115 kV circuit D10H between Detweiler TS and Hanover TS is operated normally-open at Palmerston TS whereby Palmerston TS is normally supplied from Hanover TS (D10H-North) while Elmira TS is normally supplied from Detweiler TS (D01H – South).

Over the past 3 years, Palmerston TS has been classified as a Group Outlier for both frequency and duration of interruption. It has not been classified as an Individual Outlier over the 10 year review period.

Over the past 3 years, Elmira TS has been classified as a Group Outlier for both frequency and duration of interruption. It has been classified as an Individual Outlier once in the 10 year review period; specifically in 2013 for frequency of interruption.

The review showed that the root cause of interruptions is due to the performance of the transmission lines D10H-North and D10H-South during adverse weather. When D10H-North is interrupted, all load connected to Palmerston TS is left unsupplied. When D10H-South is interrupted, all load connected to Elmira TS is left unsupplied. Since there are several 115 kV in-line switches along D10H and depending on prevailing system conditions, circuit D10H can be reconfigured to supply Palmerston TS and Elmira TS from either the Hanover TS or Detweiler TS ends. 115 kV in-line switches at Palmerston TS have the capability to be operated remotely. There are two other manual-operated switches surrounding the tap to Elmira TS.

Overall, customers supplied from Palmerston TS and Elmira TS have similar delivery point performance compared to other customers supplied by a single radial circuit and poor delivery point performance comparable to other customers supplied by dual circuits. Additionally, a technical review concluded that the transmission line is performing as originally designed with respect to line design security parameters which correspond to a line's susceptibility to faults caused by external forces such as lightning and storms.

Consultations with customers supplied from D10H are expected to be undertaken in 2017. Additional assessment and/or infrastructure to adhere to the OEB-approved funding rules for customer delivery point reliability improvements. Improvements may entail installing 115 kV in-line remotely operated switches for approximately $1.5M.

APPENDIX G: 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

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Niagara

Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Alectra Utilities
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

The Niagara Region includes 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.

The Needs Assessment ("NA") report for the Niagara Region was completed on April 30th, 2016 (see attached). The report concluded that there were only two needs in the Region and that they should be addressed as follows:

- Thermal overloading of 115kV circuit Q4N: Addressed in a Local Plan ("LP") report.

The loading constraints on 115kV circuit Q4N was addressed in a LP report led by Hydro One Networks Inc. and published on November 11th, 2016. The report concluded that Hydro One already has plans to replace the existing section of conductor between Sir Adam Beck SS #1 and Portal JCT with a 910A continuous rating conductor at 93°C as part of their Beck #1 SS Refurbishment project. The expected in-service date for this conduction section upgrade is December 2019.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the Niagara Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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 Needs Assessment 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 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"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

Region	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Niagara Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings

The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.

B. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

System Reliability, Operation and Restoration Review

There are no known issues with system reliability, operation and restoration in the Niagara region.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Niagara Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Niagara Region 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. A map of the region is shown below in Figure 1.

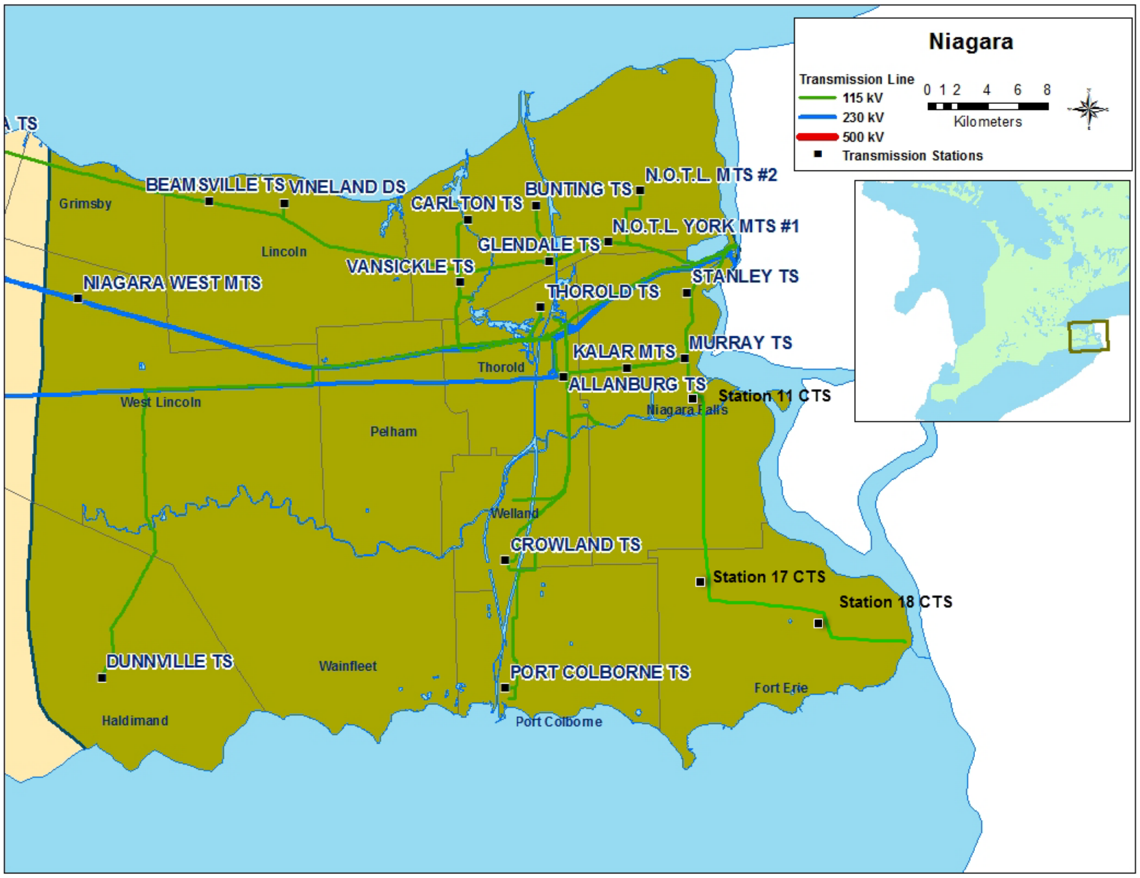

Figure 1: Niagara Region Map

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 autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

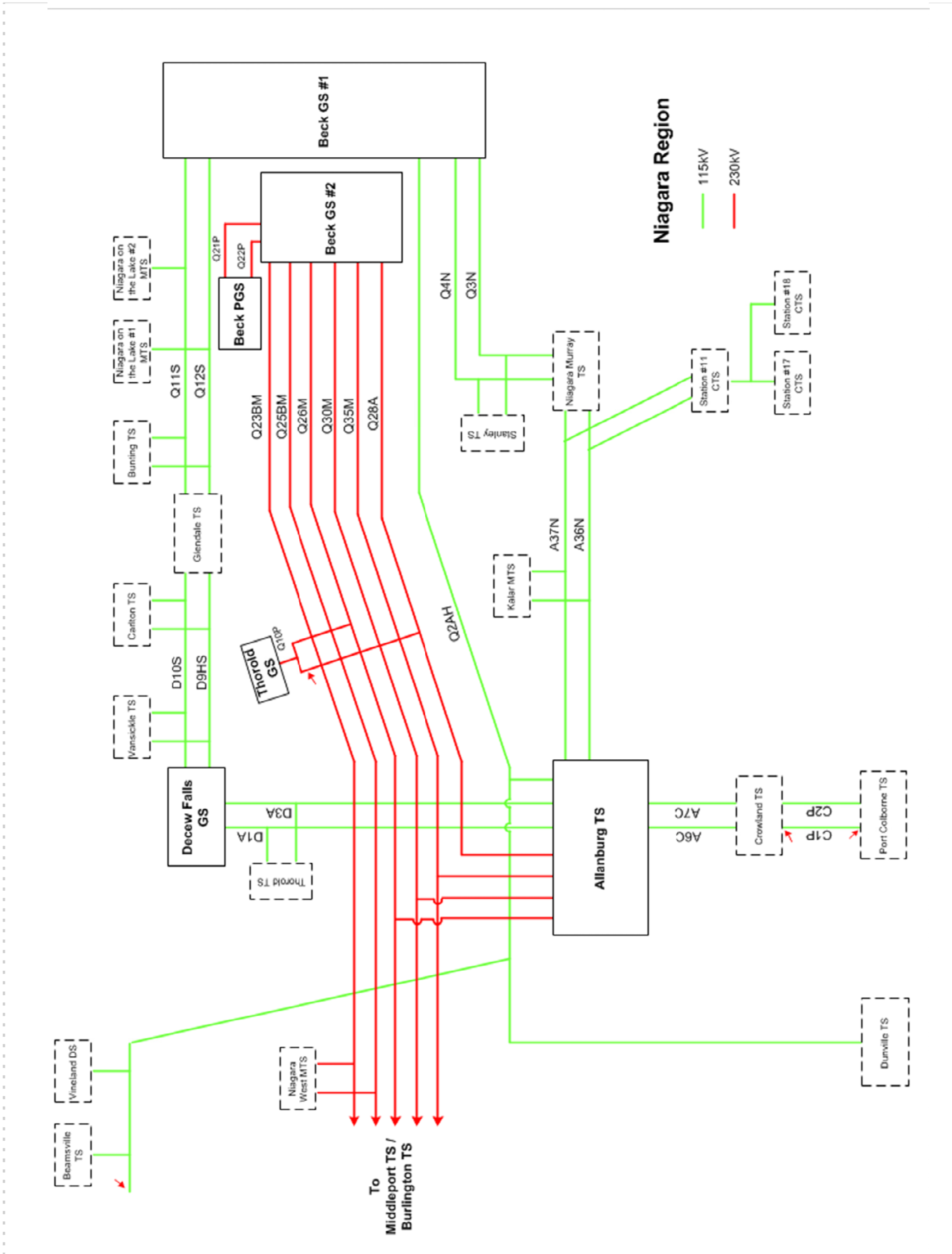

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

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

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed 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 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.

- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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LOCAL PLANNING REPORT

Q4N THERMAL OVERLOAD

Region: Niagara

Revision: Final
Date: November 11th 2016

Prepared by: Niagara Region Study Team

Niagara Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Niagara Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Niagara Region ("Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	16 May 2016	**END DATE**	1 November 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to develop and recommend a preferred wires solution that will address the local needs identified in the Needs Assessment (NA) report for the Niagara Region. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group ("PPWG") Report to the Ontario Energy Board's ("OEB") and mandated by the Transmission System Code ("TSC") and Distribution System Code ("DSC").

2. LOCAL NEEDS REVIEWED IN THIS REPORT

This report reviewed the potential thermal rating violation for the Beck SS #1 x Portal Junction section of the 115kV Q4N circuit (egress out from Sir Adam Beck GS #1).

3. OPTIONS CONSIDERED

The following options were considered:

- Option 1: Status Quo
- Option 2: Uprate Circuit Section

4. PREFERRED SOLUTIONS

Option 2 is the preferred option. The uprating of limiting section of the circuit is included in Hydro One's Sustainment plan.

5. RECOMMENDATIONS

It is recommended that the circuit section upgrade proceed with current with an expected in-service date of December 2019.

TABLE OF CONTENTS

LIST OF FIGURES

1 Introduction

The Needs Assessment (NA) for the Niagara Region ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA for the Niagara Region was prepared jointly by the study team, including LDCs, Independent Electric System Operator (IESO) and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Region over the next ten years (2015 to 2024) and recommended that they should be further assessed through the transmitter-led Local Planning (LP) process.

As part of the NA report for the Niagara Region, it identified that under high generation scenarios at Sir Adam Beck GS #1, the loading on the Beck SS #1 x Portal Junction section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings in IESO's System Impact Assessment for the Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz

This Local Planning report was prepared by Hydro One Networks Inc. ("HONI"). This report captures the results of the assessment based on information provided by LDCs and HONI.

2 Regional Description and Circuit Q4N Description

Sir Adam Beck GS #1 is an 115kV hydroelectric generating station located on the Niagara Escarpment north of Niagara Falls in Queenston. Geographically, it roughly borders Highway 405 and the Canadian-American border via the Niagara River.

Electrical supply from Sir Adam Beck GS #1 is currently provided through eight (8) OPG generators connected to Hydro One's 115kV solid 'E' bus inside the station. Supply to the local 115kV area is delivered via five (5) Hydro One circuits (Q2AH, Q3N, Q4N, Q11S, Q12S) from 115kV 'E' bus within the power house. The 115 kV 'E' bus serves as a switching station for the Hydro One network as well as a connection facility for OPGI's generators. The generators, transformers and circuits on the 'E' bus are sectionalized via switches.

A single line diagram is shown of the 115 kV system originating from the 115kV Sir Adam Beck GS #1 in Figure 1.

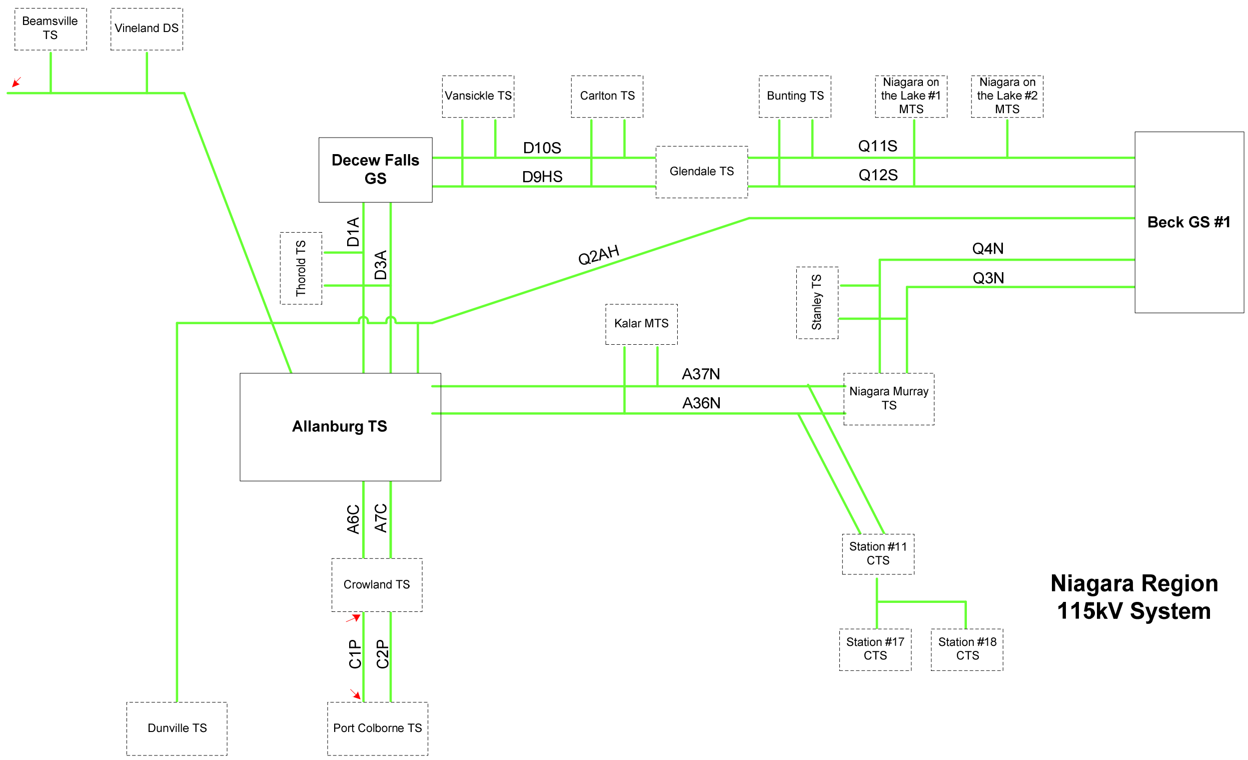

Figure 1: Single Line Diagram – Niagara Region 115kV System

From the NA report for the Niagara Region, a possible thermal limit issue on a section of the circuit Q4N was identified. Q4N is an approximately 9 km long, 115kV radial circuit from Sir Adam Beck GS #1, supplying Stanley TS and Niagara Murray TS.

The section of Q4N identified in the NA comprises of the section from Sir Adam Beck GS #1 to Portal Junction. This section of circuit is shown in Figure 2.

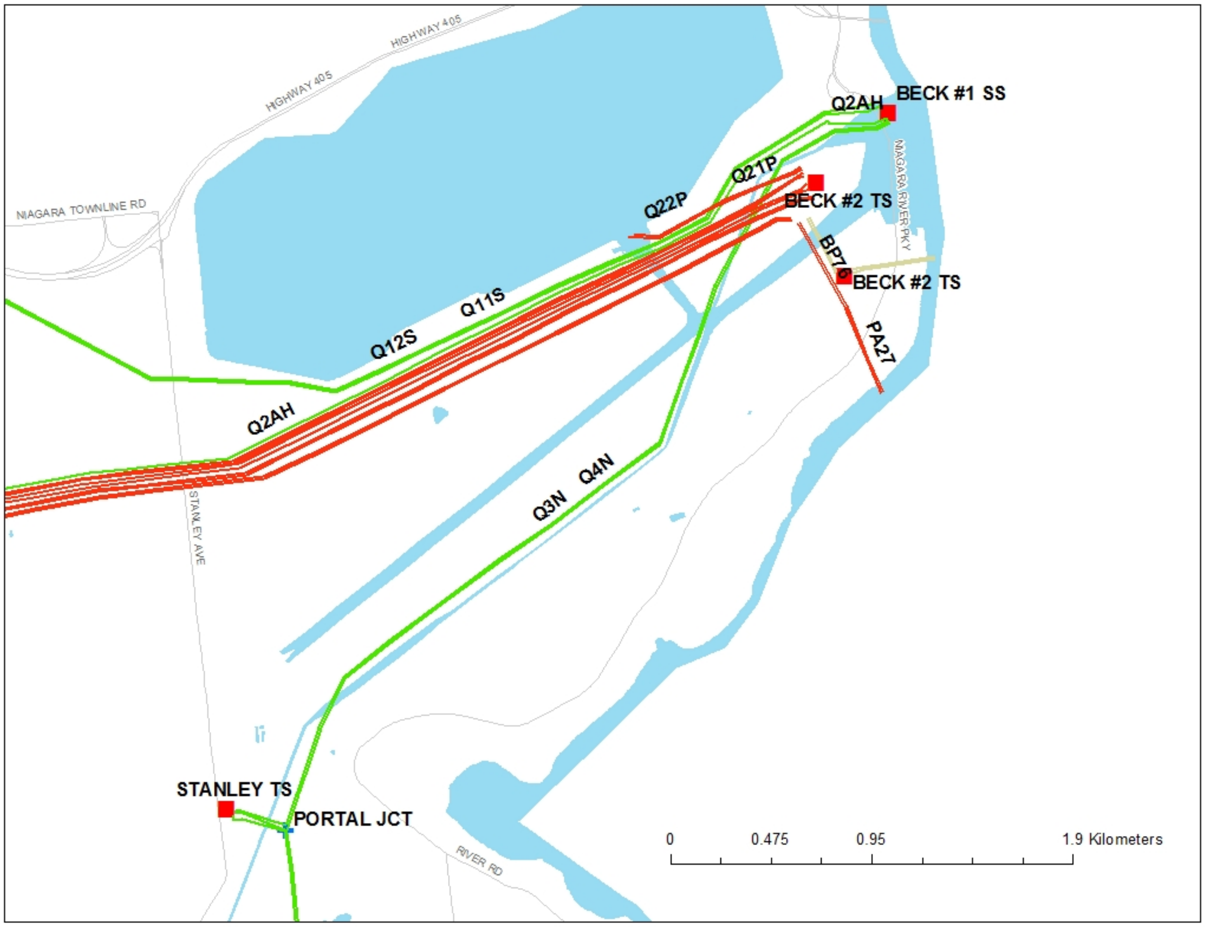

Figure 2: Single Line Diagram – Q4N from Beck #1 SS to Portal Junction

3 Local Niagara Need (Q4N)

In the past decade, OPG has been steadily increasing the power output of their generators with station upgrades.

In the IESO SIA for "Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz" it was identified that the thermal loading on circuit section Q4N from Beck #1 SS to Portal junction exceeds its continuous rating by 109.6% at total generation output of Sir Adam Beck #1 GS. This study was based on 2018 summer peak demand with high generation dispatch in the 115 kV transmission system in the vicinity with the existing 8 generators and 2 future generators (G1 and G2) at full output. This thermal loading is based on an ambient 35ºC temperature condition with 4 km/hr wind speed during daytime.

Reducing the generation output of Sir Adam Beck #1 GS from its maximum capacity of 556 MW to 509 MW reduces the loading on Q4N (Beck #1 SS by Portal Junction) to below its continuous rating.

4 Study Result / Options Considered

The conductor on a 64m section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. is comprised of 605.0 kcmil aluminum, 54/7 ACSR. The continuous rating for this type of conductor at 93^{o}C is 680A. The options considered are outlined below.

4.1 Option 1: Status Quo

Status Quo is not an option because there is a risk that for maximum generation dispatch in extreme weather conditions. Under these conditions generation would have to be curtailed to meet line thermal rating requirements and thus causing financial losses to customer.

4.2 Option 2: Uprate Conductor Section

Hydro One has plans already in place to replace the existing section of conductor with a 910A continuous rated conductor at 93^{o}C as part of their Beck #1 SS Refurbishment project. This will enable this section of circuit to meet all pre and post contingency thermal limits during max generation and under extreme weather conditions.

5 Recommendations

It is recommended that Hydro One continues with their sustainment plans (Option 2) on replacing the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. with a larger ampacity conductor (increase of 680A to 910A).

The expected in-service date for this conduction section upgrade is December 2019.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iii) Needs Assessment Report Niagara Region

Appendix A: Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One, NPEI - Embedded	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One & NPEI, Grimsby Power, NPEI - Embedded	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro & Hydro One, CNPI - Embedded	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Hydro One	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One & NPEI	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power, NPEI Embedded	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland DS	Net Load Forecast	17.4	17.0	17.0										
Hydro One, NPEI - Embedded	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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North/East of Sudbury

Regional Infrastructure Plan ("RIP")

April 13, 2017

Northern Ontario Wires Inc.
Hearst Power Ltd.
North Bay Hydro Distribution Ltd.
Hydro One Networks Inc. (Distribution)

North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.

The Local Planning ("LP") report for the North/East of Sudbury Region was completed on August 8, 2016 (see attached), and identified the following needs in the region:

- Timmins TS/Kirkland Lake TS – Voltage Regulation Issues:

In the LP report, the study team acknowledged that the Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. Operating measures are established to control the voltage decline post contingency, and the study team concluded no action is currently required. Hydro One will continue to monitor Timmins area load growth to ensure operating measures outlined in the LP report continue to be effective for voltage regulations.

The LP also report concluded that corrective actions to control voltage violations on the system may be required for any new loads in the Kirkland Lake or Dymond area.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the North/East of Sudbury Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
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Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

Timmins / Kirkland Lake Voltage Regulation
Region: North & East of Sudbury

Revision: FINAL
Date: August 8, 2016

Prepared by: Hydro One Networks Inc (Transmission & Distribution)

Study Team

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	May 9, 2016	**END DATE**	November 30, 2016

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only option and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region dated April 15, 2016. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 7 of the NA report, the study team recommended that no further coordinated regional planning is required to address the needs in the North & East of Sudbury region. These needs are local in nature and will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDC.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Timmins and Kirkland Lake area voltage regulation are local needs addressed in this report.

3. OPTIONS CONSIDERED

Hydro One (Transmitter) and Hydro One Distribution (LDC) have considered addressing the Timmins TS voltage regulation need with the following options;
Alternative 0 – Status Quo.
Alternative 1 - Implement a Load Rejection Scheme on T61S and P7G

Hydro One (Transmitter) and Hydro One Distribution (LDC) have agreed that Alternative 0 – Status Quo is the only option to be considered for Kirkland Lake TS voltage regulation need.

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time for both the Timmins TS and Kirkland Lake TS voltage regulation needs are Alternative 0 – Status Quo. See Section 4 for details.

5. NEXT STEPS

The next steps are summarized in section 5

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1 Introduction

The Needs Assessment (NA) for the North & East of Sudbury ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address some specific station capacity needs. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the North & East of Sudbury Region over the next ten years (2016-2026) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

1.1 North & East of Sudbury Region Description and Connection Configuration

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

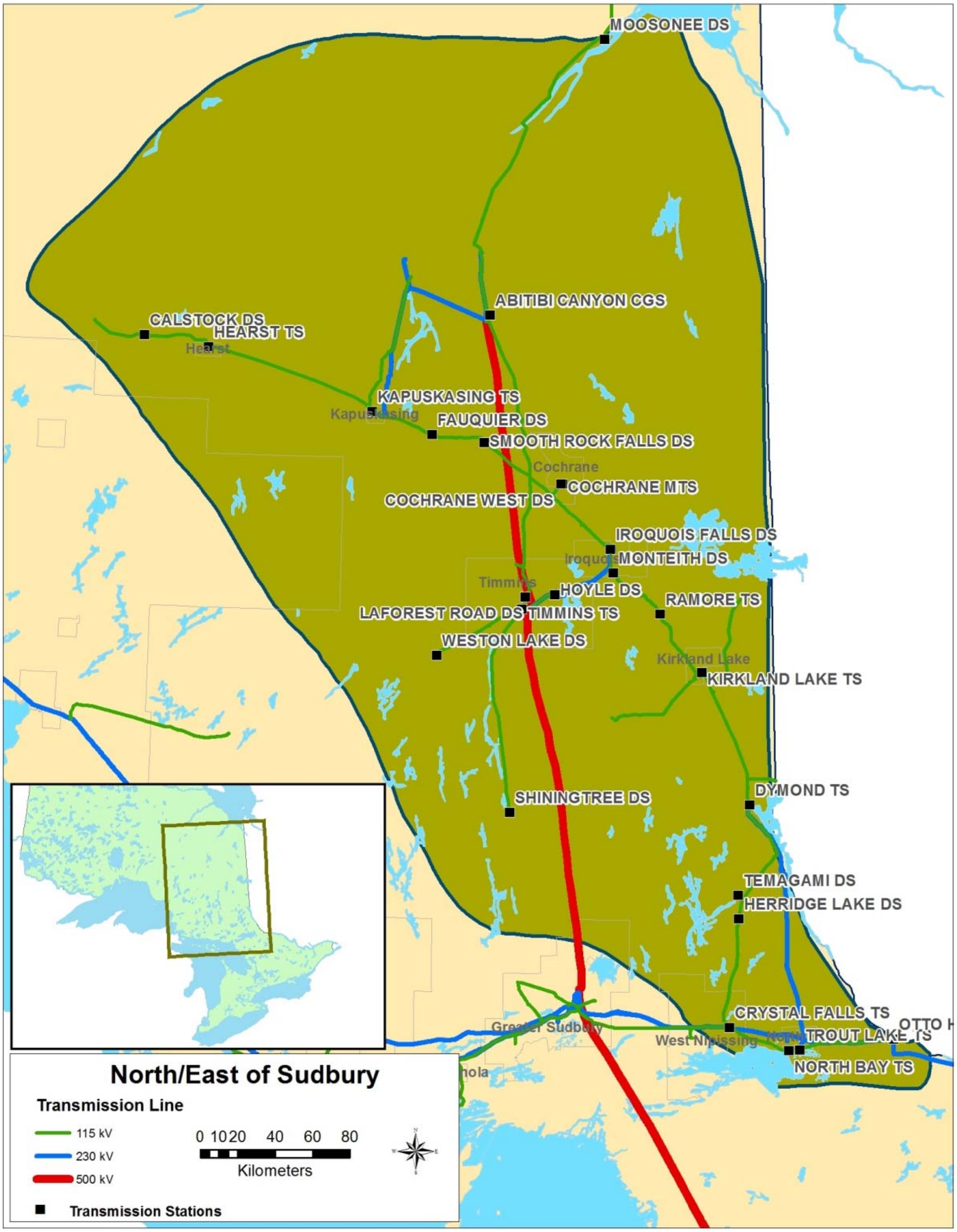

Figure 1: North & East of Sudbury Region Map

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 Pinard TS to Hanmer 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.

Table 1: Transmission Lines and Stations in North & East of Sudbury Region

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS* Timmins TS Trout Lake TS Widdifield SS

*Stations with Autotransformers installed

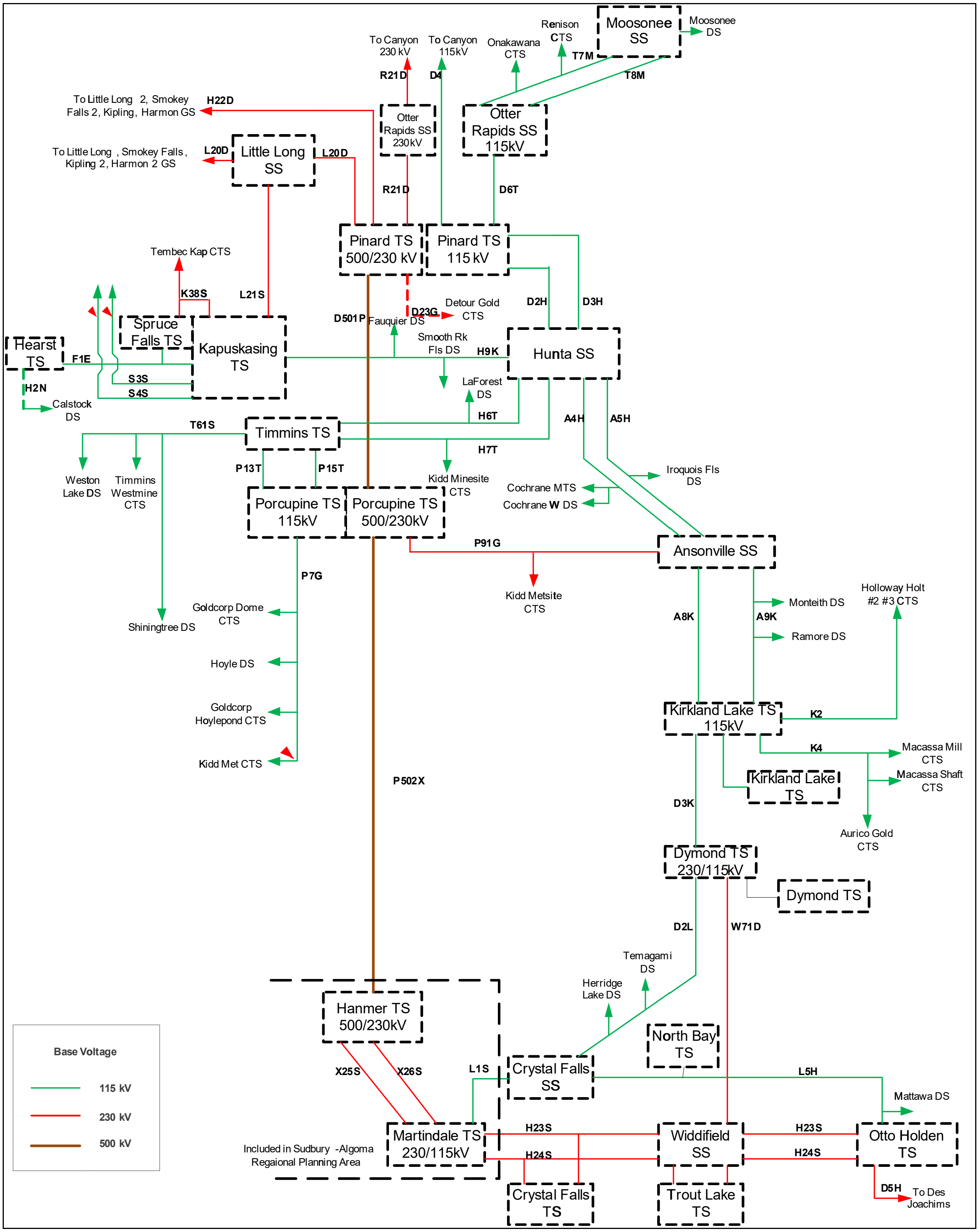

Figure 2: North and East of Sudbury Regional Planning Electrical Diagram

2 Area Needs

2.1 North & East of Sudbury Region Needs

As an outcome of the NA process, the study team identified voltage regulation issues at Timmins TS and Kirkland Lake TS which are addressed in this report. Local planning was recommended, and Hydro One as the transmitter, with the impacted LDC further undertook planning assessments to address the following needs;

- Timmins TS voltage regulation - The loss of Porcupine TS 115kV circuit breakers (K1K4 and K1K2) may result in voltage declines at Timmins TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and load rejection following the loss of the second element was proposed by IESO to improve post contingency voltage performance. See Figure 3 – Timmins area connection diagram for reference.

- Kirkland Lake TS voltage regulation - The loss of Ansonville T2 and D3K may result in voltage declines at Kirkland Lake TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and all new loads in the area will be required to participate in a local load rejection scheme to help improve post contingency voltage performance.

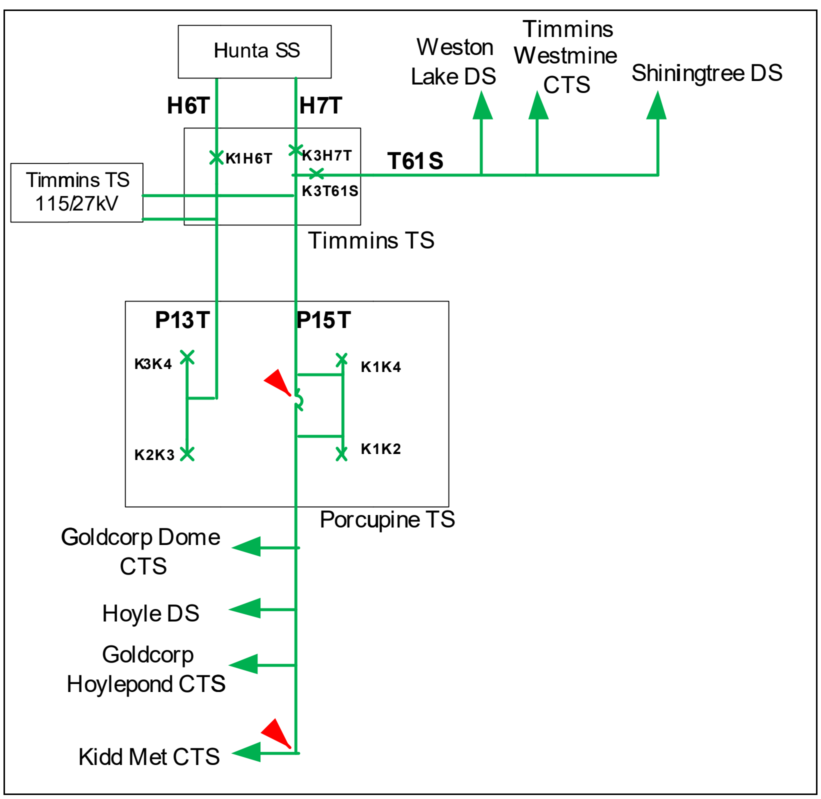

Figure 3: Timmins area connection diagram

3 Alternatives Considered

3.1 Timmins TS Voltage regulation

Alternative 1 – Status Quo.

No further action is required at this time. Hydro One and LDC will monitor the loads and voltages in the area in the upcoming years. Further review of this issue will be undertaken in the next planning cycle or earlier if there is evidence that load cannot be served or system cannot be operated in a safe, secure and reliable manner. Voltage issues can be addressed with operating procedures which are presently in place without any use of load rejection.

Alternative 2 – Implement Load Rejection on T61S, P7G, P15T to control Timmins TS voltages

This option will require expansion of the Northeast LR/GR scheme to include tripping of the Hydro One 115kV T61S, P7G, and P15T circuits upon contingency of both Porcupine TS K1K4 and K1K2 circuit breakers. This will allow for automatic load rejection of approximately 40MW of load.

Table 2: Budgetary Cost for Alternatives

Options Considered	Cost
Alternative 1 – Hydro One to assess voltage performance with no immediate investment.	--
Alternative 2 – Expand Northeast Special Protection Scheme (SPS) to include P15T, P7G, T61S circuits	$2M

3.2 Kirkland Lake TS Voltage regulation

Alternative 1 – Status Quo. See details in section 4 below.

4 Preferred Solution and Reasoning

4.1 Timmins TS Voltage regulation

Hydro One Networks and Hydro One Distribution have reviewed all alternatives and the preferred solution at this time is, Alternative 1 – Status Quo.

The study team acknowledges that Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. The possibility of this scenario is remote and there are established operating measures in place should the first Porcupine TS breaker (either K1K4 or K1K2) be placed out of service. The following control measures are taken which help alleviate the voltage decline post contingency.

- Open Timmins TS LV breaker to offload Timmins TS from P15T
- Transfer P7G load to P91G by closing breaker B5L2 at Kidd Creek Metsite and open Porcupine TS switch 30-P7G
- Place one Abitibi Canyon 115kV unit on condenser mode.

Hydro One Networks and Hydro One Distribution have agreed that these operating measures are a preferred alternative to load rejection. In addition, implementing the load rejection scheme will expose the customers in the area to unnecessary interruption due to misoperation of the load rejection scheme.

Hydro One will continue to monitor Timmins area load growth from both LDCs and industrial customers to ensure load growth (if any) does not make voltage situation worse whereby the above operating measures are no longer effective. The next planning cycle will take place within five years and an investment can be triggered at any time should there be a situation where load cannot be served or system cannot be operated safely and reliably.

4.2 Kirkland Lake TS Voltage Regulation

Hydro One Networks and Hydro One Distribution agree that new loads in the Kirkland Lake or Dymond area may be subject to participate in an under voltage load rejection scheme as part to help control voltages in the area post contingency. Presently there is no load growth in the area over the study period. Investments are not required at this time for existing LDC loads and Hydro One will monitor load growth in the area and take corrective action as required or when instructed to do so by the IESO as proponent connection requirements. These will be identified during the load connection process after the connection applications and will be implemented by Hydro One.

5 Next Steps

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Table 3: Solutions and Timeframe

Need	Action / Recommended Solution	Lead Responsibility	Timeframe
Timmins TS Voltage Regulation	• No Immediate action required • Hydro One and LDC to monitor area load growth	Hydro One Networks	Five years
Kirkland Lake TS Voltage Regulation	• No Immediate action required • Connection requirements for new transmission or distribution connections to be implemented as identified during system studies.	Hydro One Networks	N/A

6 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] North & East of Sudbury Needs Assessment Report

Appendix A: Load Forecast for North & East of Sudbury Stations

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kapuskasing TS	Gross Peak Load				13.5	13.6	13.6	13.7	13.8	13.8	13.9	13.9	14.0	14.0	14.0
	Net Load Forecast	26.1	16.1	13.5	13.4	13.3	13.2	13.2	13.1	13.1	13.1	13.0	13.0	13.0	13.0
Trout Lake TS	Gross Peak Load				121.9	122.2	122.7	123.3	123.9	125.3	126.7	127.1	128.4	129.8	131.2
	Net Load Forecast	147.5	124.1	119.4	120.6	120.0	119.1	118.5	118.1	118.7	119.2	119.1	119.7	120.5	121.1
Dymond TS	Gross Peak Load				32.7	32.9	33.1	33.6	34.0	34.2	34.4	34.6	34.8	35.0	35.2
	Net Load Forecast	37.7	34.6	32.4	32.4	32.3	32.2	32.2	32.4	32.4	32.4	32.4	32.4	32.5	32.5
Kirkland Lake TS	Gross Peak Load				32.2	32.3	32.6	32.9	33.3	33.5	33.7	33.8	34.0	34.1	34.3
	Net Load Forecast	43.8	35.7	31.9	31.9	31.7	31.6	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.6
Timmins TS	Gross Peak Load				53.4	53.7	54.2	54.9	55.6	56.0	56.4	56.7	57.0	57.4	57.7
	Net Load Forecast	51.0	51.1	52.9	52.8	52.7	52.6	52.7	53.0	53.0	53.0	53.1	53.2	53.2	53.3
Hearst TS	Gross Peak Load				27.5	27.6	28.8	29.1	29.3	29.5	29.7	29.9	30.0	30.2	30.4
	Net Load Forecast	27.8	27.3	27.2	27.2	27.1	28.0	27.9	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Herridge Lake DS	Gross Peak Load				3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5	3.5
	Net Load Forecast	3.5	3.8	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Temagami DS	Gross Peak Load				2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6
	Net Load Forecast	2.5	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
LaForest Rd TS	Gross Peak Load				10.4	10.4	10.5	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2
	Net Load Forecast	12.8	9.7	10.3	10.3	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Hoyle TS	Gross Peak Load				8.9	8.9	9.0	9.2	9.3	9.4	9.5	9.5	9.6	9.7	9.7
	Net Load Forecast	9.3	10.4	8.8	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9	9.0	9.0
Monteith DS	Gross Peak Load				2.8	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
	Net Load Forecast	3.1	2.9	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Ramore TS	Gross Peak Load				9.1	9.2	9.3	9.5	9.7	9.8	9.9	10.1	10.2	10.3	10.4
	Net Load Forecast	8.2	9.1	8.9	9.0	9.0	9.1	9.1	9.2	9.3	9.4	9.4	9.5	9.6	9.6
Cochrane West DS	Gross Peak Load				3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.1
	Net Load Forecast	4.1	4.1	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Smooth Rock Falls DS	Gross Peak Load				2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
	Net Load Forecast	2.4	2.4	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Fauquier DS	Gross Peak Load				2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4
	Net Load Forecast	2.3	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2
Moosonee DS	Gross Peak Load				14.2	14.3	14.4	14.6	14.8	14.9	15.0	15.0	15.1	15.2	15.3
	Net Load Forecast	18.0	13.5	14.1	14.1	14.0	14.0	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Calstock DS	Gross Peak Load				5.0	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5
	Net Load Forecast	5.1	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1
Mattawa DS	Gross Peak Load				5.5	5.5	5.6	5.7	5.7	5.8	5.8	5.8	5.9	5.9	5.9
	Net Load Forecast				5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Iroquois Falls DS	Gross Peak Load				10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3
	Net Load Forecast	5.1	4.9	4.9	10.7	10.7	10.6	10.6	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Crystal Falls TS	Gross Peak Load				9.9	10.0	10.0	10.2	10.3	10.4	10.4	10.5	10.5	10.6	10.6
	Net Load Forecast	18.7	11.1	9.8	9.8	9.8	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Cochrane MTS	Gross Peak Load				11.3	11.4	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
	Net Load Forecast	10.3	10.9	11.1	11.1	11.2	11.2	11.1	11.0	11.0	10.9	10.8	10.8	10.7	10.7
North Bay	Gross Peak Load				39.0	39.0	39.0	39.0	39.0	39.4	39.8	40.2	40.6	41.0	41.4
	Net Load Forecast	29.0	39.0	25.0	38.6	38.3	37.9	37.5	37.2	37.3	37.4	37.7	37.8	38.0	38.2

Load Forecast for North & East of Sudbury Stations (Continued)

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weston Lake DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.1	4.3	4.1	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2
Shiningtree DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.2

Appendix B: Acronyms

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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NEEDS ASSESSMENT REPORT

Region: North and East of Sudbury

Date: April 15, 2016

Prepared by: North and East of Sudbury Region Working Group

North & East of Sudbury Working Group	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kirpal Bahra Qasim Raza
Independent Electricity System Operator	Chris Reali Philip Woo
Hydro One Networks Inc. (Distribution)	Richard Shannon Daniel Boutros
Northern Ontario Wires Inc	Dan Boucher
Hearst Power Ltd	D Sampson J Richard
North Bay Hydro Distribution Ltd	Matt Payne

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the North & East of Sudbury region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by Working Group participants.

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 Needs Assessment 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 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"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 15, 2015	**END DATE**	April 15, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the North & East of Sudbury Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The North & East of Sudbury Region belongs to Group 3, triggered on October 15, 2015 and completed on April 17, 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2026. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Working Group participants included representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2026). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required.

6. RESULTS - TRANSMISSION NEEDS

A. 500/230kV Autotransfomers The 500/230kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/230kV unit.
B. 500/115kV Autotransfomers The 500/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/115kV unit
C. 230/115 kV Autotransformers The 230/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 230/115kV unit
D. Transmission Lines & Ratings The 500kV, 230kV transmission lines are adequate over the study period. Sections of the 115kV H9K circuit may experience thermal overloads during high generation scenarios. This is a bulk system issue and will be addressed jointly with the IESO outside of regional planning.
E. 230 kV and 115 kV Connection Facilities The 230kV and 115kV connection facilities in this region are adequate over the study period.
F. Outage Condition resulting in P15T,P7G and T61S radially connected to Timmins TS The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus
G. Ansonville T2 or D3K Outages With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at the Kirkland Lake TS 115kV bus.

<u>System Reliability, Operation and Restoration Review</u>

Circuit reliability in the region is acceptable, and Hydro One will continue to monitor performance of supply stations and circuits to ensure customer delivery performance criteria are met.

Restoration requirements for the loss of one element can be met by Hydro One.
Restoration requirements for the loss of up to two elements can be met by Hydro One.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following work is part of Hydro One approved sustainment business plan

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

7. RESULTS – NEEDS ASSESSMENT REPORT

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and following needs identified be further assessed as part of Local Planning:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the North & East of Sudbury Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the North & East of Sudbury Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by Hydro One Inc ("Hydro One") on behalf of the North & East of Sudbury Region NA Working Group (Table 1). The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Working Group Participants for North & East of Sudbury Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Northern Ontario Wires Inc
4.	Hydro One Networks Inc. (Distribution)
5.	Hearst Power Ltd
6.	North Bay Hydro Inc.

2 Regional Issue / Trigger

The NA for the North & East of Sudbury Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The North & East of Sudbury Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the North & East of Sudbury Region over an assessment period of 2016 to 2026. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

North & East of Sudbury Region Description and Connection Configuration
The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

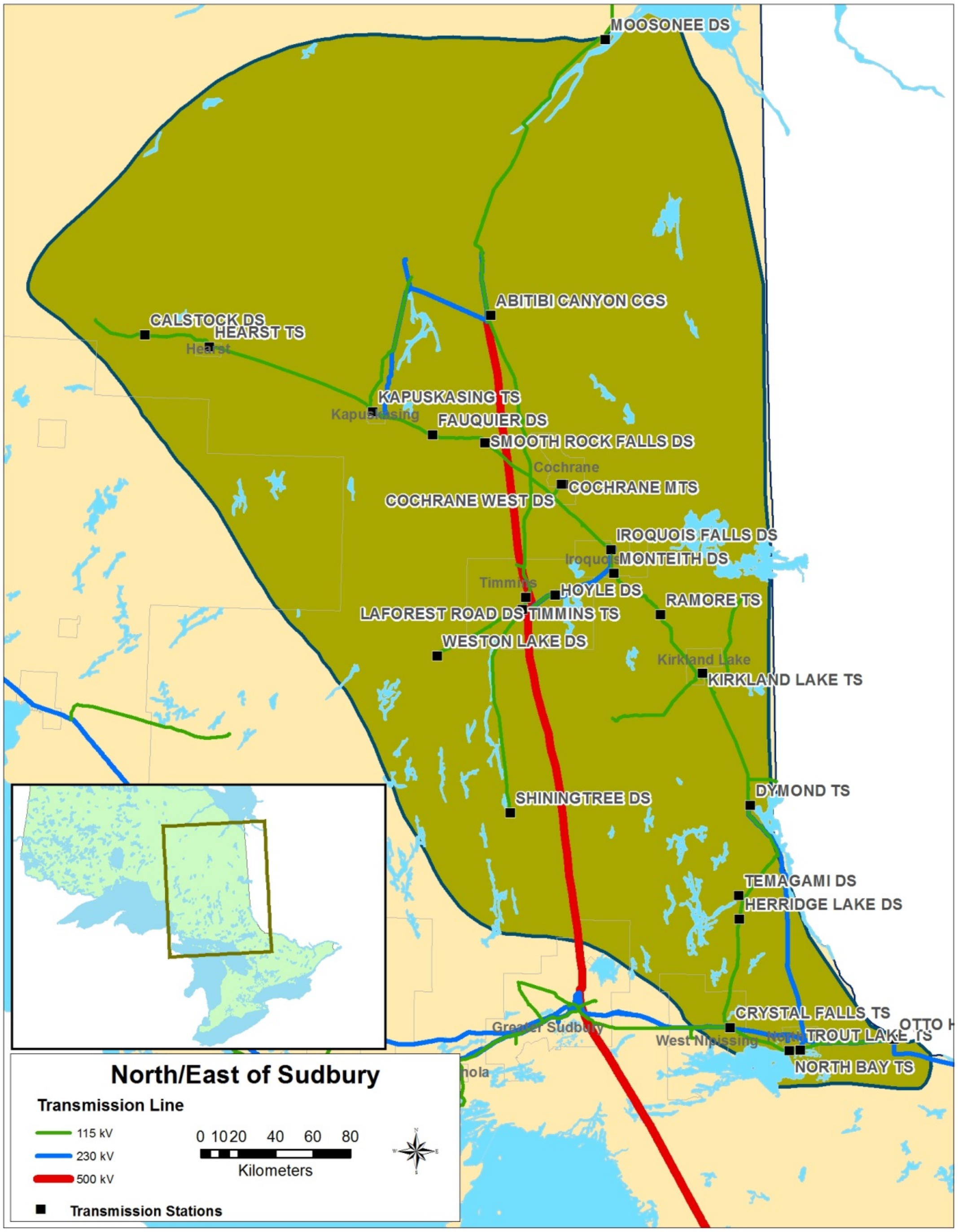

Figure 1: North & East of Sudbury Region Map

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 Pinard TS to Hanmer 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.

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS * Timmins TS Trout Lake TS Widdifield SS

***Stations with Autotransformers installed**

Table 2: Transmission Lines and Stations in North & East of Sudbury Region

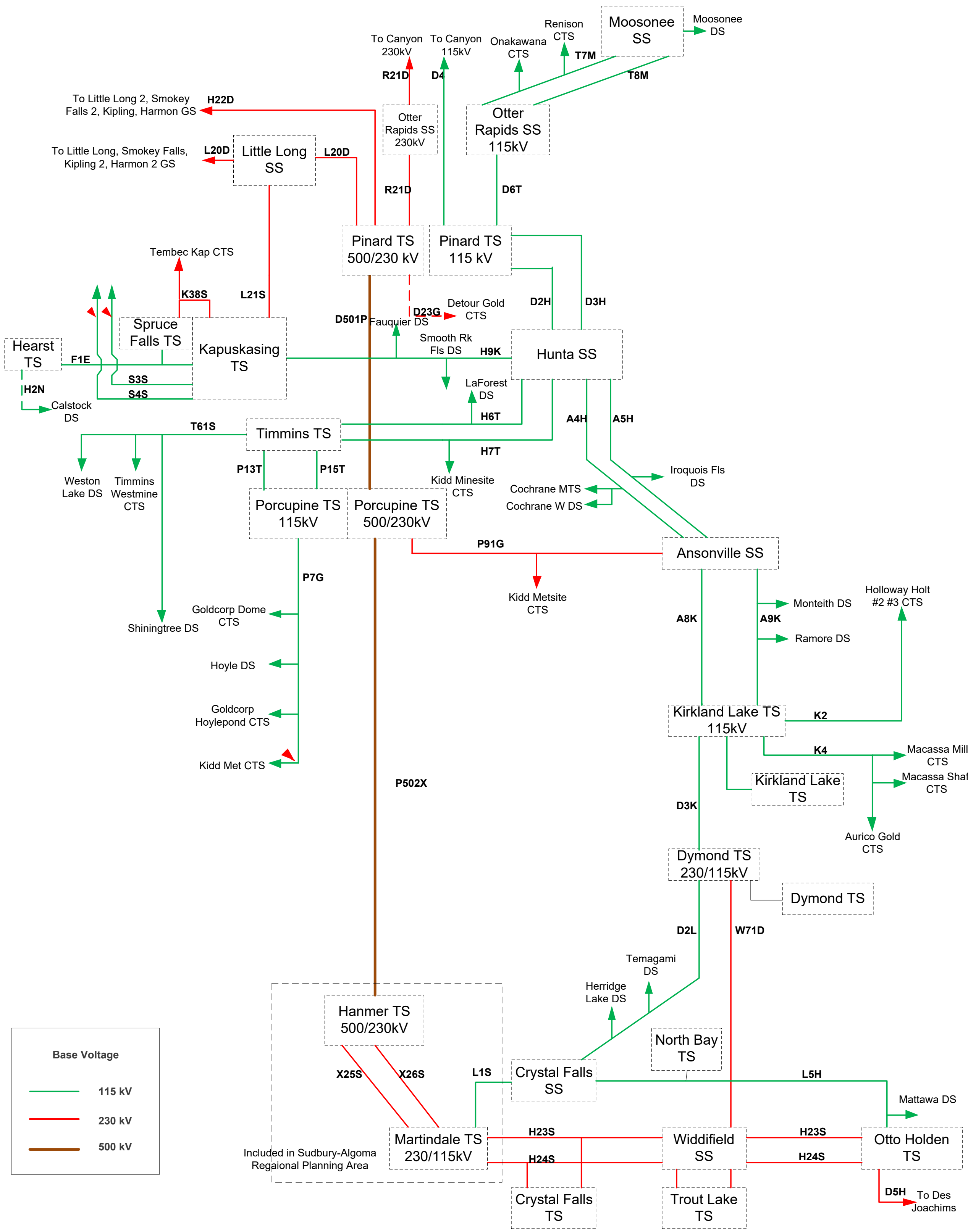

Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, Working Group participants provided the following information and data to Hydro One:

- IESO provided:
  - i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  - ii. List of existing reliability and operational issues
  - iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2026) Note: 2026 gross load values were extrapolated from 2025 if required.
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the Working Group, the gross load in region is expected to grow at an average rate of approximately 0.7% annually from 2016-2026.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.04% annually from 2016-2026.
Note: Extreme weather scenario factor at 1.057 assessed over the study term.

5 Needs Assessment Methodology

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

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. Accounting for (2), (3) above, the gross load forecast and net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report. A gross and net region-coincident peak load forecast was used to perform the analysis.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed 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 winter 10-Day Limited Time Rating (LTR). Summer LTR ratings also were reviewed against the station load forecasts over the study period.
8. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
9. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. Note: This criterion was put in place after the 500 kV Northeast system was built and as such, the system was not originally designed to respect this criteria for the loss of the 500 kV circuits P502X or D501P. Currently the loss of either these circuits can result in the loss of more than 150 MW.
    - With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With up to two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 500/230kV Autotransfomers

The 500/230 kV transformers supplying the region are adequate for loss of single 500/230 kV unit.

6.2 500/115kV Autotransfomers

The 500/115kV transformers supplying the region are adequate for loss of single unit.

6.3 230/115kV Autotransfomers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

6.4 Transmission Lines and Ratings

The 500kV and 230 kV circuits supplying the region are adequate over the study period for the loss of a single 500kV or 230 kV circuit in the Region.
As per section 7.2 below – the 115kV H9K circuit may experience thermal overloads and will be addressed as a bulk system issue outside of regional planning.

6.5 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the Working Group. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario

7 System Reliability, Operation and Restoration

7.1 Performance

The areas of Timmins, Dymond and Abitibi Canyon have experienced severe weather patterns over the last 5 years causing periodic increases of both momentary and sustained outages which have been highlighted by the IESO. The region (including the three mentioned above) does not have circuit performance outliers which would fall below customer delivery point performance standards set forth by the Ontario Energy Board.

Hydro One continually monitors performance of supply stations, and high voltage circuits and will make the necessary steps to address the problem should this issue persist.

7.2 Restoration

Depending on system conditions, the loss of P502X may result in the greatest amount of load lost through North East LR/GR special protection schemes. Based on the load levels in the study period of this assessment, load can be restored within the 30 minute, 4 hour and 8 hour time frames as required by IESO ORTAC Section 7.0. The maximum load which may be interrupted by configuration or load rejection due to the loss of two elements is up to 450MW which is below the ORTAC requirement of 600MW. (loss of P502X with D3K out of service, or vice versa)

7.3 Thermal overloading on H9K section

Under high generation scenarios, IESO has identified pre and post contingency overloads on the 115 kV circuit H9K between *Tembec SRF x H9K 127A* junction.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.4 Congestion on D3K, A8K, A9K, H6T and H7T

Under high generation scenarios, IESO has identified there may be congestion on D3K, A8K, A9K, H6T and H7T circuits.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.5 Kapuskasing and Calstock Area Generation

Non-utility Generator ("NUG") contracts are reaching end of term for the Kapuskasing and Calstock Generating Stations. The NUG Framework Assessment Report [1] indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.6 Outage Condition Resulting in P15/P7G/T61S radially connected to Timmins

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus.
This scenario will be addressed in the next stage of regional planning.

7.7 Ansonville T2 or D3K outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at Kirkland Lake TS. This scenario will be addressed in the next stage of regional planning.

8 Aging Infrastructure and Replacement of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. during the study period. At this time the major committed system investments are;

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

9 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, it is further recommended that voltage regulation issues at Timmins TS and Kirkland Lake TS be best addressed by wires options solution thru local planning led by Hydro One:

10 NEXT STEPS

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and the two voltage regulation needs identified in Section 7 be further assessed as part of Local Planning to be entitled:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

11 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

12 Acronyms

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
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IESO	Independent Electricity System Operator
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NERC	North American Electric Reliability Corporation
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ULTC	Under Load Tap Changer

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Renfrew Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

The Renfrew Region consists of Renfrew County and it is roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast.

The Needs Assessment ("NA") report for the Renfrew region was completed in March, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time although circuit X1P is nearing its capacity and will be monitored on a regular basis over the next three to five years.

There are no other major development projects planned for the Renfrew Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB, the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the Renfrew Region.

The next regional planning cycle for the region is expected to be undertaken in five years from the start of this planning cycle (2015) or earlier if there is a new need emerging in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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NEEDS ASSESSMENT REPORT

Region: Renfrew

Revision: Final
Date: March 11, 2016

Prepared by: Renfrew Study Team

Transmission

Distribution

Peterborough to Renfrew Region Study Team
Organization
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Renfrew Hydro Inc.
Ottawa River Power Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Renfrew Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	October 23, 2015	**END DATE**	March 11, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Renfrew Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Renfrew Region belongs to Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 11, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal, and voltage analysis, system reliability, and assets approaching end-of--life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Renfrew Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2015 to 2024). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. Station Capacities

- All stations in the region have sufficient capacity to supply the loads in studied period under normal and single contingency condition.

B. Transmission Circuits Capacities

- All transmission circuits have sufficient capacity under normal and single contingency condition.

System Reliability, Operation and Restoration Needs

There are no transmission system reliability issues and no operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, loss of one element will not result in load interruption for more than 150MW by configuration.

All load within the region can typically be restored within eight hours as per the ORTAC requirement for loads under 150 MW.

In recent years, maintenance activity in the region with respect to vegetation management has been enhanced resulting in an improvement in reliability and/or load restoration.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at three stations will increase station capacities. Further details of these investments can be found in Section 3.2 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team's recommendations are as follows:

- Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

- No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Renfrew Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Renfrew Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Renfrew Region Needs Assessment study team. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1 Study Team Participants for Renfrew Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Networks Inc. (Distribution)

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Renfrew Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on October 23, 2015 and was completed on March 4, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Renfrew Region over an assessment period of 2015 to 2024. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuits thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Renfrew Region Description and Connection Configuration

The Renfrew Region includes all of Renfrew County. Fig.1 shows the map of the Region. The 2014 peak load in this Region was 124 MW.

The electricity supply to the region is mainly through one 230kV circuit X1P and three 115 kV radial circuits: D6, X6 and X2Y (Fig.1). 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 roughly bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the Southeast. The distribution system in this region consists of voltage levels 44 kV, 13.8 kV, and 12.5 kV. The main generation facilities in the Renfrew Region are Chenaux Generation Station (GS) of 143.7 MW (according to Transmission Connection Agreement, applicable thereafter), Mount Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW.

Hydro One Networks Inc. (Distribution) is the main customer in the area. Other Local Distribution Companies (LDC) supplied from electrical facilities in the Renfrew Region includes Ottawa River Power Corporation and Renfrew Hydro Inc, both are embedded into Hydro One's distribution system. Major transmission connected customers in the area include Canadian Nuclear Laboratories and Magellan Aerospace.

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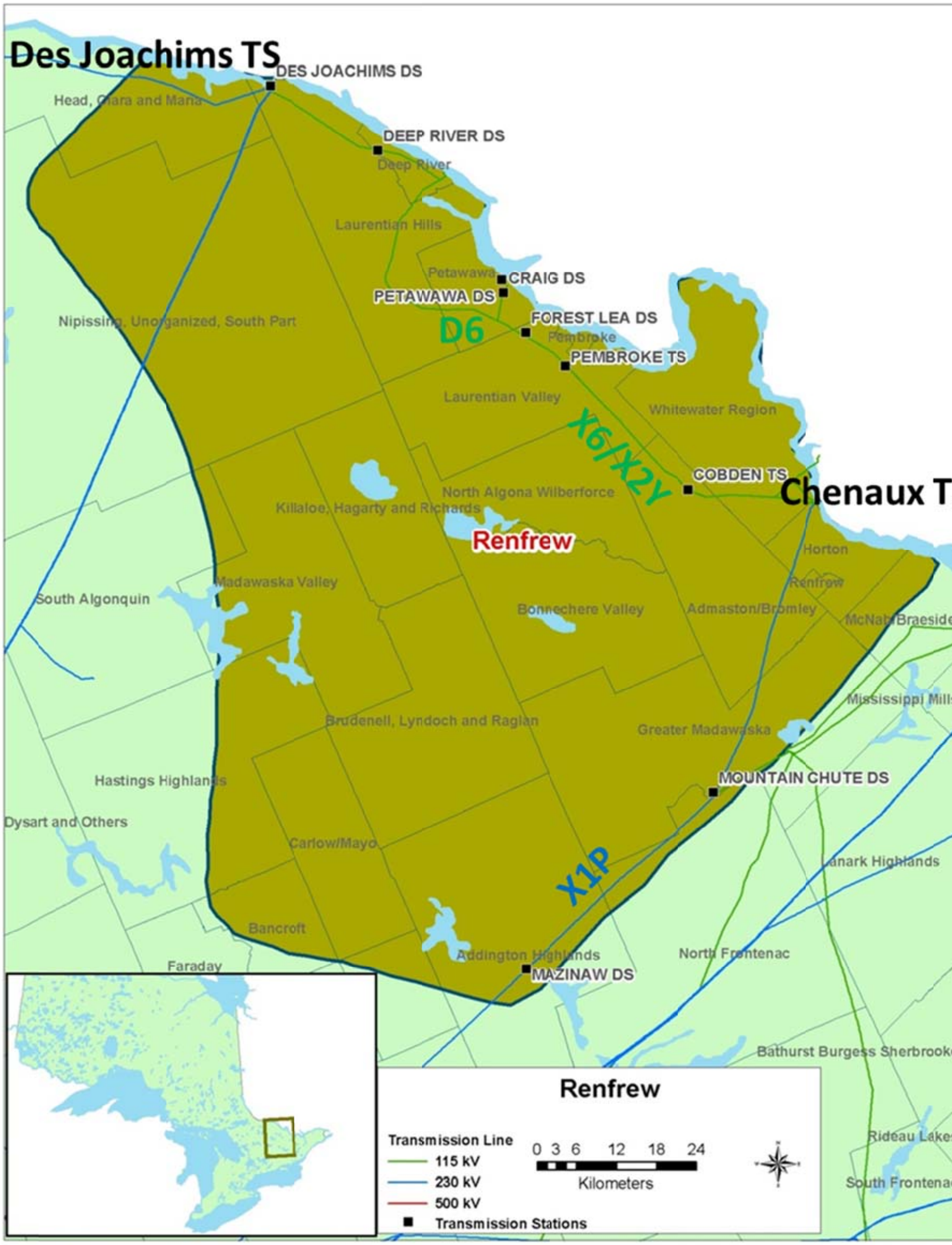

Fig. 1 Renfrew Region Map

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Fig. 2.

- Des 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 Magellan Aerospace CTS. The two circuits are coupled via and only via Pembroke 44kV bus tie breaker

- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation units 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 Chalk River Customer Transformer Station (CTS).

- All the 115kV circuits X6/X2Y/D6, all the 115kV stations tapped to the 115kV circuits, and all the autotransformers at Des Joachims TS and Chenaux TS are not NERC BES element.

- Bryson GS of Hydro Quebec can be radially connected to Renfrew region via X2Y.

- 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 DS typically has load less than 1MW.

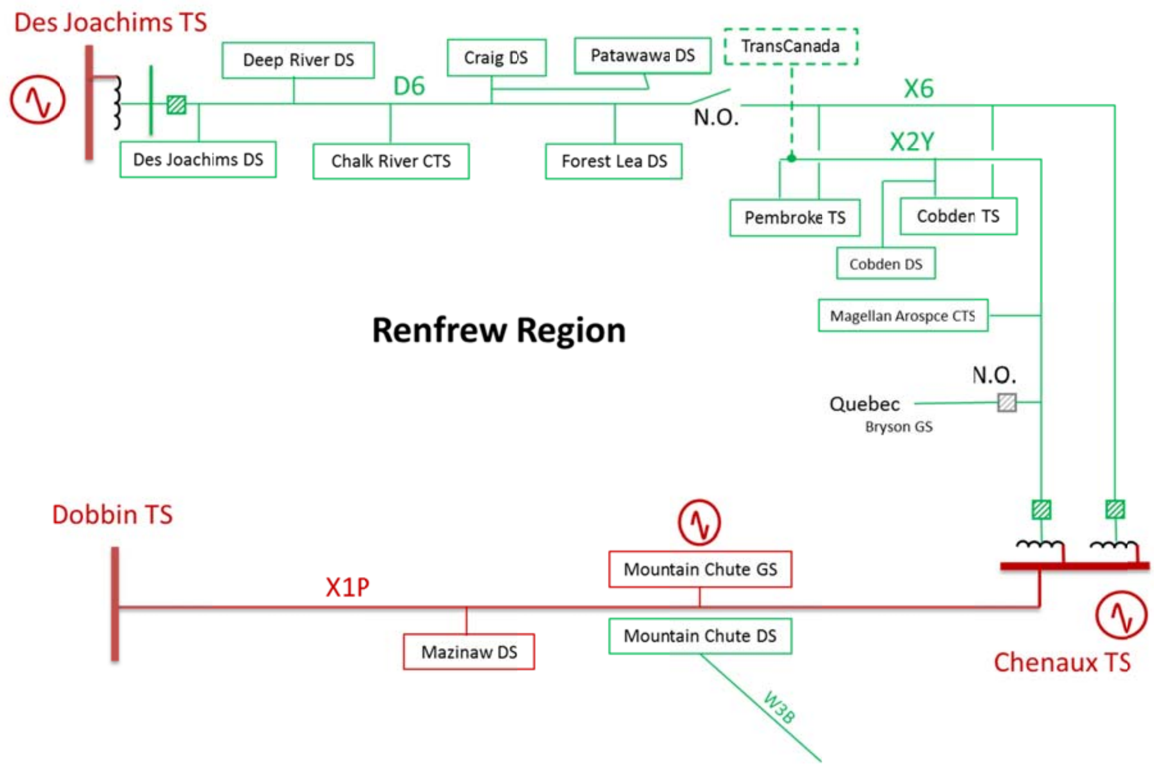

Fig. 2 Single Line Diagram – Renfrew Region

3.2 Planned Work in Renfrew Region

Following work has been planned in Renfrew Region:

- Two step-down transformers at Deep River DS (T1 and T2) will be replaced due to end-of-life for an in service date of end of 2016. This will also result in uprating the transformer capacity from 10MVA to 12.5MVA.
- Mountain Chute DS transformer will be replaced due to end-of-life with an in service date of end of 2016. This will also result in uprating the transformer capacity from 3MVA to 12.5MVA.
- Chenaux TS 230/115kV autotransformers T3 and T4 will be replaced due to end-of-life with an in service date of end of 2018. The existing units are rated 78MVA and 115MVA respectively. The new T3/T4 will both have continuous rating of 125MVA. This is a transmission pool investment and LDCs are not expected to pay.
- A TransCanada pump station is expected to tap to X2Y at Pembroke TS (Fig.2). The peak load of the station is 19.4MW. Two capacitor banks, each rated at 10Mvar, are assumed to be in service with the load. The station is expected to be in service in 2020.

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
  i. Historical regional coincident peak loads and station non-coincident peak loads between 2012 and 2014
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and future Distributed Generation (DG) data
- LDCs provided historical (2012-2014) net loads and gross loads forecasts (2015-2024) for each station.
- The study team could not get response from Chalk River CTS and Magellan Aerospace CTS regarding their load forecasts. It is assumed that the loads at these two stations would not increase over the study period.
- Any relevant planning information, including planned transmission and distribution investments are provided by the transmitter and LDCs.

As per the data provided by the study team, the net load (i.e. after DG and CDM adjustment) in the Renfrew Region is expected to grow at an average rate of approximately 0.6% annually from 2015 to 2024.

5 ASSESSMENT METHODOLOGY

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

1. The Region typical typically has winter peak. Fig. 3 plots the load profiles at Pembroke TS and Cobden TS from July 2013 to July 2015, which evidences the winter peaking characteristics. Therefore this assessment is based on winter peak load.

2. Loads forecasts are provided by the LDCs, i.e., Hydro One Networks Inc. (Distribution) in this case.

3. Average gross load growth rate at each station is calculated from the LDC’s load forecast. The growth rates are then applied to the 2014 coincidental winter peak load to generate each year’s coincidental peak load.

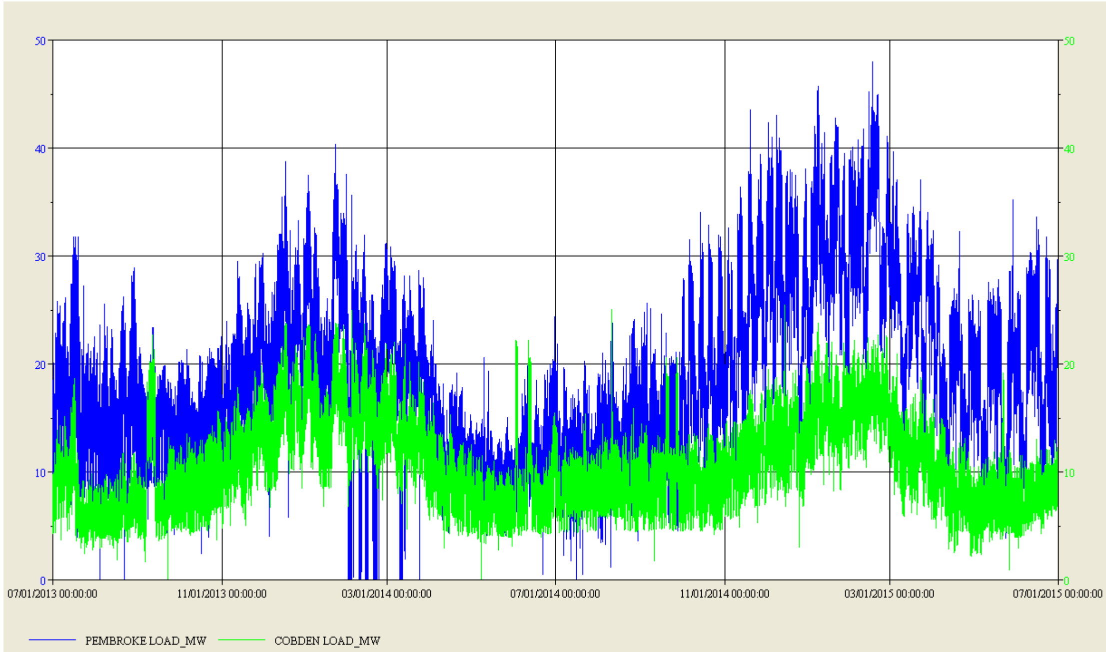

Fig. 3 Pembroke TS and Cobden TS Winter Peak Load Profiles

4. The 2014/15 winter was already extremely cold; therefore no extreme weather adjustment was used.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and planned development projects in the Region during the study period. This includes:

   - A new 19.4MW load is expected to connect to circuit X2Y at Pembroke in 2020. This Needs Assessment assumes that the load is in service.

7. Review and assess impact of any major elements planned to be replaced at the end of their useful life such as transformers, cables, and stations.

8. 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 and 95% lagging power factor for stations with low-voltage capacitor banks. Normal planning supply capacity for transformer stations in this Region is determined by the 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range. Projected coincidental peak loads are used in such assessment.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC). Des Joachims and Chenaux 115kV bus voltages are maintained between 122kV and 127kV according to established operation practice.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration time limits as per ORTAC criteria.

11. Full load transfers for restoration purposes are not mandatory requirement. Restorations of load between Chenaux TS and Des Joachims TS via D6-X6 load transfers are performed to the extent possible.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Renfrew Region.

6.1 Transmission Capacity Needs

This is to assess a) adequacy of each station's load supply capacity which is mainly to inspect the step-down transformer ratings; and b) adequacy of transmission facility to deliver the power within the Region under normal and contingency conditions, which is mainly determined by circuit thermal rating and voltage profile.

6.1.1 Station Adequacy Assessment

Non-coincident peak load at each station is compared against corresponding transformer maximum continuous rating or 10-day LTR if the continuous rating is exceeded. The peak loads are all forecasted to happen in 2024. Table 2 compares the net peak load against transformer ratings at each station. It can be seen that all stations are adequate to supply the loads in studied period.

Table 2 Station Adequacy Assessment

Station	Transformers	Net Peak Load (MW)	Transformer Rating/LTR* (MW)
Cobden DS	T3	7.2	11.3
Cobden TS	T1/T2	27.1	37.5
Craig DS	T1/T2	12.2	15.9
Deep River DS	T1/T2/T3	11.1	23.8
Des Joachims DS	T1	3.3	11.3
Forest Lea DS	T1/T2	9.2	9.9
Mazinaw DS	T1	3.4	5.4
Mountain Chute DS	T1	1.0	11.3
Pembroke TS	T1/T2	49.1	49.6
Petawawa DS	T1/T2	14.3	14.8
Chalk River CTS***		10	N/A
Magellan Aerospace CTS***		3.1	N/A
Chenaux TS	T3/T4	101.7**	112.5
Des Joachims TS	T6/T7	57.1	112.5

*: LTR is listed only if the peak load exceeded transformer continuous rating
**: Including 19.4MW new load, all station MVAs add up arithmetically
***: Load customer owned transformers, capacity not assessed in this study

6.1.2 Transmission Facility Adequacy Assessment

Under normal condition with all elements in service and the D6-X6 in-line switch open, the study found that:

- All transmission circuits supplying the Region, namely D6, X6, X2Y and X1P have adequate capacity over the study period.

The projected regional peak loads can be supplied even if the local generations at Des Joachims GS and Chenaux GS are out of service. In the X6/X2Y corridor, loss of one circuit (including breaker failure condition to cause additional loss of Chenaux generation) would not cause overload or under-voltage on the accompanying circuit. .

6.2 System Reliability, Operation and Restoration Review

- The Region's total coincidental peak load is less than 150MW, therefore load loss violation due to configuration does not apply in this assessment.
- All loads are expected to be restored within 8 hours.
- The most critical contingency in the Region would be loss of 230kV circuit X1P which would produce an island at Chenaux. Stable islanding operation might be

achieved depending on pre-contingency flow and generation rejection arming. Reliability data recorded 13 X1P non-planned outages in past ten years, among which seven events show stable islanding operations before the system was paralleled back to the grid. In another two events the island collapsed after more than one hour of operation. The performance is expected to be unchanged in the study period.

- Studies show that under this contingency, Des Joachims TS may not be able to radially supply all the loads in the Region, under peak load conditions.
- Due to the fact that the loads are supplied via radial circuits and the Region is prone to storms, extended outages on D6 were experienced in the past (in 2011 for example). Further, outage analysis indicated that the most common cause for sustained outages was under severe storm. This issue cannot be addressed by building additional line in the same right-of-way. As a result, improved vegetation management and outage responses have effectively reduced sustained outages considerably in recent years. Table 3 lists sustained outage records of D6 in past five years.

Table 3 Outage Records of D6 from 2011 to 2015

Year	No. of Sustained Outages	Cumulative Duration (min)	Causes
2015	1	367	Conductor Broken
2014	1	5	Human Error
2013	3	1381	Isolated Electrical Storm
2012	1	1341	Tree Contact
2011	4	7792	Tree Contact

Studies show that under D6 terminal outage at the Des Joachims terminal, load can be restored by transferring D6 to Chenaux TS 115kV via X6 supply. Note, there is a maximum limit of 125 MW, which is the peak regional load in 2015, that can be supplied radially from Chenaux.

a) The following potential needs will be monitored and assessed in the next Regional Planning cycle for the Renfrew Region:

- Hydro One and the LDCs will continue to monitor and assess the load restoration performance under X1P and D6 outages.

- Major Hydro One facilities and equipment are continually monitored to ensure their safe and reliable operation. Circuit X1P is one of these facilities and, as such, its performance is monitored by Hydro One's Ontario Grid Control Centre (OGCC) in Barrie. OGCC's records will be reviewed regularly to ascertain the adequate performance of this circuit. The next planning cycle will take place in five years however, if the performance of X1P fall below adequate levels the Hydro One will undertake to assess and address this issue with the LDCs.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Section 3.2 lists the sustainment initiatives that are currently planned for the replacement of any aged transformers. There are no major line replacement plans scheduled in the near term in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

No further coordinated regional planning is required for this region at this time. The next regional planning cycle for the region is expected to be undertaken in Q1 2019 or earlier if there is a new need emerging in the region. Should the performance of X1P fall below adequate levels (as shown by standard OGCC monitoring systems) the Hydro One will undertake to assess and address this issue with the LDCs.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: January 2016 – June 2017
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

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
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A. LOAD FORECAST

Table A-1: Station Net Load Forecast (MW)

Transformer Station Name	Rating (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	11.3	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.1	7.2
Cobden TS T1/T2	37.5	25.8	25.9	26.0	26.0	26.2	26.5	26.6	26.8	26.9	27.1
Craig DS T1/T2	15.9	11.2	11.3	11.3	11.4	11.6	11.7	11.9	12.0	12.1	12.2
Deep River DS T1/T2/T3	23.8	10.9	11.0	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.1
Des Joachims DS T1	11.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Forest Lea DS T1/T2	9.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2
Mazinaw DS T1	5.4	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4
Mountain Chute DS T1	11.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Pembroke TS T1/T2	49.6	46.0	46.3	46.5	46.7	47.1	47.6	48.0	48.3	48.7	49.1
Petawawa DS T1/T2	14.8	12.8	13.1	13.2	13.4	13.6	13.8	13.9	14.1	14.2	14.3

Table A-2: Regional Coincidental Net Load Forecast (MW)

Transformer Station Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cobden DS T3	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Cobden TS T1/T2	25.5	25.5	25.7	25.8	25.9	26.1	26.3	26.5	26.8	27.1
Craig DS T1/T2	11.1	11.2	11.3	11.3	11.4	11.5	11.6	11.8	11.9	12.1
Deep River DS T1/T2/T3	10.8	10.7	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.0
Des Joachims DS T1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Forest Lea DS T1/T2	9.0	9.0	9.1	9.0	9.0	9.0	9.1	9.1	9.2	9.2
Mazinaw DS T1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Mountain Chute DS T1	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Pembroke TS T1/T2	38.7	38.9	39.3	39.6	39.9	40.3	40.8	41.3	42.0	42.6
Petawawa DS T1/T2	5.0	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Total Regional Load	125.2	127.2	128.0	128.2	128.6	129.3	130.3	131.4	132.7	133.8

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St. Lawrence Region

Regional Infrastructure Plan ("RIP")

July 22nd, 2016

Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

The St Lawrence Region covers the southeastern part of 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 Needs Assessment ("NA") report for the St. Lawrence region was completed in April, 2016 (see attached). The report concluded that no regional planning needs were identified for the region at this time.

There are no other major development projects planned for the ST. Lawrence Region over the near and mid-term.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no regional planning was required, this letter and the attached NA report will be deemed to form the ("RIP") for the St. Lawrence Region.

The next regional planning cycle for the region is expected to be undertaken in five years form the start of this planning cycle (2015) or earlier if new needs emerge in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

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

NEEDS ASSESSMENT REPORT

Region: St Lawrence

Date: April 29, 2016

Prepared by St Lawrence Region Study Team

St Lawrence Region Study Team

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the St Lawrence region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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 Needs Assessment 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 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"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	St Lawrence (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	March 1, 2016	**END DATE**	April 29, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the St Lawrence Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the St Lawrence Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3. The St Lawrence Region belongs to Group 3. The NA for this Region was triggered on March 1, 2016 and was completed on April 29, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO) and Hydro One transmission provided information for the St Lawrence Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2025). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. 230/115 kV Autotransformers

The 230/115kV Autotransformers at St Lawrence TS are adequate over the study period for the loss of a single 230/115kV unit

B. Transmission Lines & Ratings

The 230kV lines are adequate over the study period. A Special Protection Scheme is in place to reject generation at Beauharnois GS and/or Saunders GS under post contingency conditions to ensure the loading on the St Lawrence to Hinchinbrooke TS 230KV circuits are within ratings.

The 115kV lines are adequate over the study period to supply the forecasted load. The section of the 115kV lines L2M/L1MB between St Lawrence TS and Lunenberg Jct may be overloaded under light load conditions and high DG and Cardinal Power generation, for the loss of the companion circuit. Since 2012, Morrisburg TS has been restricted and no additional generation is accepted. At the same time, this situation is also mitigated using the Cardinal Power CGS run back scheme or by limiting generation dispatch during these light load conditions. No further action is required.

C. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

Inadvertent breaker operation (IBO) at Cardinal Power on either L1MB or L2M can result in Morrisburg TS transformers exceeding their reverse flow limits and/or cause a transformer to be loaded beyond ratings at Dyno Nobel CTS. Morrisburg TS has been restricted and no additional generation is accepted since 2012. This situation is also mitigated by using Cardinal Power runback scheme. No further action is required.

System Reliability, Operation and Restoration Review

Based on the gross coincident load forecast, the loss of one element does 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. No action is required.

Chesterville TS missed its delivery point performance standard in recent years due to momentary outages resulting from severe weather patterns. The delivery point performance at Chesterville TS will be assessed and monitored to determine if corrective actions are required. No further action is required as part of regional planning.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- Morrisburg TS: components replacement (2019 in service)
- Smiths Falls TS: components replacement (2021 in service)
- St Lawrence TS: components replacement (2024 in service)

7. Recommendations

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the St Lawrence Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the St Lawrence Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the St Lawrence Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1 Study Team Participants for St Lawrence Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the St Lawrence Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The St Lawrence Region belongs to Group 3.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the St Lawrence Region over an assessment period of 2016 to 2025. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

St Lawrence Region Description and Connection Configuration

The St Lawrence Region covers the southeastern part of 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 western part of the region is supplied from Hydro One owned stations connected to the 230kV network. The reminder 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. A map of the region is shown below in Figure 1.

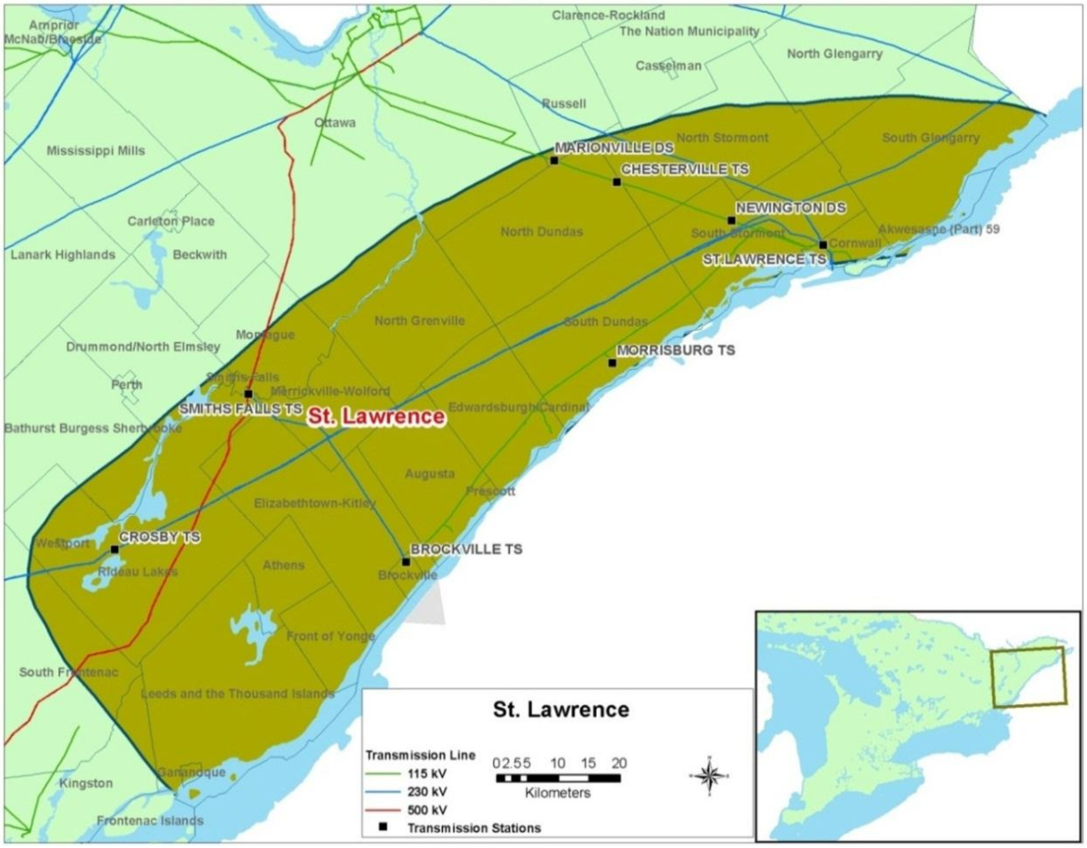

Figure 1 Map of St Lawrence Regional Planning Area

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 Saunder Hydro Electric station which connects to St Lawrence TS 230kV yard.

This region has the following three local distribution companies (LDC):

- Hydro One Networks (Distribution)
- Cooperative Hydro Embrun Inc. (embedded in Hydro One Distribution)
- Rideau St Lawrence Distribution Inc. (embedded in Hydro One Distribution)

Table 2 Transmission Lines in the St Lawrence Region

115kV circuits	230kV circuits	Hydro One Transformer Stations
L1MB, L2M, L5C[1]	L20H, L21H, L22H, L24A[2], B31L[2]	Brockville TS, Chesterville TS, Crosby TS Morrisburg TS, Newington DS, Smith Falls TS St Lawrence TS*

*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.

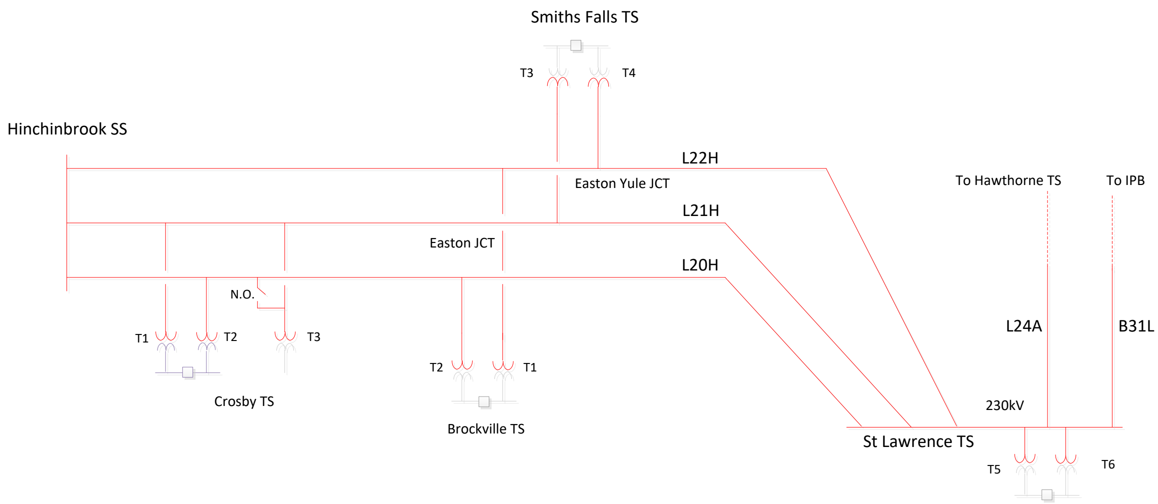

Figure 2 Single Line Diagram 230 kV St Lawrence Regional Planning Area

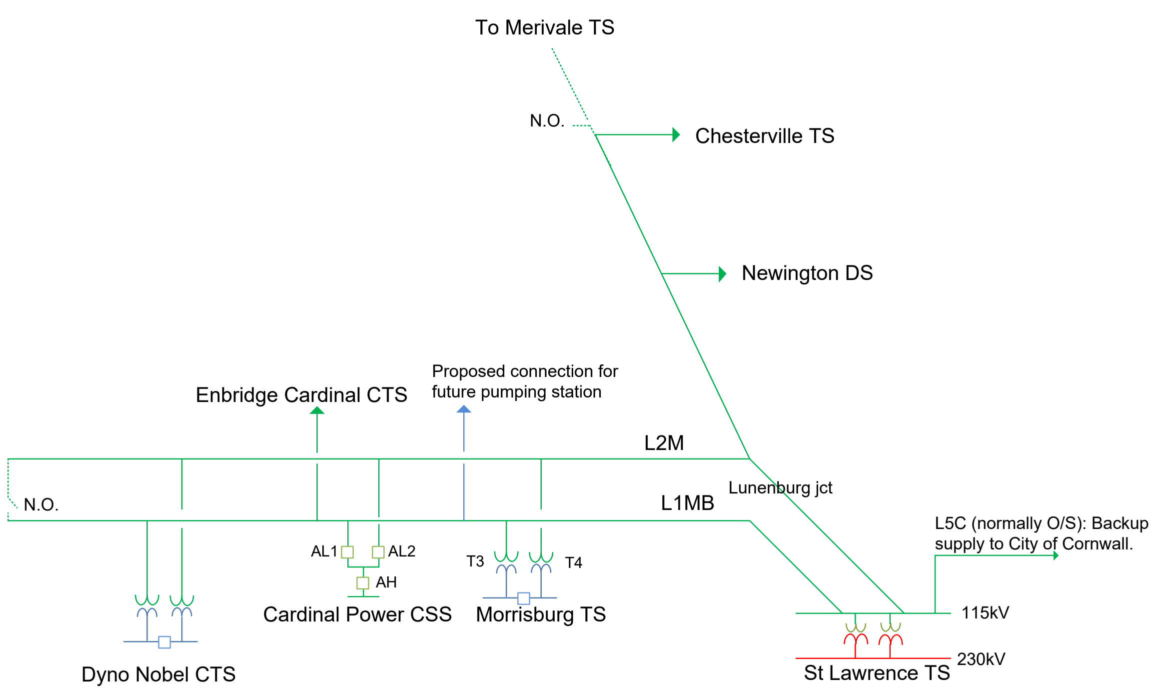

Figure 3 Single Line Diagram 115 kV St Lawrence Regional Planning Area

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2025).
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.8% annually from 2016-2025.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.2% annually from 2016-2025.

Future Project
As shown in Figure 3, there is a proposal to connect a pumping station for the TransCanada Energy East project that will add 18MW of load to the area. The pumping station is planned to be connected to circuit L1MB close to Morrisburg TS. The current in-service date is 2021.

5 NEEDS ASSESSMENT METHODOLOGY

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

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Saunders GS was assumed to generate at its average 98% of time dependable hydro generation level which is 542MW.
3. Forecast loads are provided by the Region's LDCs

4. Load data was requested from industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
5. Accounting for (3), (4), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to verify each station is within its rating to supply the forecasted load. The net forecast was used for system study.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed 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 winter 10-Day Limited Time Rating (LTR). Winter LTR ratings were reviewed.
8. Extreme weather scenario factor at 1.0582 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their winter long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using winter loading with winter 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

230/115 kV Autotransformers
The 230/115kV Autotransformers at St Lawrence TS are adequate over the study period for the loss of a single 230/115kV unit

Transmission Lines & Ratings

230kV Lines
The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

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 Hinchinbrooke TS lines are not overloaded under peak summer conditions.

115kV Lines
Under the assumptions made for regional planning, the 115kV lines are adequate over the study period for the loss of a single circuit in the Region.

The following operating issues have been previously in the SIA/CIA done for Cardinal Power G3 Expansion [4, 5]:

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.

To manage the situation, Morrisburg TS has been restricted to accept new generation connection since 2012. In addition, there is Cardinal Power's runback scheme 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 [4, 5].

230 kV and 115 kV Connection Facilities
A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

Reverse Power Flow
At Morrisburg TS, under light load condition and high distributed and directly connected generation, a reverse power flow issue was identified in the Cardinal Power G3 Expansion SIA/CIA [4, 5]. 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. As noted previously, since 2012, additional generation connection has been restricted at Morrisburg TS to manage the reverse power flow at the station.

Dyno Nobel CTS
Under the same conditions mentioned above, an IBO at Cardinal Power can also result in power flow through the Dyno Nobel CTS to exceed their rating [4, 5].

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 [4,5]. No further action is recommended within the scope of this regional planning.

7 System Reliability, Operation and Restoration

Based on the gross coincident load forecast, the loss of one element does 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 for the duration of the 10-year study period.

Chesterville TS and Newington DS are on single supply from L2M for a combined gross load of 50MW in 2025. If the supply from St Lawrence TS becomes unavailable, these two stations can be supplied from Merivale TS.

All loads in the St Lawrence area can be restored within the 8 hour requirement.

IESO indicated in their unsupplied energy report that the 115kV area did not meet its target in the past. Chesterville TS missed its customer delivery point target (frequency of interruption) in recent years due to momentary outages seen as a result of severe weather patterns. Hydro One will review and monitor its supply point performance at Chesterville TS to determine if corrective measures are required. No further actions required as part of regional planning.

8 AGING INFRASTRUCTURE AND REPLACEMENT PLAN OF MAJOR EQUIPMENT

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables during the study period. At this time the following sustainment work is planned for the stations in the area:

Morrisburg TS: Protection upgrade, 44kV breakers (2019 in service)

Smiths Falls TS: Protection replacement, battery and charger, switches (2021 in service)

St Lawrence TS: Replacement of oil breakers at 230kV, 115k, and 44kV; replacement of AC/DC station service supplies; and protection upgrade work. (2024 in service)

The facilities at these stations are adequate and there is no need to increase the equipment rating.

9 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

10 NEXT STEPS

No further Regional Planning is required at this time. The St Lawrence Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

11 REFERENCES

1. Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
2. IESO 18-Month Outlook: March 2014 – August 2015
3. IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
4. Cardinal Power 15MW Plant Expansion SIA (2011-432)
5. Cardinal Power 15MW Plant Expansion CIA

APPENDIX A: Load Forecast

Winter Load: Normal Weather Condition.

Station		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Brockville	Non Coincidental Gross		135.8	136.7	137.9	139.7	141.4	142.5	143.6	144.6	145.6	146.5
	CDM (MW)		1.1	1.9	3.2	4.3	5.4	6.3	7.0	7.5	8.2	8.8
	DG (MW)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Non Coincidental Net	134.3	132.9	132.8	132.8	133.5	134.2	134.4	134.6	135.2	135.5	135.8
	Coincidental Net	115.6	115.9	115.9	115.9	116.4	117.0	117.2	117.4	117.9	118.2	118.5
Chesterville	Non Coincidental Gross		42.0	42.5	43.2	44.1	45.0	45.7	46.3	46.9	47.6	48.2
	CDM (MW)		0.3	0.6	1.0	1.4	1.7	2.0	2.3	2.4	2.7	2.9
	DG (MW)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Non Coincidental Net	41.2	40.6	40.9	41.2	41.7	42.3	42.7	43.0	43.5	43.9	44.3
	Coincidental Net	41.2	41.6	41.9	42.2	42.8	43.3	43.7	44.1	44.5	44.9	45.3
Crosby	Non Coincidental Gross		28.8	29.0	29.2	29.6	30.0	30.2	30.4	30.6	30.8	31.0
	CDM (MW)		0.2	0.4	0.7	0.9	1.1	1.3	1.5	1.6	1.7	1.9
	DG (MW)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Non Coincidental Net	28.5	25.9	25.9	25.9	26.1	26.2	26.2	26.3	26.4	26.5	26.5
	Coincidental Net	18.9	18.9	18.9	18.9	19.0	19.1	19.1	19.2	19.2	19.3	19.3
Morrisburg	Non Coincidental Gross		61.5	61.7	62.1	62.7	63.3	63.7	64.0	64.3	64.6	64.9
	CDM (MW)		0.5	0.9	1.4	1.9	2.4	2.8	3.1	3.3	3.6	3.9
	DG (MW)	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
	Non Coincidental Net	60.0	52.6	52.4	52.3	52.3	52.5	52.4	52.4	52.5	52.5	52.5
	Coincidental Net	53.9	53.9	53.8	53.6	53.7	53.8	53.8	53.8	53.9	53.9	53.9
Newington	Non Coincidental Gross		1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1
	CDM (MW)		0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	DG (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non Coincidental Net	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Coincidental Net	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Smiths Falls	Non Coincidental Gross		124.2	125.1	126.6	128.1	128.8	129.5	130.2	130.8	131.4	132.1
	CDM (MW)		1.0	1.8	2.9	4.0	4.9	5.7	6.4	6.8	7.4	7.9
	DG (MW)	3.9	4.0	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
	Non Coincidental Net	122.5	119.2	118.8	119.2	119.5	119.4	119.3	119.3	119.5	119.5	119.6
	Coincidental Net	112.7	112.8	112.4	112.7	113.1	113.0	112.9	112.8	113.0	113.1	113.2
St Lawrence	Non Coincidental Gross		44.5	44.7	45.1	45.5	45.6	45.7	45.8	45.9	46.0	46.0
	CDM (MW)		0.4	0.6	1.0	1.4	1.7	2.0	2.2	2.4	2.6	2.8
	DG (MW)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Non Coincidental Net	44.2	41.6	41.5	41.5	41.5	41.3	41.1	41.0	40.9	40.8	40.7
	Coincidental Net	43.0	42.9	42.8	42.8	42.8	42.6	42.4	42.3	42.2	42.1	42.0

APPENDIX B: Acronyms

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
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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May17, 2021

Mr. Peter Faltaous
Director, Distribution Asset Management
Hydro One Distribution
Toronto

Subject: Regional Planning Status

As per your request, this Planning Status letter is provided to meet one of the requirements of your upcoming Rate Application to the Ontario Energy Board (OEB).

As you are aware, the province of Ontario is divided into 21 Regions for the purpose of Regional Planning (RP), a map of Ontario showing the 21 Regions and the list of Local Distribution Companies (LDCs) in each of the Region are attached as Appendix A and B respectively.

Hydro One Distribution (HOD) is an LDC in all regions across the province, except for North of Moosonee, and Hydro One Networks Inc. (Hydro One) is the lead transmitter for 20 of the regions. The table below provides list of all 21 regions.

Regional Planning Regions

Burlington to Nanticoke	Northwest Ontario	Chatham/Lambton/Sarnia
Greater Ottawa	Windsor-Essex	Greater Bruce/Huron
GTA East	East Lake Superior	Niagara
GTA North	London Area	North/East of Sudbury
GTA West	Peterborough to Kingston	Renfrew
KWCG	South Georgian Bay/Muskoka	St. Lawrence
Toronto	Sudbury/Algoma	North of Moosonee*

*This region is not within Hydro One's territory.

This letter confirms that the first cycle of RP has been completed for all 21 regions. The second cycle of regional planning is currently underway, with Needs Assessment ("NA") for fifteen (15) regions and Regional Infrastructure Plan ("RIP") for five (5) regions completed to date. Each region's current status and corresponding reports are published online and can be accessed through Hydro One's Regional Planning website[1]. The regional planning status for the individual regions is discussed in the appropriate section.

Please note that the Regional Planning didn't identify / address any Renewable Energy Generation (REG) specific investments mainly because such investments are more local in nature and are being address directly by the

[1] https://www.hydroone.com/about/corporate-information/regional-plans

LDCs as part of their Distribution Planning activities.

Burlington to Nanticoke

Burlington to Nanticoke Region comprises the municipalities of Burlington, Hamilton, Oakville, Brantford, and the Counties of Brant, Haldimand, and Norfolk. Within the context of regional planning, the region is divided into four sub-regions: Brant, Bronte, Greater Hamilton, and Caledonia-Norfolk sub-regions.

Since the previous regional planning cycle, the following projects have been completed and/or underway:

- Replacement of EOL Equipment at Bronte TS, Horning TS, Mohawk TS
- Bronte TS: 115 kV B7/B8 Transmission line capacity
- Brant Switching Station: 115 kV B12BL/ B13BL Transmission line capacity
- Cumberland TS: Power Factor Correction

None of the projects listed above are expected to have any cost allocation to HOD.

The second cycle of RIP was completed and published in October 2019 (Appendix C). Based on the assessment, there are several major infrastructure investments recommended by Hydro One in the near-term planning horizon. One of the projects at Dundas TS (as indicated below) has cost allocation to HOD. The projects include but not limited to following:

- Refurbishment of EOL Line sections
- Replacing EOL equipment
- Reconfiguring 2 DESNs to single DESN at Kenilworth TS and Elgin TS
- Reconfiguring 3 DESNs to 2 DESN at Gage TS
- Installation of Capacitor Banks at Norfolk TS

Dundas TS: Load Transfer – Dundas TS has two DESN units; one of the two units has loads in excess of its supply capacity while the other DESN has spare capacity to accommodate these excess loads. The recommended plan is for HOD to balance the load between the two Dundas TS DESNs. This requires HOD to transfer excess load from Dundas TS to Dundas TS #2 by utilizing two new additional breaker positions at an estimated cost of $2 million. It is estimated that HOD will have to invest approximately $9 million in distribution infrastructure to fully implement this plan. This project is currently planned to be completed by 2021.Hydro One Distribution will be required to make capital contribution for two new additional feeder breaker position at Dundas TS # 2 in accordance with Transmission System Code.

The mid and long-term needs in the region will be assessed in the next regional planning cycle. Some of the needs include:

- EOL Equipment (i.e. cables, switchgears etc.) at several stations in the region
- Norfolk area supply capacity
- EOL 230 kV auto-transformers and DESN transformers at Beach TS and Burlington TS, which will be assessed as part of the Middleport Bulk Study by the IESO in coordination with Hydro One

The above projects are expected to improve the overall reliability performance in the region.

None of the upcoming projects (in the mid and long-term) are expected to have any cost implication to HOD.

<u>Greater Ottawa</u>

Greater Ottawa Region covers the municipalities bordering the Ottawa River from Stewartville in the West to Hawkesbury in the East and North of Highway 43. For the purpose of regional planning, the region is divided into two sub-regions: Ottawa Area and Outer Ottawa.

The first cycle RIP for the Greater Ottawa Region was published in December 2015.

The second cycle Needs Assessment report was completed and published in June 2018. The second cycle IRRP by IESO was completed in March 2020. The Hydro One led RIP will be completed and the report to be published in Q1 2021 (Appendix C).

Based on the assessments, the major infrastructure needs and or investments recommended by Hydro One in the near and mid term planning for the two sub-regions are provided below:

- Replacement of EOL Equipment at Lincoln Heights TS, Longueuil TS, Riverdale TS, Albion TS, Russell TS, Bilberry Creek TS, Merivale TS
- Overbrook Station Capacity
- Transformation Capacity in South East Ottawa
- Build Hawkesbury MTS
- Install two new LV breakers at Bilberry Creek TS

None of the projects listed above are expected to have any cost implication to HOD.

The above projects are expected to improve the overall reliability performance in the region. The future system capacity need for Greater Ottawa will be studied during the next phases of regional planning.

<u>GTA North</u>

The GTA North Region is approximately bounded by the Regional Municipality of York, and also includes parts of the Cities of Toronto, Brampton, and Mississauga. For the purpose of regional planning, the region was divided into two sub-regions: York and Western sub-regions.

Since the previous regional planning cycle, the following projects have been completed with no expected cost allocation to HOD.

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

The second cycle RIP has been completed and the report was published by Hydro One in October 2020 (Appendix C). Based on the assessment, there are several major infrastructure investments recommended by Hydro One in the near and mid-term planning horizon intended to improve the overall reliability of the region. None of the projects below are expected to have any cost implication to HOD.

- Building new stations (i.e. Markham #5 MTS, Vaughan #5 MTS, Northern York Station) to meet transformation capacity

- Replacement of EOL replacement at Woodbridge TS
- Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS

None of the projects listed above are expected to have any cost implication to HOD
The above projects are expected to improve the overall reliability performance in the region. The future system needs for GTA North will be studied during the next phases of regional planning.

GTA West
The GTA West Region covers 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 second cycle of Regional Planning for the GTA West Region is currently underway. The Needs Assessment Report was completed and published in May 2019 (Appendix C). The IRRP is currently underway, and is expected to be completed by Q1 2021.

Based on the assessment, there are several major infrastructure investments recommended by Hydro One in the near, mid and long-term planning horizon with no cost implication to HOD. The projects include but not limited to following:

- Replacement of end of life component at several stations
- Building of Halton TS # 2 to address overloading at Halton TS (T3/T4) DESN based on latest load forecast

The following needs require further regional coordination in the next phase after the completion of NA:

- Overloading circuits,
- Supply Security & supply Restoration needs,
- EOL replacement of Palermo TS transformers T3/T4 and
- GTA West Transmission corridor

These projects are expected to improve the overall reliability performance in the region, however, none of these projects are expected to have any cost implication to HOD. The needs stated in the NA will be further discussed in the upcoming IRRP and RIP.

Kitchener-Waterloo-Cambridge-Guelph Region

The KWCG region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington Counties and the Townships of Wellesley, Woolwich, Wilmont and North Dumfries.

The following transmission projects were completed by Hydro One to address near-term supply needs that were recommended in the first cycle RIP (Appendix C) with no expected cost allocation to HOD:

- The Guelph Area Transmission Refurbishment Project (GATR), placed into service since Q4 2016.
- The switching facilities work at Galt Junction to improve supply reliability for the Cambridge-Kitchener 230 kV Sub-system, placed into service in Oct 2017.

The second cycle Needs Assessment phase was completed and the report was published in December 2018.The IRRP phase will be completed and the report to be published by IESO in Q1 2021. The second cycle RIP will be completed subsequently.

The Needs Assessment has identified new needs in the region. The near and mid-term needs mainly address the aging infrastructure:

- EOL Transformer replacement at Campbell TS, Hanlon TS, Cedar TS and Preston TS
- Circuit upgrade: 115 kV B5C/ B6C, D7F/D9F and 230 kV D6V/ D7V
- Detweiler TS -Auto T2 &T4

The above projects are expected to improve the overall reliability performance in the region and are not expected to have any cost implication to HOD for the projects listed above. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

Toronto

The Toronto (formerly referred to as Metro Toronto) Region comprises the area within the municipal boundary of the City of Toronto. In the first regional planning cycle, the region was divided into two sub-regions: Central Toronto and Northern Toronto sub-regions. In the second Regional Planning cycle, the Toronto Region was assessed as a whole and no sub-regions were created.

Since the previous regional planning cycle, the following projects have been completed, none of which had any cost contribution to HOD:

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

The second cycle RIP was completed in March 2020 (Appendix C). Based on the assessment, the major infrastructure investments recommended by Hydro One in the near and mid-term planning horizon are listed below:

- Replace EOL equipment at Main TS, Manby TS, Bermondsey TS and John TS
- Refurbish EOL line sections (i.e. H1L/H3L/ H6LC/H8LC section, L9C/L12C section)
- Replace underground cables at Esplanade TS and Terauley TS
- Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS

The above projects are expected to improve the overall reliability performance in the region, however none of these projects are expected to have any cost implication to HOD. The future system needs for Toronto will be studied during the next phases of regional planning.

Windsor-Essex

The Windsor-Essex region includes the most southerly portion of Ontario, extending from Chatham southwest to Windsor. It consists of 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.

Since the previous regional planning cycle, the projects listed below have been completed and or underway. The project at Leamington TS (as indicated below) had cost allocation to HOD.

- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): two 27.6 kV feeder breakers have been replaced.
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- 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 2019)
- **Leamington TS expansion**: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)
- Kingsville TS transformers replacement (in progress, I/S 2022): Transformers T2 and T4 have been replaced with 50/83 MVA T6 in 2018. Transformers T1 and T3 replacement is underway.
- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (expected I/S 2024).

HOD will pay capital contribution as per the TSC for the expansion work at Leamington TS.

The second cycle RIP was completed and the report was published by Hydro One in March 2020 (Appendix C). The major infrastructure investments recommended by Hydro One in the near-term planning horizon are:

- Replace Lauzon TS T5 & T6 transformers replacement with larger 75/125 MVA units
- Upgrading station capacity at Kent TS
- **Build new switching station at Leamington Junction (Lakeshore TS), and new DESN station (South Middle Road TS)**
- Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS

HOD will have cost allocation to complete the new DESNs at South Middle Road TS. Each of the two DESNs at South Middle Road TS will consist of 2 x 75/100/125 MVA, 230/27.6 – 27.6 kV power transformers, twelve LV feeder positions and 2 LV capacitor banks, plus required switchgear.

Hydro One has completed necessary engagement activities and Class Environmental Assessment work for the establishment of the two stations. Hydro One obtained EA approval for the stations with the submission of the final Environmental Study Report to the Ministry of the Environment, Conservation and Parks, in January 2020. Construction is planned to commence in Q3 2020 for both Lakeshore TS and the first of the two DESNs at South Middle Road TS, and both facilities are planned to be in service in Q2 2022. The second DESN at South Middle Road TS is planned to be in service in Q3 2025.

The above projects are expected to improve the overall reliability performance in the region. The future system need for Windsor-Essex region will be studied during the next phases of the regional planning.

GTA East

GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and parts of Clarington and other parts of Durham Region.

Since the previous regional planning cycle, the following project have been completed:

- **Enfield TS**: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

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 adjacent to Clarington TS 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.

For the Enfield TS project, HOD was required to make capital contribution according to TSC.

The second cycle RIP was completed and report published in February 2020 (Appendix C). Based on the assessment, the major infrastructure investments recommended by Hydro One over near- and mid-term are as follows:

- Build Seaton MTS to increase capacity in Pickering-Ajay-Whitby Sub-region
- Replace 230 kV and 500 kV ABCB at Cherrywood TS
- Refurbish 44 kV DESN switchyard at Cherrywood TS
- Refurbishment work at Wilson TS

The above projects are expected to improve the overall reliability performance in the region, however none of the projects are expected to have any cost implication for HOD. The future system need for GTA East will be studied during the next phases of the regional planning.

Northwest Ontario

The Northwest Ontario region encompasses a large geographic area, stretching from the town of Marathon to the western and northern borders of the province, with diverse characteristics. This region is divided into four sub-regions for regional planning purposes: North of Dryden, Greenstone-Marathon, Thunder Bay and West of Thunder Bay.

Since the previous regional planning cycle, the following projects have been completed and/or underway, with no expected cost allocation to HOD:

- The new 230kV Watay connection between Pickle Lake Switching Station ("SS") and Dinorwic Junction ("Jct") will provide relief to the capacity constraint on E1C by 2021
- The forecasted load growth at Kenora MTS is anticipated to reach 23MW by year 2027, which is also near the station's 10-Day Limited Time Rating ("LTR").

The second cycle Needs Assessment was completed and the report was published in July 2020 (Appendix C). Scoping Assessment was triggered in October 2020, and it is anticipated for completion in Q1 2021. Based on the recent NA, new needs identified in the region include but not limited to:

- Aging Infrastructure at several station

- Lakehead TS Capacity Need
- Marathon TS Capacity Need
- **Sapawe DS** – This station is a 115/12.5kV distribution station owned by Hydro One Distribution. The station has a Winter Planned Loading Limit (PLL) of 4.30MW and a Summer PLL of 3.42MW (assuming 0.9 power factor), and its load growth is anticipated to reach these levels by year 2028 and 2026 respectively. Hydro One Distribution will take the lead to look into this need in co-ordination with Hydro One Transmission as part of the Distribution Planning.

There will be cost implications for HOD for the Sapawe DS project consistent with the requirements set in the TSC. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

East Lake Superior (ELS)

The ELS Region includes all of Hydro One Sault Ste. Marie's 560km of 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 region also includes Hydro One's 115kV W2C circuit supplying the Town of Chapleau from Wawa TS. During the first cycle of regional planning (led by the former Great Lakes Power Transmission), only local needs were identified and they did not require further regional coordination.

Since the previous regional planning cycle, the following projects have been completed, underway and/or on hold:

- Transmission Supply Capacity of Hollingsworth TS / Anjigami TS Transformers
- Transmission Supply Capacity of No. 1 Algoma Circuit
- Transmission Supply Reliability at Echo River TS

The second cycle of Regional Planning was initiated by Hydro One in 2019, with the NA report published in June 2019 (Appendix C) and the IRRP is currently underway, and is expected to be completed in Q1 2021. Based on the Needs Assessment, following major infrastructure investments are recommended by Hydro One over the near- and mid-term:

- Overloading of 230/115 kV Autotransformers at Third Line TS – to be addressed in Scoping Assessments
- Load restoration need at Andrew TS, Batchawana TS and Goulais TS
- Replacement of Aging Infrastructures at several stations

None of these projects above are expected to have any cost implication to HOD.

The above projects are expected to improve the overall reliability performance in the region. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

London Area

The London Area includes the Cities of Woodstock, London and St. Thomas as well as the Counties of Middlesex, Elgin and Oxford. The London Area region was divided into five sub-regions based on electrical supply boundaries for further regional planning purposes:

The RIP for the region was completed in August 2017. Based on the previous assessment the following needs were identified:

- Load Restoration for loss of M31W/M32W or loss of W36/W37
- Voltage Constraint at Tillsonburg TS
- Thermal constraint on line W8T
- **Delivery point performance at Tillsonburg TS: Aylmer-Tillsonburg Project**

The customer delivery points serving Tillsonburg Hydro and HONI distribution at Tillsonburg TS is not meeting CDPPS requirements with regards to frequency of interruptions. A number of options were explored to address the delivery point performance need. It was agreed that reversing the existing normal operating points at Cranberry Junction will be the most cost-effective option. Upon the completion of the Aylmer-Tillsonburg project, Tillsonburg TS will be normally supplied by W3T/W4T/T11T while Aylmer TS will remain normally supplied by W8T. This project is currently underway with expected in-service date of Q2 2022.

There will be cost allocation to HOD for the Aylmer-Tillsonburg project.

The second cycle NA was completed and report published in May 2020 (Appendix C). Based on the findings of the Needs Assessment, Hydro One recommends that load restoration need following the loss of W36 and W37 should be further assessed as part of Local Planning by Hydro One.

The future system need for London Area will be studied during the next phases of the regional planning.

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 region includes Frontenac County, Hasting County, Northhumberland County, Peterborough County, and Prince Edward County and related municipalities.

Since the previous regional planning cycle:

- The load supplied by Gardiner TS DESN 1 T1/T2 exceeded its summer 10 day Limited Time Rating (LTR) of 125 MW. As recommended in the previous NA, Hydro One Distribution has completed the transfer of load from DESN 1 to lightly loaded DESN 2 with excess capacity resulting in a load relief for Gardiner TS DESN 1.

The second cycle of Needs Assessment was completed and report was published in February 2020 (Appendix C). The second cycle IRRP is currently underway with expected completion date of Q4 2021. The RIP will follow. Based on the assessment, the major infrastructure investments recommended by Hydro One over near- and mid-term are:

- Replacement of EOL equipment at Lennox TS, Port Hope TS, Havelock TS and Belleville TS
- Line/ Station capacity needs at Frontenac TS, Gardiner TS and Belleville TS

Frontenac TS Over loading need shall be managed by Hydro One Transmission by coordinating with Hydro One Distribution and Kingston Hydro to undertake distribution load transfers between Gardiner TS and Frontenac TS over the near term. There is no expected cost allocation to HOD for this project.

The needs identified in the NA will be further discussed in the upcoming RIP.

South Georgian Bay/Muskoka

The geographical area of the South Georgian Bay/Muskoka 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 second cycle Needs Assessment of this region was completed and report was published in April 2020 (Appendix C). The Scoping Assessment is currently in progress with expected completion date of Q4 2020.

Based on the assessment, the major transmission and distribution infrastructure investments planned for the South Georgian Bay/Muskoka Region over the near and mid-term, as identified in the various phases of the regional planning process are:

- Replacement of 115-44kV transformers at Barrie TS, uprating 115kV circuits to 230kV, adding additional feeders to Barrie DESN
- Replacement of 230-44kV transformers and possible rebuild of low voltage switchyard at Minden TS
- Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)
- **Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS**
- Replacement of 230/44 kV transformers at Parry Sound TS
- Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS

Hydro One Distribution currently has a number of on-going maintenance and outage mitigation initiatives on the feeder lines (out of Parry Sound TS and Muskoka TS) to reduce frequent outages. Another option to mitigate outages on the 44 kV is to build new distribution lines from Bracebridge TS, and transfer some load over to Bracebridge TS. A cost-benefit/responsibility analysis will be considered by Hydro One Distribution, and other LDCs to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system.

The above projects are expected to improve the overall reliability performance in the region. The needs identified in the NA will be further discussed in the upcoming RIP.

Sudbury/ Algoma

The Sudbury/Algoma region includes the municipalities of Greater Sudbury and Espanola and surrounding areas. There are municipal LDCs serving each of those municipalities and Hydro One Distribution serves the remainder of the Region. The area is supplied from transformer stations Clarabelle TS, Coniston TS, Elliot Lake TS, Larchwood TS, Manitoulin TS and Martindale TS.

Based on the previous assessment, the following the major transmission and distribution infrastructure investments planned for the Sudbury/ Algoma Region over the near and mid-term, as identified in the various phases of the regional planning process are:

- EOL equipment replacement at Coniston TS, Espanola TS (I/S 2016), Martindale TS
- Voltage Regulation at Manitoulin TS

The second cycle of Needs Assessment was completed in June 2020 (Appendix C). Based on the N/A, the following needs were observed:

- Manitoulin TS - The station transformer capacity is restricted by a setting of a series limiting component.

- Martindale TS – Address supply capacity need

None of the above needs/projects are expected to have any cost allocation to HOD. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

Chatham/Lambton/Sarnia

The Chatham-Lambton-Sarnia region is located to the west of the Greater Toronto Area in southwestern Ontario. The region includes the municipalities of Lambton Shores and Chatham-Kent. It also includes the Townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick and the Villages of Oil Springs and Point Edward.

Hydro One developed and published a RIP in August 2017 (Appendix C). The next cycle of Regional Planning for this region is currently anticipated to commence in 2021.

The Study Team determined that no further regional coordination is required. However, several needs that are local in nature such as

- **Thermal overload of transformer T3 at Kent TS** - Based on the load forecast, there is sufficient transfer capability on the existing system to mitigate the potential transformer overload at Kent TS over the ten year study period from 2017 to 2026. Therefore Hydro One Distribution, Entegrus Inc. and Hydro One Transmission agreed that no further action is required at this time.

Therefore, there is no expected cost allocation to HOD at this point.

The future system need for Chatham/Lambton/Sarnia will be studied during the next phases of the regional planning.

Greater Bruce/ Huron

The Greater Bruce/Huron area is located to the west of the Kitchener-Waterloo region in southwestern Ontario. The region includes the municipalities of Arran–Elderslie, Brockton, Kincardine, Northern Bruce Peninsula and South Bruce. It also includes the township of Huron-Kinloss.

Hydro One completed the first cycle for the region and published the RIP report in August 2017 (Appendix C). The following Needs were identified:

- 115kV L7S Circuit – Capacity Increase
- Power Factor Review at Wingham TS and Bruce HWP B TS
- Poor Customer Delivery Point Performance Review at circuits 61M18, L7S and D10H
- **Step-down Transformation Capacity at Kincardine area**
- End-of-Life Assets at Wingham TS, Stratford TS, Seaforth TS and Hanover TS

The second cycle Needs Assessment report was published in May 2019 by Hydro One. This was followed by a Scoping Assessment report published by IESO in September 2019. The IRRP for this region is currently underway and is expected to be completed by Q2 2021.

Station capacity at Douglas Point TS was approaching limits based on anticipated load growth in the Kincardine area, in the last Regional Planning cycle. Possible solutions to address the increase load demand, such as upsizing existing transformers, permanent load transfers to neighboring load supply stations and building a new DESN facility were considered. Hydro One Distribution was working with its customer to determine their connection capacity requirements, size and timeline. Due to lack of committed load, and the incoming of natural gas in the Kincardine area, a decline in winter load demand is observed at Douglas Point TS, based on new load forecast. Therefore no mitigation is required at the time.

None of the above needs/projects are expected to have any cost allocation to HOD. The needs identified in the NA will be further discussed in the upcoming RIP.

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 has been included in the Niagara Region for Needs Assessment.

Hydro One developed and published the RIP report in March 2017 (Appendix C), and the next cycle of Regional Planning for this region is currently anticipated to commence in 2021 due to emerging needs in the region.

Based on the previous assessment, the following needs were identified:

- Replacement of EOL Equipment at several stations
- Thermal Overloading on 115kV Q4N - Under high generation scenarios at Sir Adam Beck GS #1, the loading on Q4N (Beck #1 SS x Portal Jct) can exceed circuit ratings. The potential overloading issue will be addressed under sustainment project that is scheduled for completion in 2021.

None of the projects above are expected to have any cost allocation to HOD

The second cycle of Needs Assessment for this region is currently in progress with anticipated completion date in May 2021.

North/East of Sudbury

The geographical area of the North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.

Hydro One developed and published a RIP in April 2017 (Appendix C). Based on the assessment the following needs were identified:

- Voltage regulations at Timmins TS and Kirkland Lake TS – both of which require no immediate action.

The second cycle of Regional Planning for this region is currently anticipated to commence in Q1 2021.

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.

Hydro One led Study Team developed and published a NA followed with a RIP report in July 2016 (Appendix C). There was no near-term need identified other than circuit X1P nearing its capacity, which will be monitored on a regular basis over the next three to five years.

The second cycle of Needs Assessment for this region is currently in progress with anticipated completion date in May 2021.

St. Lawrence

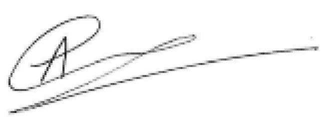
The region starts at Gananoque on the eastern end of Lake Ontario and extends to the inter-provincial boundary with Quebec. The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region.

Hydro One developed and published a NA report followed by RIP report in July 2016 (Appendix C). There were no needs in the region that required regional coordination.

The next cycle of Regional Planning for this region is currently anticipated to commence in Q2 2021.

Hydro One Distribution is an active participating member on the regional Study Teams and Hydro One is looking forward to continue working with Hydro One Distribution in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,



Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A. Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee*
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge- Guelph ("KWCG")	Northwest Ontario	Renfrew
Toronto	Windsor-Essex	St. Lawrence

*This region is not within Hydro One's territory.

Appendix B. List of LDCs for Each Region

(Hydro One as Upstream Transmitter)

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. • Centre Wellington Hydro Ltd. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity • Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines lnc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior* *Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region.	• Algoma Power Inc. • Chapleau PUC • Sault Ste. Marie PUC • Hydro One Networks Inc.
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Elexicon Energy Inc.
11. London Area	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Elexicon Energy Inc.

13. South Georgian Bay/Muskoka	• EPCOR • Hydro One Networks Inc. • InnPower Corporation • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Alectra Utilities Corporation • Elexicon Energy Inc. • Elexicon Energy Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines lnc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc.

Appendix C

Most Recent Regional Planning Reports

1. Burlington to Nanticoke: 2nd Cycle RIP Report
2. Greater Ottawa: 2nd Cycle NA Report
3. GTA North: 2nd Cycle RIP Report
4. GTA West: 2nd Cycle NA Report
5. Kitchener-Waterloo-Cambridge-Guelph: 2nd Cycle NA Report
6. Toronto: 2nd Cycle RIP Report
7. Windsor-Essex: 2nd Cycle RIP Report
8. GTA East: 2nd Cycle RIP Report
9. Northwest Ontario: 2nd Cycle NA Report
10. East Lake Superior: 2nd Cycle NA Report
11. London Area: 2nd Cycle NA Report
12. Peterborough to Kingston: 2nd Cycle NA Report
13. South Georgian Bay/Muskoka: 2nd Cycle NA Report
14. Sudbury/Algoma: 2nd Cycle NA Report
15. Chatham/Lambton/Sarnia: 1st Cycle RIP Report
16. Greater Bruce/Huron: 2nd Cycle NA Report

17. Niagara: 1st Cycle RIP Report

18. North/East of Sudbury: 1st Cycle RIP Report

19. Renfrew: 1st Cycle RIP Report

20. St. Lawrence: 1st Cycle RIP Report

SECTION 1.3 – SPF – PROCUREMENT PROCESS FOR THIRD-PARTY REPORTS

1.3.1 INTRODUCTION

In support of the Application, 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, with further details on the selection process and selected experts in Sections 1.3.2 and 1.3.3 below.

Table 1 – Reports included in the System Plans by Section

Section	Attachment	Report(s)	Witness
SPF Section 1.4	2	Hydro One Productivity Framework Review - Concentric Energy Advisors	JODOIN Joel
SPF Section 1.6	1	Customer Engagement - Overview Report – IRG	GILL Spencer
	2	Customer Engagement - First Nations Engagement Report - IRG	
	3	Customer Engagement - Métis Nation of Ontario Engagement Report - IRG	
	4	Customer Engagement - Municipalities Engagement Report - IRG	
	5	Customer Engagement - Stakeholders Engagement Report - IRG	
	6	Customer Engagement - Planners' Phase 2 Placemat - IRG	
	7	Customer Engagement - COVID Pulse Check Survey - IRG	
TSP Section 2.3	1	Transmission Capital Project Execution Review - UMS	SPENCER Andrew
	2	Pole Replacement Program Study - Guidehouse and First Quartile	JABLONSKY Donna
	3	Transformer Condition Assessment - Electric Power Research Institute, Inc. (EPRI)	JABLONSKY Donna
	4	Line Loss Assessment - Stantec	JABLONSKY Donna
DSP Section 3.3	1	Distribution Poles and Substations Benchmarking - Guidehouse (formerly Navigant) and First Quartile	FALTAOUS Peter
	2	Vegetation Management Program - CN Utility	FALTAOUS Peter
	3	Optimal Cycle Protocol – Clear Path Utility Solutions	FALTAOUS Peter
	5	Accelerated Life Testing of Meters - Hydro Quebec	PAISH David
	6	AMI Replacement Costs Benchmarking - Guidehouse and First Quartile	PAISH David
	7	Billing and Call Center Costs Benchmarking - Information Services Group (ISG)	GILL Spencer
GSP Section 4.3	1	Fleet Operations Benchmarking Report - Utilimarc	BERARDI Rob
	2	Fleet Lifecycle Study - Utilimarc	BERARDI Rob
	3	Enterprise IT Spending & Staffing Benchmark – Gartner	MARCOTTE Kevin

In the prior transmission application (EB-2019-0082), the OEB directed Hydro One to "demonstrate that its selection process for consultants for future TSPs, or similar matters, is based on a more transparent, competitive process than the approach used to select Boston Consulting Group in this proceeding."[1] Where appropriate, a competitive Request for Proposal (RFP) process was utilized to engage independent experts in connection with the Application. The following sections describe the expert engagement process in relation to the studies provided in the System Plans and provide summary information regarding the qualifications of the selected experts.

For reference, third party reports that are included in Exhibits A, C, E, H and L of the Application are provided in Table 2.

Table 2 – Reports included in Exhibits A, C, E, H and L

Exhibit	Attachment	Report	Procurement Method	Qualifications
A-04-01	1	Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application – Clear Spring Energy Advisors	Sole Sourcing	Qualifications are provided in report
A-06-01	1	US GAAP to IFRS Conversion Impact Review - PwC	RFP	Qualifications are provided in report
C-05-01	1	Working Capital Requirements of Hydro One Networks Inc.'s Transmission Business - Guidehouse	Sole Sourcing	Qualifications are provided in report
C-05-01	2	Working Capital Requirements of Hydro One Networks Inc.'s Distribution Business - Guidehouse	Sole Sourcing	Qualifications are provided in report
C-08-02	2	Capitalization of Common Corporate Costs Review - PwC	RFP	Qualification are provided in report
E-04-02	1	Common Corporate Costs Benchmarking Study - UMS	RFP	Qualification are provided in report
E-04-08	1	Report on Corporate Cost Allocation Review - Black & Veatch	RFP	Qualification are provided in report
E-06-01	1	Compensation Benchmarking Study - Mercer	Sole Sourcing	Qualifications are provided in report

[1] OEB, Decision and Order, EB-2019-0082, April 23, 2020, page 182.

E-08-01	1	Electricity Utility Plant Depreciation Rate Study - Alliance	RFP	Qualification are provided in report
H-09-01	1	Export Transmission Service Rate Cost Allocation Methodology - Elenchus	Sole Sourcing	Qualifications are provided in report
H-09-01	2	Jurisdictional Review of Export Transmission Service (ETS) Rates Study – Charles River Associates	Sole Sourcing	Qualifications are provided in report
L-04-01	1	Specific Service Charges Consultation Report – Innovative Research Group (IRG)	Sole Sourcing	*See Section 1.3.3.2 below*

1.3.2 SUMMARY OF SELECTION PROCESS

In alignment with the OEB's direction, Hydro One approached the engagement process for each third-party expert study with a view to procuring the relevant expertise and services, either through (i) a competitive RFP process where feasible and appropriate, or (ii) sole sourcing where warranted based on the scope of a particular study relative to an expert's qualifications or experiences. By tailoring the selection process in this manner, Hydro One was mindful to balance the need for a market approach to maximize competition and transparency as well as the need to be efficient given the parameters of each study and the practical cost/benefit of a RFP vs. sole sourcing process.

1.3.2.1 COMPETITIVE RFP PROCESS

Where a RFP process was undertaken, a number of third-party experts that were likely to have the requisite experience and resources to complete the study were invited to participate in the process. Upon receipt of their expression of interest, RFPs were issued describing the selection process and the scope of the engagement. Hydro One reviewed each proposal to ensure that pertinent factors – including technical, non-technical and cost considerations – were accounted for and assessed during the bid evaluation phase. Proposals were evaluated based on the aforementioned factors to determine the expert to be selected.

1.3.2.2 SOLE SOURCE

Third-party experts were selected by sole source where a study required specific expertise or technical resources, or where relevant knowledge and experience from prior Hydro One studies would significantly aid in providing continuity and efficiency.

1.3.3 SELECTED EXPERTS FOR SYSTEM PLANS' THIRD-PARTY REPORTS

The qualifications of the third-party experts noted in Table 1 are summarized below, in order of the studies' appearance in the System Plans.

1.3.3.1 CONCENTRIC ENERGY ADVISORS

Report: Hydro One Productivity Framework Review

Concentric was selected to perform the Hydro One Productivity Framework Review through a competitive RFP process. The following excerpt from the report provides an overview of Concentric's qualifications:

> *Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised North American regulated utilities on matters related to productivity measurement and reporting, benchmarking, and the quantification of synergies in the context of rate setting proceedings.*[2]

[2] Concentric Energy Advisors, Hydro One Productivity Framework Review – SPF Section 1.4, Attachment 2, Page 6

1.3.3.2 IRG

Reports: Customer Engagement Reports

i. Overview Report
ii. First Nations Engagement Report
iii. Métis Nation of Ontario Engagement Report
iv. Municipalities Engagement Report
v. Stakeholders Engagement Report
vi. Planners' Phase 2 Placemat
vii. COVID Pulse Check Survey

IRG was selected by sole source because of their expertise in public opinion research and consultation, and experience in completing similar engagements in Hydro One's last transmission filing.

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.[3]

1.3.3.3 UMS GROUP

Report: Transmission Capital Project Execution Review

UMS Group was selected to perform the Transmission Capital Project Execution Review through a competitive RFP process. *The following excerpt from the report provides an overview of UMS Group's qualifications:*

> *UMS Group has been a leading provider of utility benchmarking services for 31 years. UMS conducted its first utility benchmark in 1989 and began its first Benchmarking and Best Practice Consortia in 1990 (PACE - Performance and Competitive Excellence).*

[3] Innovative Research Group, About Innovative, 2021 – (https://innovativeresearch.ca/)

Since that time, UMS Group has continued to be a global leader in electric industry multi-company assessment and benchmarking studies. The key differentiator in our performance assessment approach is the depth of our understanding of industry best practices to drive operational performance. Our benchmark programs define current best practice productivity and service level performance in all major functional areas. Demonstrating the breadth of our experience, we have performed engagements on six continents with more than 300 companies.

UMS Group's performance database developed and maintained over the past 30 years and its UMS Group-facilitated industry consortia of leading Generation, Transmission, and Distribution companies around the world provide significant insights into the drivers of best practices and resulting top quartile service and cost level performance.[4]

1.3.3.4 GUIDEHOUSE AND FIRST QUARTILE

Reports:

i. Pole Replacement Program Study (TSP)
ii. Pole Replacement Program Study (DSP)
iii. Station Refurbishment Program Study (DSP)
iv. AMI Replacement Costs Benchmarking (DSP)

For (i) through (iii), Guidehouse (formerly Navigant Consulting) was selected by sole source because of their benchmarking expertise, access to relevant benchmarking data, and experience in completing similar prior studies related to Hydro One's pole replacement and station refurbishment practices. Guidehouse subcontracted First Quartile to form the consortium of Guidehouse and First Quartile. For (iv), the consortium of Guidehouse and First Quartile was selected through a competitive RFP process to complete the AMI Replacement Costs Benchmarking study. Their respective qualifications are further described below.

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[4] UMS Group, Transmission Capital Project Execution Review – TSP Section 2.3, Attachment 1, Page 23

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. Guidehouse's global Energy Sustainability and Infrastructure practice is the largest energy and sustainability consulting team in the industry. Guidehouse collaborates with utilities and energy companies, government and NGOs, large corporations, product manufacturers, and investors including the world's 50 largest electric, water, and gas utilities.

Guidehouse's Energy practice team has conducted cost benchmarking and best practice reviews of utility functions and investment programs for over two decades. In Ontario, Guidehouse has previously conducted cost benchmarking studies for Hydro One, Enbridge Gas Inc. and other benchmarking and comparative review work for SaskPower, BC Hydro and the OEB. Guidehouse experts have also testified on a number of occasions in support of benchmarking activities before the OEB.

First Quartile has been conducting large-scale benchmarking studies covering electric transmission, distribution, and customer service since its founding in 2007. The firm's Principals began conducting similar studies in 1989 when they were with other consulting firms, and have continued under the First Quartile name. The firm conducts annual and one-time benchmark studies each year to investigate performance and practices in greater depth for specific areas of transmission, distribution, and customer services for utilities.

Consultants at the firm have provided benchmark reports filed by Hydro One in rates proceedings since 2005, for both Transmission and Distribution, most of those as joint projects with Navigant Consulting (now known as Guidehouse). They have also supported regulatory proceedings in multiple jurisdictions in the U.S., Canada, the UK and the United Arab Emirates, providing both written and oral testimony.

1.3.3.5 EPRI

Report: Transformer Condition Assessment

EPRI was selected by sole source because of its proprietary PTX transformer condition assessment tool and experience in completing similar studies related to Hydro One's power equipment.

EPRI is an independent, non-profit organization that researches electricity generation, delivery and utilization to enhance quality of life by making electric power safe, reliable, affordable, and environmentally responsible. EPRI has an established reputation within the energy sector as a leading research and development organization that provides thought leadership, industry expertise, and collaborative value to help the electricity sector identify issues, technology gaps, and broader needs that can be addressed through effective research and development programs for the benefit of society. Its membership represents approximately 90% of the electric utility revenue generated in the U.S. and extends to participation in more than thirty five countries.

1.3.3.6 STANTEC

Report: Line Loss Assessment

Teshmont Consultants was selected by sole source because of its transmission system expertise and experience in the area of transmission line losses. After this selection was made, Teshmont Consultants was acquired by and integrated with Stantec. The description of qualifications below is provided with respect to the integrated entity.

Stantec has over 55 years of experience in the study, design, and implementation of high voltage transmission systems. Stantec is recognized as a leader in power system simulations, performing a wide variety of feasibility, planning, integration, and phenomena investigation studies using industry standards and specialized software packages. Stantec's transmission line loss experience includes bulk transmission planning studies, project feasibility studies and system impact studies, transmission line loss allocation, techno-economic analysis, and loss factor studies.

1.3.3.7 CN UTILITY

Report: Vegetation Management Program

CN Utility was selected by sole source because of its benchmarking expertise and experience in completing similar prior studies related to Hydro One's vegetation management program.

Founded in 1999, CN Utility 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.[5]

1.3.3.8 CLEAR PATH UTILITY SOLUTIONS

Report: Optimal Cycle Protocol

Clear Path was selected by sole source because of its vegetation management expertise and experience in completing similar prior studies related to Hydro One's vegetation management program (including the study that underpinned Hydro One's adoption of the optimal cycle protocol).

Clear Path is a recognized subject matter expert on utility vegetation management that helps guide gas and electric utility operations, suppliers and contractors to achieve long-term success. Clear Path lends its expertise to conceptualize and develop integrated technology solutions, workforce strategy, contract strategy and negotiations, quality assurance, regulatory outlooks and operational performance assessments. It also serves as an expert witness testifying on vegetation management and related public safety and regulatory compliance matters.[6]

[5] CN Utility Consulting, Who We Are, 2021 – About Us (https://wearecnuc.com/about/)
[6] Stephen Tankersley, About – (https://www.linkedin.com/in/stephen-tankersley-39510712/)

1.3.3.9 HYDRO QUEBEC

Report: Accelerated Life Testing of Meters

Hydro Quebec was selected by sole source because it is uniquely positioned in North America in terms of its specialized lab functionalities to handle ALT analysis.

Hydro Quebec has direct experience with Measurement Canada requirements and the typical form factors of meters. Their testing laboratories are CLAS/ISO17025 accredited and the location allowed for simplified shipping of devices within Canada. Hydro Quebec has appropriate cellular coverage on Canadian networks that makes testing with Hydro One collectors possible. It also has experience in the testing of Landis & Gyr meters which are also used by Hydro One.

1.3.3.10 INFORMATION SERVICES GROUP (ISG)

Report: Billing and Call Center Costs Benchmarking

ISG was selected to perform the Billing and Call Center Costs Benchmarking through a competitive RFP process. The following excerpt from the report provides an overview of ISG's qualifications.

> *A trusted business partner to more than 700 clients, including 75 of the top 100 enterprises in the world, ISG is committed to helping corporations, public sector organizations, and service and technology providers achieve operational excellence and faster growth. The firm specializes in digital transformation services, including automation, cloud and data analytics; sourcing advisory; managed governance and risk services; network carrier services; technology strategy and operations design; change management; market intelligence and technology research and analysis. Founded in 2006, and based in Stamford, Conn., ISG employs more than 1,300 professionals operating in more than 20 countries—a global team known for its innovative thinking, market influence,*

deep industry and technology expertise, and world-class research and analytical capabilities based on the industry's most comprehensive marketplace data.[7]

1.3.3.11 UTILIMARC

Reports:

i. Fleet Operations Benchmarking Report
ii. Fleet Lifecycle Study

Utilimarc was selected by sole source to perform these two 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 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.[8]

1.3.3.12 GARTNER

Report: Enterprise IT Spending & Staffing Benchmark

Gartner was selected to perform this study through sole sourcing because of its benchmarking expertise and experience in completing similar studies related to Hydro One's IT costs.

Gartner is a global research and advisory company, founded in 1979, with nearly 17,000 associates serving more than 14,000 client enterprises across 100 countries. Gartner specializes

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[7] Information Services Group, Billing and Call Center Costs Benchmarking – DSP Section 3.3, Attachment 7, Page 32

[8] Utilimarc, About Us, 2021 – (https://www.utilimarc.com/about-us/)

in providing senior leaders with business insights, advice and tools they need to achieve their mission-critical priorities and build the organisations of tomorrow. Gartner's insights are developed through rigorous proprietary research methodologies to ensure insights are independent and objective.[9]

[9] Gartner, Gartner at a Glance, August 4, 2020 – (https://emtemp.gcom.cloud/ngw/globalassets/intl-gb/about/documents/gartner-at-a-glance-en-gb.pdf)

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. In this regard, Hydro One continues to execute its comprehensive and rigorous process for productivity - a process that 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 ratepayers since its inception, and will continue to do so.

In response to OEB's direction in EB-2019-0082, Hydro One engaged an external consultant, Concentric Energy Advisors (Concentric), to independently review the Productivity Framework and assess how it compares to frameworks from an appropriate peer group. As a result of its review, Concentric concluded that the Productivity Framework is an effective program, and stands out as a strong and robust program compared to that of utility peers across North America. Additionally, in response to best practices confirmed by Concentric, and also in response to questions or concerns raised by intervenors in prior proceedings, Hydro One has updated and enhanced its Productivity Framework in connection with this Application and going forward, as described further in this exhibit.

This exhibit is organized as follows:

- Section 2 describes the elements of the Productivity Framework, including governance, methodology and review process, as well as Hydro One's productivity performance and achievements relative to the commitments made in the prior transmission and distribution rate applications.
- Section 3 describes Concentric's independent review of Hydro One's Productivity Framework, and the updates and enhancements that have been made to the Productivity Framework for the 2023-2027 period.

- Section 4 describes the approach by which sustained productivity savings will be passed onto ratepayers and incremental productivity savings will be quantified and passed onto ratepayers in revenue requirement.

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 on-going tracking, reporting and auditing of performance; and (iv) integrating savings into the business plan.

The main goal of Hydro One's Productivity Framework is to achieve and demonstrate continuous improvement in work execution and to manage, and achieve, the proposed capital and OM&A productivity factors, as well as the supplemental stretch factor on capital for both the Transmission and Distribution businesses. The productivity factors are based on the results of an independent third party cost benchmarking study as well as the industry productivity trend, as described in Exhibit A-04-01. The productivity factors are 0.0% for Transmission and 0.3% for Distribution, and to incent further productivity Hydro One is proposing a supplemental stretch factor on capital of 0.15% for both Transmission and Distribution consistent with the OEB's decisions in the last Transmission and Distribution applications (EB-2019-0082 and EB-2017-0049). All productivity factors are applied on a top-down, cumulative basis to the revenue requirement, reflecting the ongoing benefit to ratepayers of Hydro One's productivity program.

Incremental OM&A achievements will be tracked as part of the Earnings Sharing Mechanism proposed in this Application, as further described in Exhibit A-04-01. 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 are already obtaining the upfront benefit of this productivity via the above-described stretch factors, and could also benefit in the long-term via a lower than planned rate base. In the approved period, Hydro One will not be penalized via the

Capital In-service Variance Account (CISVA), as any verifiable productivity is intended to be excluded from the calculation, as described in Exhibit A-04-01.

1.4.2.1 PRODUCTIVITY GOVERNANCE

The Productivity Framework is managed and maintained by Finance, which oversees its effective, consistent and disciplined implementation so as 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 Finance before any savings can be reported against the established targets. This approval process ensures that each productivity initiative is carefully tracked using a detailed and robust calculation methodology so as to ensure savings are verifiable and auditable.

In a given year, productivity achievements in relation to plan commitments are reported by the executing Line of Business (LOB) on a monthly basis, and governed by Finance who subsequently reports the results to senior executives. Finance manages the overall governance of the Productivity Framework and 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 reviewed and approved by a VP or delegate).

1.4.2.2 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 are asked to identify incremental productivity initiatives that can produce savings. In consultation with Finance, the LOBs are required to demonstrate that each proposed initiative has an objective baseline as well as a defined and auditable measurement methodology.

Once these points are demonstrated, Finance works with initiative owners to validate specific planning assumptions in order to quantify demonstrable savings, and the LOBs are then asked to embed anticipated productivity improvements in the company's annual business plan and the associated investments. The embedded savings 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 of the LOBs then play an integral role in the implementation process to ensure execution of Hydro One's productivity initiatives.

In respect of reporting, the LOBs report on forecast and actuals on a monthly basis, which are verified by Finance using the approved baseline and calculation methodology for reporting to senior leaders monthly[1], and reviewed in more detail quarterly with the respective VPs for each of the LOBs. The program's results are also audited twice annually by Finance and assessed for reasonableness at year-end as part of Hydro One's Internal Audit's year-end corporate scorecard assurance review.

1.4.2.3 OVERVIEW OF ACTUAL/FORECASTED ACHIEVEMENT AGAINST PRIOR APPLICATIONS

Hydro One has used the Productivity Framework to achieve significant savings and provide benefits to ratepayers since the inception of the program, and will continue to do so. Ratepayers have received, and continue to receive, the benefit of sustained and ongoing productivity improvements. OM&A based productivity savings from previous initiatives have contributed to sharing of earnings with Distribution ratepayers through an Earning Sharing Mechanism (ESM) in 2018-20. Transmission and Distribution capital savings reflect the ability to efficiently replace or find alternate replacement opportunities of aging assets to serve ratepayers while mitigating rate impacts. The sustained impacts of, and savings from, these initiatives are ongoing and are now being considered part of regular business planning practices, by having been included in (and thus reducing) the OM&A and capital plans supporting this Application.

As shown in the Productivity Status Report, included as Attachment 1 to this exhibit, and as presented in Hydro One's productivity update to the OEB for Distribution; Hydro One has

[1] A monthly report of productivity results to the CEO and senior executives can be found within Attachment 1 to this exhibit.

maintained alignment to prior rate applications for OM&A and capital savings. The Productivity Status Report represents the actuals and forecast of savings up to 2022 reflected in Hydro One's business plan that underpins this Application.

In the prior distribution rates application, the OEB directed Hydro One to file a Productivity Status Report showing the status of the productivity initiatives listed under OEB staff IR 123 within 12 months of the Decision, and the OEB indicated that the report should be updated in the next rebasing application.[2] Accordingly, on March 4, 2020, Hydro One submitted the Productivity Status Report discussing any variances between as-filed and actual savings for 2018 and 2019. In this current application, the Productivity Status Report has been updated to reflect 2020 actuals, as well as forecast for 2021 and 2022. In addition, to ensure consistent reporting and to assist in the OEB's review, Hydro One has also included, in the Productivity Status Report, the Transmission savings from the prior transmission rates application, reflecting 2020 actuals as well as forecast for 2021 and 2022 relative to targets.

1.4.3 THIRD PARTY REVIEW AND UPDATES/ENHANCEMENTS TO THE PRODUCTIVITY FRAMEWORK

Since the time of the prior transmission rates application, Hydro One retained Concentric to perform an independent review of the Productivity Framework, and Hydro One has incorporated some updates and enhancements to its Productivity Framework as part of this Application. These have been done in order to: ensure alignment with industry best practices; address prior OEB and intervenor questions or concerns; and ensure that upfront benefits of productivity savings continue to be provided to ratepayers.

[2] EB-2017-0049, Decision and Order, March 7, 2019, p. 57, which states that "Hydro One to file, within twelve months of this Decision and Order, a report showing the status of the productivity initiatives listed in I-25-Staff-123, including actual savings, with a discussion of any deviation from plan."

1.4.3.1 CONCENTRIC'S REVIEW

As part of Concentric's review, they prepared a report detailing the results and their conclusions, entitled "Hydro One Productivity Framework Review" (the Productivity Report), which is provided as Attachment 2 to this exhibit**.**

In particular, Concentric was retained to:

- perform an independent review and assessment of Hydro One's Productivity Framework; and
- assess how Hydro One's Productivity Framework compares to frameworks of an appropriate peer group.

As described in the Productivity Report, Concentric conducted a detailed review of the Productivity Framework, and a comparison of it to productivity programs at various other utilities across North America. As part of their review, Concentric independently established a set of specific criteria that an effective productivity program encompasses. Hydro One's Productivity Framework was evaluated against those objective criteria.

In summary, Concentric concluded that Hydro One's Productivity Framework is an effective productivity program that benchmarks well in comparison to similar programs at other utilities. More specifically, Concentric's findings and conclusions in its Productivity Report include the following:

- Hydro One's Productivity Framework is an effective productivity program that meets all of the objective criteria established by Concentric;
- The Productivity Framework is effective at identifying and quantifying sustainable productivity improvements and initiatives; appropriately applies baselines data to measure productivity gains; has an appropriate validation and audit process; drives benefits that can be considered true productivity gains; and considers productivity in the context of forward looking planning;

- In respect of peer utility benchmarking, Hydro One's Productivity Framework stands out as being uniquely robust, well defined, and transparent and distinguishes itself in its continuity and scope;
- When compared to other programs that might be considered formal or rigorous (not all utilities have formal or rigorous programs), Hydro One's Productivity Framework is distinguished by the role the Productivity Framework plays in the incentive compensation process and the degree of regulatory review; and,
- Hydro One's Productivity Framework is not a 'catch all' for every component of Hydro One's provision of value to customers, but rather is focused on delivering hard cost savings that can be measured, validated, and included in the Company's business planning.

1.4.3.2 UPDATING AND RESETTING OF BASELINES

Consistent with industry best practices as confirmed in the Productivity Report[3], Hydro One is updating the Productivity Framework by updating and resetting the baseline of its Productivity Initiatives beginning in 2023. This update/enhancement will achieve the following:

- demonstrate a clear link to continuous improvement during the 2023-2027 period relative to prior proceedings;
- assist in aligning the Productivity Framework and the Custom IR Framework to the OEB's Framework of Incentive Regulation;
- align with industry best practice;
- embed historical achievement of existing initiatives in the new baseline, so as to measure and report on incremental savings over and above the prior and continuing savings from those initiatives. These legacy, though continuing, savings will now essentially be considered 'regular course planning'. This will further challenge Hydro One to identify and deliver on new and incremental savings initiatives going forward in

[3] Productivity Framework Report, p. 13, "Targets and baselines also need to be recalibrated as programs mature" and at p. 20, "Best practice in the industry supports resetting baselines regularly to achieve continuous improvement."

2023, even though prior initiatives will continue to deliver savings that are embedded into the business plan; and

- simplify the governance and reporting process.

1.4.3.3 PROGRESSIVE PRODUCTIVITY

A further enhancement that Hydro One has made relates to progressive productivity. In the prior transmission rates application, Hydro One applied progressive productivity as a bottom line reduction to its capital envelope and to the associated in-service additions to represent undefined productivity the Company would strive to achieve (i.e. additional productivity for which there were no identified initiatives), over and above the defined initiatives that were already embedded in the capital plan. In this Application, Hydro One has updated and enhanced its approach in two ways to further demonstrate how the Productivity Framework directly benefits customers:

- First, instead of applying a bottom line reduction to the capital envelope in respect of progressive productivity as was previously done for Hydro One Transmission, Hydro One will achieve its progressive productivity targets in connection with the Custom IR Framework for both Hydro One Transmission and Distribution - through productivity factors and supplemental stretch factors, as previously described in Section 2.0. This approach to progressive productivity provides direct and upfront savings and revenue requirement reductions to customers in respect of both the Distribution and Transmission businesses.
- Second, Hydro One proposes that the productivity factors and the supplemental stretch factor on capital be applied in a cumulative manner. Exhibit A-04-01 outlines the productivity factors and incremental stretch factor on capital that apply to the Distribution and Transmission businesses as part of the Custom IR proposal.

Hydro One will use the Productivity Framework, and in particular the Progressive Productivity commitments for both OM&A and capital, in order to achieve the productivity factors and supplemental stretch factors on capital proposed in this Application.

This updated approach to achieve new and incremental productivity savings will meaningfully incent savings that align with the annual, formulaic reductions to the revenue requirement. Productivity savings are expected to be captured on a cumulative basis, with achievements embedded into rate base, to deliver the annual applied productivity factors and supplemental stretch factor on capital, which will be tracked and corroborated at the initiative level using Hydro One's Productivity Framework.

Further, Hydro One remains committed to the sustained impacts of the capital based Progressive Productivity embedded in the prior Transmission rate application. Hydro One has embedded $61.0M annually from 2023 to 2027, as outlined in Table 1 below, which represents the 2022 capital commitment in the last Transmission application. Once Hydro One is able to identify $61.0M worth of productivity savings, it expects that these savings will continue in the 2023-2027 period, consistent with the goal of finding sustained productivity improvements. As at the time of filing this application, approximately $36.0M of the $61.0M has been defined by way of specific productivity initiatives annually.

Table 1 – Progressive Productivity Embedded In the Current Plan - Transmission ($M)

Description	Bridge	Test				
	2022	2023	2024	2025	2026	2027
Reduction to Capital	(48.1)	(61.0)	(61.0)	(61.0)	(61.0)	(61.0)
Reduction to In-Service Additions	(24.1)	(54.6)	(61.0)	(61.0)	(61.0)	(61.0)
Estimated Impact to rate base	(24.1)	(78.7)	(139.7)	(200.7)	(261.7)	(322.7)

As further described in the Productivity Status Report, included as Attachment 1, incrementally, other capital based initiatives as well as corporate common based initiatives allocated to capital have overachieved their targets.

1.4.4 PRODUCTIVITY SAVINGS IN THE PLAN

As indicated above, for the 2023-2027 period, Hydro One intends to achieve stretch targets, above and beyond the savings achieved up to 2022, and which are included in the 2023-2027 plan, aligned to the stretch factors proposed in this Application. The achieved savings targets will be measured and tracked continuously, and reported on a monthly basis to senior leaders to ensure that Hydro One is integrating productivity throughout the organization and meeting its planned deliverables and outcomes at a lower cost. Developing initiatives and processes that drive Hydro One to continuously become more productive and efficient over time are cornerstones of executing Hydro One's business plan.

Section 2.3 above and Attachment 1 to this exhibit outline historical and continuing savings which are embedded as part of this Application. The section below provides a further overview of the approach going forward, including in respect of new and incremental savings, for 2023 to 2027.

1.4.4.1 OVERVIEW OF PRODUCTIVITY SAVINGS GOING FORWARD

Hydro One is committed to continuing to plan and execute the work program with the aggregated legacy and continuing savings, as well as to finding new and incremental operational efficiencies to deliver on the upfront savings provided to ratepayers as part of the Custom IR Framework during the 2023-2027 period.

Hydro One's current productivity plan is expected to achieve approximately $351M of savings in 2022 between Transmission and Distribution based on the current measurement approach. This is the equivalent of reducing revenue requirement by $52M and $115M in 2023, for each of Transmission and Distribution, respectively. In other words, had Hydro One not implemented these forecasted initiatives, while holding output constant, 2023 revenue requirement would be greater by these amounts. Ratepayers will continue to receive the benefit of these initiatives as planning at this level of efficiency has become part of normal business practice.

In addition and incrementally, ratepayers will also 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 $24M and $60M of revenue requirement reductions across 2023-2027. Incremental benefit will be achieved by identifying new initiatives as well as incremental achievement of current initiatives versus their updated baselines. For example, initiatives contributing to incremental productivity are expected to be in Transmission & Stations Continuous Improvement Model, Supply Chain Procurement and Distribution Lines Project Lighthouse.

In summary, Hydro One will use the Productivity Framework in order to execute and achieve the stretch factor reductions to revenue requirement while meeting planned deliverables and outcomes. Any incremental savings in capital and OM&A beyond those embedded in Hydro One's Application as part of the Custom IR Framework both for Transmission and Distribution will result in a lower rebasing in Hydro One's next application for 2028, and incremental OM&A savings may accrue to the ratepayer through the ESM during the rate period.

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IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application and Evidence.

DISTRIBUTION PRODUCTIVITY REPORT

1 INTRODUCTION

On March 31, 2017, Hydro One Networks Inc. ("**Hydro One**") filed a Custom Incentive Rate application (EB-2017-0049) (the "**Application**") seeking approval of its distribution rates from January 1, 2018 to December 31, 2022. The Ontario Energy Board (the "**OEB**") released its decision on March 7, 2019 (the "**Decision**") approving Hydro One's Application. Among other things, the OEB directed Hydro One to file a report showing the status of the productivity initiatives listed under OEB staff IR 123 within 12 months of the Decision.[1]

In accordance with the above directive, on March 4, 2020 Hydro One filed this Productivity Status Report, addressing the status of productivity initiatives and any variances between as filed and actual savings for 2018 and 2019. Section 2 of this report has now been updated below to reflect 2020 actuals, as well as the forecast for 2021 and 2022.

In addition, as an extension of the above directive relating to the Distribution business, and to assist by ensuring consistent reporting in respect of the Transmission business, Hydro One is now also providing similar reporting for Transmission. A section further below addresses the Transmission savings from the EB-2019-0082 Transmission Application (2020-2022) (the "Prior Transmission Application"), reflecting 2020 actuals, as well as the forecast for 2021 and 2022 relative to targets.

Also provided within Section 3 of this report is a summary of the monthly reporting that show results summarized by Line of Business and reported monthly to the CEO and Senior Executives. This has been provided in response to the directive in the Prior

[1] EB-2017-0049 Decision, p. 57, which states that "Hydro One to file, within twelve months of this Decision and Order, a report showing the status of the productivity initiatives listed in I-25-Staff-123, including actual savings, with a discussion of any deviation from plan."

Transmission Application which states: “Provide a summary of its monthly reporting of productivity results to the CEO and senior executives as well as reporting on verifiable results in the next rebasing application”.[2]

2 PRODUCTIVITY STATUS REPORT

2.1 DISTRIBUTION

Consistent with the productivity savings which were forecasted for 2018 to 2022 and provided in response to OEB Staff IR 123, the table below is specific to initiatives which were identified as those that benefit the Distribution business. The actuals for 2018, 2019 and 2020 are directly aligned to the aggregated corporate results that Hydro One reports on its Corporate Scorecards.

2018 RESULTS

In 2018, Hydro One achieved $74.5 million in productivity savings as compared to $69.9 million of productivity savings which were previously forecasted in the Application. The variances between actual productivity savings achieved and forecasted productivity savings are discussed in the following three categories: capital, OM&A and common costs.

Capital: In 2018, Hydro One achieved $33.5 million in capital related productivity savings as compared to the $36.4 million previously forecasted in the Application. The main drivers for the lower productivity savings achieved are as follows:

- Hydro One achieved lower than planned savings in the Move to Mobile initiative due to higher than planned unit costs relative to the baseline; and

[2] EB-2019-0082 Decision, p. 45

- Procurement savings in Distribution were below plan largely due to lower external spend on IT projects relative to forecast, affecting savings from negotiated rate reductions which are volume driven.

The reductions in productivity savings were partially offset by increases in productivity savings achieved in the following areas:

- Hydro One worked to find incremental opportunities and accelerated the Fleet Rationalization initiative (Telematics); and
- Hydro One introduced a new productivity initiative for utilization of lower cost Pad-Mounted transformers under the Operations Category.

OM&A: In 2018, Hydro One achieved $34.9 million in OM&A related productivity savings as compared to the $29.4 million previously forecasted in the Application. The OM&A productivity savings initiatives were materially in line with forecasted levels. Higher achieved productivity savings were mostly due to the following initiatives:

- Accelerated savings in the Cable Locate Outsourcing initiative;
- Accelerated saving in the In-Sourcing of the IT contract initiative; and
- Savings realized due to Customer Call Centre Insourcing which is a new initiative.

Common: In 2018, Hydro One achieved $6 million in common related productivity savings as compared to the $4 million previously forecasted in the Application. The increase in productivity savings was due to accelerated savings opportunities achieved via Early Pay discounts under the Procurement category.

2019 RESULTS

In 2019, Hydro One achieved $97.0 million in productivity savings as compared to $72.0 million of productivity savings which were previously forecasted in the Application. The variances between actual productivity savings achieved and forecasted productivity savings are discussed in the following three categories: capital, OM&A and common costs.

Capital: In 2019, Hydro One achieved $34.9 million in capital related productivity savings as compared to the $34.2 million previously forecasted in the Application. The main drivers for the higher productivity savings achieved are as follows:

- Continued acceleration of Fleet Rationalization savings initiative (Telematics);
- Incremental Procurement savings; and
- Incremental savings in the utilization of lower cost Pad-Mounted transformers which falls under the Operations Category.

These additional savings were partially offset by decreases in productivity savings mostly in the Move to Mobile initiative due to higher unit costs.

OM&A: In 2019, Hydro One achieved $39.1 million in OM&A related productivity savings as compared to the $33.7 million previously forecasted in the Application. Higher achieved productivity savings were mostly due to the following initiatives:

- Productivity savings realized due to Customer Call Centre Insourcing which is a new initiative; and
- Accelerated savings in the Cable Locate Outsourcing initiative.

These increases in productivity savings were partially offset by decreases in productivity savings realized in the following areas:

- Lower Move to Mobile initiative savings due to higher unit cost; and
- Lower ISD savings related to the Application maintenance contract reductions.

Common: In 2019, Hydro One achieved $23.0 million in common related productivity savings as compared to the $4.2 million previously forecasted in the Application. The increase in productivity savings was due to Hydro One's Corporate Costing initiative which significantly reduced vacancies and limited contract spending to critical functions. This was discussed in detail within the Prior Transmission Application.

2020 RESULTS

In 2020, Hydro One achieved $146.9 million in productivity savings as compared to $82.9 million of productivity savings which were previously forecasted in the Application. The variances between actual productivity savings achieved and forecasted productivity savings are outlined below.

Capital: In 2020, Hydro One achieved $50.3 million in capital related productivity savings as compared to the $37.8 million previously forecasted in the Application. The main drivers for the higher productivity savings achieved are as follows:

- Continued savings driven by annual reductions of Fleet capital replacements;
- Procurement savings due to lower external spend on construction contracts and materials; and
- Improved Planning in distribution station designs, which enabled the deployment of lower cost infrastructure.

These additional savings were partially offset by decreases in productivity savings, mostly in the Move to Mobile initiative due to higher unit costs.

OM&A: In 2020, Hydro One achieved $73.8 million in OM&A related productivity savings as compared to the $40.9 million previously forecasted in the Application. Higher achieved productivity savings were mostly due to the following initiatives:

- Productivity savings realized due to Customer Call Centre Insourcing;

- Forestry Line Patrols cost reductions as a result of bundling overhead asset inspections with vegetation management defect patrols; and
- Accelerated savings from outsourcing Cable Locates to lower cost service providers.

Common: In 2020, Hydro One achieved $22.9 million in common related productivity savings as compared to the $4.2 million previously forecasted in the Application. The increase in productivity savings was due to Hydro One's Corporate Costing initiative which significantly reduced vacancies and limited contract spending to critical functions.

Below is an updated chart as it appeared in OEB staff IR 123, reflecting the as filed forecast for 2018-2022, actual numbers for 2018-2020 and revised forecast for 2021 and 2022.

	Category in Rate Filing	Initiative Summary	Measurement and Expected Benefit	2018 As Filed	2018A	2019 As Filed	2019A	2020 As Filed	2020A	2021 As Filed	2021B	2022 As Filed	2022P
Capital	Move to Mobile / Distribution Optimization & Transformation	Field Force	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Field Meter Service, Component Replacement*	$ 10.3	$ 2.7	$ 10.5	$ (4.2)	$ 10.7	$ (2.3)	$ 10.7	$ -	$ 10.7	$ -
		Workforce Planning	Workforce planning *Measures the reduction in headcount as a result of the elimination of manual tasks/activities completed by both the BASC and FBC. There are two major projects that contribute to the reduction in headcount; M2M (Move to Mobile) and DOT (Design Optimization and*	$ -	$ 1.3	$ -	$ 0.7	$ -	$ 1.0	$ -	$ 2.3	$ -	$ 5.0
	Procurement	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 (Capital program spend)*	$ 12.7	$ 7.2	$ 13.2	$ 17.7	$ 17.0	$ 22.7	$ 16.7	$ 16.9	$ 18.6	$ 17.2
	Information Techr	Contract Reductions	Infrastructure Rationalization/Contract Reductions *Expected capital allocation of negotiated reductions*	$ -	$ -	$ 0.3	$ -	$ 0.3	$ 0.6	$ 0.3	$ -	$ 0.3	$ -
	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.01	$ -	$ 0.01	$ -	$ 0.01	$ -	$ 0.01	$ -	$ 0.01	$ -
		Pole Replacement	Distribution Pole Replacements *Measures the unit cost reduction of Pole Replacements. Distribution Asset Planning began using the Risk Spend Efficiency (RSE) Planning approach where assets were replaced based on their risk score after an assessment of their impact to Reliability, Safety and Environment.*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.0	$ -	$ 11.2
		Station Design	Padmount Transformers *Improved Planning to enable deployment of lower cost infrastructure with like-for-like service*	$ -	$ 1.97	$ -	$ 1.51	$ -	$ 4.85	$ -	$ 13.4	$ -	$ 5.9
	Telematics	Fleet Telematics and Right-Sizing	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ 13.4	$ 20.3	$ 10.1	$ 19.3	$ 9.8	$ 23.5	$ 9.6	$ 22.7	$ 9.3	$ 22.8
OM&A	Customer	eBilling	Lower Cost per Customer *Expected customers enrolled in eBilling x Unit Savings*	$ 1.8	$ 1.8	$ 2.6	$ 3.5	$ 3.2	$ 5.5	$ 4.1	$ 5.3	$ 4.8	$ 6.3
		Insourcing	*Insourcing the contact centre has improved customer service, increased flexibility, and reduced costs as a result of the decline in the number of FTE required to successfully operate the Customer Contact Centre.*	$ -	$ 2.2	$ -	$ 9.1	$ -	$ 12.8	$ -	$ 10.5	$ -	$ 12.5
	Information Technology	Contract Reductions	Infrastructure Rationalization/Contract Reductions *Expected savings from server/database decommissioning and negotiated infrastructure and application maintenance contract reductions*	$ 7.4	$ 9.1	$ 8.3	$ 5.4	$ 11.5	$ 11.7	$ 11.5	$ 14.5	$ 11.5	$ 16.7
		Contract Rates - Minor Enhancement	(Old Rate - New Rate) * Expected ME Hours *Negotiated savings x Expected need for minor enhancement hours in business plan*	$ 0.9	$ 1.5	$ 1.0	$ 0.7	$ 0.9	$ 0.6	$ 0.9	$ 0.8	$ 0.9	$ 0.8
		Telecom Services Contracts	Lower Cost per Contract *Reflects negotiated reduction in contract price*	$ 0.6	$ 0.6	$ 0.7	$ 0.6	$ 0.7	$ 1.1	$ 0.7	$ 0.6	$ 0.7	$ 0.6
	Move to Mobile / Distribution Optimization & Transformation	Workforce Planning	Workforce planning *Measures the reduction in headcount as a result of the elimination of manual tasks/activities completed by both the BASC and FBC. There are two major projects that contribute to the reduction in headcount; M2M (Move to Mobile) and DOT (Design Optimization and*	$ 2.7	$ 0.5	$ 2.8	$ 0.3	$ 2.9	$ 0.4	$ 2.9	$ 0.6	$ 2.9	$ 0.7
		Field Force	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Field Meter Service, Component Replacement*	$ -	$ 1.3	$ -	$ (1.9)	$ -	$ 2.4	$ -	$ -	$ -	$ -
	Operations	Cable Locate Outsourcing	(Historical Cost - New Cost) * # of Units *Reflects negotiated savings for planned units being outsourced*	$ 7.6	$ 11.4	$ 7.8	$ 14.6	$ 7.9	$ 15.5	$ 8.1	$ 14.3	$ 8.2	$ 14.5
		Crew Dispatch Optimization	Single Person Dispatch *Measures the reduced cost of trouble calls by increasing the instances where trouble calls could be resolved with a single person dispatched*	$ -	$ -	$ -	$ -	$ -	$ 1.2	$ -	$ 1.1	$ -	$ 1.1
		Fault Indicator Deployment	Lower Labour Hours per Unit *Estimate based on expected time savings for responding to a line fault. Tracked using historical data compared to actual response time*	$ 0.8	$ -	$ 0.8	$ -	$ 0.8	$ -	$ 0.8	$ -	$ 0.8	$ -
		Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to bundling overhead asset inspections with defect patrols and expected overall unit volume reduction in trouble calls*	$ 2.8	$ 1.5	$ 4.1	$ 2.2	$ 5.9	$ 14.1	$ 6.9	$ 14.6	$ 7.9	$ 36.7
		Stations Efficiencies	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.3	$ 0.4	$ 0.4	$ 0.1	$ 0.4	$ 0.1	$ 0.4	$ 0.6	$ 0.4	$ 0.6
		Engineering	FTE Reduction *A reduction in support staff that was utilizing the legacy software*	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
		Flexible Bill Window	Lower Cost per Unit for Meter Reads *Expected savings from a unit reduction in demand for manual meter reads and lower unit cost due to gained scheduling efficiencies*	$ 1.5	$ 1.5	$ 1.5	$ 1.6	$ 1.5	$ 3.5	$ 1.5	$ 1.8	$ 1.5	$ 1.8
	Procurement	Procurement	IT Software Cost Reduction & RFP Rationalization *Reflects expected and negotiated savings*	$ 0.9	$ 1.7	$ 1.7	$ 1.5	$ 2.6	$ 3.2	$ 2.6	$ 4.7	$ 2.6	$ 4.7
	Facilities and Real Estate	Property Tax Appeals	Property Tax Reductions and Refunds *Measures benefit as a result of having proceeded through the Statutory Appeal process*	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ -
		Faclities Maintenance	Lower Contract Cost *Reduced facilities maintenance costs as a result of re-tendering the contract*	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ -	$ -	$ -	$ -
	Telematics	Fleet Telematics and Right-Sizing	Lower Liters of Fuel per KM *Reflects results of pilot program with expected reduction in Liters of fuel per KM driven*	$ 0.8	$ 0.1	$ 0.8	$ 0.1	$ 1.4	$ (0.2)	$ 1.3	$ 0.2	$ 2.2	$ 0.2
CCC	Administrative	Corporate Common Head Count Reductions	FTE Reduction *Identified headcount reductions by position in Corporate Common*	$ 1.7	$ 1.3	$ 1.9	$ 19.2	$ 1.9	$ 18.7	$ 1.9	$ 18.2	$ 1.9	$ 17.0
	Procurement	Procurement	Lower Cost *Realized reduction in contracted spend in Corporate Common*	$ 2.3	$ 4.8	$ 2.3	$ 3.9	$ 2.3	$ 4.2	$ 2.3	$ 3.2	$ 2.3	$ 3.2
Total	Capital			**$ 36.4**	**$ 33.5**	**$ 34.2**	**$ 34.9**	**$ 37.8**	**$ 50.3**	**$ 37.3**	**$ 66.2**	**$ 39.0**	**$ 62.0**
	OM&A			**$ 29.4**	**$ 34.9**	**$ 33.7**	**$ 39.1**	**$ 40.9**	**$ 73.8**	**$ 42.9**	**$ 70.9**	**$ 45.5**	**$ 98.4**
	Corporate Common			**$ 4.0**	**$ 6.0**	**$ 4.2**	**$ 23.0**	**$ 4.2**	**$ 22.9**	**$ 4.2**	**$ 21.4**	**$ 4.2**	**$ 20.2**
	Total Distribution			**$ 69.9**	**$ 74.5**	**$ 72.0**	**$ 97.0**	**$ 82.9**	**$ 146.9**	**$ 84.4**	**$ 158.6**	**$ 88.7**	**$ 180.6**

In summary, Hydro One achieved an additional $4.5 million in 2018, an additional $25.0 million in 2019, and an additional $64.0 million in 2020, relative to the forecast filed in the Application. Ratepayers have directly benefited from the incremental OM&A savings as the associated cost reductions have contributed towards Hydro One's Earnings Sharing Mechanism, resulting in a refund to customers. For 2021 and 2022, the favourable trajectory relative to the prior application is forecasted to continue, which also includes savings associated with repatriating Inergi staff. As of March 1, 2021 Hydro One has reached an agreement to repatriate a majority of the Inergi IT staff which were supporting the execution of the Inergi LP outsourcing contract. Certain sustainment and project functions will continue to be provided by Capgemini, with the remaining staff moving in-house. Additionally, Hydro One will be repatriating Inergi staff in the Source to Pay function effective November 1, 2021, and in the Finance and Human Resources (Payroll) effective January 1, 2022. The incremental cost reductions from this agreement have been reflected in this current application.

2.2 TRANSMISSION

Consistent with the productivity savings which were forecasted for 2020 to 2022 in the Prior Transmission Application, the table below is specific to initiatives which were identified as those that benefit Transmission. The actuals for 2020 are directly aligned to the aggregated corporate results that Hydro One reports on its Corporate Scorecards.

2020 RESULTS

In 2020, Hydro One achieved $127.6 million in productivity savings as compared to $97.9 million of productivity savings which were previously forecasted in the Prior Transmission Application. The variances between actual productivity savings achieved and forecasted productivity savings are discussed below.

Capital: In 2020, Hydro One achieved $68.2 million in capital related productivity savings as compared to the $61.7 million previously forecasted. These results include progressive related capital productivity, which shows that in aggregate, Hydro One achieved the total capital commitments set out in the Prior Application. The main drivers for the higher productivity savings achieved are as follows:

- Procurement savings due to lower external spend on construction contracts and materials;
- Leveraging power quality monitoring on existing wholesale revenue meters; and
- Reduction in percentage of overtime hours worked versus prior year baseline.

OM&A / External Revenue: In 2020, Hydro One achieved $32.5 million in OM&A and external revenue related productivity savings as compared to the $14.7 million previously forecasted. Higher achieved productivity savings were mostly due to the following initiatives:

- Secondary Land Use revenue which reduces revenue requirement and successful Property Tax appeals;
- Stations scheduling efficiencies and lower ground and site maintenance costs; and
- Reductions in percentage of overtime hours and lower costs from repatriating Inergi staff.

Common: In 2020, Hydro One achieved $26.8 million in common related productivity savings as compared to the $21.5 million previously forecasted in the Transmission 2020-2022 application. The increase in productivity savings was driven by Hydro One's Corporate Costing initiative.

Below is an updated chart for Transmission, reflecting the as filed forecast for 2020-2022, actual numbers for 2020 and revised forecast for 2021 and 2022.

	Category	Initiative Summary	Measurement and Expected Benefit	2020 Tx As filed	2020A	2021 Tx As filed	2021B	2022 Tx As filed	2022P
Capital	Operations	Engineering	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE reductions in Engineering through the implementation of EDM software enhancements*	$ 0.9	$ 1.5	$ 1.1	$ 1.6	$ 1.4	$ 1.7
Capital	Operations	Fleet Telematics and Right-Sizing	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ 11.0	$ 11.6	$ 11.1	$ 11.4	$ 11.4	$ 11.4
Capital	Operations	Transmission and Stations	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for Transmission and Stations efficiencies and Temporary work HQ. Calculated by measuring expected benefit per occurrence*	$ 0.7	$ 1.3	$ 0.7	$ 1.0	$ 0.7	$ 1.0
Capital	Operations	OT Reductions	Overtime Reductions *Targeted effort to reduce the number of relative OT hours worked as a % vs prior year baseline*	$ 0.5	$ 3.2	$ 0.5	$ 1.6	$ 0.5	$ 1.7
Capital	Operations	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 (Capital program spend)*	$ 30.3	$ 42.4	$ 34.9	$ 29.2	$ 35.8	$ 37.4
Capital	Operations	Progressive Defined	Targeted Efficiencies - Defined *Efficiencies that have been allocated to specific Operating initiatives that are not yet proven. Allocations taken in Business Plan are primarily based on preliminary estimates. Ex - Continuous Improvement Model. Actuals are proven achievements and continue to be planned as Progressive.*	$ 6.1	$ 4.7	$ 11.6	$ 26.8	$ 11.6	$ 28.8
Capital	Operations	Progressive Undefined	Targeted Efficiencies - Undefined *Escalating commitment of 1-3% of capital work program to be allocated to future initiatives as they are defined.*	$ 10.9	$ -	$ 27.4	$ 6.7	$ 49.4	$ 19.3
Capital	Operations	Scheduling Tool	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE reductions in Scheduling Staff through the implementation of software enhancements*	$ 0.9	$ 0.4	$ 0.9	$ 0.5	$ 0.9	$ 0.5
Capital	Operations	System Planning	Transformer Right-Sizing and Wholesale Meters Power Quality Monitoring *Transformer right-sizing will result in reduced costs associated with the difference between the right-sized replacement and the like-for-like replacement of transformers and associated equipment. Leveraging power quality monitoring on exisiting wholesale revenue meters enabled Capital reductions*	$ -	$ 2.8	$ -	$ 4.7	$ -	$ 12.7
Capital	Operations	Wrench Time	Lower Cost Per Unit of Operation *Utilize unit reporting to compare like for like work in actuals vs baseline year to determine $ savings per operation.*	$ 0.5	$ -	$ 0.5	$ -	$ 0.5	$ -
Capital	Information Technology	Contract Reductions	Overhead Optimization *Lower cost resulting from reduced Inergi IT Contract overheads applied to IT Capital projects*	$ -	$ 0.4	$ -	$ -	$ -	$ -
OM&A / External Revenue	Information Technology	Contract Reductions	Cost Reduction Based on Historical Spend *Lower cost resulting from Inergi IT Contract renegotiation. Measured against baseline spend for same scope of work*	$ 6.4	$ 7.8	$ 8.9	$ 9.2	$ 9.6	$ 10.4
OM&A / External Revenue	Customer Service	Insourcing	Settlements In-sourcing *Insourcing the Inergi settlements team has to reduced costs while successfully operating the settlement function.*	$ -	$ 0.1	$ -	$ -	$ -	$ -
OM&A / External Revenue	Facilities and Real Estate	Property Tax Appeals	Property Tax Reductions and Refunds *Measures benefit as a result of having proceeded through the Statuatory Appeal process*	$ -	$ 1.0	$ -	$ -	$ -	$ -
OM&A / External Revenue	Facilities and Real Estate	Faclities Maintenance	Lower Contract Cost *Reduced facilities maintenance costs as a result of re-tendering the contract*	$ -	$ 0.2	$ -	$ -	$ -	$ -
OM&A / External Revenue	Facilities and Real Estate	Secondary Land Use Revenue	Secondary land use revenue (e.g., parking, pipelines, transit) *Generated on HONI-owned lands and provincially owned lands through licences, easements and land sales transaction*	$ -	$ 11.3	$ -	$ 5.8	$ -	$ 6.1
OM&A / External Revenue	Operations	Condition Assessments	Preventive Maintenance and Condition Assessment *Efficiencies from improved approach foot and helicopter patrol cycle methods, as well as reduced maintenance from RTV coated insulators*	$ -	$ -	$ -	$ 1.5	$ -	$ 2.1
OM&A / External Revenue	Operations	Engineering	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE and contractor reductions in Engineering through the implementation of PCMIS software enhancements*	$ 0.6	$ 0.6	$ 0.6	$ 0.5	$ 0.6	$ 0.7
OM&A / External Revenue	Operations	Fleet Telematics and Right-Sizing	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ -	$ (0.0)	$ -	$ 0.1	$ -	$ 0.1
OM&A / External Revenue	Operations	Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit cost reduction right-of-way brush control*	$ 2.0	$ 1.1	$ 3.4	$ -	$ 2.0	$ -
OM&A / External Revenue	Operations	Transmission and Stations	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for Transmission and Stations efficiencies and Temporary work HQ. Calculated by measuring expected benefit per occurrence*	$ 1.2	$ 3.2	$ 1.2	$ 2.4	$ 1.2	$ 2.4
OM&A / External Revenue	Operations	Network Operating Efficiencies	Operational Program Efficiencies *Unit cost reduction in completing Load Transfer studies through Network Operating group*	$ 1.0	$ 0.9	$ 1.0	$ 0.9	$ 1.0	$ 1.3
OM&A / External Revenue	Operations	OT Reductions	Overtime Reductions *Targeted effort to reduce the number of relative OT hours worked as a % vs prior year baseline*	$ 0.5	$ 2.2	$ 0.5	$ 2.4	$ 0.5	$ 2.4
OM&A / External Revenue	Operations	Progressive Defined	In-house Oil Analysis *Crews now have local oil sample analysis devices required to undergo analysis to assess the operability of the equipment. Past practice was to outsource all oil samples for testing.*	$ -	$ 0.2	$ -	$ 0.2	$ -	$ 0.2
OM&A / External Revenue	Operations	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*	$ 0.8	$ 1.2	$ 0.8	$ 2.6	$ 0.9	$ 2.6
OM&A / External Revenue	Operations	Scheduling Tool	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE reductions in Scheduling Staff through the implementation of software enhancements*	$ -	$ 0.4	$ -	$ 0.5	$ -	$ 0.5
OM&A / External Revenue	Operations	Wrench Time	Lower Cost Per Unit of Operation *Utilize unit reporting to compare like for like work in actuals vs baseline year to determine $ savings per operation.*	$ 2.3	$ 2.2	$ 2.3	$ 1.5	$ 2.3	$ 1.5
CCC	Corporate	Corporate Initiatives	Corporate Cost Initiative *Identified reductions in vacancies and contractor and consulting spending*	$ 19.1	$ 22.6	$ 16.5	$ 23.2	$ 13.6	$ 22.1
CCC	Operations	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 (Corporate Allocation)*	$ 2.3	$ 4.2	$ 2.3	$ 3.2	$ 2.3	$ 3.2
Total	**Total Capital**			**$ 61.7**	**$ 68.2**	**$ 88.7**	**$ 83.3**	**$ 112.2**	**$ 114.4**
Total	**Total OM&A / External Revenue**			**$ 14.7**	**$ 32.5**	**$ 18.6**	**$ 27.5**	**$ 17.9**	**$ 30.2**
Total	**Total Common**			**$ 21.5**	**$ 26.8**	**$ 18.8**	**$ 26.4**	**$ 16.0**	**$ 25.3**
Total	**Total Transmission**			**$ 97.9**	**$ 127.6**	**$ 126.1**	**$ 137.3**	**$ 146.1**	**$ 169.9**

In summary, Hydro One achieved an additional $29.7 million in 2020 relative to the forecast filed in the Prior Transmission Application. For 2021 and 2022, the favourable trajectory relative to the prior application is forecasted to continue, which also includes savings associated with repatriating Inergi staff, as previously described. As of March 1, 2021 Hydro One has reached an agreement to repatriate a majority of the Inergi IT staff which were supporting the execution of the Inergi LP outsourcing contract. Certain sustainment and project functions will continue to be provided by Capgemini, with the remaining staff moving in-house. Additionally, Hydro One will be repatriating Inergi staff in the Source to Pay function effective November 1, 2021, and in the Finance and Human Resources (Payroll) effective January 1, 2022. The incremental cost reductions from this agreement have been reflected in this current application.

3 MONTHLY REPORTING OF RESULTS

In-year, the above results are summarized by Line of Business and reported monthly to the CEO and Senior Executives. By way of example, below is the report summarizing the December 2020 Year-To-Date actuals and Year-End forecast for all initiatives in the Productivity Program.

Productivity $mm LoB	Description	December YTD Actual	December YTD Budget	Year-End Forecast Current	Year-End Forecast Budget	Status
Distribution Lines	Two key initiatives comprise the majority of the YE Budget: the Cable Locate Outsourcing initiative that decreased the unit price per locate and Move to Mobile that improves field labour efficiency using vehicle installed tablets and new software integrated with SAP.	18.2	22.8	18.2	22.8	
Forestry	Forestry Dx Line Patrol initiative to reduce the need for Provincial Lines to conduct their own patrols of the same lines. OCP Trouble Call Reduction initiative, where hazard tress have been removed proactively which decreases the number of trouble calls required.	15.2	21.8	15.2	21.8	
Tx and Stations	Overtime Reduction initiative that implemented stricter controls and constraints on overtime requests to reduce overall overtime hours. Other key initiatives include; Wrench Time Studies to improve labour efficiency, Reducing Hydro Vac Excavations in Stations and Reconditioning Oil in house.	17.8	24.0	17.8	24.0	
System Operations	Load Transfer Studies initiative that reduces the unit cost to complete a Load Transfer Study using the Distribution Management System.	1.0	1.4	1.0	1.4	
Planning	Deploying Padmount Transformers technology in Distribution Stations, reduces the cost of the infrastructure for equivalent service. Enabling Power Quality Monitoring capability on existing Wholesale Revenue meters forgoes the redundancy to install Power Quality Monitors and has been reflected as a reduction in the business plan.	7.8	10.3	7.8	10.3	
Engineering	GIS and DOM Team Migration and PCMIS Software upgrade, reducing organizational costs vs historical cost. EDM Platform will change the way we track, manage and store drawings, increasing productivity and compliance.	3.4	2.8	3.4	2.8	
Operations Total		**63.4**	**83.1**	**63.4**	**83.1**	
Customer Service	Savings driven by Call Center Insourcing and switching customers to eBilling.	22.0	14.4	22.0	14.4	
Fleet	Reduction of Fleet vehicles as a result of increased visibility to LOB requirements from Telematics software. This lead to reduced capital costs to purchase replacement vehicles and lower overall maintenance costs from a reduced fleet.	34.9	28.9	34.9	28.9	
Supply Chain	Strategic Sourcing initiatives that have driven down material and service prices compared to historical costs. Also includes savings from Non-Sourcing initiatives such as enhanced Early Pay Discounts and Volume rebates.	80.7	58.9	80.7	58.9	
Real Estate	Secondary Land Use Revenue Initiative to drive more competitive lease rates by leveraging appraisal reports and property assessments to ensure full value is achieved in lease contracts.	12.9	5.2	12.9	5.2	
Corporate	Savings are measured by comparing in year Corporate Costs compared to a historical baseline. The reduction compared to historical baseline is the savings.	49.9	49.1	49.9	49.1	
Information Technology	Savings primarily from the Inergi ITO Contract Reduction measured through a lower fixed price contract compared to historical cost.	22.2	20.9	22.2	20.9	
Corporate Total		**222.6**	**177.4**	**222.6**	**177.4**	
Hydro One Total		**286.0**	**260.5**	**286.0**	**260.5**	

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HYDRO ONE PRODUCTIVITY FRAMEWORK REVIEW

June 23, 2021

CONCENTRIC ENERGY ADVISORS

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SECTION 1:
LIMITATIONS AND CAVEATS

The following are limitations and caveats associated with the Study:

- Our analysis included a review of the Productivity Framework, as well as multiple rounds of communications with the Company and its peers through which Concentric was able gain an understanding of Hydro One's and other utilities' productivity programs, but we relied on Hydro One and the companies in our survey to provide complete and accurate data, and did not independently validate such data.
- Because the majority of the data provided by the peer companies was not otherwise publicly available, the peer utilities that Concentric surveyed provided their information on a confidential basis. Concentric lists the companies in Section 5, but otherwise masked the names of the utilities in our analyses and figures to preserve that confidentiality. Further, we did not share peer group-specific details or data (other than those disclosed in this report) with Hydro One.
- As discussed herein, the Productivity Framework is focused on achieving hard cost savings. Given the scope of the engagement, the Study did not encompass a review of other key elements of customer value like safety, reliability, and customer satisfaction.
- Our review of the Productivity Framework focused on the initiatives and results embedded in Hydro One's most recent business plan.

SECTION 2:
EXECUTIVE SUMMARY

Overview

On behalf of Hydro One, Torys LLP ("Torys") (legal counsel to Hydro One Networks Inc. ("Hydro One" or the "Company")) retained Concentric Energy Advisors, Inc. ("Concentric") to (i) provide an independent assessment of Hydro One's process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs (the "Productivity Framework"), and (ii) compare the Productivity Framework to comparable frameworks from an appropriate peer group (together referred to as the "Study"). This report provides the results of the Study.

The Productivity Framework is a structured program developed by Hydro One to identify, measure, and report increases in productivity and cost savings in both capital and operating, maintenance, and administration ("OM&A") spending across the Company. At its most detailed level, the Productivity Framework identifies "initiatives" that represent specific, calculable measurements of productivity. Proposed initiatives must meet certain criteria to be included in the Productivity Framework, including that the initiative must be measurable, verifiable, and auditable. The current Productivity Framework focuses only on hard cost savings.

Productivity Framework initiatives are identified and tracked in each of Hydro One's lines of business, and Hydro One incorporates productivity improvement resulting from the Productivity Framework in its budgets and forward-looking business plans. Furthermore, results from the Productivity Framework are included in the Company's corporate scorecards upon which incentive compensation is based.

In addition to specific initiative-based productivity, Hydro One has also historically included "Progressive Productivity" in the Productivity Framework targets and its business plan. Progressive Productivity is a reduction to Hydro One's business plan costs that are over-and-above its identified productivity savings and is a method by which to stretch the organization and commit to additional savings in advance of identifying specific initiatives.

Definition of an Effective Productivity Framework

Concentric independently established a set of criteria against which to evaluate Hydro One's Productivity Framework, drawing from Concentric's experience, observations regarding other utility productivity programs, a review of Ontario Energy Board findings regarding productivity, and industry research. These criteria indicate that an effective productivity program exhibits the following characteristics:

1. Effective at identifying and quantifying sustainable productivity improvements and initiatives;
2. Holistic in nature (i.e., targets all levels of the business);
3. Promotes a corporate culture that embraces productivity as a core value;
4. Applies appropriate baseline data to measure productivity gains;
5. Benefits are validated with an appropriate validation and audit process;
6. Avoids perverse incentives (i.e., does not sacrifice customer value, safety, and reliability for short term savings);
7. Drives benefits that can be considered true productivity gains (i.e., more output for the same resources, or the same output using fewer inputs); and
8. Integrates bottom-up business line initiatives with top-down planning, and considers productivity in the context of forward-looking planning.

These criteria provided Concentric with an objective basis for evaluating Hydro One's program and benchmarking it against programs at other utilities. These are not minimum criteria, as a productivity program can incorporate some of these elements and still be effective at delivering meaningful productivity gains and cost savings for the benefit of customers.

Methodology

To evaluate how Hydro One's program scored against the above criteria, as well as in relation to industry peers, Concentric conducted the Study in two parts: the first part involved an assessment of Hydro One's framework by reviewing primary source documentation provided by Hydro One and conducting interviews with internal stakeholders of the Productivity Framework, and the second involved research of productivity programs employed by other utilities to benchmark Hydro One's program in terms of its effectiveness and comprehensiveness.

Findings

Based on Concentric's assessment, Hydro One's Productivity Framework is an effective productivity program that meets the above criteria. Specifically, the Productivity Framework: (1) is effective at identifying and quantifying sustainable productivity improvements and initiatives; (2) is holistic and targets all levels of business; (3) is driven by a corporate culture that embraces productivity as core value; (4) utilizes appropriate baselines to measure productivity gains; (5) has an appropriate validation and audit process; (6) avoids perverse incentives; (7) drives benefits that can be considered true productivity gains; and (8) considers productivity in the context of forward-looking planning. Concentric also finds that the Progressive Productivity element of the Productivity Framework provides incentives and challenges the Company to deliver additional productivity and savings.

Concentric also identified a potential challenge and a potential opportunity for Hydro One's program. First, Concentric understands from our review of the Productivity Framework that Hydro One has already achieved significant and material productivity initiatives and savings. This means the Company 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 existing program. However, we would expect a utility of Hydro One's scale to be able to meet this challenge by continuing to identify opportunities for productivity improvements, even over the long term. This may require enhancements to the current program to accommodate long-term continuous productivity.

Second, there may also be an opportunity to capture additional sources of productivity (*e.g.*, avoided costs) not currently included in the program, but this would need to be balanced with maintaining the key criteria discussed above and complying with the rigorous nature of the Productivity Framework.

In terms of findings from our peer utility benchmarking, Concentric found that Hydro One's Productivity Framework stands out as being uniquely robust, well defined, and transparent when compared to productivity programs at other North American utilities. Concentric's research indicates that many peer utilities do not have a clearly defined productivity program with robust tracking and reporting mechanisms such as those used by Hydro One. Among the utilities that Concentric reviewed, a few cited their regulatory framework or an overall organizational emphasis on productivity as a key driver for their commitment to productivity savings rather than a specific program and governance structure. To the degree that other utility productivity programs do formally exist, they are typically targeted towards: (1) one-time transformational programs; (2)

achieving post mergers and acquisitions ("M&A") synergies; or (3) achieving incentives embedded in their ratemaking structure (*e.g.*, performance-based ratemaking ("PBR")). Even when compared to other programs that might be considered formal or rigorous, Hydro One's Productivity Framework is distinguished by the role the Productivity Framework plays in the incentive compensation process and the degree of regulatory review.

In conclusion, Concentric finds that overall, the Productivity Framework is an effective productivity program and is more rigorous and challenging to the organization than industry standards. Concentric also finds that the Productivity Framework is not a "catch all" for every component of Hydro One's provision of value to customers, but rather is focused on delivering hard cost savings that can be measured, validated, and included in the Company's business planning.

SECTION 3:
INTRODUCTION

On behalf of Hydro One, Torys retained Concentric to perform the Study, which (i) provides an independent assessment of Hydro One's Productivity Framework, including its process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs, and (ii) compares the Productivity Framework to comparable frameworks from an appropriate peer group. This report provides the results of the Study. Biographies for the Concentric team that performed the Study and prepared this report are contained in Appendix I.

A. Overview of Concentric

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised North American regulated utilities on matters related to productivity measurement and reporting, benchmarking, and the quantification of synergies in the context of rate setting proceedings.

B. Background on Hydro One and Description of Its Productivity Framework

Hydro One is Ontario's largest electricity transmission and distribution service provider. It is wholly owned by Hydro One Inc., which is wholly owned by Hydro One Limited, and has been publicly traded on the TSX since 2015 when the Province of Ontario offered shares of Hydro One Limited to the public in an initial public offering ("IPO"). Hydro One distributes electricity across Ontario to nearly 1.4 million customers, or approximately 26% of the total number of customers in Ontario. In addition, Hydro One's transmission system accounts for approximately 98% of Ontario's electricity transmission capacity. Although both the distribution and transmission businesses are owned and operated by Hydro One, each is regulated separately by the Ontario Energy Board ("OEB") for purposes of licensing, setting rates and other matters.

The Productivity Framework is a structured program developed by Hydro One to identify, measure, and report increases in productivity and cost savings in both capital and OM&A spend across the Company. The program was initiated in 2015 and the Company introduced additional governance and oversight structures into the program in 2017, at which time it was re-labeled the Productivity Framework.

The Productivity Framework is administered by Hydro One's Finance group. At its most detailed level, the Productivity Framework identifies "initiatives" that represent specific, calculable measurements of productivity. Each initiative's background, methodology, and approval are documented. An example is the Forestry line of business's initiative to bundle overhead asset inspections with Hydro One's vegetation management defect patrols, which increased the frequency of inspections (from once every six years to approximately once every three years) and eliminated the cost associated with an inspection. Another example is the Distribution Lines line of business's "single person dispatch" initiative. The Company recognized many trouble calls could be resolved by changing the Company's practice of dispatching two person crews to single person crews.

Proposed initiatives must meet certain criteria to be included in the Productivity Framework. Those criteria include that the initiative must be measurable, verifiable, and auditable. The current Productivity Framework focuses on hard cost savings and does not include or permit avoided costs to be counted as savings. Legacy initiatives that were originally identified in the program used 2015 (*i.e.*, pre-IPO) as a baseline year, while new initiatives use the most recent available set of actual results at the time of establishing those new initiatives as the baseline. Pre-IPO baselines were used for legacy initiatives to measure savings achieved under the Company's new organizational structure, and the Company has attributed $738 million of cumulative productivity savings as of year-end 2020 since the inception of the program.

Productivity Framework initiatives are identified and tracked in each of Hydro One's lines of business, which are Transmission and Stations, Distribution Lines, Corporate, Supply Chain, Fleet, Customer Service, Information Technology ("IT"), Real Estate, Network Operating, Planning, Engineering, and Forestry. The figure below summarizes the roles that Finance and the lines of business play in the Productivity Framework.

Figure 1: Finance and Lines of Business Roles in Productivity Framework

Finance	Lines of Business
Accountable For:	***Accountable For:***
➢ Ownership of Productivity Framework	➢ Identification of initiatives and calculation methods
➢ Approving initiatives and calculation methods	➢ Uploading of trended budget and forecast, as well as monthly actual results
➢ Tracking results on team scorecard	➢ Achieving unit-level saving
➢ Documenting new and existing initiatives	
➢ Maintaining governance documents	
Consulted on:	***Consulted on:***
➢ Identification of initiatives and calculation methods	➢ Approval of initiatives and calculation methods
➢ Uploading by lines of business of trended budget and forecast, as well as monthly actual results	➢ Scorecard reporting (performed by Finance)
➢ Identification of Potential i iti ti d ri i f th	➢ Documentation of new and existing initiatives
	➢ Identification of potential initiatives deriving from the business case submission process

Hydro One incorporates productivity improvements resulting from the Productivity Framework in its budgets and forward-looking business plans. Furthermore, results from the Productivity Framework are included in the Company's corporate scorecards upon which incentive compensation is based. Results of the Productivity Framework are reported monthly to senior executives. In addition, the Company performs a "Quarterly Productivity Review" with key executives that reviews the program's initiatives, discusses risks to forecast results, and discusses the program's strategy. The program's results are also audited twice annually by Finance and assessed for reasonableness at year-end as part of Hydro One's Internal Audit's year-end corporate scorecard assurance review. The following is an illustrative example of the monthly reporting template provided to senior executives.

Figure 2: Example of Productivity Framework Monthly Reporting Template

Productivity $mm LoB	Description	December YTD		Year End Forecast		Status
		Actual	Budget	Current	Budget	
Distribution Lines	Two key initiatives comprise the majority of the YE Budget: the Cable Locate Outsourcing initiative that decreased the unit price per locate and Move to Mobile that improves field labour efficiency using vehicle installed tablets and new software integrated with SAP.	18.2	22.8	18.2	22.8	
Forestry	Forestry Dx Line Patrol initiative to reduce the need for Provincial Lines to conduct their own patrols of the same lines. OCP Trouble Call Reduction initiative, where hazard tress have been removed proactively which decreases the number of trouble calls required.	15.2	21.8	15.2	21.8	
Tx and Stations	Overtime Reduction initiative that implemented stricter controls and constraints on overtime requests to reduce overall overtime hours. Other key initiatives include; Wrench Time Studies to improve labour efficiency, Reducing Hydro Vac Excavations in Stations and Reconditioning Oil in house.	17.8	24.0	17.8	24.0	
System Operations	Load Transfer Studies initiative that reduces the unit cost to complete a Load Transfer Study using the Distribution Management System.	1.0	1.4	1.0	1.4	
Planning	Deploying Padmount Transformers technology in Distribution Stations, reduces the cost of the infrastructure for equivalent service. Enabling Power Quality Monitoring capability on existing Wholesale Revenue meters forgoes the redundancy to install Power Quality Monitors and has been reflected as a reduction in the business plan.	7.8	10.3	7.8	10.3	
Engineering	GIS and DOMTeam Migration and PCMS Software upgrade, reducing organizational costs vs historical cost. EDMPlatform will change the way we track, manage and store drawings, increasing productivity and compliance.	3.4	2.8	3.4	2.8	
Operations Total		**63.4**	**83.1**	**63.4**	**83.1**	
Customer Service	Savings driven by Call Center Insourcing and switching customers to eBilling.	22.0	14.4	22.0	14.4	
Fleet	Reduction of Fleet vehicles as a result of increased visibility to LOB requirements from Telematics software. This lead to reduced capital costs to purchase replacement vehicles and lower overall maintenance costs from a reduced fleet.	34.9	28.9	34.9	28.9	
Supply Chain	Strategic Sourcing initiatives that have driven down material and service prices compared to historical costs. Also includes savings from Non-Sourcing initiatives such as enhanced Early Pay Discounts and Volume rebates.	80.7	58.9	80.7	58.9	
Real Estate	Secondary Land Use Revenue Initiative to drive more competitive lease rates by leveraging appraisal reports and property assessments to ensure full value is achieved in lease contracts.	12.9	5.2	12.9	5.2	
Corporate	Savings are measured by comparing in year Corporate Costs compared to a historical baseline. The reduction compared to historical baseline is the savings.	49.9	49.1	49.9	49.1	
Information Technology	Savings primarily from the Inergi ITO Contract Reduction measured through a lower fixed price contract compared to historical cost.	22.2	20.9	22.2	20.9	
Corporate Total		**222.6**	**177.4**	**222.6**	**177.4**	
Hydro One Total		**286.0**	**260.5**	**286.0**	**260.5**	

In addition to specific initiative-based productivity, Hydro One has also historically included "Progressive Productivity" in the Productivity Framework targets and its business plan. Progressive Productivity is a reduction to Hydro One's business plan costs that is over-and-above its initiative-based productivity savings, and has been described by the Company as a method by which to stretch the organization and provide additional savings to customers. For instance, of the $704 million in forecast productivity savings in EB-2019-0082, $237 million was Progressive Productivity.[1] Historically, Progressive Productivity targets have only been set for capital spending, because the Company's Custom IR "I-X" formula provides similar incentives to stretch the organization on OM&A spending.

1 EB-2019-0082, Exhibit B-1-1, TSP Section 1.6.

C. Scope of Work

The Study includes both (i) an independent assessment of the Productivity Framework, and (ii) a comparison of the Productivity Framework to comparable frameworks from peer companies. More specifically, the Concentric's scope of work included the following tasks:

a) Assess the Productivity Framework in terms of (i) its effectiveness to identify and quantify productivity improvements and initiatives; (ii) its application of baseline data; (iii) its validation and audit process, (iv) the extent to which the identified savings can be considered true productivity gains, and (iv) how productivity is considered in the context of forward-looking planning; and
b) Identify an appropriate peer group of utilities and any information to be collected from them, and compare the Productivity Framework to the frameworks employed by the identified peers, including in particular with respect to the effectiveness of the framework in identifying, measuring, tracking and validating productivity improvements and the relevance of that framework for rate-making purposes.

The remainder of this report provides Concentric's definition of an effective Productivity Framework against which we compared Hydro One's and peer utilities' programs, our approach to the scope of work, and our findings.

SECTION 4:
DEFINITION OF AN EFFECTIVE PRODUCTIVITY FRAMEWORK

To evaluate Hydro One's Productivity Framework, Concentric established criteria against which to measure the program. The following criteria are based on Concentric's experience in measuring utility productivity programs and designing incentive-based regulatory frameworks, our observations regarding other utility productivity programs, a review of OEB findings regarding productivity, and related industry research. Specifically, Concentric defines an effective Productivity Framework as containing the following elements and/or exhibiting the following characteristics:

1. Effective at identifying and quantifying sustainable productivity improvements and initiatives;
2. Holistic in nature (*i.e.*, targets all levels of the business);
3. Promotes a corporate culture that embraces productivity as a core value;
4. Applies appropriate baseline data to measure productivity gains;
5. Benefits are validated with an appropriate validation and audit process;
6. Avoids perverse incentives (*i.e.*, does not sacrifice customer value, safety, and reliability for short term savings);
7. Drives benefits that can be considered true productivity gains (*i.e.*, more output for the same resources, or the same output using fewer inputs); and
8. Considers productivity in the context of forward-looking planning.

Concentric was also guided by discussions of productivity put forth by the OEB. Specifically, in its Decision in Hydro One's 2015-2019 distribution rates application (EB-2013-0416), the OEB provided guidance regarding key considerations for alignment of a productivity program with the Renewed Regulatory Framework for Electricity, including that the program: (a) has externally imposed incentives; (b) appropriately considers the importance to the OEB of benchmarking; (c) demonstrates continuous improvement; and (d) provides value to customers, including customer engagement and a demonstration of the value proposition of the Company's plan.[2]

Concentric also performed research regarding productivity programs in the industry, and literature on the topic of productivity and continuous improvement, with the findings largely overlapping the Concentric criteria and OEB guidance. Per industry research, an effective productivity program: (a) is supported by senior leadership; (b) targets continuous improvement; (c) is validated and audited regularly; and (d) is communicated clearly both internally and externally (as appropriate) to demonstrate alignment with strategy and corporate objectives.

For example, Dominion Energy Resources, Inc., a diversified utility based in Virginia, has been recognized by the International Quality and Productivity Center for its Six Sigma programs. Key takeaways from Dominion's program include that Dominion excludes avoided costs from its "hard savings" results, baselines are revisited regularly, the utility has a rigorous validation and audit process, and projects within the program relate to specific business goals.[3]

Furthermore, a 2018 Harvard Business Review article, "Making Process Improvements Stick" (Nov.-Dec. 2018) studied factors that led to sustained process improvements, including:

- "[V]isible support from board members and senior leadership;"
- "[C]onsistent measurement and monitoring;" and
- "[C]ommunicating the program in a clear narrative that aligns with the organization's purpose."

The criteria summarized above provided Concentric an objective basis to evaluate Hydro One's program and to benchmark it against programs at other utilities. These are not minimum criteria, as a productivity program can incorporate only some of these elements and still be effective at delivering meaningful productivity gains and cost savings for the benefit of customers. There is also a time element to be considered. New programs can be expected to satisfy the criteria focused on design; established programs should reflect demonstrated results; and mature programs should

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2 EB-2013-0416/EB-2014-0247, "In the Matter of an Application by Hydro One Networks Inc. for Approval of Distribution Rates for 2015 to 2019," Decision, March 12, 2015, at 12-20.

3 University of Virginia Darden Business Publishing, "Six Sigma at Dominion Resources, Inc.: Investing in Excellence," September 2, 2011.

aspire to cultural change and full integration in the planning process. Targets and baselines also need to be recalibrated as programs mature.

Utility goals must also respond to shifts in regulatory policy, customer preferences, and new technologies. Never has that been more apparent than in the current environment where the confluence of regulatory policy, customer preferences and technology are pushing utilities to decarbonize, requiring significant investment and changes across the entire industry. Ultimately, an effective productivity program reinforces these broader strategic goals, while delivering value for customers.

SECTION 5:
METHODOLOGY

Concentric adopted a two-pronged approach to assess Hydro One's Productivity Framework. This approach included a detailed review of Hydro One's internal framework and governance process as well as a benchmarking survey to compare Hydro One's Productivity Framework against those employed by other North American utility companies. Each component of our assessment is discussed further below.

A. Review of Hydro One's Framework

Concentric's review of Hydro One's Productivity Framework entailed a review of documents provided by the Company and filed before the OEB, interviews with key stakeholders, and reviews of industry literature and case studies.

In terms of documentation, Concentric reviewed several key pieces of supporting documentation for Hydro One's Productivity Framework, including a tracking spreadsheet for forecast and actual initiative savings, initiative descriptions, and various examples of reporting materials for the program. A list of the documents that Concentric reviewed and relied on is provided in Appendix II. Concentric also reviewed evidence supporting the Productivity Framework filed by Hydro One in its previous rate cases.

In terms of interviews, Concentric interviewed Hydro One's Finance team to gain an overview of the Productivity Framework, the methodology employed in the program, and the program's oversight and governance.

Concentric also interviewed subject matter experts from seven lines of business of Hydro One to further our understanding of the Productivity Framework. As discussed in Section 3, the lines of business are responsible for identifying, proposing, implementing, reporting and tracking productivity initiatives. The seven lines of business that Concentric interviewed were collectively responsible for more than 80% of all savings captured in the Productivity Framework. The seven lines of business included Transmission and Station Services, Supply Chain, Corporate, IT, Forestry Services, Fleet, and Distribution Lines. The questionnaire that Concentric used to guide each interview is included in Appendix III.

Concentric also interviewed executive stakeholders of Hydro One's Productivity Framework, including the Senior Vice President ("VP") of Finance, the VP of Distribution, the VP of Transmission and Stations, and the VP of Shared Services. In terms of the Productivity Framework, the VPs are responsible for ensuring the productivity targets for their lines of business are understood and that their lines of business are implementing and executing on the initiatives. The interviews with executives focused on the executive team's role within the Productivity Framework and views regarding how the program operates, the degree to which productivity is embedded in Hydro One's culture, and the sustainability of the program.

B. Benchmarking against Peer Utilities

Concentric's benchmarking of the Productivity Framework included industry research and confidential interviews with industry participants. In terms of industry research, Concentric began by performing a broad review of North American utilities to identify candidate companies for productivity program comparisons. For this research, Concentric relied on publicly available regulatory filings, company websites, and investor materials. Concentric began with North American utilities that operate under PBR or other forms of incentive regulation. Concentric also identified other large North American utilities that publicly disclose programmatic productivity initiatives, efficiency benchmarking, or other productivity and efficiency-related programs.

Because there is limited detailed information on productivity programs available in the public domain in some instances, Concentric also conducted confidential interviews with industry participants to gather more detailed information on how peer utilities view and implement productivity programs. For this effort, Concentric targeted mostly large electric transmission and distribution companies, as well as some large generation companies and one large gas utility. These interviews focused on first identifying if the subject utility has a productivity program in place, and, if so, understanding how peer utilities identify, develop, and monitor productivity initiatives, how productivity savings (and what types of savings) are tracked and recorded, how baselines are established, and whether the productivity programs are considered by regulators as part of rate case processes or other regulatory oversight. A copy of the questionnaire used to guide benchmarking interviews is provided in Appendix IV.

Concentric requested interviews of 12 companies. Four companies ultimately participated in a confidential verbal interview, one company provided a written response to Concentric's questionnaire, one company directed Concentric to a rate case proceeding which included evidence related to its productivity program, and the remainder declined to participate in the survey. The companies that responded to Concentric (either verbally or in writing) include Hydro Quebec, FortisBC, FortisAlberta, Enbridge Gas, and New Brunswick Power. Because the majority of the data provided was not otherwise publicly available, the utilities that provided verbal and written responses to Concentric's survey provided their information on a confidential basis. Concentric necessarily had access to the names and company-specific data for each utility, but Hydro One did not have such access (except as provided herein). As such, the names of the utilities are not linked with the results in the Study so as to preserve that confidentiality.

SECTION 6:
FINDINGS

A. Hydro One's Framework

This section provides a summary of Concentric's findings, and also provides our specific findings for each of the criteria described in Section 4 of this Report.

1. *Summary Findings*

The following are Concentric's summary level findings regarding our review of Hydro One's Productivity Framework.

- Overall, the Productivity Framework is an effective productivity program. Specifically, the Productivity Framework is effective at identifying and quantifying sustainable productivity improvements and initiatives; is holistic and targets all levels of business; is driven by a corporate culture that embraces productivity as core value; utilizes appropriate baselines to measure productivity gains; has an appropriate validation and audit process; avoids perverse incentives; drives benefits that can be considered true productivity gains; and considers productivity in the context of forward-looking planning.
- The Productivity Framework is also very detailed in nature. This level of detail is indicative of robustness and rigor. This can also make it challenging for stakeholders outside the Company to understand the Productivity Framework at a detailed level. In Concentric's experience, clear articulation of a productivity program both internally and externally (as appropriate) is key to its success and acceptance by regulators and both internal and external stakeholders.
- The Productivity Framework also includes Progressive Productivity over-and-above what the Company has been able to identify as hard cost savings from defined initiatives. Progressive Productivity causes the organization to stretch to achieve additional productivity savings.
- The Productivity Framework is focused on cost savings. It does not capture improvements in reliability, safety, and customer satisfaction, which are other metrics on its scorecard. That is not a flaw in the framework itself, and Hydro One manages the other elements of its scorecard outside of the Productivity Framework to demonstrate that service quality is not negatively impacted by the achievement of cost savings.

- Concentric understands from our review of the Productivity Framework that Hydro One has already achieved significant and material productivity savings. This means the Company may be more challenged to continue to find new initiatives and cost savings going forward that meet the rigorous standards of the existing program over the long term. However, we would expect a utility of Hydro One's scale to be able to meet this challenge by continuing to identify opportunities for productivity improvements, even over the long term. This may require enhancements to the current program to accommodate long-term continuous productivity.
- The Productivity Framework has support from the Board of Directors and senior leadership, and due to the complexities of the program the Company educates new Board of Directors members on its structure and governance. Effective internal and external communications are necessary to achieve the full potential of the program.

2. *Criteria-Specific Findings*

In addition to the summary-level findings provided above, Concentric also provides the following findings specific to each criteria of an effective productivity program.

<u>**Criteria 1** – A productivity program is effective at identifying and quantifying sustainable productivity improvements and initiatives</u>.

The "bottom-up" approach used by Hydro One whereby the lines of business identify initiatives at the business line level is integrated with the Company's strategic planning, which ensures that the Productivity Framework is aligned with corporate strategy. The lines of business are responsible for identifying and proposing initiatives while executive leadership sets targets and provides feedback and direction where needed. Assigning the responsibility for identifying and proposing initiatives to the lines of business promotes engagement from employees closest to the actual work being performed. Concentric found that the understanding of the Productivity Framework has reached a level of maturity within the Hydro One organization that allows for efficient coordination with Finance to get initiatives approved and to validate cost savings. Concentric also found examples where initiatives that did not fit the Productivity Framework were rejected, maintaining the integrity of the program. In addition, lines of business may "pre-reject" an initiative if it may not readily yield savings under the Productivity Framework.

Concentric further found that the periodic review of actual results against the forecast improves the Company's ability to achieve its targets. If a line of business is not on track to meet forecasted savings, Finance will pro-actively engage with the line of business to assist in identifying opportunities to mitigate risks and Finance may also assist a line of business in identifying potential savings opportunities.

Concentric's review of the individual initiatives also found that the Framework encourages and uses technology to drive productivity. The Productivity Framework appropriately considers costs and activities that are controllable, and excludes non-controllable costs and activities (*e.g.*, the Fleet line of business targets kilometers per litre of fuel instead of targeting fewer kilometers).

Criteria 2 – A productivity program is holistic (*i.e.*, targets all levels of the business).

The Productivity Framework is technical in nature, involves very detailed calculations, and is applied across a total of 12 lines of business. As discussed later in this report, the Productivity Framework is also integrated with the business planning process.

This level of detail is indicative of robustness and rigor, but also requires the Company to clearly describe and communicate the benefits of the Productivity Framework in order to demonstrate that the program is consistent with the organization's strategy, impacts the most important cost drivers of the business, and incorporates a linking between the individual initiatives of the framework and Hydro One's strategic objectives.

Part of the Productivity Framework's rigor is that it only accepts initiatives where Hydro One has identified hard dollar savings. The program does not include forms of savings or initiatives that do not meet the framework's standards, even though they may still result in business improvements. To that point, the Productivity Framework does not include or permit the tracking of avoided costs. While there may be opportunities in this regard, any such additions could risk adding subjectivity and assumptions into the Productivity Framework.

Criteria 3 – A productivity program has a corporate culture that embraces productivity as a core value.

The Productivity Framework is embedded within the management of the Company with the goal of having all lines of business focus on productivity in their day-to-day activities. This is evidenced by "top-down" communication of productivity targets to lines of business and the inclusion of productivity results in the executive compensation structure and corporate scorecards. Concentric found that lines of business expressed a clear understanding that they should be seeking productivity gains and that the Productivity Framework provides reinforcement of the importance of productivity. Identification of initiatives and reporting on them is built into the Company's processes. This commitment is demonstrated by the assignment of employees within Finance to oversee and administer the program, as well as the assignment of points of contact in the lines of business to be liaisons to Finance on productivity matters. The Productivity Framework aims to target behaviors and is thus translatable to field staff in terms of how initiatives contribute to beneficial changes for Hydro One.

Criteria 4 – A productivity program applies appropriate baseline data.

The baselines underlying the Productivity Framework reviewed by Concentric appear reasonable and appropriate, particularly in demonstrating the success of the Productivity Framework and in measuring the pre-IPO to post-IPO transformation, but risk becoming less meaningful as the Company moves further away from the IPO. Best practice in the industry supports resetting baselines regularly to achieve continuous improvement.

Concentric believes that as the more readily achievable and larger dollar value savings are identified, and if the Company re-baselines its initiatives, it may be more challenging to continually find meaningful new initiatives that meet the rigorous standards of the Productivity Framework on a long-term basis.

Criteria 5 – A productivity program includes an appropriate validation and audit process

There is a formal and rigorous audit process in the Productivity Framework, and initiatives are designed so that data can be accessed readily and in a systematic way to assess performance. There is a centralized governance process specifically established to approve and validate initiatives across all the lines of business. During the initiative approval process, Finance works with the lines of business to establish a savings calculation methodology and actual savings are reported using this methodology. This ensures that the reported savings are verifiable and auditable, actual results are provided to Finance on a monthly basis and audited twice annually. The monthly results are also distributed to the executive leadership team. The monthly reporting process reinforces productivity by providing regular opportunities to evaluate progress towards pre-established savings targets, and ensures frequent checks of reported productivity data. Validation of savings has become more rigorous as the Productivity Framework has matured with more initiatives now able to be validated at the unit level.

There is a quarterly productivity review with all the VP sponsors of the program. These quarterly reviews assess performance based on the actual results for each initiative, identify risks and opportunities in the forecast, and discuss status of new initiatives.

Criteria 6 – A productivity program avoids perverse incentives (*i.e.*, does not sacrifice customer value, safety, and reliability for short term savings).

While Concentric did not observe trade-offs of customer value, safety, or reliability, the Productivity Framework itself does not reward positive outcomes related to those factors. That is not a flaw in the framework itself, but simply means that Hydro One needs to provide evidence on other elements of its scorecard and how those are not negatively impacted by the achievement of cost savings.

Criteria 7 – A productivity program drives benefits that can be considered true productivity gains.

Concentric reviewed the detailed initiatives and confirmed that the initiatives are developed so as to achieve hard cost savings. In addition, the Productivity Framework also includes Progressive Productivity over-and-above what the Company has been able to identify as hard savings from its detailed initiatives. Progressive Productivity causes the organization to stretch to achieve additional productivity savings.

Concentric understands that the Productivity Framework itself does not incorporate capital costs incurred to achieve savings. Capital costs incurred to achieve savings (often referred to as "costs to achieve," or "CTAs"), are a common variable considered in savings analyses. For instance, following utility M&A activity, utilities are often provided the opportunity to recover CTAs (*e.g.*, investments in IT) from customers to the extent they can show net savings. While Hydro One does not embed CTAs directly in its Productivity Framework calculations, it instead captures such costs in its business case analyses, from which Hydro One identifies and sets targets for many Productivity Framework initiatives.

Criteria 8 – A productivity program considers productivity in the context of forward-looking planning.

There is a formal process for coordination with the planning function; initiative owners have the opportunity to comment on feasibility and whether the plan appropriately reflects productivity forecasts. The productivity planning process is executed concurrently with the business planning process and also serves as an input to the business planning process. Savings commitments resulting from the productivity initiatives are embedded with the OM&A and capital plans. The savings are included within the productivity plan only after Finance has validated the planning assumptions and spending reductions. This integration of productivity initiatives with the business planning process provides continuity to the program.

Productivity savings are included in rate plans; in the most recent Transmission Application (EB-2019-0082) Hydro One filed separate evidence regarding the Productivity Framework, and quantified productivity savings, including progressive savings. Similar details were provided in the prior Distribution Application (EB-2017-0049).

B. Benchmarking

1. *Summary Findings*

Concentric's benchmarking findings primarily relied upon direct outreach to utilities due to the aforementioned lack of detailed information in the public domain, supplemented by industry research. In two instances, Concentric did find detailed overviews of utility frameworks that have been documented as part of a regulatory proceeding, and we have intermingled those cases with our outreach results to preserve the confidentiality of respondents.

In general, Concentric found that Hydro One's Productivity Framework stands out as being uniquely robust, well defined, and transparent. Hydro One's Productivity Framework distinguishes itself from other North American utilities in its continuity and scope. While cost containment and productivity are identified as central to most utilities' corporate strategies and culture, most companies do not have a clearly defined productivity program with robust tracking and reporting mechanisms such as those used by Hydro One. A few of the companies Concentric interviewed cited their regulatory framework or an overall organizational emphasis on productivity as a key driver for their commitment to productivity savings rather than a specific program and governance structure. To the degree that other utility productivity programs do formally exist, they are typically targeted towards: (1) one-time transformational programs; (2) achieving post M&A synergies; or (3) achieving incentives embedded in their ratemaking structure (*e.g.*, PBR).

Concentric's research did find examples of rigorous productivity programs that were focused on continuous improvement and lean management techniques. Hydro One's Productivity Framework, however, is differentiated by the combination of the role of the Productivity Framework in the incentive compensation process and the degree of regulatory review.

2. Detailed Benchmarking Findings

The table below provides a summary of Concentric's findings based on reviews of seven companies' productivity programs. Direct outreach was performed to five of the companies, as described above. Concentric included two additional companies in this comparison based on those utilities having a similar level of detailed information about their frameworks that was publicly available. Check marks indicate whether a particular feature was present within a company's productivity framework or process; however, they do not indicate the level of importance or relative complexity of each feature within each company's productivity program. In some cases, detailed data for one or more criteria was unavailable and has been indicated in the table below as "not disclosed."

Hydro One's Productivity Framework is also presented in the table. As shown, Hydro One's program is more expansive than the majority of the companies researched as it includes all the features that were tested for, with the exception of the measurement of avoided costs, which, as

	Hydro One	Company A	Company B	Company C	Company D	Company E	Company F	Company G
Defined Productivity Program	✓	✓			✓	✓	✓	✓
Driver of Productivity	Formal Productivity Framework	Specific initiatives	PBR	PBR	Merger	Continuous improvement framework	Business reorganization and transformation	Merger
Considered by regulator as part of rate case/other oversight	✓	✓	✓	✓	✓	✓	✓	✓
Measures initiative-specific savings	✓	✓	✓		✓	✓		✓
Measures hard savings ($)	✓	✓	✓	✓	✓	✓	✓	✓
Measures avoided costs		✓				✓		Not Disclosed
Audits savings	✓	✓				Not Disclosed		✓
Tied to management/ executive compensation	✓		✓	✓		Not Disclosed		Not Disclosed
External reporting	✓	✓	✓	✓	✓	✓	✓	✓

discussed earlier in this report, do not meet Hydro One's strict standards.

Additional detail regarding the elements in the table is provided below, along with comparisons to Hydro One where appropriate for context.

Defined Productivity Program. Of the companies reviewed in depth, five had defined productivity programs. In one instance (Company D), a utility's program was not formally defined as it was still taking shape following a merger, but the company has identified the process it will use to identify and record productivity savings. Companies B and C did not have formal productivity programs, but noted that productivity was embedded in their corporate cultures and that their regulatory PBR models provided sufficient incentives to achieve savings.

Driver of Productivity. Concentric identified only one other utility (Company E) that had an overarching productivity framework (labeled as a "Continuous Improvement Framework") that was designed as a long-term program. Company A had a comprehensive productivity program in place that was geared towards achieving a certain percentage productivity target within five years. Companies D and G are in the process of developing productivity programs as a result of a merger, one of which has a program that is targeted at a five-year transformation to achieve merger synergies and incremental savings targets. Company F's productivity initiatives were driven by a company reorganization and transformation.

Considered by Regulator as Part of Rate Case/Other Oversight. The degree to which productivity is considered by the regulators of the companies above varied. In some cases, productivity is considered for the purposes of determining an X-factor, and otherwise not heavily investigated as part of rate proceedings. In the case of Company E, the regulator requires annual reporting of progress towards individual initiatives.

Measures Initiative-Specific Savings. Hydro One is unique in the degree to which it tracks initiative-specific savings. While other companies do track initiative savings, some only do so for large initiatives as part of their business case process, and in those instances only track savings for a limited period of time. Company D has established a business function to track merger-related savings and separate out productivity savings to the degree possible; however, the details and breadth of initiatives was more limited compared to Hydro One's.

Measures Hard Savings ($). All of the companies interviewed or researched measured hard savings (*i.e.*, savings that generated actual reductions in forecast costs).

Measures Avoided Costs. Two companies measured and counted avoided costs towards their productivity savings. Company A uses statistical measures of avoided costs to justify upfront costs of programs that ultimately avoid later expenditures. Company E also claims that it tracks avoided costs; however, the methodology and ultimate purpose of such tracking was not disclosed.

Audits Savings. Two companies noted that they audit their productivity savings. Company D mentioned that while it does not formally audit savings, VPs are held accountable for delivering on savings targets. Other programs were either more relaxed in confirming or auditing savings or did not disclose whether they audit savings.

Tied to Management/Executive Compensation. For Companies B and C, productivity performance is tied to executive compensation through corporate scorecards that include OM&A performance, or operating cost per customer as metrics. For other companies in the survey, productivity was either not directly tied to executive compensation or such ties were not disclosed.

External Reporting. While the frequency and types of external reporting varied, each company had some level of reporting on their productivity progress either to regulators or external stakeholders. Notably, only one company reported specific levels of savings by initiative. Other companies either provide summaries, or general scorecard indicators.

In addition to the companies targeted for interviews, Concentric conducted research of public disclosures regarding productivity for an additional ten utilities. This research did not prove valuable for purposes of direct comparison with Hydro One's program. In general, we found:

- Companies operating under PBR regimes where reporting was limited to cumulative performance under the rate plan;
- Broad commitments to productivity without details on underlying programs;
- High-level goals achieved (*e.g.*, an $X million reduction in capital or operating costs over some period of time); and
- Results achieved from a specifically targeted program (*e.g.*, savings from a voluntary staff reduction program).

None of these utilities had sufficient information disclosed that would allow a detailed comparison to Hydro One's framework. Of note, one company requested for an interview declined on the basis of confidentiality around its program, effectively signaling it believed its program was a competitive advantage.

SECTION 7:
CONCLUSIONS

As discussed herein, Concentric used a two-pronged approach to assess Hydro One's Productivity Framework for purposes of the Study that included: (1) a detailed review of Hydro One's internal framework and governance process; and (2) a benchmarking survey to compare Hydro One's Productivity Framework against those employed by other North American utility companies.

Based on our review and benchmarking, Concentric found that the Productivity Framework is effective at identifying and quantifying sustainable productivity improvements and initiatives; appropriately applies baselines data to measure productivity gains; has an appropriate validation and audit process; drives benefits that can be considered true productivity gains; and considers productivity in the context of forward-looking planning. Concentric also found that Hydro One's Productivity Framework stands out as being uniquely robust, well defined, and transparent when compared to industry peers. Hydro One's Productivity Framework distinguishes itself from other North American utilities in its continuity and scope.

Concentric had certain other observations associated with the Productivity Framework, including that: (1) the level of detail in the Productivity Framework, while indicative of its robustness and rigor, requires the Company to clearly describe and communicate the benefits of the program in order to demonstrate that the program is consistent with the organization's strategy, impacts the most important cost drivers of the business, and incorporates a linking between the individual initiatives of the framework and Hydro One's strategic objectives; (2) the Productivity Framework does not capture improvements in reliability, safety, and customer satisfaction, or CTAs, but Hydro One manages those other elements of its scorecard and business planning process outside of the Productivity Framework to demonstrate that service quality is not negatively impacted by the achievement of cost savings; (3) the Productivity Framework does not allow for the tracking of avoided costs as those costs do not meet the strict standards of the program; and (4) as the more readily achievable and larger dollar value savings are identified, Hydro One may find it more challenging to find new initiatives that meet the rigorous standards of the Productivity Framework over the long term. To this latter point, we would expect a utility of Hydro One's scale to be able to meet this challenge by continuing to identify opportunities for productivity improvements, even over the long term. This may require enhancements to the current program to accommodate long-term continuous productivity.

Concentric does not perceive the above observations as flaws in the framework, as these challenges or opportunities have not detracted from the Productivity Framework's mandate to deliver hard cost savings. In addition, any changes to the Productivity Framework (*e.g.*, to potentially allow for the capturing of avoided costs in addition to hard savings) would need to be done deliberately and in a manner that did not weaken the overall program. Furthermore, the inclusion of Progressive Productivity in the Productivity Framework continues to stretch the organization to achieve greater and greater productivity savings, even when it cannot readily identify new initiatives.

In conclusion, Concentric finds that overall, the Productivity Framework is an effective productivity program and is more rigorous and challenging to the organization than industry standards. Concentric finds that the Productivity Framework is not a "catch all" for every component of Hydro One's provision of value to customers, but rather is focused on delivering hard cost savings that can be measured, validated, and included in the Company's business planning.

APPENDIX I:
BACKGROUND ON AUTHORS

James M. Coyne, Senior Vice President, is an energy industry expert who provides financial, regulatory and strategic support services to clients in the power and gas utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, cross-border trade, rate and regulatory policy, capital cost determinations and energy markets. He is a frequent speaker and author of numerous articles on the energy industry and regularly provides expert testimony before federal, state and provincial jurisdictions in the U.S. and Canada. He testifies on matters pertaining to the cost of capital, capital structure, business risk, alternative ratemaking mechanisms and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North Hampshire American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New.

Daniel S. Dane, Senior Vice President, has 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has also provided expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

Bickey Rimal, Assistant Vice President, has over eleven years of progressive experience in the energy and environmental sector. Mr. Rimal joined Concentric in 2011 after completing his Masters in International Public Affairs with a focus on Energy Policy from the University of Wisconsin in Madison. Mr. Rimal has contributed to projects involving cost of service, rate design, expert testimony preparation, energy market assessments, valuations of energy assets, and utility performance benchmarking. His work often involves financial modeling, statistical and econometrics analysis, and regulatory research. His modeling involves statistical software SPSS and R and programming using Visual Basic for Applications (VBA). Prior to enrolling in the graduate program, Mr. Rimal worked at ICF International, a global energy and environmental consulting firm, for three years. At ICF, Mr. Rimal was extensively involved in projects dealing with policy design and implementation, cost-benefit analysis, economic impact analysis, regulatory evaluation, and environmental risk assessment.

Olivia A. Prieto, Senior Consultant, has used her quantitative and advanced research skills to support various projects through model development, data management and analysis, and report writing. She has contributed to a number of rate cases for gas, electric, and water utilities through regulatory research and return on equity analysis. In addition, Ms. Prieto has also supported due diligence activities including appraisal and valuation analyses, margins analyses, and origination. Ms. Prieto holds a B.A. in International Relations and Global Affairs from Eckerd College, and a Master's of Science in Public Policy from Georgetown University.

APPENDIX II:
DOCUMENTS REVIEWED

As part of Concentric's detailed review of Hydro One's Productivity Framework, Concentric reviewed and relied on a combination of industry and academic literature, regulatory filings, and various supporting documentation provided by Hydro One, including the following types of documents:

- Productivity Framework overviews;
- Analyses containing historical and forecasted savings under the Productivity Framework;
- Hydro One's monthly Productivity Template, which is used to track monthly updates towards productivity savings from each line of business;
- Summaries of Hydro One's productivity initiatives, including descriptions of their methodologies;
- Hydro One's Team Scorecard;
- Various regulatory filings and OEB decisions; and
- Industry and academic literature on productivity, continuous improvement, and utility productivity programs.

APPENDIX III:
LINE OF BUSINESS QUESTIONNAIRE

Concentric conducted interviews with subject matter experts from seven of Hydro One's lines of business. For each interview, Concentric used a common questionnaire template that included the below questions.

1. Please describe what your line of business does.
2. Please describe the process for identifying and proposing new productivity initiatives within your line of business.
3. Please walk through each of the initiatives under your line of business at a high level.
4. Have any proposed initiatives been rejected? Please provide examples.
5. Do you have a process to pre-check recorded savings prior to validation by Finance?
6. Please describe your reporting responsibilities (*i.e.*, how often and to whom do you report productivity results, etc.).
7. Please describe your coordination with Business Planning and how forecast savings are incorporated into the Business Plan.
8. Is there anything else you would like to share about your productivity initiatives or process, or the Productivity Framework more generally?

APPENDIX IV:
BENCHMARKING QUESTIONNAIRE

As part of the benchmarking exercise, Concentric developed and used a common questionnaire for each confidential interview with other North American Utilities. The questions that Concentric posed to each company included:

1. Does your company have a defined program for increasing productivity and/or achieving cost savings? (please describe)
2. What is your company's process for identifying, developing, implementing, monitoring and measuring productivity initiatives?
3. How are productivity savings opportunities differentiated from other savings that occur over time?
4. Does your company track and count as productivity avoided costs and/or total cost of ownership?
5. What is your company's process to quantify potential savings?
6. What are savings measured against (i.e., what is the baseline)? Does the baseline get reset?
7. How are results tracked, validated, and/or audited?
8. Is the program considered by your regulator as part of the rate case process or the regulator's oversight?
9. Is your productivity program an element of management's compensation?
10. What public statements or regulatory filings has your company made regarding the program?
11. How is your productivity program considered in your company's forward-looking planning?
12. Does your company look to other utilities for strategy?

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 Ontario Energy Board's (OEB) 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, the methodologies used for each of the measures and the manner in which Hydro One has responded to specific concerns raised by the OEB in Hydro One's last rate filing proceedings.

1.5.1.1 PERFORMANCE MEASUREMENT STRUCTURE, PROCESS, AND GOVERNANCE

Hydro One is focussed on performance measurement and planning. Hydro One has increased transparency in its budgeting and performance measurement processes to 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 and DSP Section 3.5 detail Hydro One's historical performance in each area and establish performance outcomes that Hydro One has targeted to achieve over the 2023 to 2027 plan 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.

1.5.1.1.1 TRANSMISSION AND DISTRIBUTION SCORECARDS OVERVIEW

Hydro One has three scorecards that it uses to assess its performance relative to the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF) outcomes of Customer Focus, Operational Effectiveness, Policy Responsiveness and Financial Performance. 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 the Transmission Scorecard approved in EB-2019-0082 (see TSP Section 2.5). For Distribution, Hydro One will continue to file both the Electricity Distributor Scorecard that the OEB requires from all electricity distributors and Hydro One's Distribution OEB Scorecard, which provides measures offering additional granularity in the areas of Customer Satisfaction, Cost Control and System Reliability. The Distribution OEB Scorecard has been included in recent distribution applications and is further refined in this Application (See DSP Section 3.5).

TSP Section 2.5 discusses each measure in the Transmission Scorecard. The discussion provides the definition of the measures, historical performance against targets for 2019 and 2020, the first two years of this scorecard's operation, and targets for the period 2021-2027.

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 information for 2016-2017, actual performance and targets for 2018-2020 and targets for 2021-2027. This portion of the DSP also addresses proposals to modify or eliminate certain measures in Hydro One's Distribution OEB Scorecard.

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Performance Reporting Governance Framework

Distribution & Transmission

January 2021

Witness: JESUS Bruno

CONTENTS

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 Board'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 to align the interests of customers and utilities. The outcomes are supported by key principles in the RRF which include the expectation for continuous improvement, robust integrated planning and asset management which paces and prioritizes 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 and to assess alignment between a utility's rate application and the RRF, and the alignment of the utility's interests with those of its customers. This document describes how Hydro One tracks and reports its performance outcomes on its scorecards to align with the performance and outcomes-based approach of the Board

In governing this process, the Finance team receives information and support from Hydro One's various operational lines of business, as further described below. The Chief Operating Officer has ultimate accountability for the Performance Reporting Governance Framework and working with various stakeholders to deliver on the requirements of the framework.

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's *Electricity Distributor Scorecard* (at Appendix A); and (ii) Hydro One's *Distribution OEB Scorecard* (at Appendix B). The Electricity Distributor Scorecard is produced by the OEB using the annual Reporting and Record-keeping Requirements (RRR) filings of Hydro One, Distribution. The Distribution OEB Scorecard was proposed by Hydro One in its 2018 to 2022 Distribution Rate Application (EB-2017-0049) to fulfill the requirements set forth in the Handbook for Utility Rate Applications[1] and to propose measures in addition to those in the Electricity Distributor Scorecard.

For transmission rate applications, Hydro One uses the following scorecard: (iii) Hydro One's *Transmission Scorecard* (at Appendix C). Together, the three scorecards are referred to as the "regulatory scorecards". At the overall corporate level, Hydro One uses (iv) the Team Scorecard (at Appendix D) and for Operations (v) the Operations Scorecard (at Appendix E). 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 a time and compared to targets that are specific to either the industry, Hydro One, or both. The regulatory scorecards are included at Appendices A through C and include the complete list of measures utilized 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 three regulatory scorecards are included in two of Hydro One's internal scorecards – the Team Scorecard and the Operational Scorecard.

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[1] Handbook for Utility Rate Applications, October 13, 2016, Ontario Energy Board

Figure 1 below shows how the RRF principles are incorporated into the performance reporting process for the regulatory scorecards and Hydro One's Team Scorecard and Operational Scorecard.

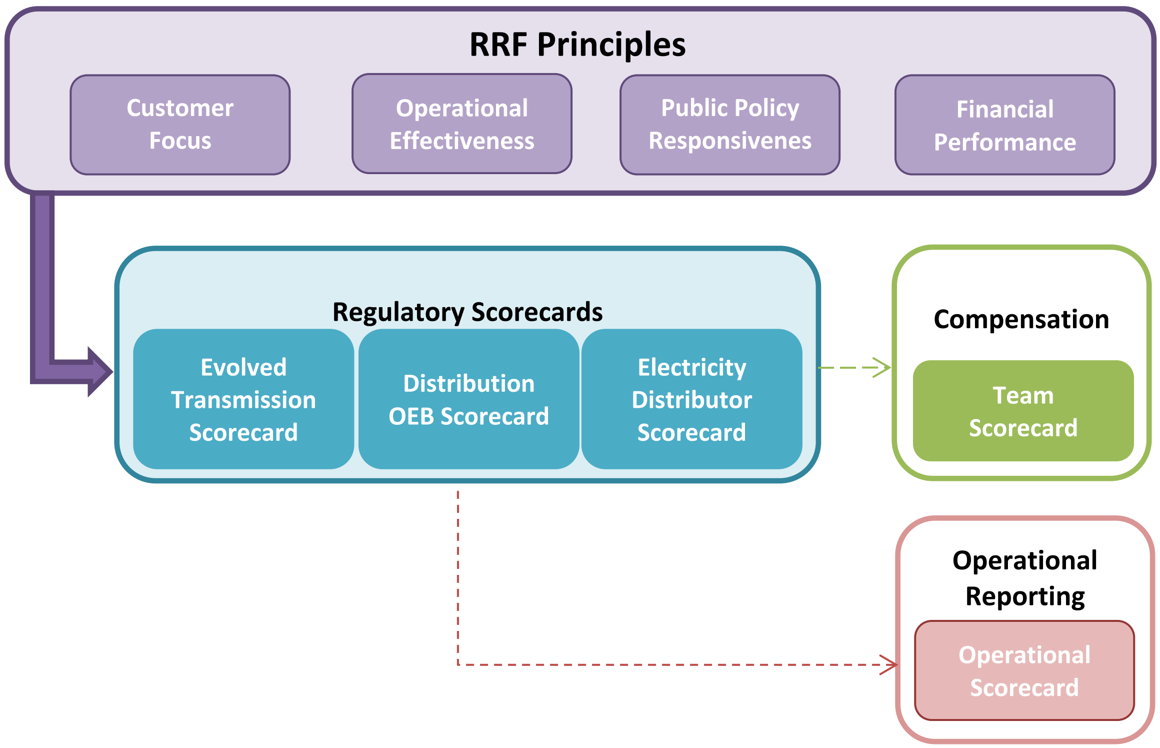

Figure 1: Performance Reporting Scorecards & Interactions

GOVERNANCE FOR REPORTING & DEVELOPMENT OF MEASURES AND TARGETS

Hydro One's governance framework is designed to support the key principles of the RRF of continuous improvement, robust integrated planning and asset management, strong incentive to enhance performance, ongoing monitoring of performance against targets, and customer engagement to inform rate applications. The framework focuses on two primary activities of (i) performance reporting and (ii) measure and target development.

The primary stakeholders supporting the governance framework are:

- The Chief Operating Officer
- Line of Business Vice President (LoB VP)
- Line of Business (LoB)
- Finance
- Regulatory Affairs

APPENDIX A - ELECTRICITY DISTRIBUTOR SCORECARD – EXAMPLE

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target Industry	Target Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.40%	97.40%	97.50%	98.60%	98.06%	↑	90.00%	
		Scheduled Appointments Met On Time		98.40%	99.30%	98.50%	99.50%	98.94%	↑	90.00%	
		Telephone Calls Answered On Time		63.90%	69.60%	76.40%	74.20%	81.85%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		78.30%	79%	82%	82	0.85			
		Billing Accuracy			94.63%	98.	99.04%	99.28%	↑	98.00%	
		Customer Satisfaction Survey Results		87%	85%	8	84	0.85			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				81.00%	81.00%	81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	C	NI	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	7	[illegible]	5	11	8	↑		5
			Rate per 10, 100, 1000 km of line	[illegible]	0.0	0.042	0.091	0.070	→		0.070
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		6.	7.49	7.65	7.83	7.95	↓		10.31
		Average Number of Times that Power to a Customer is Interrupted [2]		.49	2.70	2.63	2.47	2.32	↓		2.93
	Asset Management	Distribution System Plan Implementation Progress		Under R w	97%	116%	105	1.03			
	Cost Control	Efficiency Assessment		5	5	5	4				
		Total Cost per Customer [3]		$1,046	$1,069	$983	$987				
		Total Cost per Km of Line [3]		$10,682	$10,916	$10,198	$10,551				
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Ene vings [4]				17.27%	42.50%				1,220.69 GWh
	Connection of Renewable Generation	Renewable Generati Con n Impact Assessments Com eted On Time		100.00%	100.00%	100.00%	100.00%	99.71%			
		Nev icro-embedded eration Facilities Connected On Time		99.71%	100.00%	99.78%	99.22%	99.77%	↓	90.00%	
Financial Performance Financial viability is maintained and savings from operational effectiveness are sustainable.	Financial P s	Li Current Ratio (Current Assets/Current Liabilities)		1.00	0.99	0.97	0.80	0.55			
		Le age: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.35	1.31	1.19	1.46	1.39			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.30%	9.19%	8.78%			
			Achieved	8.00%	6.26%	8.77%	8.41%	7.94%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.

Legend: 5-year trend ↑ up ↓ down → flat
Current year ● target met ● target not met

Witness: JESUS Bruno

APPENDIX B - DISTRIBUTION OEB SCORECARD – EXAMPLE

			Historical Results							Targets					
RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2017	2018	2019	2020	2021	2022
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	71%	72%	74%	75%	75%	76%	76%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	[illegible]	77%	78%	78%	79%	79%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	90%	86%	87%	88%	88%	89%	89%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	78%	[illegible]	83%	84%	84%	85%	85%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,431	8,640	8,733	8,908	9,080	9,256	9,437
		Vegetation Management - Gross Cyclical Cost per km $			New Pro[illegible]				7,888	[illegible]	3,600	3,643	3,687	2,400	2,428
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	318,000	[illegible]	500,000	[illegible]	443,000	461,000	454,000	447,000	40,000	434,000	427,000
		OM&A dollars per customer	456	451	498	[illegible]	453	[illegible]	430	449	466	466	466	454	455
		OM&A dollars per km of line**	[illegible]	4,676	5,109	[illegible]	4,719	[illegible]	4,605	4,712	4,797	4,813	4,829	4,823	4,839
	System Reliability	Number of Line Equipment Caused Interruptions	[illegible]	7,316	7,266	[illegible]	8,164	7,674	8,786	8,200	8,200	TBD	TBD	TBD	TBD
		Number of Vegetation Caused Interruptions	[illegible]	[illegible]	[illegible]	[illegible]	6,944	7,439	7,800	6,900	6,500	TBD	TBD	TBD	TBD
		Number of Substation Caused Interruptions	159	[illegible]	[illegible]	158	141	103	123	145	145	TBD	TBD	TBD	TBD
		SAIDI - Rural - duration in hours	8.2	[illegible]	8.1	8.6	9.1	9.1	9.4	9.1	9.0	TBD	TBD	TBD	TBD
		SAIFI - Rural - frequency of outa[illegible]	3.3	3.3	3.0	3.4	3.4	3.1	3.0	3.4	3.4	TBD	TBD	TBD	TBD
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.4	2.8	2.8	TBD	TBD	TBD	TBD
		SAIFI - Urba[illegible]quency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.4	1.7	1.7	TBD	TBD	TBD	TBD
		Large Custo[illegible] Interruption Frequen[illegible] frequency of outages***	New Measure		118	147	228	136	227			N/A***			
		Large Custom[illegible]uption Frequen[illegible] (LDAs) [illegible]nterruptions per LDA				New Measure			1.7	New Measure	1.6	1.6	1.6	1.6	1.6

*There were no station refurbishment units ma[illegible]ng the criteria completed in 2012.
**Number of line kms are based on the annual O[illegible]k of Electricity Distributors' report, with 2017 and 2018 targets based on 2015 line km actuals. Targets for 2019 to 2022 are based on the RRR km of line for year-end 2017.
***Replaced by Large Customer Interruption Frequency (LDAs) - Interruptions per LDA. For 2018 onwards, only the normalized measure will be reported and managed.

APPENDIX C - TRANSMISSION SCORECARD – EXAMPLE

Performance Categories	Measures		2013	2014	2015	2016	2017	Target for 2022	Target for 2023
Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)			86	92	89	94	87	88
	Overall Customer Satisfaction (% Satisfied)		81	77	85	78	88	90	90
Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs		12.8	11.8	14.3	9.7	9.5	11.3	11.0
Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		2.5	1.8	[illegible]	[illegible]	1.2	0.9	0.9
System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.57	0.60	0.59	0.46	0.65	0.52	0.51
	T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.69	[illegible]	0.50	[illegible]	0.47	0.47	0.46
	T-SAIDI (Ave minutes of interruptions per Deliver Point)		66.0	[illegible]	44.3	80.8	42.8	33.3	32.6
	System Unavailability (%)		[illegible]	[illegible]	0.63	0.71	0.68	0.46	0.45
	Unsupplied energy (minutes)		20.9	12.2	11.8	11.4	13.2	9.2	9.0
Asset & Project Management	Transmission System Plan Implementation Progress (%)		94	99	105	100	94	100	100
	CapEx as % of Budget		73	90	106	105	100	100	100
	OM&A Program Accomplishment (composite index)				96.6	99.2	107.7	100.0	100.0
	Capital Program Accomplishment (c mposite index)				122.2	59.4	87.8	100.0	100.0
Cost Control	Total OM&A and Capital per Gros x set Value (%)		7.6	8.4	9.0	8.6	7.9	7.7	7.3
	OM&A per Gross Fi d Asset Value)		2.7	2.7	2.9	2.5	2.3	1.6	1.5
	Line Clearing Cos r kilometer ($/)		1,805	2,495	2,234	1,966	2,100	2,175	2,100
	Brush Contro r Hectare ($/Ha		1,703	1,624	1,566	1,542	1,356	1,608	1,608
Connection of Renewable Generation	% on-time compl on ewables customer impact assessments		100	100	100	100	100	100	100
Regional Infrastructure Planning (R Long-Term Energy Plan (LTEP) Right-	R gional Infrast ure Planning progress - Deliverables met, %			100	100	100	100	100	100
	End-of-Life Right-Sizing Assessment Expectation						Met	Met	Met
Financial Ratios	uity: Current Ratio (Current Assets/Current Liabilities)		0.80	0.69	0.13	0.20	0.13		
	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.10	1.16	1.39	1.43	1.47		
	Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.93	9.36	9.30	9.19	8.78		
		Achieved	13.22	13.12	10.93	10.02	9.03		

APPENDIX D - TEAM SCORECARD – EXAMPLE

Corporate Goal	Definition	Measure	2017 Performance Levels				% Weight	Achievement	% STIP
			Actual	Threshold	Budget	Maximum			
Health and Safety (10%)	Recordable Incidents	Incidents per 200,000 hours	1.2	1.6	1.1	1.0	10.0%		
Work Program (25%)	Reliability – Tx (SAIDI)average length of unplanned interruptions to multi-circuit supplied delivery points	Minutes per Delivery Point	5.4	10.0	[illegible]6	9.2	6.3%		
	Reliability - Dx (SAIDI) average length of outages in hours that a customer experiences	Hours per Customer	7.[illegible]	7[illegible]	7.5	7.2	6.3%		
	Tx In Service Additions Delivery Accuracy	Variance (%) to approved budget of $931M (Tx Application)	7[illegible]*	+/- 7% (978-996; 866-884)	+/- 5% (950-978; 884-912)	+/- 2% (912-950)	6.3%		
	Dx In Service Additions Delivery Accuracy	Variance (%) to approved budget of $663[illegible]	681	+/- 6% (690-703; 623-636)	+/- 4% (676-690; 636-650)	+/- 2% (650-676)	6.3%		
Net Income (30%)	Net Income to Common Shareholders	$M	694***	615	665	715	30.0%		
Productivity (10%)	Productivity Savings (Capital and OM&A) - Tier 1 savings on[illegible]	Savings in $M	89.5	64.3	70.6	77.7	10.0%		
Customer (25%)	Dx Satisfaction - Improve overall Small and Residential Dx customer satisfaction	Customer Satisfaction	71.1%	70.0%	72.0%	75.0%	12.5%		
	Tx Satisfaction - Improve overall Large Tx customer satisfaction	Customer Satisfaction	88.3%	80.0%	82.0%	85.0%	12.5%		

APPENDIX E - HYDRO ONE'S OPERATIONAL SCORECARD – EXAMPLE

Strategic Priority	Corporate Goal	Definition
Be the Safest & Most Efficient Utility	Health and Safety	Serious Injuries and Fatalities
		Recordable Incidents
		Near Misses and Safety Catches
	Productivity	Productivity Savings in $M
Build a Grid for the Future	Reliability	Transmissions (Tx) Reliability - average length of unplanned interruptions to multi-circuit (multi-supplied) delivery points (SAIDI)
		Distribution (Dx) Reliability - average length of outages in hours that a customer experiences (SAIDI)
	Work Program	Tx In Service Additions - Delivery Accuracy
		Dx In Service Additions - Delivery Accuracy
Innovate & Grow the Business	Net Income	Operations OM&A*
Advocate for Our Customer	Customer	ETR Accuracy - Normal Operations
		ETR Accuracy - Storm Events
		Tx & Stations Customer Commitments Met

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SECTION 1.6 – SPF – CUSTOMER ENGAGEMENT

1.6.1 INTRODUCTION AND OVERVIEW

To identify customer needs and preferences in preparation for its 2023 – 2027 investment planning process and this Application, Hydro One engaged an independent third party research and consultation firm, Innovative Research Group (IRG), to develop and conduct a comprehensive customer engagement study (the IRG Study). Hydro One and IRG employed a two-phased approach, engaging customers at the beginning of the investment planning process, and again after draft investment plans were prepared. This allowed Hydro One to develop and finalize investment plans that are based on customer input, and have been refined based on specific investment trade-offs to achieve outcomes valued by customers.

The IRG Study is the most comprehensive study Hydro One has ever undertaken. It collected input from more customers than any other similar engagement in Ontario to-date (to Hydro One's knowledge). In total, over 48,000 customers participated in the IRG Study through various types of activities, including focus groups, in-depth interviews, telephone surveys, and online workbooks.[1] The activities also included conversations with First Nation 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, and the IRG Study results indicate customers across all segments support the investments proposed in the plans and are willing to accept bill increases in return for these investments.[2] Throughout both phases of the IRG Study, customers sent a strong message that they expect Hydro One to be a good steward of the electricity system in Ontario and make the

[1] IRG Report p. 25
[2] IRG Report p. 26

investments necessary to maintain the system for future generations.[3] Customers are in favour of replacing distribution and transmission assets when or before they deteriorate and are willing to pay more for investments that improve reliability or the overall health of the system.[4] Customers see value in investing in grid modernization and support technology investments that reduce costs, improve reliability, and help customers manage electricity usage.[5] Customer feedback from the IRG Study was integrated directly into the investment plans as described in section 2 below.

The IRG Study is further described below and IRG's reports detailing the IRG Study are filed as the following attachments to this exhibit:

- Attachment 1 – Overview Report (the IRG Report)
- Attachment 2 – First Nations Engagement Report
- Attachment 3 – Métis Nation of Ontario Engagement Report
- Attachment 4 – Municipalities Engagement Report
- Attachment 5 – Stakeholders Engagement Report
- Attachment 6 – Planners' Phase 2 Placemat
- Attachment 7— COVID Pulse Check Survey

Additional customer feedback from other forms of engagement was also taken into account in, and helped inform, the investment planning process. These other forms of engagement include in-depth conversations with large customers through the Account Executive Program, customer satisfaction research, conversations with customer service representatives in its contact centers, and regular dialogue with industry stakeholders and consumer groups. These and other ongoing customer engagement activities are described in Section 2 of this exhibit.

[3] IRG Report p. 26
[4] IRG Report p. 5
[5] IRG Report p. 5

1.6.2 THE IRG STUDY

1.6.2.1 TIMING AND PROCESS

As detailed in the IRG 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 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.

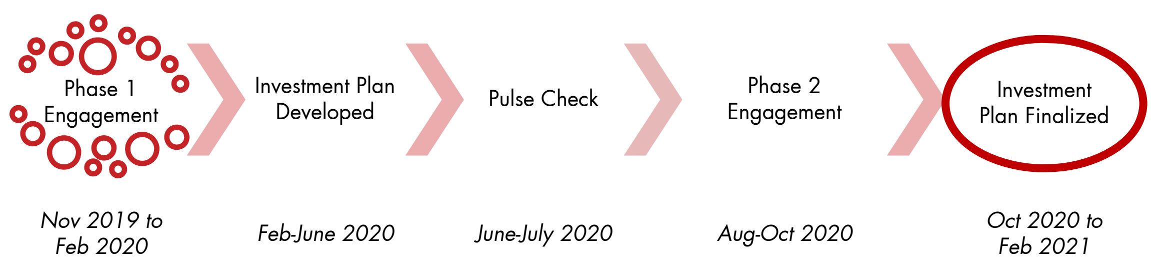

Figure 1: Integrated Customer Engagement and Investment Planning Process

Phase 1 took place in late 2019 and early 2020, prior to the beginning of the investment planning process for the years 2023-2027, and focused on identifying customer needs and preferences to inform the initial stages of investment planning. Phase 2 was carried out in the late summer and fall of 2020 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 2 results informed and were incorporated into the final investment plans submitted in this Application.

1.6.2.2 BROAD PARTICIPATION

Given the variety and number of Hydro One's customers, the IRG Study needed to obtain feedback from a broad range of customers. Hydro One serves about 1.4 million predominantly rural customers—approximately 26% of the total number of electricity customers in Ontario—through its distribution network. 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.

Hydro One's distribution customers fall into three categories: (i) Residential and Small Business (GS<50kW) customers; (ii) Commercial and Industrial customers (<2MW); and (iii) Large Distribution Accounts, 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 Nation and Métis communities in different areas of the province.

The IRG Study included a range of outreach methods tailored to different customer segments. All of Hydro One's distribution customers—both residential and non-residential—were invited to participate, and thus have had input into the distribution and transmission system planning process and resulting investment plans:

- (Primary and seasonal) residential customers
- First Nation and Métis customers
- Small business customers (GS<50kW)
- Commercial and Industrial Customers (50kW – 2MW)
- Large Distribution Accounts (>2MW)

The following customers who are directly connected to Hydro One's transmission system, as well as Ontario rate payers that are served by other Local Distribution Companies (LDCs), had the opportunity to participate in the IRG Study and the transmission system planning process:

- Transmission-connected end-users
- Transmission-connected generators
- LDCs
- Residential rate payers outside of Hydro One's distribution territory
- Small Business rate payers outside of Hydro One's distribution territory

As further detailed in the IRG Report, and shown on Figure 2 below, over 48,000 customers from all segments participated in a variety of engagement activities throughout both phases of the IRG Study.

	Direct Hydro One Customers					Ontario Ratepayers		
Activity	Residential	Small Business	C&I	LDA	LTX	Residential	Small Business	Timeframe
Phase I: Focus on Needs and Outcome Priorities								
Focus Groups	46	31	--	--	--	--	--	Sep 2019
In-depth interviews	--	--	15	9	19	--	--	Oct-Dec 2019
Telephone Surveys	633	266	100	--	--	600	200	Dec 2019-Jan 2020
Online Workbooks	1,520	282	261	10	23	1,015	408	Dec 2019-Feb 2020
Customers Engaged	**2,199**	**579**	**376**	**19**	**42**	**1,615**	**608**	Sep 2019-Feb 2020
Phase II: Feedback on Hydro One's Draft Investment Plan								
Online Workbook	40,022	1,121	200	18	51	1,260	412	Aug-Nov 2020
Customers Engaged	**40,022**	**1,121**	**200**	**18**	**51**	**1,260**	**412**	Aug-Nov 2020

Figure 2: Overview of IRG Study Customer Engagement Activities[6]

[6] IRG Report p. 25

In the OEB's decision in Hydro One's previous Transmission application (EB-2019-0082), the OEB directed Hydro One to further consider ways of seeking input from end-use LDC customers who are served by Hydro One's transmission system but receive distribution service from other LDCs. Hydro One did so, and in response to this direction, customers of other LDCs were given the opportunity to directly participate in the IRG Study during both phases of the customer engagement. These customers were able to directly voice their needs and outcome priorities (during Phase 1), and to comment on investments in Hydro One's draft transmission system plan (during Phase 2), including proposed price increases.This was accomplished through representative surveys of electricity customers in Ontario that are outside of Hydro One's distribution territory. Phase 1 included both a telephone and an online survey. Phase 2 focused on online activities, including both a representative online survey and an open call to participate through Hydro One's website.

Hydro One also obtained and incorporated timely and meaningful input from First Nation representatives. All First Nation customers were invited to complete an online workbook in Phases 1 and 2 of the IRG Study. In addition, First Nation Chiefs or delegates had the opportunity to participate in the investment planning process and share their communities' specific needs and preferences during Phases 1 and 2. Hydro One further reached out to the Métis Nation of Ontario (MNO), whose views were considered throughout the engagement. In addition to collecting feedback from individual customers, MNO representatives were invited to discuss the needs and outcome preference of their communities. Likewise, stakeholders and municipalities across Ontario had opportunities to provide their input into Hydro One's investment planning process.

Undertaking a comprehensive IRG Study enabled Hydro One to develop investment plans that are truly responsive to customer needs and preferences. 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 and distribution capital investments are closely aligned with and responsive to the needs and preferences of its customers.

1.6.2.3 PHASE 1: CUSTOMER NEEDS AND PREFERENCES

Phase 1 of the IRG Study focussed 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 nine outcomes they felt are important for Hydro One, with price, reliability, safety and customer service listed as the top priorities across all customer segments.[7] Customers also support investments in reliability and technology to reduce costs and help manage their electricity usage.[8]

Customers had the opportunity to provide their feedback on a number of high-level investment trade-offs in Phase 1 as well. For purposes of this portion of the engagement, Hydro One's planners identified a range of example types of investments that have typically represented the largest investments in past plans. The goal was to get an early indication of the types of investments customers would value and their general willingness to pay for these investments, before Hydro One's planners started the investment planning process.

Despite overall price concerns, customers indicated a preference for Hydro One to be a good steward of Ontario's electricity system, and that they are generally willing to pay more to invest in renewing aging infrastructure and improving reliability.[9] While business customers are generally less willing to pay more to make these investments than residential customers, they

[7] IRG Report p. 15
[8] IRG Report p. 16
[9] IRG Report p. 29

still support investments in the electricity system and are willing to accept potential bill impacts.[10]

Customer feedback and key findings from Phase 1 were provided to Hydro One's planners for their consideration in identifying relevant capital investment decisions and in developing draft investment plans for the distribution and transmission systems. Throughout the spring and summer of 2020, the system 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 1 customer feedback, including preferences for specific investments in respect of the distribution and transmission systems.

1.6.2.3.1 DISTRIBUTION SYSTEM

As described in the IRG Report, key customer feedback from Phase 1 in respect of distribution included the following:

- A clear majority of customers support investments in the distribution system based on a general preference for a more proactive approach to replacing aging distribution infrastructure when, or before, it starts to deteriorate.[11]
- Most customers want Hydro One to invest in reliability but are divided over the level of investment—between what is necessary to maintain the current level of distribution system reliability and what is needed to improve reliability in order to get the number and length of outages closer to the Ontario average.[12]

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[10] IRG Report p.5
[11] IRG Report pp. 5, 17
[12] IRG Report pp. 5, 17

- The majority of customers support investments in hardening the system, either as part of ongoing system renewal or as proactive investments.[13]
- Almost all customers want to place more emphasis on helping those experiencing poor reliability, either by shifting or increasing spending.[14]
- Customers support technology investments that reduce costs, improve reliability, and help customers manage electricity usage.[15]
- Customers are split on whether it is better to proactively build capacity for economic development or if capacity should be added on when new customers are ready to pay for it.[16]
- A majority of customers support Hydro One making the necessary investments in general plant to meet the same standard as similar businesses, rather than just ‘making do’ and only investing to address the most urgent needs.[17]

1.6.2.3.2 TRANSMISSION SYSTEM

As described in the IRG Report, key customer feedback from Phase 1 in respect of transmission included the following:

- Customers strongly support investments in the transmission system; the majority of customers want to either maintain or increase the current level of investment to keep pace with aging transmission infrastructure.[18]
- Customers support investments in a more reliable transmission system, either as part of ongoing renewal or as proactive investments.[19]
- Most customers want Hydro One to make investments to improve power quality and reduce the number of momentary outages.[20]

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[13] IRG Report pp. 5, 18
[14] IRG Report pp. 5, 18
[15] IRG Report pp. 5, 18
[16] IRG Report pp. 5, 18
[17] IRG Report pp. 5, 18
[18] IRG Report pp. 5, 19
[19] IRG Report pp. 5, 19

Taking into account the Phase 1 customer feedback and results, Hydro One's planners developed alternative investment plan scenarios for each of transmission and distribution: a draft plan; a plan that adopts a somewhat "accelerated pace" of investment relative to the draft plan; and a plan that adopts a somewhat "slower pace" of investment relative to the draft plan. These alternative investment scenarios formed the basis of options presented to customers in Phase 2, as described in Section 2.5 below. Further detail is provided in Section 1.7 of the SPF.

1.6.2.4 PULSE CHECK

The COVID-19 pandemic started shortly after completion of Phase 1. Before proceeding to Phase 2, and to assess whether customer feedback received in Phase 1 was altered in any way by the pandemic, IRG carried out a "pulse check" survey among Hydro One's residential and small business customers in June-July 2020.

The results of this pulse check survey were in line with the Phase 1 results, as further described in the IRG pulse check report. The key priorities identified by residential customers continued to be delivering electricity at reasonable rates, ensuring reliable electrical service, ensuring the safety of electricity infrastructure, and helping customers with conservation and cost savings.[21] Small business customers also continued to rank providing quality customer service as a top outcome priority. The pulse check survey results indicated that customers' needs and preferences going forward had not shifted in any material way as a result of the pandemic and confirmed that the Phase 1 results remained a valid base and instructive for purposes of the 2023-2027 investment planning process.

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[20] IRG Report pp. 5, 19
[21] Attachment 7, COVID Pulse Check Survey, p. 2

1.6.2.5 PHASE 2: FEEDBACK ON THE DRAFT INVESTMENT PLANS

Phase 2 of the IRG Study, over the late summer and fall of 2020, gave customers an opportunity to provide feedback on Hydro One's draft investment plans, including on specific investment trade-offs included in the plans.

The Phase 2 results indicated that customers across all segments value the proposed investments in the electricity system and are supportive of Hydro One's draft investment plans.[22] They are willing to accept bill or 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.

Among the customer segments, residential and small business customers expressed the most support for investments that exceed spending levels included in the draft plan, even if those lead to larger increases on their monthly bill.[23] Larger business customers, namely C&I and LDA customers, are evenly split in their preferred level of investment between the draft plan and a higher level of spending (accelerated pace).[24] Large transmission (LTX) customers favour the draft plan over an accelerated pace. Across all segments, a significantly larger share of customers prefer an accelerated pace over a pace that is slower than the draft plan.[25]

The sections immediately below provide further details regarding the Phase 2 customer feedback, including their preferences for specific investments in the distribution and transmission systems.

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[22] IRG Report pp. 6, 20
[23] IRG Report p. 20
[24] IRG Report p. 20
[25] For detailed results, see Planner's Placement at Attachment 6 to this exhibit.

1.6.2.5.1 DISTRIBUTION SYSTEM

As described in the IRG Report, key customer feedback from Phase 2, in respect of distribution, included the following:

- Customers support the investments included in the draft plan regarding the replacement of distribution assets in poor condition, such as poles and transformer stations.[26]
- Regarding investments in grid modernization, a plurality of customers would like to see an increased level of investment beyond the level in the draft plan.[27]
- For investments in battery energy storage, there is a clear preference for the draft plan.
- Customers prefer the draft plan for investments in system capacity to facilitate community and economic growth.[28]
- Residential and small business customers prefer a 7-year replacement pace of the current smart meter system.[29]

1.6.2.5.2 TRANSMISSION SYSTEM

As described in the IRG Report, key customer feedback from Phase 2, in respect of transmission, included the following:

- Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to maintain the overall health of the system.[30]
- Across all customer segments, the draft plan is the preferred option for replacing transmission lines in poor condition and aging and deteriorating transmission stations.

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[26] IRG Report pp. 6, 21
[27] IRG Report pp. 6, 21
[28] IRG Report pp. 6, 22
[29] IRG Report pp. 6, 22. Hydro One ultimately elected to replace the smart meter system over a 5-year period after receiving analysis showing total costs of the 5-year and 7-year pacing options are $921.8M and $979.8M respectively, resulting in savings of $58.0M associated with the 5-year pacing option, which requires fewer failed AMI 1.0 meters to be replaced on a reactive basis. See D-SR-12 section E-2 for further detail
[30] IRG Report pp. 6, 23

Residential and small business customers show greater support than other customer segments for a higher spending level beyond the level in the draft plan.[31]

Hydro One's planners used the Phase 2 customer feedback to revise and finalize the proposed investment plans. This approach allowed Hydro One to ensure the final plans for 2023-27 are responsive to customer needs and preferences. Section 1.7 of the NSP further describes the integrated nature of the customer engagement process and the investment planning process and how the above customer feedback was taken into account in Hydro One's investment planning process. Section 2.7 of the TSP, Section 3.7 of the DSP and Section 4.7 of the GSP further describe how the final proposed capital expenditure plans reflect the customer feedback will achieve the outcomes valued by customers.

1.6.3 ADDITIONAL CUSTOMER ENGAGEMENT ACTIVITIES

In addition to the IRG Study, Hydro One regularly engages with and obtains feedback from its customers through a variety of channels and methods. This further 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.

Each customer segment has unique needs, and Hydro One engages with different customer segments in different ways. Larger customers (Large Distribution Accounts (LDA) and Large Transmission Customers (LTX)) often require customized solutions and consultations. Hydro One engages with these customers through its Large Customer Account Management Group (Section 3.1 below) and through oversight committees and working groups (Section 3.2 below).

[31] IRG Report pp. 6, 23

To ensure Hydro One maintains a regular view of its customers' needs and preferences, Hydro One performs the following activities on an ongoing basis to monitor changing customer service trends:

- Customer Satisfaction Research (Transactional and Surveys) (Section 3.3 below)
- Call Centre Trends (Section 3.4 below)
- External Relations (MPPs, Agencies, and Municipalities) (Section 3.5 below)
- Indigenous Relations (First Nations and Métis) (Section 3.6 below)
- Hydro One's Ombudsman Office (Section 3.7 below)

1.6.3.1 LARGE CUSTOMER ACCOUNT MANAGEMENT

The Large Customer Account Management Group (formerly, Customer Business Relations) provides large distribution-connected customers and large transmission-connected customers with a single point of contact at Hydro One for all types of interactions. In particular, this group communicates with customers on matters that include customer connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality. 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.

To manage its performance and customer satisfaction, Hydro One consolidated the service delivery model for its largest customers, including LDA, C&I and transmission-connected customers. An Account Executive is assigned to each of these large customers to track customer information and interactions and to identify opportunities to advocate for them across the organization.

Account Executives from Hydro One's Large Customer Account Management Group 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, then 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 proactively engage with larger C&I, LDA and LTX customers to review and coordinate 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 Ontario Grid Control Centre (OGCC) 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 OGCC's meetings with customers to discuss planned outages and work as part of the regional planning process.

The OGCC's Customer Operating Support 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.

The Outage Planning Group organizes 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 OGCC 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, 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.

1.6.3.2 OVERSIGHT COMMITTEES

Hydro One has established a number of oversight committees to engage and obtain feedback from customers on topics with a high level of customer interest. Ongoing coordination with other entities is particularly valuable where there is a need for coordinated health and safety oversight. The purpose and value of the oversight committees is to ensure that the ongoing operational needs and preferences of these customer groups are accounted for in a timely fashion. 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.

1.6.3.2.1 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.

1.6.3.2.2 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.

1.6.3.2.3 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 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.

1.6.3.2.4 METROLINX OVERSIGHT COMMITTEE

Hydro One's Metrolinx Working Group provides a forum to reviews issues arising during the large scale transportation infrastructure work that Metrolinx is undertaking in Ontario. This working group is made up of staff from Hydro One's Large Account Management, Real Estate, and Transmission Planning groups and staff from Metrolinx. The working group reviews and addresses customer escalations arising from the Metrolinx work program and ensures that issues are addressed in a timely manner.

1.6.3.2.5 HYDRO OTTAWA OVERSIGHT COMMITTEE

The Hydro Ottawa Oversight Committee was established in 2018 and provides a forum for Hydro Ottawa 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 Hydro Ottawa. Meetings also allow the parties to coordinate efforts relating to capital projects and other matters.

1.6.3.2.6 ALECTRA OVERSIGHT COMMITTEE

The Alectra Oversight Committee was established in 2020 and 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.

1.6.3.2.7 OPG OVERSIGHT COMMITTEE

Hydro One facilitates and participates in switchyard oversight committees and plant group meetings with Ontario Power Generation. 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.

1.6.3.3 CUSTOMER SATISFACTION RESEARCH

Since 1999, Hydro One has been collecting feedback from all customer segments through a comprehensive customer satisfaction research program. This research is conducted by independent expert customer research firms and incudes both perceptional and transactional satisfaction research.

Hydro One conducts transactional surveys on an ongoing basis to monitor customer needs and preferences, monitor trends, address transactional concerns in a timely fashion, and influence those practices in the future. These surveys contact a sub-set of Hydro One customers after they have had an interaction with the company to determine how well its customer service met their expectations. These surveys measure operational effectiveness for the call centre, the myAccount portal, service upgrades, new connections, and forestry work.

Hydro One also measures customers' perception of the company as a whole, whether they have interacted with Hydro One recently or not. These surveys monitor how well the company meets customers' expectations and delivers on critical success factors. These perception surveys are conducted monthly for residential and small business customers. All other customers, including C&I, LDA and LTX customers are surveyed on an annual basis.

The trending of results over time assists Hydro One in identifying areas to improve customer satisfaction. Hydro One uses this data to inform and improve business practices and stay informed about the trends that matter most to its distribution and transmission customers. Customer Satisfactions scores serve as important performance measures, and are includes in various scorecards (as described in TSP 2.5, DSP 3.5).

1.6.3.4 CALL CENTER TRENDS

Residential and small business customers work with the Customer Call 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 assure Hydro One's performance is continuously improving and distribution system outcomes are aligned with customer needs and preferences.

Customer calls 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 Relationship Centre, which addresses escalated calls that require more detailed investigation and resolution.

C&I customers who are demand or interval metered are serviced by a dedicated team within the Business Contact Center. This dedicated team is the customer's "one-stop-shop" for questions regarding technical support or their bill. These representatives have the training to address billing questions or concerns and are readily able to navigate through the company's lines of business to get the technical information or contacts as required.

1.6.3.5 EXTERNAL RELATIONS

Hydro One's External Relations department maintains relationships with representatives of the Ontario government, Members of Provincial Parliament, municipality representatives and elected officials, and key stakeholder groups that represent large customer segments for Hydro One, such as the Ontario Federation of Agriculture and the Federation of Ontario Cottagers' Associations. Through these interactions, Hydro One is able to stay current with the issues these key stakeholders and their constituents or members may have, and External Relations is able to coordinate assistance on behalf of the company.

External Relations also coordinates Hydro One's presence at several stakeholder and community events to interact directly with customers and community leaders, providing information about Hydro One's services and programs and listening to their views and concerns. Public consultation for major infrastructure investments and operational programs across Ontario is also a large part of the department's work.

1.6.3.6 INDIGENOUS RELATIONS

For over ten years, Hydro One has engaged, and continues to engage, with First Nations and Métis communities through ongoing relationship building efforts. Hydro One seeks input from First Nations and Métis to understand their specific customer needs and preferences with respect to its distribution and transmission systems. Further information relating to Hydro One's First Nations and Métis Relations Strategy can be found in Exhibit A-07-02.

1.6.3.7 HYDRO ONE'S OMBUDSMAN OFFICE

When customers do not feel that a response or decision made by Hydro One was appropriate or fair, they can reach out to the Hydro One Ombudsman. The Ombudsman addresses these specific customer issues, but also performs systemic investigations. These investigations can highlight where changes are needed to better meet customers' needs and preferences. Customer Service works with the Ombudsman's office on a regular basis to understand any underlying trends of concern which may have arisen, which can then assist Customer Service to better align how it works with its residential and commercial customers.

1.6.3.8 INCORPORATING CUSTOMER NEEDS AND PREFERENCES INTO THE INVESTMENT PLANS

By integrating Hydro One’s business and investment planning and customer engagement processes, Hydro One planners were able to (and did) use direct customer feedback at each stage of the process to inform, shape and finalize the investment plans:

- Phase 1 IRG Study feedback: Initial customer feedback was presented to planners in early February 2020, before the start of the planning process. Planners considered and incorporated this feedback into three investment scenarios developed throughout the spring and early summer of 2020, which scenarios were then presented to customers in Phase 2.
- Phase 2 IRG Study feedback: Customers were invited to review the draft investment plans and provide feedback on these investment scenarios in late summer and fall of 2020. Planners used the Phase 2 customer engagement feedback and results to revise and finalize the investment plans.
- In addition to the IRG Study results, in developing and finalizing the investment plans Hydro One’s planners also took into account customer feedback received through certain other types of customer engagement activities, such as the Large Customer Account Management group’s activities

This approach allowed Hydro One to develop final investment plans for 2023-27 that are truly responsive to customer needs and preferences.

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Hydro One's Joint Rate Application Customer Engagement

Understanding Customer Needs and Preferences

December 2020

Prepared for:

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Customer Engagement Report

December 2020

Confidentiality

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Torys on behalf of its client Hydro One, in connection with Hydro One's joint rate application. The conclusions drawn and opinions expressed are those of the authors.

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Introduction

Innovative Research Group Inc. (INNOVATIVE) was engaged in January of 2019 to help design, execute, and document the results of Hydro One's customer engagement, as part of Hydro One's Joint Rate Application (JRAP) to the Ontario Energy Board (OEB) for the years 2023 to 2027.

There was a strong customer response to this engagement. **This is the largest engagement that INNOVATIVE has conducted in Ontario's electricity system. Over 48,000 First Nations and Metis representatives, stakeholders and customers of all sizes participated in Hydro One's customer engagement.**

Following the OEB's guidelines for a "consumer-centric" approach to rate applications, as laid out in the *Renewed Regulatory Framework for Electricity (RRF)*[1] and the *Handbook for Utility Rate Applications (Handbook)*[2], the engagement focused on customer **needs** and **preferences.**

> **Needs** questions focus on understanding the gap between the services and experience customers want, and the services and experience customers are receiving.
>
> **Preferences** questions focus on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.

This engagement was deeply embedded in the Hydro One capital investment planning process and the work was completed in two phases. Phase I took place from September 2019 until January 2020 and focused on identifying customers' needs and preferences for outcomes. In February 2020, customer feedback and key findings from this phase were presented to Hydro One planners to provide initial customer input into the development of draft investment plans for the distribution and transmission systems.

Phase I of the customer engagement was finalized before the outbreak of the COVID-19 pandemic. COVID-19 raised questions about whether the priorities identified in Phase I had changed and whether customers continued to be willing to participate in engagement activities for Phase II. In June 2020, a "pulse check" survey was carried out among Hydro One's residential and small business customers to check on these questions. The results showed that customer needs and preferences were consistent with the Phase I findings and customers remained willing to participate in ongoing engagement activities, allowing Hydro One to proceed with its planning efforts and its Phase II engagement activities.

Phase II was carried out in the Fall of 2020, with the objective of soliciting Indigenous, stakeholder and customer feedback on Hydro One's draft investment plan for the years 2023-2027, including a set of specific investment trade-offs. These were selected by Hydro One's planners, after reviewing the Phase I results, as examples of specific large investment decisions that represented trade-offs between the outcome priorities identified by customers. All contact was online to ensure full adherence to public health directions. Customer feedback from Phase II was presented to Hydro One's planners in November 2020 in advance of the preparation of the final investment plan.

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[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)

INNOVATIVE also provided Hydro One with feedback from non-representative engagements covered in separate reports including Indigenous viewpoints, voluntary workbook respondents, and stakeholder feedback.

This document provides an overview of Hydro One's 2019/20 customer engagement process and a summary of the generalizable results from the representative surveys.

- Insights into customer needs, preferences, and outcome priorities (Phase I) come from representative online workbooks among all customer segments, including both direct and indirect customers (conducted from December 2019 to January 2020).
- Results for customer views on Hydro One's draft investment plan, as well as specific investment decisions and trade-offs (Phase II) are derived from representative online workbooks among all customer types, including both direct and indirect customers (conducted between August and November 2020).
- For transmission investments, Hydro One included the results of representative samples of end users served by other utilities as well as Hydro One distribution and direct transmission customers.
- A detailed description of the methodology can be found in the section ("Designing This Engagement")
- Detailed results can be found in the attached customer engagement Appendices.

Key Findings

Phase I: Needs and Outcome Priorities

The Phase I workbook focused on identifying Hydro One customers' needs through open-ended probes. Customer preferences (outcome priorities) were assessed in three ways:

1. Rating priorities individually,
2. Ranking priorities relative to each other, and
3. Providing a variety of illustrative choices to see how customer priorities apply to actual distribution and transmission investment choices at this time.

Customer Needs

Most customers are satisfied with the electricity service they received from Hydro One and do not list any unfulfilled needs. Among those who do, the top two needs are improved reliability and power quality, and lower rates. When asked to describe how they know if Hydro One is doing a good job for them or not, providing a reliable electricity service is mentioned most frequently.

Outcome Priorities

Customers rated the importance of nine outcomes identified through qualitative research. Opportunity was provided to identify additional priorities. Reliability, affordability, and safety are the most important customer priorities, but all nine are considered important in their own right.

Customers also ranked by importance the same list of nine priorities. Relative to others, price, reliability, safety, and customer service are identified as the top priorities across all customer segments.

Reliability outcomes were probed in more detail. Customers ranked the number of day-to-day outages, the length of day-to-day outages, the number of major event outages, the length of major event outages, and power quality. Customers choose reducing the number and length of outages during extreme weather events and reducing the number of day-to-day outages as their top priorities.

High-level Investment Trade Offs

Finally, customers were asked to make a series of choices between improved outcomes and lower costs. Distribution topics included:

- General plant,
- System renewal,
- Day-to-day reliability and major event reliability,
- Whether to fund improvements by shifting resources or adding resources,
- What approach to take on investing in new technologies and the areas that should be priorities for new technology, and
- Whether to be proactive or reactive in enabling economic growth.

Customers were also asked about pacing and reliability for lines and stations in the transmission system.

Despite price concerns, a majority of customers are generally willing to pay more to invest in renewing aging infrastructure and improving reliability. When making concrete investment decisions, customers give precedence to safety and reliability over keeping the price down. Generally, business customers and LEAP-qualified residential customers are less willing to consider paying more to make these investments than residential customers. However, those customers still supported investments in the electricity system and accepted potential bill impacts, just at lower levels than the average residential customer.

Investing in the Distribution System

A clear majority of customers support investments in the distribution system based on a general preference for a more proactive approach to replacing aging distribution infrastructure when, or before, it starts to deteriorate.

Most customers want Hydro One to invest in reliability but are divided over the level of investment—between what is necessary to maintain the current level of distribution system reliability and what is needed to improve reliability to get the number and length of outages closer to the Ontario average. Similarly, the majority of customers support investments in hardening the system, either as part of ongoing system renewal or as proactive investments.

Almost all customers want to place more emphasis on helping those experiencing poor reliability, either by shifting or increasing spending.

Customers support technology investments that reduce costs, improve reliability, and help customers manage electricity usage.

Customers are split on whether it is better to proactively build capacity for economic development or if capacity should be added on when new customers are ready to pay for it.

A majority of customers support Hydro One making the necessary investments in general plant to meet the same standard as similar businesses rather than just make do and only invest to address the most urgent needs.

Investing in the Transmission System

Customers strongly support investments in the transmission system. Just as in distribution choices, a majority of customers want to either maintain or increase the current level of investment to keep pace with aging transmission infrastructure. Customers also want investments in a more reliable transmission system, either as part of ongoing renewal or as proactive investments. A majority of customers want Hydro One to make investments to improve power quality and reduce the number of momentary outages.

Phase II: Feedback on Hydro One's Draft Investment Plan

Between the Phase I reporting and Phase II, Hydro One planners prepared a draft capital investment plan. The Phase II workbook focused on collecting reactions to Hydro One's draft plan. In addition to seeking feedback on the overall cost of the draft capital investment plan, the workbook also explored pacing and trade-off choices in respect of specific, large investments.

Support for Hydro One's Draft Plan

Customers across all segments support Hydro One's draft investment plan or a higher level of investment. A plurality of residential and small business customers supports an increase in their monthly bill that exceeds the amount included in the draft plan to accelerate some of the programs described in the workbook. C&I and LDA customers are evenly split between the draft plan and an accelerated pace. Large transmission (LTX) customers clearly favour the draft plan over an accelerated pace. Across all segments, the share of customers preferring an accelerated pace over a slower pace is significantly larger. Even among LEAP-qualified customers, 40% favour an accelerated pace and 29% support the draft plan.

Specific Investment Trade Offs

There is strong customer support for Hydro One to make investments in both its distribution and transmission systems and customers are willing to accept bill or rate increases in return. However, there are differences between investment areas regarding the level of investment customers support.

Investing in the Distribution System

Customers' views on pacing were explored on two issues: pole replacement and station transformer replacement. In both cases, most customers support either the pace of investments included in the draft plan or an accelerated pace. Residential customers are more likely to support an accelerated pace while large volume customers tend to support the draft plan.

Customer opinions of specific reliability investments were also explored in two questions: battery energy storage and grid modernization through smart devices. A plurality of customers support a level of investment that goes beyond the draft plan on grid modernization. However, on battery energy storage, there is a clear preference for the draft plan, with less appetite for an accelerated pace than in other investment choices—especially among larger business customers.

When asked to what extent Hydro One should make investments in system capacity to facilitate community and economic growth, a majority of customers across all segments prefer the draft plan over an accelerated or slower pace. Similarly, both residential and small business customers have a clear preference for the draft plan with includes a 7-year replacement pace of the current smart meter system.

Investing in the Transmission System

Customers strongly support the replacement of aging and deteriorating transmission system assets to maintain the overall health of the system. Across all customer types, the draft plan is the preferred option for replacing transmission lines in poor condition and aging or deteriorating transmission stations. However, residential, and small business customers show similar levels of support for the accelerated pace as they do for the draft plan while larger business customers prefer the draft plan.

Designing This Engagement

Methodology

Engaging customers in a meaningful way when it comes to electricity is a challenge. Some customers may begin an engagement feeling they do not know enough to contribute to an engagement because of their limited familiarity with the electricity system, including how the different components of generation, transmission, and distribution work together.

While most customers have some familiarity with their local distribution company (LDC)—the company they receive their electricity bill from—few understand that Hydro One is also responsible for the transmission system in the province. This is particularly true for those who receive their electricity bill from another LDC.

This engagement was designed to address those information needs. The results of the diagnostic questions indicate that customers feel the workbook found the right balance in how much information was provided.

A second challenge is collecting input from a representative sample of customers to ensure that the feedback provided reflects the views of Hydro One's broader customer base.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of knowledge, INNOVATIVE developed a process built on six key principles:

Customer Engagement Principles

- Create open voluntary processes that allow anyone who wants to be heard an opportunity to express themselves.
- Use random-sampling research elements to ensure a representative sample of customers are engaged ensuring the generalizability of the findings.
- Provide customers with the context they require to make informed decisions in a transparent manner that are articulated in real terms.
- Create an opportunity for customers to learn the basics of the electricty system so they can provide a more informed point of view.
- Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
- Give customers an opportunity to "colour outside the lines" through qualitative feedback.

One cornerstone of this approach is to allow everyone who wants to have a say an opportunity to be heard. This is done through voluntary processes that are open for everyone to participate. However, voluntary processes can attract certain types of participants (e.g. more engaged citizens, interest groups, etc.) and do not necessarily reflect the attitudes and opinions of a utility's broader customer base. Thus, another core element of any customer engagement process is obtaining feedback from a representative sample of customers to make sure every type of customer is heard.

To give everyone who wants to have a say the chance to express themselves, while giving a representative sample of customers the last word, there is a fixed sequence to these activities. Early activities, such as focus groups and one-on-one interviews, provide opportunities for customers to “colour outside the lines” and shape the content of the engagement material. This allows the engagement to be responsive to customer input and ensures that the process covers what customers want to talk about. Open-ended “safety valve” questions throughout the workbooks provide a further opportunity for customers to share comments about their own priorities and the workbooks themselves.

The basic challenge for designing Hydro One’s customer engagement was to get meaningful input from a wide variety of customers on both the distribution and the transmission systems. INNOVATIVE recommended a workbook-based customer engagement as the best vehicle for seeking that input. The core idea behind this approach was to provide customers with choices based on basic values illustrated with trade-offs among different outcomes. To provide meaningful feedback on those choices, workbooks create an opportunity for customers to learn the basics of the electricity system and provide the context needed to make informed choices.

In approaching the design of this engagement, INNOVATIVE and Hydro One considered the utility’s unique position as a distributor that serves about 25% of electricity customers in Ontario through its distribution system, and as a province-wide transmission company that serves every electricity customer in Ontario but has no direct access to customers outside of its distribution service territory. A key concern was how Hydro One could reach customers and motivate them to participate in this engagement, given the lack of customer lists and the company’s limited visibility to customers that are not served by its distribution system.

Another challenge was the joint nature of the engagement that required collecting feedback on both the distribution and the transmission system. The workbook needed to provide essential background information on both systems to allow customers to make meaningful and informed decisions. The challenge here was to provide enough information without overwhelming customers or taking up too much of their time. The fact that 43,000 customers completed the Phase II workbook and most felt it had the right balance of information indicates customers were satisfied with the workbook design.

The following sections provide a detailed overview of the various activities carried out during each phase of Hydro One’s 2019-2020 customer engagement program.

Customer Engagement Process Overview (Phase I)

Phase I (2019) of the engagement was designed to identify customer needs and preferences as they relate to the outcomes that the utility should focus on and prioritize. Given the importance placed on identifying customer preferences in the *Handbook for Utility Rate Applications*, the focus of Phase I was to develop a list of customer outcomes and to identify customer priorities among those outcomes to aid in Hydro One's planning process.

Based on the engagement principles outlined in the introduction, INNOVATIVE worked with Hydro One to design and execute a multi-faceted engagement program that both aligns with OEB expectations and provides meaningful input for the utility's investment planning.

In Phase I of the customer engagement, a subset of Hydro One distribution and transmission customers were invited to participate. Customers were randomly selected from Hydro One's customer database to receive invites to the different engagement activities.

Pre-Engagement

The first phase of this program was a pre-engagement. INNOVATIVE and Hydro One worked together to understand what was already known about customer needs and preferences, which topics should be addressed, as well as how best to engage with customers.

Exploratory Research (Qualitative)

This qualitative phase, including focus groups (among residential and small business customers) and in-depth interviews (among larger business customers), provided customers an opportunity to "colour outside the lines" through qualitative feedback. It was designed to provide customers with some education about Hydro One's role in Ontario's electricity system and hear about their needs and outcome priorities. The interviews and focus groups followed structured discussion guides and were led by professional interviewers/moderators. The feedback gathered from these activities helped inform the subsequent phases of the customer engagement, including the telephone surveys and online workbooks.

Workbook Development

Based on the information gleaned from the pre-customer engagement and exploratory phases, INNOVATIVE developed a workbook that was used throughout both the quantitative phase of the customer engagement. The key objective was to develop a workbook that provided meaningful, balanced and comprehensive information. A core challenge was finding the right balance between too little and too much information and presenting this information in a non-technical way that customers can understand.

Representative Research (Quantitative)

The core of Hydro One's customer engagement encompassed two elements—telephone surveys and online workbooks—covering residential and business customers across Ontario.

Telephone Surveys

While online workbooks are customers' preferred means of providing input, we need to be sure the online participants are representative of the broader Hydro One customer base. This engagement included live-caller telephone surveys using a random-sampling approach to provide a representative sample of Hydro One's residential, small business and C&I customers that provided a profile of Hydro One's customers that could be used to assess the online workbook sample and weight that sample, as necessary. Separate telephone surveys were also conducted among residential and small business electricity customers across Ontario who are served by another LDC.

All telephone surveys followed a stratified random sampling methodology. This is a method of sampling that involves the division of a "population" (in this case, Hydro One's customer base) into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or known characteristics. A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample. This element of the engagement served as a reference study to ensure that the results of the online workbooks are representative of Hydro One's broader customer base.

Online Workbook

The online workbook sampling approach varied by rate class. For Hydro One's residential and small business customers, a random-sampling approach was used to provide a representative sample of Hydro One's residential and small business customers to ensure the generalizability of the findings. All C&I, LDA and LTX customers were invited to complete a workbook that was tailored to their respective rate class.

The three biggest advantages of online surveys are: 1) the ability to use visuals to convey information, 2) giving respondents the opportunity to complete the survey at their own speed, and 3) the cost being a fraction of telephone surveys. The fact that online surveys are more cost effective enabled INNOVATIVE to double the sample size, compared to the telephone survey among ratepayers for whom Hydro One has no direct customer contact lists.

This online workbook, was accessible for one month (between December 17th, 2019 and January 17th, 2020 for residential and small business customer and between January 13th and February 12th, 2020 for larger business customers), and gave customers the opportunity to engage with an interactive platform to both educate and collect detailed feedback on needs, preferences, outcome priorities and high-level investment trade-offs.

Given the large amount of information, INNOVATIVE asked focus group and interview participants for their preferred method of engagement. Participants did not feel telephone surveys could work as effectively as online. They particularly valued the use of visuals and the opportunity to go back over information as necessary to comprehend the material and come to informed opinions.

Hydro One promoted the online workbook, primarily relying in email communication, which resulted in 2,096 unique responses from direct customers. INNOVATIVE, on behalf of Hydro One, also reached out to residential and business customers of other LDCs for the first time, using online panels to engage a representative sample of electricity rate payers in Ontario that are served by Hydro One's transmission system. In total, 1,423 rate payers outside of Hydro One's distribution territory completed an online workbook pertaining to the transmission system. Both the residential and business samples were validated against census and phone survey data to ensure that they are representative of the broader population.

2019/20 Customer Engagement Process

Phase I: Focus on Needs and Outcome Priorities	
Step 1: Exploratory Qualitative Research	*Randomly recruited*
Step 2: Workbook Development	
Step 4: Representative Telephone Survey	*Randomly recruited*
Step 5: Representative Online Workbook	*Randomly recruited + use of online panels*

Presentation of Results

The results of this first engagement phase were presented to Hydro One's planners in early February. The key findings were summarized in a "Planning Placemat" that was provided to planners (provided in an Appendix). Planners had the opportunity to review the results and ask questions in additional smaller group sessions mid-February 2020.

Customer Engagement Process Overview (Phase II)

Following the Phase I engagement, Hydro One developed a draft capital investment plan. Phase II of the engagement in the Fall of 2020 solicited customer feedback on the cost impact of the overall draft investment plan as well as exploring trade-offs in relation to specific programs and the associated bill impacts and the pacing of investments.

Workbook Development

Based on the insights gained in Phase I, INNOVATIVE worked closely with different business units to identify investment decisions with potential trade-offs that may impact customers. All customer engagement materials were combined into a workbook designed to provide meaningful feedback.

This was the first engagement that sought to cover both distribution and transmission system plans. This required a particular focus on delivering the right amount and substance of information in order to enable customers to express an informed opinion about Hydro One's draft plan and specific investment examples included in this plan.

As in Phase I, different versions of the workbook were developed for different audiences. While Hydro One distribution customers were invited to comment on both the distribution and transmission plans, transmission connected customers (LTX) and customers served by other LDCs were asked about the transmission system plan only. All customers received workbooks that were tailored to their rate class, presenting relevant investment trade-offs and how each option affects their monthly electricity bill (in dollars or cents).

Customer Engagement

The main tool used to collect customer input on Hydro One's draft plan was an online workbook. As a result of the COVID-19 pandemic, all customer engagement activities were forced to shift to a virtual platform. As in Phase I, it offered an interactive platform to both educate customers about Hydro One and the electricity system and collect detailed feedback on Hydro One's draft plan.

The online workbook featured open-ended questions after every question pertaining to Hydro One's investment plan, thus allowing respondents to "colour outside the lines" by providing unrestricted feedback.

All Hydro One customers had the opportunity to complete the workbook. Email invitations to the workbook were sent to all Hydro One customers with an email address on file. Customers without an email address on file received a bill insert with their paper bill, encouraging them to participate in the engagement by accessing the workbook link through Hydro One's website. Customers outside of Hydro One's distribution territory were included in the customer engagement in two ways: by inviting them to complete the workbook through a link on Hydro One's website and through the use of online panels. Customers without internet access were able to request a paper copy of the workbook by contacting Hydro One's contact center. All versions of the online workbook were fully accessible to customers with visual impairments and compatible with standard screen readers.

The workbook was launched on August 31st, 2020. Hydro One promoted the online workbook via email, using customer lists, through bill inserts to reach customers without an email address on file, and via a digital media campaign. In total, over 43,000 customers completed the online workbook. This is not only the largest number of customers to ever participate in a Hydro One engagement, but also, to the best of our knowledge, the largest number of Ontarians who have ever participated in an electricity engagement.

2019/20 Customer Engagement Process

2020: Feedback on Hydro One's Draft Investment Plan

Step 1: Workbook Development	
Step 2: Representative Online Workbook	*Randomly recruited + use of online panels*
Step 3: Online Workbook (Qualitative)	*Voluntary*

Presentation of Results

The results of this second engagement phase were presented to Hydro One's planners in November 2020 in virtual sessions. The key findings were summarized in a "Planning Placemat" that was provided to planners (provided in an Appendix).

Customer Engagement Diagnostics

Phase I

Customers had the opportunity to provide feedback on Hydro One's engagement process, especially on how the utility is using customer feedback to inform its plan. When asked if Hydro One's customer engagement process seemed like the right approach or the wrong approach to bringing customer needs and preferences into Hydro One's plan, a clear majority felt that it was the *right approach*.

Feedback on Customer Engagement Approach	Residential	Small Business	C&I	LDA	LTX
Right approach	89%	87%	86%	90%	100%
Wrong approach	4%	5%	5%	0%	0%
Don't know	7%	8%	9%	10%	0%

Phase II

Participants approved of Hydro One's customer engagement strategy and those who completed the online workbook tended to have a favourable impression of the workbook. Moreover, while most participants had limited knowledge to start, diagnostics show that participants feel the workbook delivers the information they needed and allowed them to express informed decisions.

Overall Impression of the Workbook	Residential	Small Business	C&I	LDA	LTX
Favourable	84%	81%	78%	89%	84%
Unfavourable	12%	12%	13%	11%	14%
Don't know	4%	7%	9%	0%	2%

The workbook also found the right balance of information. A clear majority of customers stated that the workbook contained "just the right amount" of information.

Volume of Information	Residential	Small Business	C&I	LDA	LTX
Too much	10%	9%	9%	6%	0%
Just the right amount	80%	80%	81%	78%	69%
Too little	10%	11%	10%	17%	31%

Phase I: Focus on Needs and Preferences

Customer Needs and Preferences

Core elements of Phase I were "needs questions", which focus on understanding the gap between the services and experience customers want, and the services and experience customers receive.

The first step of understanding customer needs is related to overall satisfaction. When asked how satisfied they are with Hydro One's performance, a strong majority of respondents gave a positive answer.

Satisfaction with Hydro One's Performance	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
Satisfied	80%	77%	76%	80%
Dissatisfied	9%	12%	8%	20%
Neutral/Don't know	11%	11%	16%	0%

As a follow up to the overall satisfaction question, participants were asked if there was anything in particular Hydro One could do to improve its services. Most customers do not mention any unfulfilled needs. Among those who do, the top two needs are improved reliability and power quality, and lower rates. Most respondents judged Hydro One's performance by its ability to provide reliable electricity service.

Outcome Priorities

To better understand customer preferences, the customer engagement included questions that capture customer views on the outcomes that Hydro One should focus on, and what the priorities should be among those outcomes.

In the Phase I workbook, respondents were first presented with a list of nine priorities and asked to rate each of these priorities by its level of importance. While all nine were considered important, reliability, affordability, and safety were identified as the most critical.

Extremely Important	Very Important	Important
✓ Ensuring reliable electrical service ✓ Delivering electricity at reasonable rates ✓ Ensuring the safety of electricity infrastructure	✓ Being open and transparent about the way Hydro One runs its business ✓ Providing quality customer service ✓ Minimizing the impact on the environment	✓ Helping customers with conservation and cost savings ✓ Proactively preparing for community growth ✓ Enabling customer choice to access new electricity services

Customers were also asked to add priorities to the list that they considered missing, but most thought the list was complete. Many of those who made specific suggestions effectively repeated one of the priorities included in the list or mentioned issues outside of Hydro One's control (e.g. electricity generation).

After rating all priorities by level of importance, participants were asked to choose and rank their top three priorities. Overall, affordability/price, reliability, safety, and customer service are identified as the top priorities for both residential and business customers. When ranked relative to other Hydro One priorities, price moves to the top of the list.

Outcome Priorities	Residential and business combined
1st	Delivering electricity at reasonable rates
2nd	Ensuring reliable electrical service
3rd	Ensuring the safety of electricity infrastructure
4th	Providing quality customer service

With respect to reliability outcomes, customers choose reducing the length and number of outages during extreme weather events, as well as reducing the overall number of day-to-day outages as their top priorities. Larger business customers also want Hydro One to focus on improving power quality.

Reliability Outcomes	Residential and business combined
1st	Reducing length of time to restore power during extreme weather events
2nd	Reducing number of outages during extreme weather events
3rd	Reducing overall number of day-to-day outages
4th	Improving power quality

Customers support investments in technology if they help find efficiencies and reduce customer costs, reduce the number and length of outages, and help customers better manage their usage.

Technology Investments	Residential and business combined
1st	Help find efficiencies and reduce customer costs
2nd	Reduce the number and length of outages
3rd	Help customers better manage their usage

High-level Investment Trade Offs

After collecting customer input on general needs and outcome priorities, the workbook presented a series of high-level investment trade-offs. Customers connected to the distribution system had the opportunity to comment on investment choices pertaining to the distribution and transmission systems. Customers outside of Hydro One's distribution territory, who are served by another LDC were invited to comment on investment decisions for the transmission system.

Investing in the Distribution System

Overall, customers want Hydro One to invest in the distribution system, even if these investments result in a bill increase for them. On balance, residential and small business customers are more supportive of proactive investments that result in higher short-term bill impacts than larger business customers.

Keeping Pace with Aging Distribution Infrastructure

A clear majority of customers prefers a more proactive approach to replacing aging infrastructure, when or before it starts to deteriorate.

Keeping Pace with Aging Infrastructure	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
Deteriorate rapidly	2%	1%	1%	0%
Deteriorate	7%	9%	10%	0%
When it starts to deteriorate	50%	58%	56%	70%
Before it starts to deteriorate	35%	24%	23%	0%

Ensuring Day-to-Day Reliability

Most customers want Hydro One to invest in reliability but are divided over whether to maintain or improve reliability. A majority of residential and small business customers want Hydro One to improve day-to-day reliability while larger customers are divided between maintaining and improving the current level of reliability.

Ensuring Day-to-Day Reliability	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
Defer investments	4%	4%	5%	0%
Maintain reliability	36%	34%	44%	40%
Improve reliability	53%	54%	40%	40%

Responding to Severe Weather

A strong majority of customers support investments in hardening the system, either as part of ongoing system renewal or as proactive investments. Again, a majority of residential and small business customers want proactive investments while larger customers prefer investing as part of ongoing renewal.

Responding to Severe Weather	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
No investments	4%	4%	7%	0%
Invest only as part of ongoing system renewal	31%	29%	47%	60%
Proactively invest	60%	59%	41%	30%

Helping Customers with Poor Reliability

Almost all customers want to help those with poor reliability, either by shifting or increasing spending. Consistent with previous results, residential and small businesses would add spending rather than shift from other areas. C&I customers are divided between shifting existing spending or adding new spending while large customers prefer spending be shifted.

Helping Customers with Poor Reliability	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
No investments	5%	4%	6%	10%
Shift spending	31%	31%	40%	60%
Increase spending	56%	53%	42%	10%

Enabling Economic Growth

Customers are divided over additional spending on building capacity to enable economic growth.

Enabling Economic Growth	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
Customers pay	45%	37%	47%	40%
Proactively build capacity	40%	48%	31%	30%

Keeping Hydro One's Business Running

A strong majority of customers in all classes want Hydro One to make the investments necessary to keep the business running safely and reliably at a level consistent with other companies of a similar size.

Keeping Hydro One's Business Running	Residential N=1,338	Small Business N=200	C&I N=250	LDA N=10
Find ways to make do	15%	21%	17%	30%
Make necessary investments	77%	68%	71%	70%

Investing in the Transmission System

Customers across Ontario want Hydro One to invest in the transmission system and are willing to accept bill increases in return. Residential are more supportive of increasing the current level of investment than business customers. Large Transmission Customers express the highest interest in proactive investments to improve reliability.

Keeping Pace with Aging Transmission Infrastructure

The vast majority of customers want to either maintain or increase the current level of investment.

Keeping Pace with Aging Infrastructure	Residential N=1,800	Small Business N=690	C&I N=250	LDA N=10	LTX N=23
Decrease current level of investment	9%	14%	6%	10%	4%
Maintain current level of investment	41%	48%	49%	50%	57%
Increase current level of investment	37%	29%	32%	10%	26%

Investing in a More Reliable Transmission System

Again, the vast majority customers want investments in a more reliable transmission system, either as part of ongoing renewal or as proactive investments.

Investing in a More Reliable System	Residential N=1,800	Small Business N=690	C&I N=250	LDA N=10	LTX N=23
Do not make specific reliability investments	9%	14%	7%	0%	0%
Invest only as part of ongoing system renewal	43%	45%	52%	50%	43%
Proactively invest in improving reliability	38%	33%	31%	20%	43%

Reducing the Number of Momentary Outages

A strong majority of customers want Hydro One to make investments to improve power quality. Support is very strong among larger business and transmission customers.

Reducing the Number of Momentary Outages	Residential N=1,800	Small Business N=690	C&I N=250	LDA N=10	LTX N=23
Defer investments in improving power quality	22%	28%	8%	0%	9%
Make investments in improving power quality	66%	63%	81%	80%	79%

Phase II: Feedback on Hydro One's Draft Investment Plan

Phase II of the engagement was again designed with OEB customer engagement objectives in mind. Phase I had identified needs and explored preferences, including outcome priorities and trade-offs. Phase II focused on collecting customer feedback on Hydro One's draft investment plan including key outcome trade-offs and specific investment decisions. The topics covered both transmission and distribution systems among Hydro One distribution customers but only transmission among direct transmission customers and customers served by other distributors. All questions were presented in an online workbook along with information required to develop an informed opinion.

After introducing customers to the draft plan, they were asked about their preferences regarding specific investment trade-offs. Before expressing their overall view on the level of spending resulting from Hydro One's draft plan towards the end of the workbook, they had the opportunity to review the cumulative impact of their earlier choices and revise those choices with that context.

Support for Hydro One's Draft Plan

A clear majority of customers in every rate class prefer a spending level at the draft plan or above and are willing to accept bill increase in return. Residential customers are most supportive with close to a majority (49%) opting for an accelerated pace over the draft plan (29%). A plurality of small business customers also prefers an accelerated pace (44%) over the draft plan (28%). C&I and LDA customers are split between the draft plan and an accelerated pace. LTX customers mainly prefer the draft plan (59%) over an accelerated pace (18%). Across all segments, the share of customers preferring an accelerated pace over a slower pace is significantly larger.

Support for Hydro One's Draft Plan	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18	LTX N=51
Increase Above Draft Plan	49%	44%	32%	28%	18%
Increase of Draft Plan	29%	28%	31%	28%	59%
Increase Below Draft Plan	12%	17%	19%	11%	8%
Other	4%	5%	6%	22%	14%
Don't know	5%	6%	12%	11%	2%

Investing in the Distribution System

Replacing Poles in Poor Condition

Across all customer types, there is strong support for the draft plan, though residential customers are equally supportive of an accelerated pace. A larger share of customers choose an accelerated pace over the slower pace option in each customer segment.

Replacing Poles in Poor Condition	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18
Accelerated Pace	43%	39%	22%	22%
The Draft Plan	43%	45%	61%	67%
Slower Pace	14%	15%	17%	11%

Replacing Power Transformers in Poor Condition

A strong majority of customers in every rate class want Hydro One to invest at least at the level of the draft plan. Residential customers tend to favour an accelerated pace, while business customers overall favour the draft plan.

Replacing Transformers in Poor Condition	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18
Accelerated Pace	48%	44%	34%	17%
The Draft Plan	41%	44%	54%	78%
Slower Pace	11%	11%	12%	6%

Improving Reliability Through Grid Modernization

On balance, the accelerated pace is the preferred option across customer segments. C&I customers are equally likely to prefer the draft plan to the accelerated pace.

Grid Modernization	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18
Accelerated Pace	47%	42%	40%	39%
The Draft Plan	36%	39%	41%	28%
Slower Pace	16%	19%	19%	33%

Battery Energy Storage Solutions

Customers support investments in battery energy storage solutions at the level proposed in the plan. There is less appetite for an accelerated pace than in previous investment choices—especially among larger business customers where significant minorities would prefer a slower pace.

Battery Energy Storage Solutions	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18
Accelerated Pace	35%	29%	16%	6%
The Draft Plan	47%	49%	57%	50%
Slower Pace	19%	21%	27%	44%

Facilitating Growth

A majority of customers across all segments prefer the draft plan over an accelerated or slower pace.

Facilitating Growth	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18
Accelerated Pace	29%	28%	21%	17%
The Draft Plan	56%	57%	64%	67%
Slower Pace	15%	14%	15%	17%

Replacing Smart Meters

Both residential and small business customers have a clear preference for the draft plan. (*This question was only asked of residential and small business customers who are directly affected by this investment.)*

Replacing Smart Meters	Residential N=35,000	Small Business N=1,000	C&I N=200	LDA N=18
Accelerated Pace	36%	29%	N/A	N/A
The Draft Plan	64%	71%	N/A	N/A

Investing in the Transmission System

Replacing Transmission Lines in Poor Condition

Across all customer types, there is strong support for the draft plan. Residential and small business customers tend to favour an accelerated pace while the draft plan is the preferred option among business customers.

Replacing Transmission Lines	Residential N=2,500	Small Business N=800	C&I N=200	LDA N=18	LTX N=51
Accelerated Pace	44%	42%	30%	28%	27%
The Draft Plan	41%	43%	57%	61%	67%
Slower Pace	15%	15%	13%	11%	6%

Replacing Aging and Deteriorating Transmission Stations

Customers support investments in transmission stations at the level included in the draft plan. Residential and small business customers give almost as much support to the accelerated pace as they do the draft plan.

Replacing Transmission Stations	Residential N=2,500	Small Business N=800	C&I N=200	LDA N=18	LTX N=51
Accelerated Pace	42%	40%	27%	6%	31%
The Draft Plan	45%	46%	60%	94%	59%
Slower Pace	14%	14%	13%	0%	10%

Responding to OEB Direction

The OEB does not specify how customer engagement should be conducted or how customer feedback should be received. However, it has encouraged utilities to use "both existing and new processes."[3] Accordingly, Hydro One's customer engagement was designed to employ multiple methods to collect customer feedback, including focus groups, in-depth interviews, telephone surveys and online workbooks.

While it was possible to use a mix of different modes for collecting customer input in Phase I, the COVID-19 pandemic presented unprecedented challenges for Phase II of the engagement. All planned in-person activities had to be avoided and, where possible, replaced by online activities.

Noteworthy customer engagement elements in this engagement included:

- Collecting customer input at different stages prior to and during Hydro One's investment planning process, using detailed online workbooks in both phases of the engagement.
- Updating and improving the tools of customer engagement throughout the process, incorporating customer feedback along the way.
- Using online question formats that allowed the presentation of pros and cons within the question responses.
- Sending out unique email invites and bill inserts, using a PIN system to allow all customers to access the representative stream of the online workbook.
- Allowing customers to see the total cost impact of their earlier choices and providing them with the opportunity to reconsider those choices.
- Achieving record participation with over 48,000 customers participating in the engagement. More than 43,000 workbooks were completed in Phase II alone, while focusing exclusively on online activities due to COVID-19 restrictions.
- Distilling key findings of the representative results into condensed "placemats" that were widely distributed to relevant planning staff across the utility's business units.
- Engaging First Nations communities and the Metis Nation of Ontario (MNO) throughout both phases, using tailored online workbooks and in-depth interviews.
- Involving municipalities and industry stakeholders throughout both phases of the engagement process.

The OEB also expects utilities to continue to innovate and include new processes in their engagements. In addition to technical innovations in the design and administration of the workbook, Hydro One introduced several new approaches in this engagement.

- Conducting a joint customer engagement for the distribution and transmission system, including both direct customers and indirect customers across Ontario.

[3] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

- Using representative online surveys to collect input from indirect customers that allow for the presentation of visuals to illustrate technical examples, thus better enabling respondents to make informed decisions.
- Conducting a "pulse check" survey between Phases I and II to verify the validity of Phase I results amidst the COVID-19 pandemic.

The table below demonstrates the scope of the customer engagement and provides an overview of the number and types of customers engaged in different activities throughout both phases.

2019/2020 Customer Engagement Coverage

	Direct Hydro One Customers					Ontario Ratepayers		
Activity	Residential	Small Business	C&I	LDA	LTX	Residential	Small Business	Timeframe
Phase I: Focus on Needs and Outcome Priorities								
Focus Groups	46	31	--	--	--	--	--	Sep 2019
In-depth interviews	--	--	15	9	19	--	--	Oct-Dec 2019
Telephone Surveys	633	266	100	--	--	600	200	Dec 2019-Jan 2020
Online Workbooks	1,520	282	261	10	23	1,015	408	Dec 2019-Feb 2020
Customers Engaged	**2,199**	**579**	**376**	**19**	**42**	**1,615**	**608**	Sep 2019-Feb 2020
Phase II: Feedback on Hydro One's Draft Investment Plan								
Online Workbook	40,022	1,121	200	18	51	1,260	412	Aug-Nov 2020
Customers Engaged	**40,022**	**1,121**	**200**	**18**	**51**	**1,260**	**412**	Aug-Nov 2020

In a prior proceeding (EB-2017-0049), the OEB directed the utility "to plan and execute its future customer engagement activities such that the results provide meaningful and timely input to the development of its investment planning and prioritization process." The two-phased engagement was designed to address this issue and collect customer input at two critical stages within the investment planning cycle: (1) before the start of the investment planning process for the 2023-2027 period (Phase I), and (2) before finalizing the draft investment plans (Phase II). In each phase, INNOVATIVE staff participated in presentations to business planners from across Hydro One's business units and key highlights of the engagement were widely distributed.

In its 2020 transmission rate decision (EB-2019-0082), the OEB directed Hydro One to consider ways to obtain direct feedback from end-use electricity customers who are served by Hydro One's transmission system but receive distribution service from other LDCs. The OEB also acknowledged that the distributors have the primary relationship with those customers. Hydro One sought to balance those two considerations by recruiting representative samples of customers of other distributors to complete both the Phase I and Phase II workbooks and in the Phase I Telephone Reference Survey. Voluntary participation was also enabled through a link to the workbook on Hydro One's website.

Summary

Hydro One's 2023-2027 customer engagement is the most comprehensive engagement conducted on behalf of a utility in Ontario to date. Despite the challenges presented by the COVID-19 pandemic, more than 48,000 customers across the province participated in the customer engagement.

The results show that Hydro One customers generally have their needs met. Most are satisfied with the services they receive. Many have no suggestions for improvements, but those who do focus on lower bills and increased reliability.

When Hydro One customers think about the electricity system, they value it as a legacy provided by previous generations, and they want to leave it as good or better than they received it. This sense of stewardship heard in qualitative discussion is reflected in preferences. Reasonable rates are one of the top three priorities when customers *rate* priorities, and it is the first priority when they *rank* those same priorities. But time after time when customers are asked about cost in the context of the pacing of investments and other outcomes, they chose to pay more to sustain and/or improve the system. Following the individual trade-off choices, customers were shown the total cost impact of their choices and given an opportunity to change their responses. Customers continued to support their earlier choices.

The same response is seen when customers are asked about the total cost of the Hydro One plan and given the option to support the plan or to support spending above or below the amount required by the plan. A majority of customers in every rate class supports an increase in rates to at least the level in the draft plan. More than 40% of residential and small business customers support raising rates even higher to accelerate investment programs.

The process and content of this engagement are specifically intended to meet OEB direction.

1. This engagement used a two-phased approach that was integrated in the business and investment planning process. Phase I, designed to provide insights into customer needs and outcome priorities before the start of Hydro One's investment planning process was completed at the beginning of February 2020, when the findings were presented to planners. After reviewing the results of the first phase, planners developed Hydro One's draft investment plans for the distribution and transmission system. Phase II of the customer engagement asked customers for their feedback on the overall draft plan and their views on these investment decisions Hydro One must consider for its 2023-2027 plan.

2. Customers outside of Hydro One's distribution territory were engaged throughout both phases to provide their input on Hydro One's transmission system plan. Hydro One's customer engagement successfully overcame the hurdle of not having direct access to these customer contacts via customer list by using online panels.

3. Specific attention has been paid to how Low-Income Energy Assistance Program (LEAP) qualified customers' opinions vary from the broader customer base. Reflecting their financial capacity, LEAP-qualified customers generally support Hydro One's proposed investments but at a lower level than the average customer.

By adjusting to the restrictions introduced by the COVID-19 pandemic and moving to an online-only format for Phase II, the engagement allowed customers to complete the online workbook at their own speed and on their own schedule.

Participants had a favourable impression of the engagement. They felt the workbook found the right balance between too much and too little information. With more than 43,000 responses to the Phase II workbook, customers showed they are willing and able to invest their time and energy to contribute to the planning of their electricity system.

Hydro One's Joint Rate Application

First Nations Chiefs Engagement Report (Phase II)

December 2020

Prepared for:

Torys LLP and Hydro One Inc.

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Phase II:

First Nations Chiefs Engagement

December 2020

Confidentiality

This report and all of the information and data contained within may not be released, shared, or otherwise disclosed to any other party, without the prior, written consent of Torys LLP (Torys) or Hydro One Inc. (Hydro One).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Torys on behalf of its client Hydro One, in connection with Hydro One's joint rate application. The conclusions drawn and opinions expressed are those of the authors.

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Methodology

INNOVATIVE was engaged to collect feedback from First Nations Chiefs and/or their representatives on Hydro One's draft investment plan for the years 2023 to 2027. This builds on a previous engagement conducted in 2019 to collect input from First Nations Chiefs and/or their representatives on their electricity needs and general preferences. Both engagements were conducted part of Hydro One's Joint Rate Application (JRAP) to the Ontario Energy Board (OEB) for the years 2023 to 2027.

Approach to First Nations Chiefs Engagement

Phase II of the First Nations Chiefs Engagement builds on Hydro One's ongoing engagement with First Nations communities as well as an online workbook developed for Chiefs deployed in the winter of 2019/20. The objective of Phase I was to identify general *needs* and *preferences* of First Nations communities to help inform the design of Hydro One's draft investment plan.

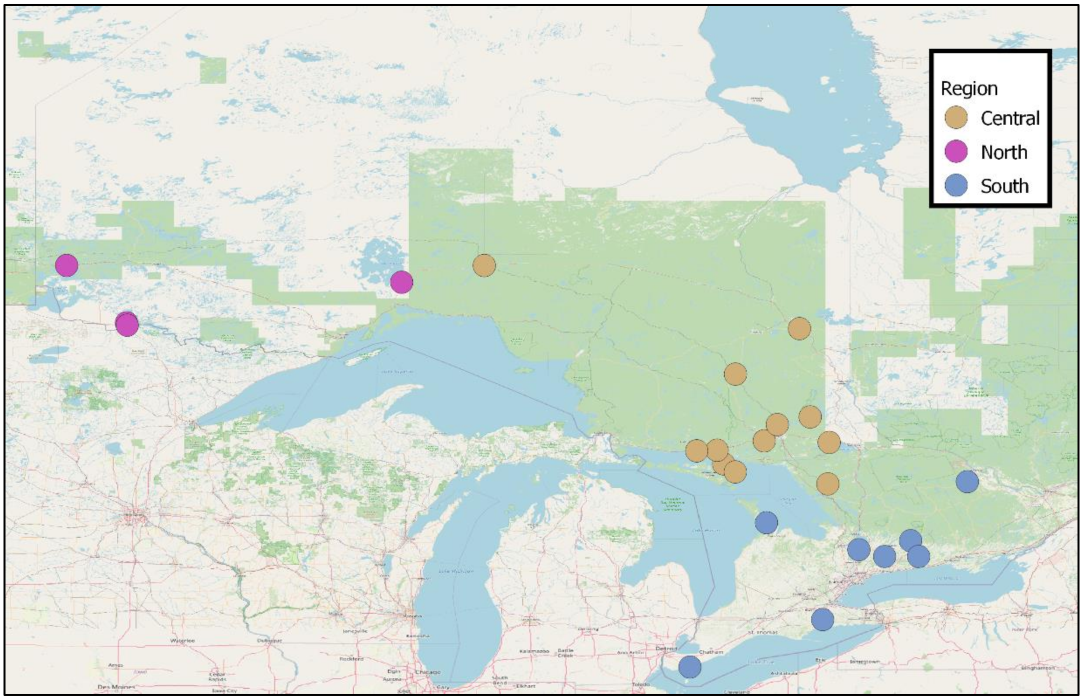
For this second phase of engagement, Hydro One invited the Chiefs and/or their representatives of all 88 First Nations it serves to schedule a meeting with INNOVATIVE to share their perceptions of their on-reserve communities' needs and preferences as they relate to Hydro One's draft investment plan.

Outreach efforts included an email invitation to schedule a meeting with INNOVATIVE. For First Nations communities that did not respond to Hydro One's initial email invitation, follow-up correspondence included additional emails and outbound calls by Hydro One's Indigenous Relations team as well as meeting coordinators from INNOVATIVE's scheduling team. All 88 First Nations that Hydro One serves were contacted and provided an opportunity to participate in this engagement in the fall of 2020.

Over the course of this three-month outreach, INNOVATIVE facilitated 24 meetings with First Nations Chiefs and/or their representatives via videoconference or telephone. In appreciation of time provided by First Nations leadership, INNOVATIVE made a $500 donation towards on-reserve COVID-19 relief to each participating community.

Meetings were conducted with representatives of the following First Nations:

Southern Region	Central Region
Algonquins of Pikwakanagan	Atikameksheng Anishnawbek First Nation
Caldwell First Nation	Aundeck-Omni-Kaning First Nation
Chippewas of Georgina Island	Dokis First Nation
Chippewas of Nawash Unceded First Nation (Cape Croker)	Ginoogaming First Nation
Curve Lake First Nation	Magnetawan First Nation
Hiawatha First Nation	Mattagami First Nation
Mississaugas of the Credit First Nation	Sagamok Anishnawbek
Mississaugas of Scugog Island First Nation	Serpent River First Nation
Northern Region	Temagami First Nation
Biinjitiwaabik Zaaging Anishinaabek	Wahgoshig First Nation
Iskatewizaagegan #39 Independent First Nation	Wahnapitae First Nation
Mitaanjigamiing (Stanjikoming) First Nation	Wikwemikong Unceded Indian Reserve
Nigigoonsiminikaaning First Nation	



Each meeting was approximately an hour in length and was conducted by a trained moderator following a discussion guide that ensured key questions were addressed while enabling First Nation representatives to raise their own issues.

Representatives from both Hydro One's *Indigenous Relations* and *Planning/Asset Management* teams participated in each First Nations meeting to answer participant questions or provide points of clarification on technical issues outside the purview of the moderator.

A package outlining Hydro One's draft investment plan was shared with First Nations representatives. This package is attached as **Appendix 1**.

All meeting participants were encouraged to provide any additional follow-up questions or comments on Hydro One's draft investment plan via direct email to INNOVATIVE. Written correspondence received from First Nations can be found in **Appendix 2** of this report.

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 strategic direction only. 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.

Key Findings

Most First Nations support the key objectives of Hydro One's draft investment plan.

First Nations generally support all four objectives of Hydro One's plan – *preserve the electricity system for future generations*, *improve system reliability and safety*, *help customers with poor reliability*, and *enable community growth*. Participants from Northern and remote communities were especially supportive of the third objective focusing on customers with poor reliability. Many First Nations in the South or communities undergoing considerable growth were especially supportive of the fourth objective, focusing on enabling community growth.

Most representatives accept Hydro One's objectives related to on-going infrastructure upgrades and investments in reliability and safety.

Northern First Nations have very different needs and preferences than Southern First Nations.

There are important differences between northern/central First Nations and southern First Nations in terms of First Nations needs and preferences related to Hydro One's plan.

Typically, the Northern and more remote First Nations communities that we interviewed reported experiencing poorer reliability than Southern reserves. For many of these communities, they said poor reliability isn't merely an inconvenience; it poses a community health and safety issue, particularly during the pandemic. These communities are most interested in solutions that will address poor reliability – both the frequency of outages and length of outages as well as power quality. Many of these communities are open to the idea of non-traditional solutions such as investments in battery storage and distributed energy resources.

On the other hand, many of the Southern First Nations representatives that were interviewed reported they were experiencing rapid economic and population growth and require additional electrical capacity to enable this growth. A few representatives suggested the First Nations Delivery Credit was one of the key drivers of population growth as it has encouraged some First Nations to return to their reserves. The lack of existing capacity and the perceived lengthy timelines to bring on additional capacity are seen by many participants as limiting First Nations communities' economic growth potential.

Affordability is a common concern for many First Nations.

While the First Nations Delivery Credit is recognized as helpful by almost all First Nations, many communities expressed a desire to apply the delivery credit to general service accounts and Band properties. There is also a request of Hydro One by many First Nations to provide regular updates on electricity conservation and rebate programs to help First Nations better manage consumption costs.

Communities experiencing rapid economic growth – particularly in the South – appear to be less concerned with the price they pay for electricity and are more focused on obtaining greater electrical capacity.

First Nations seek deeper and more meaningful partnerships with Hydro One.

For the most part, most First Nations report a positive relationship with Hydro One. However, it hasn't always been positive. Most feel the relationship between First Nations and Hydro One has improved significantly over the past decade – mainly due to the efforts made by Hydro One's Indigenous Relations team.

While relations with Hydro One have improved for most, there is a shared desire by almost all First Nations to deepen this relationship further. Most representatives suggest they want to develop a meaningful partnership with Hydro One. This collaboration would strengthen communications, planning, procurement, employment opportunities, joint ventures, and in some cases, re-examine land rights and treaty agreements.

Hydro One's Draft Investment Plan

Feedback on Plan Objectives

As part of Hydro One's First Nations Chiefs Engagement, participants were asked to provide feedback on the 2023-27 Draft Investment Plan's key objectives. As part of the participant overview package, the following information was shared:

Hydro One's Draft Investment Plan at a Glance

Combining these various inputs, Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	***Proposed Approach***
Preserve the electricity system for future generations	*Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system*
Improve system reliability and safety	*Replace equipment that poses the biggest reliability and safety risk*
Help customers with poor reliability	*Invest in new technology to help restore power faster*
Enable community growth	*Expand the electricity system to facilitate community growth and economic development*

Most First Nations agreed that the priorities outlined in Hydro One's draft investment plan aligned with the needs of their communities.

While the first objective – *preserve the electricity system for future generations* – was considered a key expectation by most First Nations, participants tended to focus their comments on the other three objectives of the draft investment plan:

- *improve system reliability and safety*
- *help customers with poor reliabilit*y, and
- *enable community growth*.

First Nations with poor reliability were especially supportive of the second and third objectives, which focus on reliability. These First Nations were mostly located in Northern or remote (often water access only) areas.

The fourth objective -- *enabling community growth* – was very much supported by First Nation communities undergoing significant population and economic growth. First Nations that strongly support the fourth objective appear to be mostly located in Southern Ontario.

Objective 1: Preserve the electricity system for future generations

Most First Nations understood the need for infrastructure replacements, as many have observed the state of the aging infrastructure that services their reserves.

In some cases, participants suggested Hydro One should be more proactive in its infrastructure renewal as the cost born by equipment failure is more significant for remote First Nations communities than it is for other communities, particularly in the South, which are believed to have greater redundancy built into their distribution system.

> *"Just keep on improving infrastructure…we would like to see the infrastructure being approved ahead of time than waiting for things to fail, because when it fails, it will inevitably fall on us unevenly versus, let's say, Southern Ontario. And so, from my perspective, fixing things now means that my First Nation won't be affected by power outages moving forward in the future."*

> *"I know that some of our community has raised concerns over aging infrastructure of poles that the bears have been chewing and climbing… There is transformers up here that I would say, are probably just about at the end of their life, if not past the end of their life, but still working."*

That said, many wanted to know when and how Hydro One would be replacing feeder lines that service their community.

> *"Our community is at the end of a very long power line … and you can see from the road into our community that the poles are rotting and leaning all over the place … and the forest trees are hanging over the line in some places. We have a lot of power outages up here … we've been asking Hydro One to come fix the poles and clear the brush for the last few years. When are they going to fix things up here?"*

Some participants also recounted the impact of recent system renewal.

> *"We're at a point where we haven't had a power outage that lasted more than a day and a half in a really long time. I think in my opinion that's phenomenal."*

Objective 2: Improve system reliability and safety

Safety concerns were not brought up in any of the First Nations meetings. However, there was strong support to improve the system's reliability among First Nations, again, particularly among representatives of northern and more remote communities.

Recognizing the cost of system hardening and susceptibility to adverse weather, a few First Nations asked how Hydro One was investing in technology to ensure better reliability outcomes. In some cases, communities are already participating in pilot projects. In other cases, communities welcome the idea of a Hydro One pilot project – particularly in the area of battery storage.

> *"I'm sitting here looking at your Hydro One customers engagement report, and you have the fact that there's…battery energy storage solutions. So, if you're looking for a pilot project, that might be something we could talk about."*

For First Nations suffering from poor reliability, it isn't just SAIDI and SAIFI measures about which they're raising concerns; it's also power quality. For these communities, poor power quality is destroying appliances, electronics, and machinery, costing First Nations reserves a significant amount of money in replacement costs.

> *"…we need better quality. With the downward spikes it's costing us a fortune: replacing equipment, TVs, everything's electronic these days. It's a huge expense. So we need better power, with an even flow."*
>
> *"Fortunately we haven't had an interruption in a few months but in the past there's been the impacts on our equipment; our computers that are at our school and our administration building –when we have these power fluctuations, we gotta buy new servers and computers."*
>
> *"I feel that we deserve a consistent power supply. That isn't surging up and downwards. I feel that we should be getting a better quality of electricity for what we're paying."*
>
> *"We've had power surges. So, you know, a lot of people lose their refrigeration and we've had to replace freezers and refrigerators at the band's costs, because those surges happen."*
>
> *"I know our power coming in the community fluctuates. We've been losing a lot of electronics lately because of the power surges."*

Objective 3: Help customers with poor reliability

Reliability is a more significant issue in Northern and remote communities (particularly water access only communities).

- Many First Nations are concerned about older populations and others who rely on medical equipment including dialysis machines and refrigeration for medicines that need to be stored at specific temperatures.
- Many of these communities are heated by electricity and when the power goes out, so does the heat. Typically, when this happens, generator-powered heating centres would be opened, but many reserves are not encouraging such gatherings during the pandemic.
- Food that gets spoiled can cost hundreds of dollars for the typical First Nations family.

Poor reliability isn't just an inconvenience for northern and remote First Nations communities – it can be a community health and safety concern.

> *"One of our biggest issues that we have…is we get too many power failures in our area."*
>
> *"When [the power] does go out, it can get pretty bad here … especially in the winter. A couple years back we went three days without power during the winter months and my house for example has a furnace as a source of heat … but I couldn't use my furnace to heat my home without electricity."*
>
> *"One of my concerns now would be power outages and how quickly we can respond and restore power, because many of our community members have electrical heat and not all of them have wood stoves."*
>
> *"We had an outage and we had to ship all of the dialysis patients and our elders, and house them in hotel rooms because that was the time that we went four or five days without power out here."*
>
> *"Living here in the community, if we have particularly bad weather, it seems like our power goes out more frequently than what I've experienced in towns close to here."*

"There's got to be a way to mitigate the time that the power is down."

"When the power does go out, we offer warming centers on occasion just because of –again, we have a high elderly population who used to rely on the wood stove but switched over to electric or propane heat. So now we're very dependent on the power, whereas before the power went out, well, everyone would just chuck another log in the woodstove and we'd be cooking until dawn but now a lot of our elders are at the whim of the power, especially during the winter, which can get a little frightening … and now that COVID is here, we can't really gather in our warming centres."

"I would probably give like maybe $150 to $200 per family to replace any meat that has been spoiled."

Objective 4: Enable community growth

Many First Nations communities are growing. Some suggested that the drivers of this growth can be attributed to many First Nations moving back to their reserve. In many cases, this results in increased infrastructure development including new housing, administrative buildings, healthcare centres, schools, elderly care homes, and critical infrastructure such as water and sewage treatment systems. A number of participants reported that limited or lack of electrical capacity is hindering this on-reserve economic development.

More so a phenomenon observed in the South and some Central communities, many First Nations reported they were experiencing a cycle of economic growth (in addition to population growth) – greenhouses, aquacultures, manufacturing, retail, food services, tourism, recreation, and gaming. Ensuring power is available (in many cases upgrades to existing service and three phase power supply) is critical to enable this growth.

"If we do bring a large business here, they're not going to be able to connect; there's not enough capacity on the transmission lines."

"We have to build a new nursing home within five years and that's going to be almost double the capacity."

"We want an economy and so we need to attract businesses. And they're gonna need power."

"We want to be able to have enough electricity to attract business to our community."

"I need the lines to be able to carry enough energy to my community."

"So there was a conversation, maybe a year ago about running in a line to power a commercial cannabis operation. Right now there is insufficient power in our community to do that."

"I anticipate significant growth, hopefully, very quickly, not two years but 5 years for a significant increase in residential properties in my community."

"We have a number of projects in our community comprehensive plan that require a lot of power…we're a small community but we need more power."

"Right now in our single phase use, we run out of power for usage on our community–we can't build anymore."

"We run on single phase power here right now; we're trying to bring three phase to this community."

When asked about the consequences of not getting additional capacity in a timely manner, one First Nation replied:

> *"Without additional capacity our Nation will be stuck in a cycle of continued poverty … and by a decision that's has been deliberately made."*

The time it takes to connect to the distribution system is a concern echoed by many First Nation communities, particularly those experiencing rapid growth. Suggested solutions include better coordination with Hydro One planning.

> *"There's a lot of time between requests and the actual work order to occur."*
>
> *"When we have projects, I don't feel that we should have to wait that long for new hookups, for new services, whatever."*
>
> *"Getting the electricity in this industrial park took over a year, and even to install it took over six months."*
>
> *"We've been talking to Hydro One about [a distribution station] for five years now, so you keep coming and asking us we want, but it doesn't seem like anything is getting done."*
>
> *"There's also the issue that we've had is just getting Hydro to this site. But I don't know if that could be streamlined, because it took so long and it actually created delays in our construction."*
>
> *"Last December, we asked for a price quote from Hydro One that would allow the [telecom provider] to be placed on the poles and Hydro One took until October to provide us with that price. And I do realize that it's COVID times. But that was ridiculous."*

Missing Objectives

Many First Nations wanted a closer partnership with Hydro One on procurement (including First Nations employment opportunities and potential infrastructure joint ventures) pilot project investments, better coordination on community growth planning, and, in some cases, a review of existing contracts and treaty negotiations.

Many felt developing a more meaningful partnership with Hydro One should be included as an objective of its draft investment plan.

> *"I think that maybe one pillar that's not there is: how do you improve the relationship with First Nations?"*
>
> *"We would want [it] to be more of a cooperative partnership as opposed to being a one sided partnership.*
>
> *"I don't know if hydro needs infrastructure or land around here, but our community does have some that we could use down the line, like we'll listen to anything really if it benefits the community."*
>
> *"We need to be able to have a relationship with Hydro One that goes beyond just customers, that respects First Nations jurisdiction, inherent responsibilities to the land … [this will] improve our relationship, so that Hydro One is succeeding, but we're also succeeding as a community and as a nation."*

“What I'd really like from Hydro One is just coming up with innovative electrical solutions, right. So as a community, we're very limited in what we can do and what we can develop. We're very dependent on the federal government in terms of programming and supports and things like that. So how can Hydro One become a true community partner?”

“I feel that it's biased in regards to Hydro One's benefiting where they're receiving the contract to install the equipment but at the same time they're not working with us in regards to having a right-of-way agreement that works in favor for both [our Nation] and Hydro One. There's no compensation that will be afforded back to the community.”

“Where do First Nations exactly fit into this plan? Are we just afterthoughts and just regular customers? Or is one of the pillars of this plan – should it specifically state First Nations customers, or First Nations members? A lot of your power is generated in our territories through dams through different things like that. And so, you know, that's just, that's one comment I get about the plan. A little bit more First Nations focus.”

“What about the investing in new technology? You know, is it just going to be something that Hydro One does by itself, or is there going to be opportunities for partnerships … that kind of thing? And what about the long-term maintenance that's going to be required for this infrastructure? Is there opportunities for [our Nation] to work on the infrastructure that's in our territory?”

“How can we work with Hydro One to help you take care of your infrastructure too, because it is going through our community –we do have some responsibility to that… how can I train my community to be able to…help clear the vegetation, or can we work on innovative solutions where…we're helping you manage [the power lines].”

Feedback on Cost Impact of Plan

Some participants mentioned that the cost of electricity for general service and other non-residential on-reserve customers is significant. It leads to many reserves deferring other important investment or spending decisions. Cost appears to be a greater concern for Northern First Nations that typically have less economic growth compared to Southern ones.

“Our arena–we spent almost close to $100,000 there in hydro bills, so it's awful for our community.”

“There's a number of members in my community who have to sacrifice a lot of things in order to be able to make those hydro bills work.”

“We have seen an improvement in the cost because of some of the credits that we’re receiving. Prior to that they were quite high. I know we've kind of taken the delivery off of the bill and that's really helped a lot of the people in the community.”

“A lot of people don't have a lot of income here and rely on either assistance or they're low income families. If we start to inflate those prices again, it will create hardships.”

“I think that [price] is a lot better since the delivery fee has been reduced on Indian reserve land … I certainly feel like the value for money is increased.”

"You always have to keep in mind that you're servicing people in the north; we have a lot of higher costs than most people in the south. So those need to be considered with regards to rates – peak time, off time needs to be different for northern communities."

Additional Community Needs and Expectations

CURRENT RELATIONSHIP: While the relationship between First Nations and Hydro One has not always been good, participants stated it had improved over the past few years and most described it as "good" today."

> *"The relationship with Hydro One…it has significantly improved within that timeframe inside the last four years, five years."*
>
> *"In terms of the relationship with the Hydro One, we really appreciate the relationship that we do have with [Hydro One's Indigenous Relations team member] and we certainly see her as an individual who would definitely see it more passionate about some of the issues that we're addressing here in the community. And so certainly she takes the extra effort to follow up on some of the requests that we have here as a community. We certainly appreciate that relationship with [our Hydro One Indigenous Relations contact]."*
>
> *"It's okay...Hydro One does a good job of reaching out."*
>
> *"There's not often power outages and when there are, they're addressed and fixed in a satisfactory time."*
>
> *"We don't have any issues, whenever they need approval to come on territory, it's a pretty good relationship."*
>
> *"I haven't heard about issues with our relationship with Hydro One. I'm very quickly learning that the only time I get called into deal with things is when they're burning down. The fact that I haven't heard about any issues with Hydro One is that the relationship is not on fire … which is good!"*
>
> *"We need an agreement which spells out how we're going to engage with each other, and what set asides are we going to have, and what opportunities are there going to be available."*
>
> *"Just keeping that line of communication open with [Hydro One's Indigenous Relation representative] and letting her know of our future plans and how we can best get things planned so it's cost efficient for everybody."*
>
> *"At this point I just like to thank everybody for being on the call and this is the first time I've been involved in a call like this other than you know on a smaller intimate group like with [Hydro One's Indigenous Relation representative], but it's good to see that we're progressing in more than one department or two departments at the most are getting involved in this and they want to know feedback from the First Nation perspective. … So going forward, I recommend and suggest and encourage [Hydro One] to continue doing [these meetings] because the First Nations obviously want to be part of the plan … and want to be involved in the negotiation side of it going forward."*

EXPECTATIONS OF HYDRO ONE: When asked about what First Nations expect from Hydro One, most identified reliable service, affordable prices, procurement opportunities, and proactive two-way communications.

> *"I would really hope that Hydro One will seriously look at this. And we will move forward in a positive direction, I know that it takes more than a few people to kind of help turn the tides of time, I guess. But I am really hoping that we will start to see some things really change with the culture of Hydro One, in not just in how they deal with First Nations, but even employment opportunities for First Nations, of making*

sure that there is opportunities out there for our people to take apprenticeships, or even people that own companies."

"I guess what we need from Hydro One is to actually understand the treaties, and understand what the federal government has done in terms of the right of ways with the transmission lines and understanding our position when it comes to aerial spraying, things like that."

"Keeping up the communication, creating strong relationships, and really not forgetting First Nations people because we usually get forgotten."

"In the past, we've had some problems; engaging Hydro has been more meaningful than we anticipated."

"For the most part, you guys are pretty much meeting all of our expectations."

"The response to outages and fixing infrastructural hiccups in the lines and stuff is good … so I'd be good if that would continue."

"I would say that the service has definitely improved."

Regardless of current reliability levels, almost all First Nation expect Hydro One to deliver reliable electrical service and provide quick outage response times when outages do occur.

"[We expect from Hydro One] to have reliable service so we don't have any outages."

"I know the First Nation had to install generators. So they had to purchase large generators, like to support the administration office. I'm pretty sure it costs a lot of money. And then we had to install generator in our manner, because we're taking care of elderly people and then generators at our health center. And then at our community center, but all the other small buildings, offices, they don't have generators....and then it does cost some money because the staff have to go home from the other smaller offices, because they can't work with no hydro."

"And then there's additional work [that occurs during a power outage] where additional staff is needed to help people like elders, seniors who live in their own residence. We have to make sure that they have water and that they're okay when the power goes out."

"I remember one year, whenever the power's out, they had to open the community center and offer that to the community to use the washroom, showers, the heat, because the power was out longer than just a few hours. Yeah, they have to do that. And then also, they have to seek more volunteers as well to help when that happens. And then also, purchasing supplies."

"Many of our homes rely on hydro for heat. And depending on the time of the year that that has major implications. Depending on the length of the outage, we can look at loss of food, so food security, things like that...like when you think about how much it takes to get everything there.... Loss of connectivity and loss of being able to do business, especially in the corporate context. You know we're relying on hydro a little bit more than the everyday, just to do business these days so that that's another kind of impact that it does have."

"I know quite a few of the community have also invested their own personal dollars into generators."

“A lot of our homes are not built up to standard as to like maybe, maybe a lot of homes that are just a kilometer away from us. So with that, with housing you know we can't have people staying in their homes without any heat especially in the winter.”

“What I've noticed here is that when the power goes out, it doesn't go out for a short amount of time. Sometimes it does go out for a significant amount of time. The band often covers the costs of food spoilage … particularly for elders and families with limited income.”

Appendices

Appendix 1: Hydro One's Draft Investment Plan (Overview Package)

Appendix 2: Written Submissions

a) Letter from ***Atikameksheng Anishnawbek First Nation (2020-10-13)*** received in advance of the scheduled meeting on October 13, 2020.

hydro one

Overview:
2023-2027 Draft Investment Plan

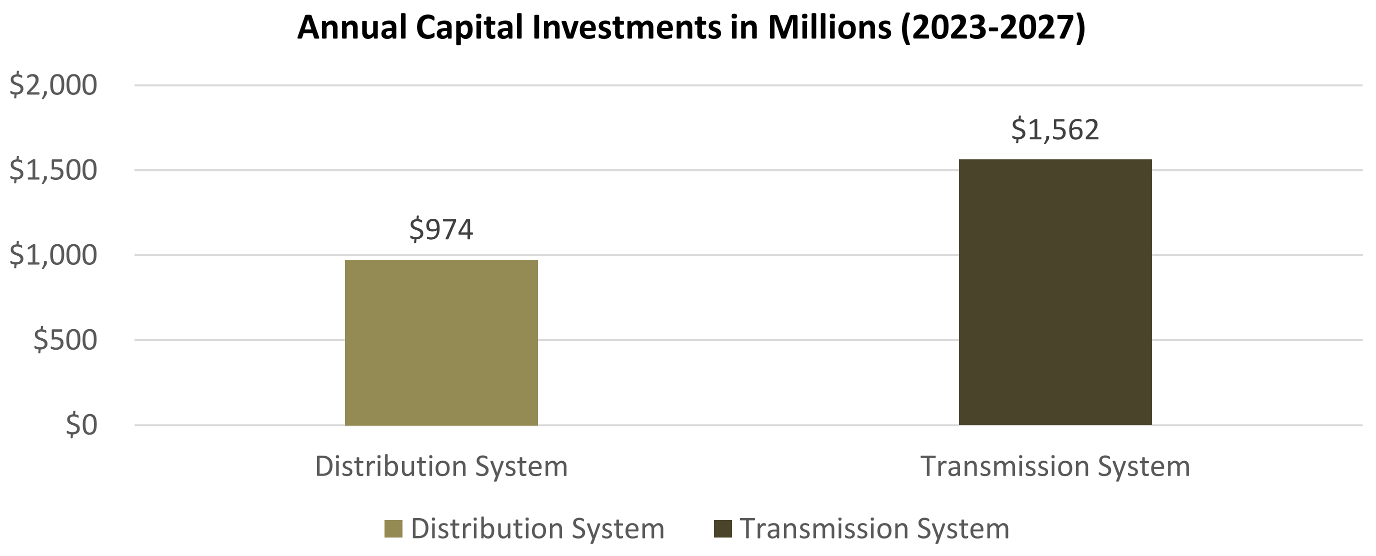
September 2020

Hydro One's Plans: Distribution and Transmission

Hydro One's Draft Investment Plan (2023–2027)

Based on initial customer feedback, information and input from Hydro One's internal engineering and technical experts, and emerging pressures on the electricity system, Hydro One developed its draft investment plan for the years 2023-2027.

This draft investment plan includes significant capital investments in both the distribution and transmission systems. The costs for **distribution system** investments are spread among all of Hydro One's 1.4 million distribution customers. For the **transmission system**, capital investment costs are shared by more than 5 million electricity customers in Ontario.



Hydro One's Draft Investment Plan At A Glance

Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	Proposed Approach
Preserve the electricity system for future generations	Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system
Improve system reliability and safety	Replace equipment that poses the biggest reliability and safety risk
Help customers with poor reliability	Invest in new technology to help restore power faster
Enable community growth	Expand the electricity system to facilitate community growth and economic development

Hydro One's Plans: Distribution and Transmission

How Much Will Hydro One's Draft Plans Cost Customers?

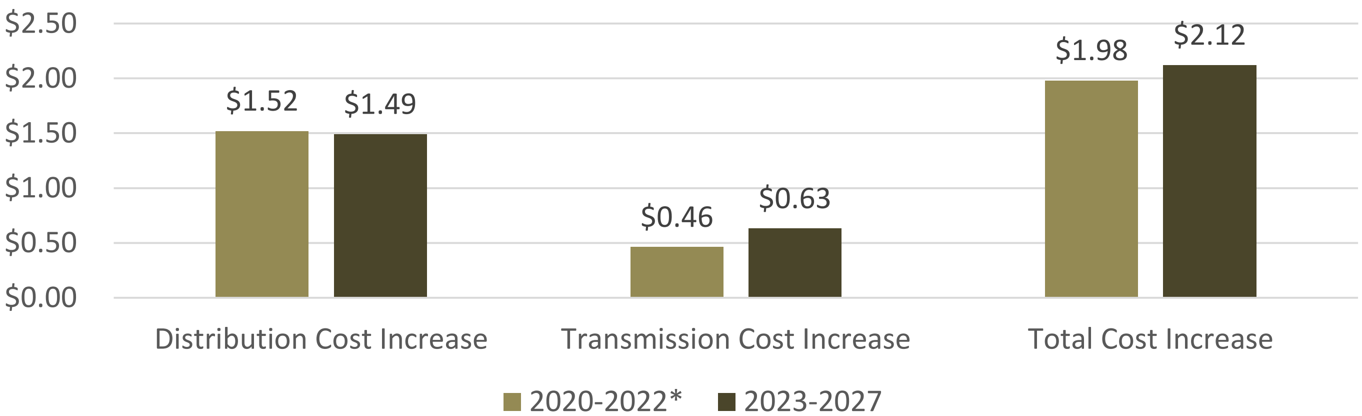
Residential Customers

If Hydro One continues with its draft investment plan, the **monthly distribution costs** for residential customers are estimated to increase by an average of **$1.49 each year** and the **transmission portion of the monthly bill** is estimated to increase by an average of **$0.63 each year** for the period 2023-2027.

That means the typical residential customer's **monthly bill is estimated to increase by an average of $2.12 (or 1.7%)** each year over the period 2023-2027.

- Rural customers benefit from *distribution rate protection* and will not see an increase in distribution costs on their monthly bill. Instead, rural customers will only see an increase in the transmission portion of their monthly bill.
- **Indigenous residential customers living on-reserve do not pay for delivery or HST.** Since July 2017, the entire delivery charge is offset by the First Nations Delivery Credit.

Average Monthly Bill Increases Each Year

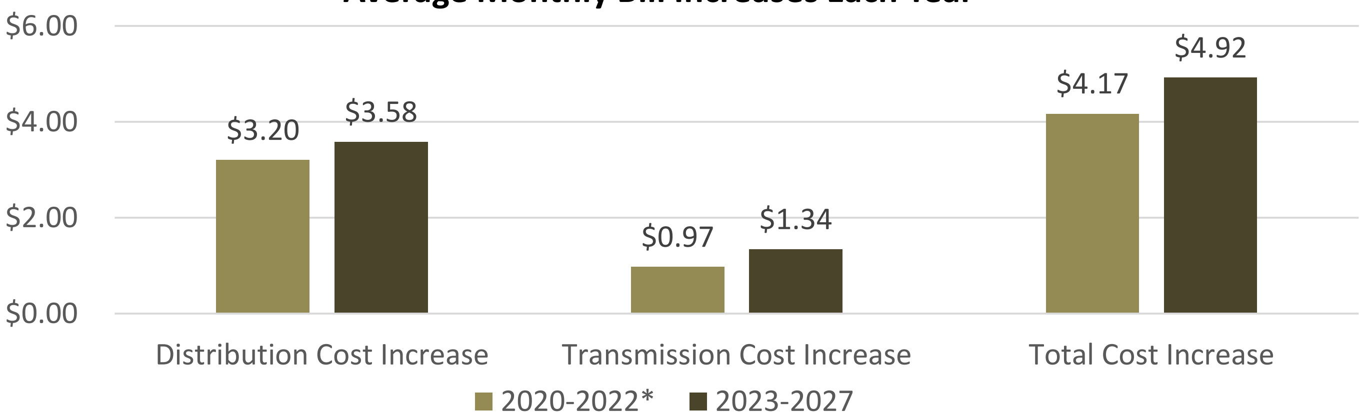


Small Business Customers

The **monthly distribution costs** for small business customers are estimated to increase by an average of **$3.58 each year** and the **transmission portion of the monthly bill** is estimated to increase by an average of **$1.34 each year** for the period 2023-2027.

That means the typical small business customer's **monthly bill is estimated to increase by an average of $4.92 (or 1.3%)** each year over the period 2023-2027.

Average Monthly Bill Increases Each Year



*Hydro One's rates until December 31, 2022 were approved by the OEB in an earlier application.

Hydro One's Distribution System: Background

Distribution System Reliability

The Make Up of Hydro One's Distribution System

Hydro One's distribution system serves about 1.4 million customers and covers about 75% of the geographic area of Ontario. A large proportion of Hydro One's distribution infrastructure is aging and is now 50 to 70 years old.

Since most of its customers live in rural areas, Hydro One's distribution system looks different than others in Ontario. Servicing more sparsely populated communities means that more equipment (e.g. wooden poles, transformers and wires) is needed to serve the same number of customers.

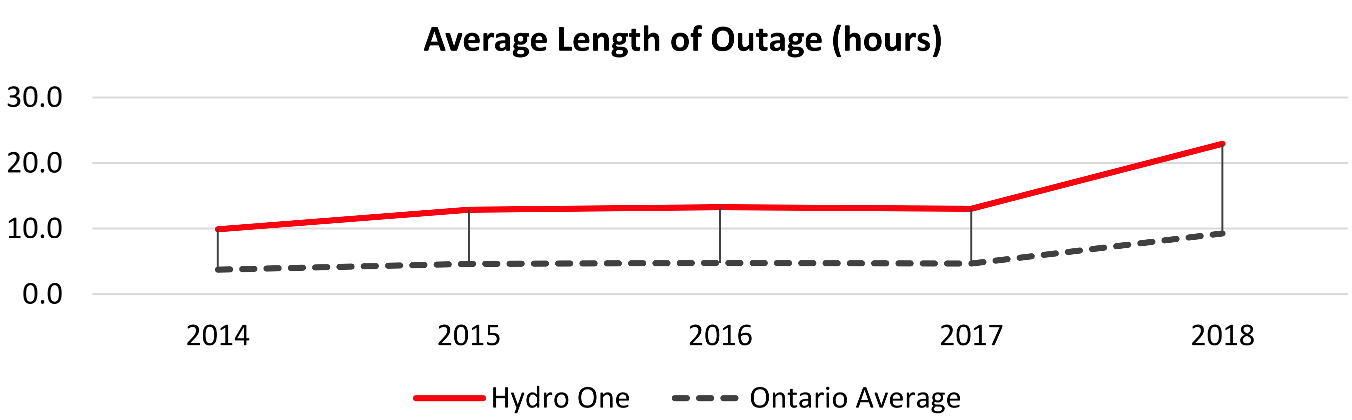
Many rural communities are connected through long lines with only one power source. If there is a disruption of power due to an equipment failure, fallen tree, or other cause, then customers further down the line experience a power interruption. Power can only be restored when the source of the outage is found and repaired.

How Does Hydro One's Distribution System Reliability Compare to Others?

Hydro One tracks both the average number of power outages per customer and how long those outages last. The average Hydro One customer experiences more frequent and longer outages than the average Ontarian.

On average, between 2014 and 2018, the typical Hydro One customer experienced 1.5 more outages per year compared to the Ontario average.

When it comes to total time spent without electricity each year, the typical Hydro One customer, since 2014, has been without power for 14.4 hours each year. That is 9 hours more than the Ontario average.



There are investments that Hydro One can make to improve reliability. While these investments are likely to reduce the length of outages, they add to the costs of the system. Different types of investments to improve reliability are presented on the following pages.

Many of the investments included in the draft plan will help Hydro One to move closer to the Ontario average. With the accelerated option, Hydro One will get there faster, while the slower option includes fewer investments to close this gap but keeps rates lower in the short term.

Distribution: Making Choices (1 of 6)

Replacing Poles in Poor Condition

Hydro One owns and maintains about 1.6 million wood poles. Some of these poles serve single households, while others supply electricity to over 5,000 customers.

The majority of Hydro One's poles are currently in good condition. However, **a significant number of wood poles (approximately 124,000) are expected to be in poor condition by the end of 2027 unless they are replaced**. These poles are more likely to fail and cause unplanned outages for customers served by these lines, and they have to be replaced at some point.

Consequences for Customers

For the current investment plan, Hydro One's planners need to decide how many poles to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If a pole fails, customers served by this pole experience an outage that lasts an average of 9 hours. A planned pole replacement doesn't necessarily lead to an outage, but if an interruption occurs, it lasts an average of 2 hours.
- **Cost considerations**: If Hydro One defers investments in poles, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to replace poles at a pace that would maintain the overall health of the system and reduce the likelihood of long outages caused by pole failures. The proposed approach prioritizes poles that serve a larger number of customers.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $650 million to replace poles in poor condition.

Distribution: Making Choices (2 of 6)

Replacing Power Transformers in Poor Condition

Hydro One owns close to 1,200 power transformers that are used to step down the voltage supplied by high-voltage lines before the electricity is distributed to households and businesses.

While the majority of these transformers are currently in good (38%) or fair (28%) working condition, Hydro One expects that **about 600 transformers will deteriorate into poor condition by the end of 2027** if they are not replaced.

Most transformers in poor condition don't require immediate replacement, but they can deteriorate quickly, at which point they must be replaced. Hydro One regularly monitors their condition with the goal to replace deteriorating transformers before they fail.

Consequences for Customers

Hydro One needs to determine how many transformer replacements to plan for in the 2023—2027 period, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If Hydro One can replace a transformer before it fails, the customers served by it experience a short outage that usually lasts a few minutes. However, if a transformer fails and needs to be replaced on an unplanned basis, customers served by the station lose power for an average of 12 hours.
- **Cost considerations:** If Hydro One defers investments in transformers, the short-term costs for customers are lower. However, pushing more replacements into the future means more uncertain costs and likely steeper cost increases in the future.

In its draft investment plan, Hydro One proposes to continue its current pace of planned transformer replacements. Alternatively, it could increase the number of planned replacements or reduce them.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to replace power transformers in poor condition.

Distribution: Making Choices (3 of 6)

Improving Reliability Through Grid Modernization

Hydro One's service territory includes challenging terrain and old infrastructure, making it prone to outages. In the past, there were few cost-effective investments Hydro One could make to significantly improve reliability and bring it closer to the Ontario average.

Technology has advanced in recent years, offering solutions that would allow Hydro One to detect, repair and restore power more quickly than in the past. This would reduce the length of time customers are without power, as Hydro One crews would be able to locate the problem and restore power faster. In some cases, Hydro One would also be able to remotely restore power.

Parts of Hydro One's distribution system are already equipped with these technologies. However, compared to other large distributors in Ontario, Hydro One's system has less.

In its draft plan, Hydro One is proposing to install smart devices to help restore power more quickly. Hydro One would target these investments at lines that have historically had high interruptions affecting a large number of customers. Hydro One's planners estimate that **these investments would lead to a 40% average reduction in the duration of power outages per year** for customers served by the lines addressed in this plan.

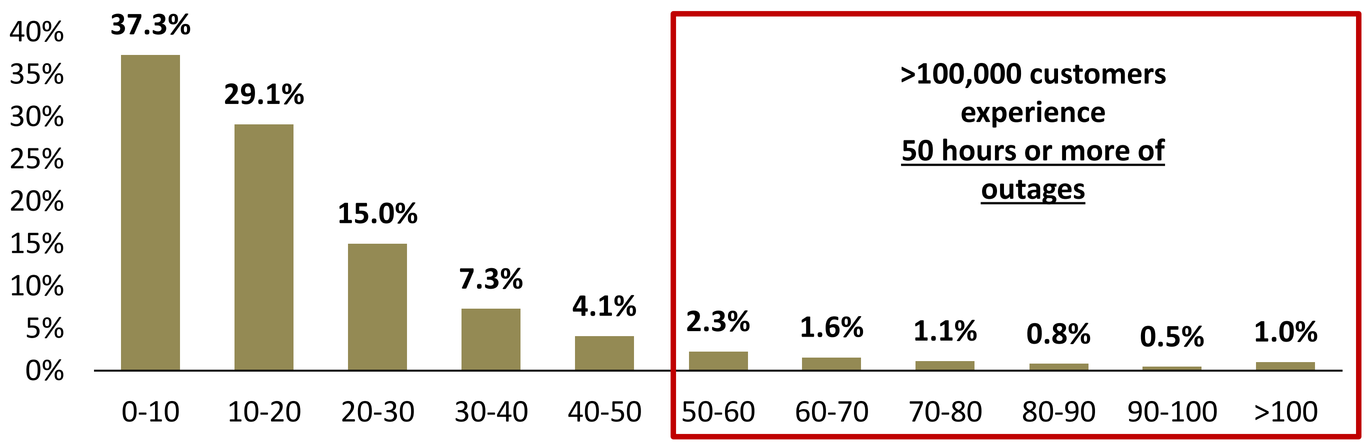
Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to improve reliability through grid modernization.

Distribution: Making Choices (4 of 6)

Battery Energy Storage Solutions

Outage experiences vary across Hydro One's service territory, and some customers experience more or longer outages than others. While some Hydro One customers didn't experience any outages between 2017 and 2019, over 100,000 customers were without power for more than 50 hours per year. Some communities experienced up to 150 hours of outages.

Customer Outage Experience in Hours/Year (2017-2019)



Recent advancements in technology and battery systems have provided better options to help these customers. These batteries store electricity and automatically provide backup if a power line experiences an interruption. Hydro One is currently testing some of these solutions in pilot projects, including:

- Centralized battery storage stations that serve a whole community
- Battery storage units that serves as a backup for a small group of customers
- Single-household battery storage installed within a customer's home (*pending OEB approval*)

In 2023-2027, Hydro One is planning a larger roll-out of these energy storage solutions that would improve reliability for customers experiencing about 50 hours of interruptions per year or more. Hydro One's planners estimate that these investments would lead to a **60% to 80% average reduction in the duration of power outages** per year for customers served by battery systems.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $150 million to improve reliability through battery energy storage solutions.

Distribution: Making Choices (5 of 6)

Facilitating Growth

Communities are growing across Ontario. When communities grow by attracting new residents or businesses, the local demand for electricity increases, which sometimes results in the need for infrastructure upgrades to build additional system capacity.

Hydro One is required to plan and build its system to provide a safe and reliable supply of energy to all its customers and accommodate load growth. However, Hydro One has some choice over the pacing of these investments.

Hydro One plans infrastructure upgrades to meet both short-term and long-term electricity demand. These plans are adjusted annually in response to the actual demand and are adapted if unexpected events occur.

In its draft plan, Hydro One is proposing to upgrade infrastructure to supply increased forecast electrical demand when equipment approaches its planning limit. This would allow new economic development to proceed as planned and maintain reliability and power quality for existing and new customers. It would also generate revenue for Hydro One that helps offset the costs of building the infrastructure.

Hydro One could also take a more **proactive approach** by upgrading infrastructure *before* equipment planning limits are reached to support regional and economic development in communities looking to grow.

Alternatively, Hydro One could take a more **reactive approach** and upgrade infrastructure *after* equipment is at or exceeding its planning limit.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $400 million to facilitate growth in Ontario.

Distribution: Making Choices (6 of 6)

Replacing Smart Meters

Hydro One is legally mandated to install smart meters, which are a critical component of the infrastructure needed to measure electricity consumption and bill customers accurately.

Between 2009 and 2013, Hydro One installed 1.3 million smart meters. In 2023, many of these meters will begin to surpass the 15-year service life. Hydro One has already started seeing meters failing at an increasing rate.

When a meter fails, it must be replaced, otherwise bills are based on estimates rather than actual consumption, and a Hydro One employee must travel out to the meter every so often to get an accurate read, which is time consuming and costly.

Currently, failing meters are replaced with a similar old technology meter. However, technological advancements have brought prices down, and meter prices on new systems tend to be lower than the current prices. Also, labour costs can be reduced by replacing groups of meters rather than one by one.

Hydro One, therefore, plans to begin replacing the old system in 2023. The new smart metering system has an expected service life of 20 years, and Hydro One will go through a competitive procurement process to select a vendor and purchase a smart metering system at the best price for customers.

While the current smart metering system must be replaced, Hydro One has some choice over how quickly or slowly it replaces the old metering system.

In its draft plan, Hydro One proposes to **spread the meter replacements and associated costs over a 7-year period** (between 2023 and 2029). Alternatively, Hydro One could **speed up** the replacement process and replace all meters over a 5-year period (between 2023 and 2027).

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $550 million to replace the old smart meter system.

Hydro One's Transmission System: Background

Transmission System Reliability

Hydro One's transmission system is the backbone of Ontario's electricity system. Its high voltage transmission lines serve as highways for electricity, transporting power from generation stations like Darlington and Niagara Falls to the distribution network in your community. About 30,000 km of transmission lines and 300 transmission stations ensure that the power flows across Ontario.

Most of Hydro One's transmission system has been built with multiple sources of supply (backup capabilities). This is why outages due to transmission system failures are less frequent than distribution related outages. However, a **transmission system failure can leave thousands without power for days**, as was the case when a severe thunderstorm occurred in the Ottawa region in September 2018, which caused significant damage and impacted over 500,000 Hydro One customers.

How Does Hydro One's Transmission System Reliability Compare to Others?

Hydro One tracks both the average number and duration of interruptions per delivery point—that is the point where power is being transferred from the transmission system to a local distribution system or a transmission connected customer. The average Hydro One delivery point experiences less frequent and shorter interruptions as compared to other utilities in Canada.

Between 2014 and 2018, the typical Hydro One delivery point experienced about 60% fewer interruptions per year than the Canadian average. When it comes to the duration, the typical Hydro One delivery point has been interrupted for 55 minutes each year since 2014—about 38 minutes less than the Canadian average.

Aging and Deteriorating Transmission Infrastructure

Portions of Hydro One's transmission system date back 50 to 100 years. Hydro One has mainly focused on maintaining this infrastructure, but it will soon be time to replace much of it. Aging equipment eventually deteriorates, increasing the risk of equipment failures. Over the past five years, failing equipment has been the biggest contributor to transmission system outages.

Currently, transmission system reliability remains high, but even backup lines are aging and may not always be able to take the load needed. In the long run, reliability is likely to go down if equipment is not replaced.

There are investments that Hydro One can make to ensure the continued high reliability of the transmission system. While these investments reduce the risk of equipment failure, they add to the costs of the system.

Transmission: Making Choices (1 of 2)

Replacing Transmission Lines in Poor Condition

According to an independent review**, 4,000 km (14%) of overhead conductors are currently in poor condition**. This overhead lines equipment is critical to the safe and reliable transmission of power from large generators to end-use customers. To ensure continued safe and reliable transmission service across Ontario, Hydro One needs to replace much of this aging lines equipment in poor condition.

Consequences for customers

Hydro One needs to decide how much of the lines equipment in poor condition to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: As most of the transmission system is built with backup lines, a failure does not necessarily lead to an outage for customers. However, as more lines are deteriorating, it is not guaranteed that a back-up line is always available to carry the load when a line fails. Planned replacements avoid outages in most cases and make the system more resilient to extreme weather, as deteriorating equipment is replaced with newer standards and technology.
- **Safety considerations**: Deteriorating transmission lines pose a safety risk. A broken and dropped conductor will result in an outage to the circuit and endangers all in proximity of its fall. In some cases a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard to its surroundings.
- **Cost considerations**: If Hydro One defers investments in transmission lines equipment, the short-term costs for customers are lower. However, deferring investments further into the future means less cost certainty in the longer run, and likely steeper rate increases in the future.

In its draft investment plan for 2023-2027, Hydro One proposes to replace equipment in poor condition that poses a particular risk to the system and the public. The goal is to maintain the overall reliability of the system and avoid increasing interruptions and safety risk caused by failing equipment. This approach includes targeting single supply radial lines, which are responsible for most interruptions.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $3.85 billion to replace transmission lines in poor condition.

Transmission: Making Choices (2 of 2)

Replacing Aging and Deteriorating Transmission Stations

Hydro One's transmission infrastructure is aging, and close to 25% of transformers (167 units) are currently in poor condition, with additional transformers expected to degrade into poor condition over the next seven years. This equipment is critical to safely and reliably transmit power from large generators to over 5 million end-use customers across Ontario. To maintain the current level of reliability and safety, Hydro One needs to replace much of this aging transmission stations equipment in poor condition.

Consequences for Customers

In terms of timing, Hydro One has some flexibility in how quickly to replace this aging and deteriorating infrastructure. Hydro One must decide how much of this equipment to replace during the 2023-2027 period, and how much to push further into the future.

- **Reliability considerations**: Most transformer stations are built with backup in place, so that a failing transformer does not cause an outage for customers. However, a transformer failure, when there is no backup in place, can leave thousands of customers without power for weeks or months. Depending on its size and location, a transformer replacement takes 6 months on average, but may take 12-18 months if spare parts need to be ordered.
- **Safety considerations**: If a transformer fails, it can cause a fire in the transmission station, which poses environmental and safety risks for customers in the area.
- **Cost considerations**: If Hydro One defers investments in transmission stations equipment, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to address high-risk elements of the transmission stations infrastructure that could pose a risk to the system and the public. The goal is to maintain the overall reliability and safety of the system.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $2.25 billion to replace aging and deteriorating transmission stations.

Appendix 2

ATIKAMEKSHENG
ANISHNAWBEK

October 13, 2020

Jason Lockhart, Vice President
Innovative Research Group Inc.
56 The Esplanade
Toronto, ON M5E 1A7

Dear Mr. Lockhart:

RE: HYDRO ONE (HON1): PRELIMINARY INVESTMENT PLAN 2023-2027

Acknowledgement:

Atikameksheng Anishnawbek does not consider this interview as proper consultation in terms of HON1's legal obligation to consult and potentially accommodate our First Nation as a result of any potential impacts from any planned infrastructure investments in Atikameksheng territory.

We do consider this interview as part of a formal notice to HON1 that before any work be approved for construction that more formal discussions with Atikameksheng Anishnawbek must occur with Gimaa Craig Nootchtai and the team responsible for discussing any potential impacts on our Nation as a result of any planned improvements.

Finally, we request a written response from HON1, specific to the notice indicated above and the need to have more formal discussions regarding any planned work in Atikameksheng territory.

Introduction:

Atikameksheng Anishnawbek is located in Northern Ontario and near the City of Greater Sudbury. The current reserve boundaries that show Atikameksheng as next to Sudbury are inaccurate; they were incorrectly surveyed in 1884 and do not reflect the true boundaries identified in our Treaty. We are addressing this matter before the courts. This is important to acknowledge and understand as we know that HON1 has a considerable amount of infrastructure and assets located in Atikameksheng territory and that any improvements will continue to have a negative impact on Atikameksheng resulting from loss of land, and access to our medicines and wildlife.

Continued…

ATIKAMEKSHENG ANISHNAWBEK

Moving forward with HON1 will require a full understanding of what the planned $2.5 billion dollars in infrastructure improvements will occur in Atikameksheng territory, and what benefits will be set aside for Atikameksheng in terms of accommodation, employment, and business opportunities. Hence the need for more formal discussions in the near future between Atikameksheng and HON1, so we can provide HON1 with an accurate description of our territory so they know the impacts we speak of.

Finally, in terms of our current relationship with HON1 activities and their service to our community, I have provided responses below from our Planning and Infrastructure Department (PID), and I have provided responses from a Governance (GOV) perspective:

1) How would you describe your community's relationship with HON1?

   PID: Our relationship with HON1 is ongoing, especially in terms of the energization of the Business Park. HON1 has energized Phase 1 of the Business Park, and will continue as the park develops further. There have been issues in terms of communication (AA and our project managers being referred to multiple contacts within HON1) but these issues have always been quickly rectified by the Sudbury HON1 team.

   GOV: We currently do not have any agreements with HON1, but there is a definite need to solidify a working relationship by developing an agreement which addresses the need for HON1 to consult and accommodate Atikameksheng. This agreement would define which benefits Atikameksheng would be entitled to in terms of accommodation, employment, and business opportunities.

2) What are the key expectations your community has of HON1?

   PID: Our key expectations that we have of HON1 is fast, diligent, and equal service. We also expect HON1 to work collaboratively with the First Nation.

   GOV: We expect that HON1 will take more effort to establish a strong working relationship with Atikameksheng by being more transparent and willing to share information on planned activities. We expect that Atikameksheng will be contacted on a frequent and timely basis so that we can prepare to discuss any impacts from HON1 activities in our territory. We also expect that HON1 will set aside certain contracts for Atikameksheng businesses and provide the right of first refusal on contracts for work performed in Atikameksheng territory.

Continued…

ADMINISTRATION OFFICE
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Website: atikamekshenganishnawbek.ca

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ATIKAMEKSHENG
ANISHNAWBEK

3) What are issues or challenges your community see emerging over the 5-10 years relating to your electrical needs and HON1 services?

   PID: In the next 5-10 years, Atikameksheng will be furthering the development of the Business Park, Hill Street subdivision, and other community projects. These new developments will require energization from HON1.

   GOV: One of the biggest challenges we will face is building capacity quick enough to fully maximize benefits to our First Nation as a result of the planned improvements. This means that HON1 could collaborate with us to provide training to potential employees, and to provide information that will help our local businesses prepare to provide services to HON1 during the improvements.

4) What do you expect from HON1 in response to emerging issues?

   PID: Atikameksheng would expect HON1 to provide clear and quick communication in response to emerging issues.

   GOV: Again, we expect HON1 to begin immediate discussions on the development of a relationship agreement with Atikameksheng that will define how Atikameksheng will be accommodated for the potential impacts that the planned improvements will cause.

5) Thinking about all the expectations we've discussed today, which are your top priorities both today and in the future?

   PID: In terms of the Business Park, our top priority both today and in the future is to energize the park and provide our local entrepreneurs with the opportunity to do business in their community.

   GOV: Development of a relationship agreement between Atikameksheng and HON1.

6) Is there anything else you'd like to share with me about HON1 or your community's electrical service that we haven't discussed today?

   PID: No comment.

Continued…

Appendix 2

ATIKAMEKSHENG
ANISHNAWBEK

GOV: We encourage HON1 to take a more proactive approach to engage with First Nations when they plan any type of work, especially with First Nations who are directly impacted such as Atikameksheng. Building meaningful relationships are key to ensuring that all parties' interests are protected.

On behalf of Atikameksheng, we thank you for taking the time to interview us regarding HON1's services to our community, and the planned infrastructure improvements for 2023-2027. Again, we anticipate a formal response from HON1 officials with details on how we can begin formal discussions on the proposed work and their impacts on Atikameksheng Anishnawbek. If you have any questions, please feel free to contact me at (705) 692-3651 x. 201, or on my cell at (705) 665-2157. Miigwetch.

Respectfully,

Gimaa Craig Nootchtai
Atikameksheng Anishnawbek

cc. Council, Atikameksheng Anishnawbek
Brendan Huston, CEO Atikameksheng Anishnawbek
Arvind Sharma, PID Director Atikameksheng Anishnawbek

Hydro One's Joint Rate Application

Métis Nation Engagement Report (Phase II)

December 2020

Prepared for:

Torys LLP and Hydro One Inc.

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Phase II:
Métis Nation Engagement

December 2020

Confidentiality

This report and all of the information and data contained within may not be released, shared, or otherwise disclosed to any other party, without the prior, written consent of Torys LLP (Torys) or Hydro One Inc. (Hydro One).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Torys on behalf of its client Hydro One, in connection with Hydro One's joint rate application. The conclusions drawn and opinions expressed are those of the authors.

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www.innovativeresearch.ca

Table of Contents

Methodology

INNOVATIVE was engaged to collect feedback from Métis Nation of Ontario (MNO) regional representatives on Hydro One's 2023-2027 draft investment plan. This engagement builds on a previous one conducted in 2019 to collect input from the Métis Nation of Ontario regional representatives on their electricity needs and general preferences. Both engagements were conducted as part of Hydro One's Joint Rate Application (JRAP) to the Ontario Energy Board (OEB) for 2023 to 2027.

Approach to Métis Nation Engagement

Phase II of the Métis Nation Engagement builds on Hydro One's ongoing engagement with Métis Nation communities. The objective of Phase I was to identify general *needs* and *preferences* of the Métis Nation to help inform the design of Hydro One's draft investment plan.

In the fall of 2020, INNOVATIVE conducted Phase II engagement meetings with all nine regional councils of the Métis Nation of Ontario via videoconference. These meetings were designed for Métis Regional councilors to share their perceptions of their citizens needs and preferences as they relate to Hydro One's draft investment plan.

A package outlining Hydro One's draft investment plan was shared with all regional representatives (see **Appendix 1**). Each regional council meeting was approximately an hour in length and was conducted by a trained moderator following a semi-structured discussion guide. A representative from Hydro One's Indigenous Relations team participated in each meeting to answer any Councilor questions or provide points of clarification on technical issues outside the purview of the moderator.

Several Métis Regional councilors are neither direct customers of Hydro One nor familiar with how Ontario's electricity system operates, including Hydro One's role within it. That said, Métis Nation engagement meetings were structured so participants did not need to be subject matter experts in Ontario's electrical system and/or the role Hydro One plays within it. Meetings were designed for regional councilors to reflect on outcome-based assessments of the needs and preferences of the Métis citizens they represent.

All meeting participants were encouraged to provide any additional follow-up questions or comments on Hydro One's draft investment plan via email directly to INNOVATIVE. INNOVATIVE received follow-up correspondence from an MNO Region 5 councilors (see **Appendix 2**).

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 strategic direction only. 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.

In addition to meeting with MNO regional councils, an additional link to the online interactive workbook was distributed via email by MNO to Métis citizens to which they have email addresses. The additional link to the online workbook was open from October 20 to November 22, 2020, but no additional workbook completions were received as a result of this additional link.

Key Findings

Métis Regional Councilors indicate general support the key objectives of Hydro One's draft investment plan but expressed concerns over the potential cost impact on their citizens.

All four objectives of the draft investment plan—*preserve the electricity system for future generations*, *improve system reliability and safety*, *help customers with poor reliability*, and *enable community growth*—received support from Métis regional representatives.

However, views were mixed both within regions and across regions when it came to:

- the reliability of electrical service that Métis citizens receive and the level of investment needed to address reliability;
- the levels of investment Hydro One is contemplating in its draft plan; and
- the impact this will have on the residential bills of Métis ratepayers.

Métis Regional Councilors perceive special treatment of First Nations by Hydro One.

Many Métis councilors feel Hydro One's Indigenous Relations team was created to serve First Nations communities and feel past engagements with Métis have been mere "lip service."

Of particular concern for Métis Regional Councilors is the ***First Nations On-reserve Delivery Credit***. Most councilors perceive the credit as a Hydro One policy initiative, and some questioned why the utility does not recognize Métis people as one of the three distinct groups of Indigenous peoples recognized by the Federal Government.

Métis Regional Councilors would like to see a deeper and more meaningful partnership with Hydro One.

Métis Regional Councilors disclosed that they currently have little to no relationship with Hydro One. That said, they would be interested in building a stronger relationship moving forward as it pertains to:

- better and more regular **communications**;
- a more significant **community presence**;
- **procurement opportunities**; and
- in some cases, **contract/treaty negotiations**

Many felt this commitment to the Métis Nation was missing from Hydro One's draft plan. Métis Regional Councillors felt **environmental stewardship** was also missing from Hydro One's initial plan.

Hydro One’s Draft Investment Plan

Feedback on Plan Objectives

As part of Hydro One’s Métis Nation Engagement, participants were asked to provide feedback on the 2023-27 Draft Investment Plan's key objectives. Participant were provided a pre-read package which included the following information:

Hydro One’s Draft Investment Plan at a Glance

Combining these various inputs, Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	***Proposed Approach***
Preserve the electricity system for future generations	*Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system*
Improve system reliability and safety	*Replace equipment that poses the biggest reliability and safety risk*
Help customers with poor reliability	*Invest in new technology to help restore power faster*
Enable community growth	*Expand the electricity system to facilitate community growth and economic development*

On initial review, most Métis Regional Councilors agreed that the priorities outlined in Hydro One’s draft investment plan align with the needs of their citizens. However, many Councilors questioned the levels of investment Hydro One is contemplating in its draft plan and its impact on the electricity bills of Métis ratepayers.

Objective 1: Preserve the electricity system for future generations

Most Councilors acknowledge the need for infrastructure replacements, as many have observed the state of the aging infrastructure in their communities. That said, a number questioned whether such investments are needed at the proposed level and subsequent bill impact. Some stated that they would like more details on Hydro One’s current asset health and justifications as to why renewal is required now and at this level.

> *“Aging infrastructure needs to be dealt with. There’s old wood poles, rock mounts are old and aging and rusting, they’re tipped over, there’s lots of woodpecker holes.”*

“[Power reliability] is pretty good where I live … it sounds like the Hydro wants to spend a bunch of money on a problem that doesn’t really exist. I think a lot of Métis would be more concerned with increases to their [electricity] bills.”

“I’d like to see a baseline on what you’re going to improve, what was your baseline and at a certain time how well did we do? We hear about ‘we’re going to improve this and that … well, we need to see where we were and where we are now. What is the data of our improvement?”

Objective 2: Improve system reliability and safety

While not all Métis Regional Councils experience poor reliability, those whose citizens live with poor reliability are quick to support this objective of the plan.

“You can only put on so many socks before you start freezing. When it’s 30 below, and [the power] goes out for 8 hours. You go stand outside for 8 hours.”

“They’re cleaning the lines finally…they are trying to improve, I think they did listen to us when we talked about that in the Spring, and they’re out cleaning the areas now. That’s nice to see.”

Objective 3: Help customers with poor reliability

Reliability appears to be a more significant issue in rural and Northern Métis Regions. Again, Councilors whose citizens have poor reliability strongly supported this objective of the plan.

“When we have a power outage up here, it takes hours and hours for a crew to get here. Some places its days. It goes out four or five times a year. There are people [that have no] heat. There are people on oxygen…They are set up pretty well with batteries, but once those batteries go down, their anxiety goes up, they’re using more oxygen.”

“Our [Hydro One] crews come from [city], four hours away. Situate those crews a little better so our people don’t have to wait so long to bring the power back on.”

“If the wind blows higher than 35 km, you’re going to lose hydro. We do see some signs where they are going to do some work, but so far we have not seen anything. As a rural customer for the last 50 some years, I would say in the last five years the Ontario Hydro performance is horrible. So, if you’re a customer with Ontario Hydro in a rural setting, you are guaranteed bad service.”

Objective 4: Enable community growth

Most Councilors agree that Hydro One should not be a barrier to community growth but didn’t see this objective being as necessary as other objectives.

“… I mean, sure … no one wants to be waiting to get connected to the Hydro … and I don’t think Ontario Hydro should be a barrier to any economic growth or anything … but I think they need to start by fixing their existing problems with poor powerlines and rotting poles before they go off building new stuff.”

Missing Objectives

Many Métis Regional Councilors felt Hydro One's commitment to the Métis Nation was missing from its draft investment plan. Specifically, Métis Regional Councilors would like to see a more significant commitment to the following areas and have it formally documented in its plan:

- better and more regular **communications**;
- a more substantial **community presence**;
- **procurement opportunities**; and
- in some cases, **treaty acknowledgement and reconciliation**

Métis Regional Councilors felt a commitment to **environmental stewardship** was also missing from Hydro One's draft investment plan.

Deeper Relationship with Hydro One

Many Métis Regional Councilors want to see improved communications and a more substantial community presence with Hydro One.

> *"They need to educate themselves on who we are. They don't understand us. They've been hired to consult for a brand new hydro line from Thunder Bay…and they sat down with the First Nations, named the new line that's going to be coming through, we were an afterthought, we were told…The Métis should not be an afterthought, they need to better educate their staff all the way to the top executive who we are."*

> *"I think it's lacking. There needs to be more outreach. There needs to be more training opportunities, they do a broad reach of Indigenous partnerships and training, there need to be more direct, working relationships with us."*

> *"We're not stakeholders, we're rights holders. We need to be seen as more of a partner and not a stakeholder…They're on our territory, they should be putting more effort into the relationship. They should be coming to us now with their long-term plan."*

> *"It would be nice to see additional information sessions like we had before the lockdown where people would be able to get the information from the horse's mouth."*

> *"I think the relationship is okay … they're trying to communicate with us as best as possible, and if we do have a program that comes from Hydro, saying they're going to give $50 off their bill in the next couple months, we try to pass that on to [our citizens]."*

> *"I would be looking at some kind of resource sharing or revenue sharing partnership down the road."*

Procurement

Most Métis Regional Councilors stated that they would like to see more procurement opportunities for Métis owned businesses and employment opportunities for their citizens.

> *"There needs to be better outreach in regards to contracts and subcontracts for line work, signage, and maintenance. We do have Métis contractors in NW Ontario that could do some of the work that's required."*

"They make [local contractors] jump through hoops. There should be preferential…advance notice for tenders and contracts, indigenous businesses should get advance notice. There should be assistance applying to get into their specific system they have to get contracts and do any work for them, I've heard its onerous."

"A lot of these are small companies, and some of the requirements they need are for companies that have large numbers…If a guy's only got three or four guys that come out to work with him to do the work, it makes it difficult."

"It's difficult to get through their procurement process … they don't make it easy for Métis business owners … they are set in their ways on how they want things done."

"They should be looking at a Northern training facility or partnering with Manitoba Hydro so that people from the North could go three hours to Winnipeg instead of 20 hours down south away from their communities."

Treaty Acknowledgement and Reconciliation

Métis Regional Council 1 representatives noted that they are signatories to Treaty 3 (the *Halfbreed Adhesion to Treaty No. 3 in 1875*) and would like to have a meaningful reconciling of their relationship with Hydro One.

"We're the anomaly in Ontario. There's no other Métis in Ontario who has treaty rights. We adhered to Treaty 3 signed in 1875. Hydro One needs to reconcile with us, because they never came to us in the beginning to put their infrastructure…on our traditional lands…They need to start with reconciling their relationship with us."

"In NW Ontario, we have a Métis business that sells safety equipment, we also have a Métis business that owns car dealerships. Maybe you should be looking at this for regional purchases…but those are signed to certain companies because they are so major for all of their protective wear and fleet crews. They should be considering smaller regional contracts that benefit the local and regional communities, and not just one super contract for all of Ontario."

"First Nations on reserves are getting discounts on Hydro relief or they mail in their Hydro bill at the end of the year and get the tax taken off. There needs to be some kind of allowance or some kind of situation that deals with us, because of our treaty rights with all of Hydro One's infrastructure and revenue they've made with us, there needs to be an agreement for the Métis in NW Ontario."

"I'm willing and ready to sit down with Hydro One…for some shared solution with Hydro One with this unique group of Métis in Ontario."

"I do not want to hear any language coming to us that there is no impact because they're just replacing the pole. What they need to remember is, we never gave them authority in the first place to be there ... we never gave them consent on our territory to start with."

Environmental Stewardship

Another area of Hydro One's draft plan that many Métis Regional Councilors felt was missing was environmental stewards, particularly vegetation management.

> *"When they do the powerlines, they spray with chemicals. There are many Métis people that are concerned with the use, it's cheaper for the company to spray and be done with it. That is not a natural way, there is a potential for animals that walk through it…somebody's going to shoot it and just because they've only sprayed along that line, doesn't mean that animal is going to stay in that area…What about five miles down?"*

> *"They can hire a Métis company to do brushing, to keep all the stuff down. It's natural, it's good for the environment, which the government of Canada is really concerned about."*

> *"Our Métis citizens are seeing real concerns … you walk through an area and it's black. How can that be good for you? Let me make you up a salad with the plants that are there … Just because you say it's safe, doesn't mean it's safe."*

> *"As long as you highlight the environmental impact this is having in Region 5 is something that we would really like you to look at…One of the fundamental things we want you to value are the environmental resources Hydro One is using in Region 5 to a detriment to the Métis way of life and the environment. We understand that it's a commodity, that Hydro One is putting in a huge cost, but we're also putting in a huge cost for the environment and the Métis way of life."*

> *"Spraying of the underbrush, different chemicals you're using, that hurts the environment like hell, the animals, it runs into the water. One person went back to pick berries this year and it's all brown, because they sprayed it."*

Feedback on Cost Impact of Plan

Métis Regional Councilors are concerned about the impact of Hydro One's plan on Métis ratepayer bills.

> *"What we were hearing a lot of is that the cost of living [during lockdown] was going way up and we found that some, an elderly couple, have worked all their lives and are living off of their pensions, and all of a sudden they're saying they're really having a hard time…hydro cost can come up, but if you're looking at everything else that's involved in basic living, that's got to be included."*

> *"We also pay the highest delivery fee because we live in a rural area, and we have the poorest service…They're raising the rates, and not keeping the lines clear."*

> *"My concern is the delivery charge, it's higher than the charge for a city, it's very expensive. Why should we pay more than someone in Toronto?"*

> *"Something to look at is modernizing homes and making them more efficient, more modern appliances at a lower rate to reduce our power consumption drastically. Help with running homes more efficiently, maybe then you might be able to have less infrastructure."*

Additional Community Needs and Expectations

CURRENT RELATIONSHIP: The relationship between the Métis Nation and Hydro One is generally described by Councilors as limited or non-existent. That said, as discussed previously, Regional Councilor would like to see this relationship strengthened moving forward.

EXPECTATIONS OF HYDRO ONE: Aside from reliable service at affordable rates, and the "missing objectives" discussed, several Métis regional councilors suggested Hydro One should extend the First Nations Delivery Credit to Métis citizens or, upon realization that this is Ontario government legislation, should help the MNO lobby the provincial government.

> *"We should have same Indigenous rights as every First Nation. This 'hydro credit' only applies to First Nations who choose to live on-reserve.*
>
> *Métis citizens don't live on reserves … we were never allowed to create reserves … the reserve system was a creation of the Federal government's Indian Act and was only ever applied to First Nations bands and their people.*
>
> *So why does the Ontario government only choose to recognize one of its only indigenous peoples based on where they choose to live?*
>
> *Hydro One should tell the government about the inequality of this First Nations Hydro credit"*

Appendices

Appendix 1: Hydro One's Draft Investment Plan (Pre-read Overview Package)

Appendix 2: Written Submissions

From: Victoria Stinson <victorias@Métisnation.org>
Sent: November-05-20 7:15 PM
To: Jason Lockhart <jlockhart@innovativeresearch.ca>
Cc: Steven Sarrazin <StevenS@Métisnation.org>; Linda Norheim <LindaN@Métisnation.org>
Subject: Re: Hydro One discussion - MNO Region 5 - Nov. 5

Hi Jason,

Thank you for the great chat with the MNO Region 5.

I wanted to bring up an issue that occurred recently, but it occurred outside of Region 5 and therefore did not want to include it in the meeting. I have heard from our citizens in Region 2 that they received letters in the mail from Hydro One that trees in their area in Thunder Bay (in MNO Region 2) would be trimmed.

However, these trees were not trimmed but cut down completely. Some of these trees were not even near Hydro One lines. This failure of communication affected Region 2 citizens and similar miscommunication in the future has the potential to affect all MNO citizens.

If this failure of communication is occurring along city streets, then what acts are being done in more rural or forested areas was a valid concern brought up.

The MNO citizens require honesty and proper communication. Please pass these along these concerns to Hydro One.

https://www.tbnewswatch.com/local-news/looks-like-a-war-zone-walsh-street-residents-blindsided-by-tree-removal-2840378

Sincerely,

Victoria Stinson

Manager
Lands, Resources and Consultations
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Overview:
2023-2027 Draft Investment Plan
Distribution and Transmission Systems

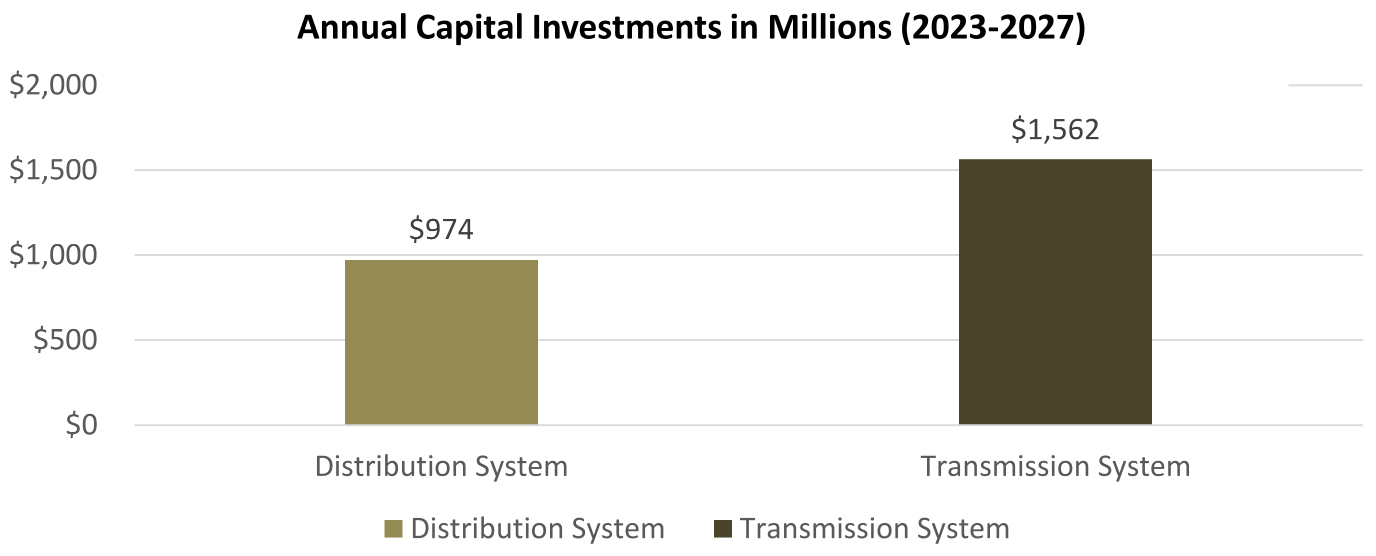
September 2020

Hydro One's Plans: Distribution and Transmission

Hydro One's Draft Investment Plan (2023–2027)

Based on initial customer feedback, information and input from Hydro One's internal engineering and technical experts, and emerging pressures on the electricity system, Hydro One developed its draft investment plan for the years 2023-2027.

This draft investment plan includes significant capital investments in both the distribution and transmission systems. The costs for **distribution system** investments are spread among all of Hydro One's 1.4 million distribution customers. For the **transmission system**, capital investment costs are shared by more than 5 million electricity customers in Ontario.



Hydro One's Draft Investment Plan At A Glance

Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	Proposed Approach
Preserve the electricity system for future generations	Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system
Improve system reliability and safety	Replace equipment that poses the biggest reliability and safety risk
Help customers with poor reliability	Invest in new technology to help restore power faster
Enable community growth	Expand the electricity system to facilitate community growth and economic development

Hydro One's Plans: Distribution and Transmission

How Much Will Hydro One's Draft Plans Cost Customers?

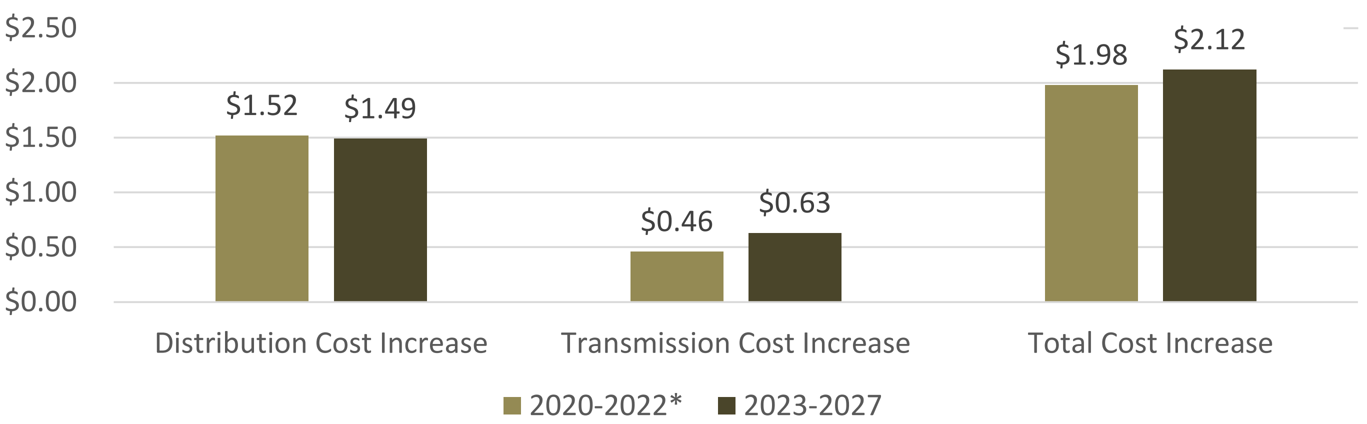
Residential Customers

If Hydro One continues with its draft investment plan, the **monthly distribution costs** for residential customers are estimated to increase by an average of **$1.49 each year** and the **transmission portion of the monthly bill** is estimated to increase by an average of **$0.63 each year** for the period 2023-2027.

That means the typical residential customer's **monthly bill is estimated to increase by an average of $2.12 (or 1.7%)** each year over the period 2023-2027.

Rural customers benefit from *distribution rate protection* and will not see an increase in distribution costs on their monthly bill. Instead, rural customers will only see an increase in the transmission portion of their monthly bill.

Average Monthly Bill Increases Each Year

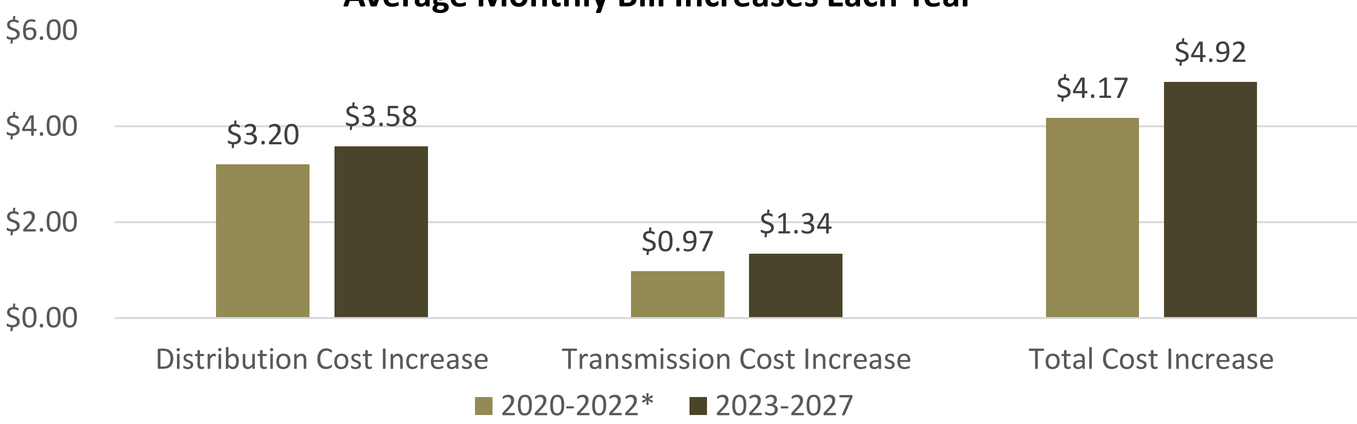


Small Business Customers

The **monthly distribution costs** for small business customers are estimated to increase by an average of **$3.58 each year** and the **transmission portion of the monthly bill** is estimated to increase by an average of **$1.34 each year** for the period 2023-2027.

That means the typical small business customer's **monthly bill is estimated to increase by an average of $4.92 (or 1.3%)** each year over the period 2023-2027.

Average Monthly Bill Increases Each Year



*Hydro One's rates until December 31, 2022 were approved by the OEB in an earlier application.

Hydro One's Distribution System: Background

Distribution System Reliability

The Make Up of Hydro One's Distribution System

Hydro One's distribution system serves about 1.4 million customers and covers about 75% of the geographic area of Ontario. A large proportion of Hydro One's distribution infrastructure is aging and is now 50 to 70 years old.

Since most of its customers live in rural areas, Hydro One's distribution system looks different than others in Ontario. Servicing more sparsely populated communities means that more equipment (e.g. wooden poles, transformers and wires) is needed to serve the same number of customers.

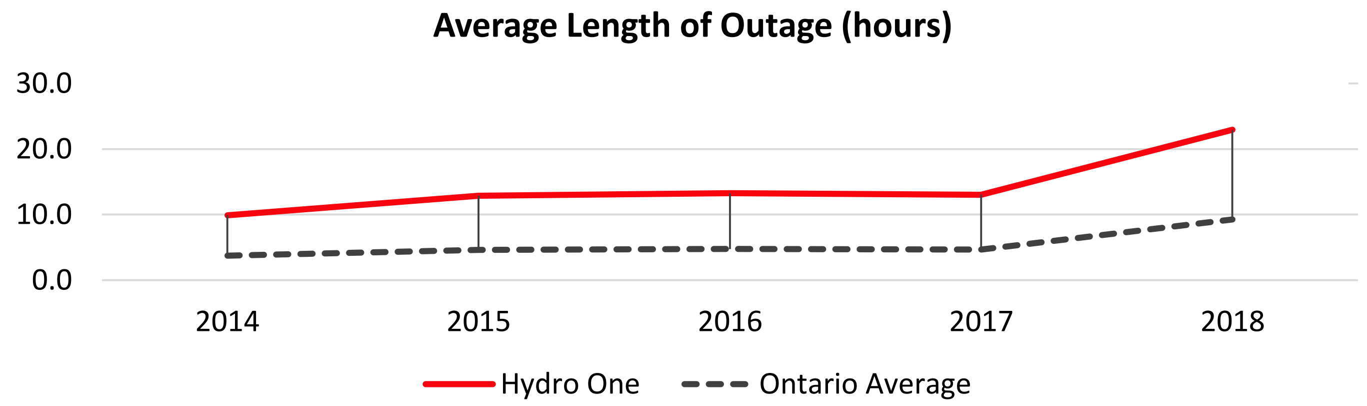
Many rural communities are connected through long lines with only one power source. If there is a disruption of power due to an equipment failure, fallen tree, or other cause, then customers further down the line experience a power interruption. Power can only be restored when the source of the outage is found and repaired.

How Does Hydro One's Distribution System Reliability Compare to Others?

Hydro One tracks both the average number of power outages per customer and how long those outages last. The average Hydro One customer experiences more frequent and longer outages than the average Ontarian.

On average, between 2014 and 2018, the typical Hydro One customer experienced 1.5 more outages per year compared to the Ontario average.

When it comes to total time spent without electricity each year, the typical Hydro One customer, since 2014, has been without power for 14.4 hours each year. That is 9 hours more than the Ontario average.



There are investments that Hydro One can make to improve reliability. While these investments are likely to reduce the length of outages, they add to the costs of the system. Different types of investments to improve reliability are presented on the following pages.

Many of the investments included in the draft plan will help Hydro One to move closer to the Ontario average. With the accelerated option, Hydro One will get there faster, while the slower option includes fewer investments to close this gap but keeps rates lower in the short term.

Distribution: Making Choices (1 of 6)

Replacing Poles in Poor Condition

Hydro One owns and maintains about 1.6 million wood poles. Some of these poles serve single households, while others supply electricity to over 5,000 customers.

The majority of Hydro One's poles are currently in good condition. However, **a significant number of wood poles (approximately 124,000) are expected to be in poor condition by the end of 2027 unless they are replaced**. These poles are more likely to fail and cause unplanned outages for customers served by these lines, and they have to be replaced at some point.

Consequences for Customers

For the current investment plan, Hydro One's planners need to decide how many poles to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If a pole fails, customers served by this pole experience an outage that lasts an average of 9 hours. A planned pole replacement doesn't necessarily lead to an outage, but if an interruption occurs, it lasts an average of 2 hours.
- **Cost considerations**: If Hydro One defers investments in poles, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to replace poles at a pace that would maintain the overall health of the system and reduce the likelihood of long outages caused by pole failures. The proposed approach prioritizes poles that serve a larger number of customers.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $650 million to replace poles in poor condition.

Distribution: Making Choices (2 of 6)

Replacing Power Transformers in Poor Condition

Hydro One owns close to 1,200 power transformers that are used to step down the voltage supplied by high-voltage lines before the electricity is distributed to households and businesses.

While the majority of these transformers are currently in good (38%) or fair (28%) working condition, Hydro One expects that **about 600 transformers will deteriorate into poor condition by the end of 2027** if they are not replaced.

Most transformers in poor condition don't require immediate replacement, but they can deteriorate quickly, at which point they must be replaced. Hydro One regularly monitors their condition with the goal to replace deteriorating transformers before they fail.

Consequences for Customers

Hydro One needs to determine how many transformer replacements to plan for in the 2023—2027 period, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If Hydro One can replace a transformer before it fails, the customers served by it experience a short outage that usually lasts a few minutes. However, if a transformer fails and needs to be replaced on an unplanned basis, customers served by the station lose power for an average of 12 hours.
- **Cost considerations:** If Hydro One defers investments in transformers, the short-term costs for customers are lower. However, pushing more replacements into the future means more uncertain costs and likely steeper cost increases in the future.

In its draft investment plan, Hydro One proposes to continue its current pace of planned transformer replacements. Alternatively, it could increase the number of planned replacements or reduce them.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to replace power transformers in poor condition.

Distribution: Making Choices (3 of 6)

Improving Reliability Through Grid Modernization

Hydro One's service territory includes challenging terrain and old infrastructure, making it prone to outages. In the past, there were few cost-effective investments Hydro One could make to significantly improve reliability and bring it closer to the Ontario average.

Technology has advanced in recent years, offering solutions that would allow Hydro One to detect, repair and restore power more quickly than in the past. This would reduce the length of time customers are without power, as Hydro One crews would be able to locate the problem and restore power faster. In some cases, Hydro One would also be able to remotely restore power.

Parts of Hydro One's distribution system are already equipped with these technologies. However, compared to other large distributors in Ontario, Hydro One's system has less.

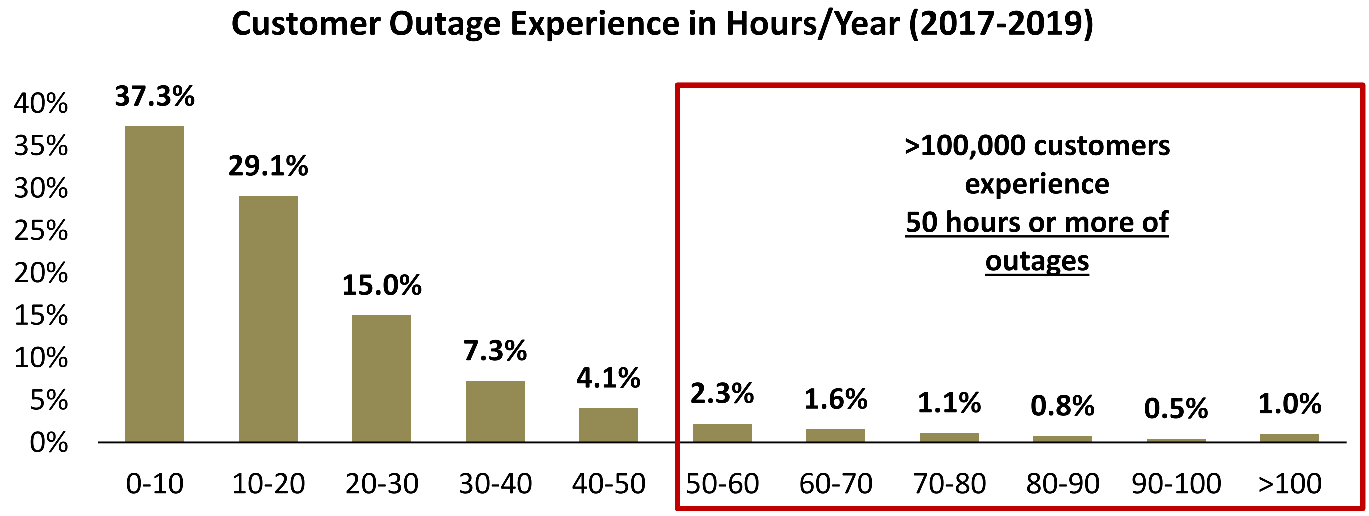
In its draft plan, Hydro One is proposing to install smart devices to help restore power more quickly. Hydro One would target these investments at lines that have historically had high interruptions affecting a large number of customers. Hydro One's planners estimate that **these investments would lead to a 40% average reduction in the duration of power outages per year** for customers served by the lines addressed in this plan.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to improve reliability through grid modernization.

Distribution: Making Choices (4 of 6)

Battery Energy Storage Solutions

Outage experiences vary across Hydro One's service territory, and some customers experience more or longer outages than others. While some Hydro One customers didn't experience any outages between 2017 and 2019, over 100,000 customers were without power for more than 50 hours per year. Some communities experienced up to 150 hours of outages.



Recent advancements in technology and battery systems have provided better options to help these customers. These batteries store electricity and automatically provide backup if a power line experiences an interruption. Hydro One is currently testing some of these solutions in pilot projects, including:

- Centralized battery storage stations that serve a whole community
- Battery storage units that serves as a backup for a small group of customers
- Single-household battery storage installed within a customer's home (*pending OEB approval*)

In 2023-2027, Hydro One is planning a larger roll-out of these energy storage solutions that would improve reliability for customers experiencing about 50 hours of interruptions per year or more. Hydro One's planners estimate that these investments would lead to a **60% to 80% average reduction in the duration of power outages** per year for customers served by battery systems.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $150 million to improve reliability through battery energy storage solutions.

Distribution: Making Choices (5 of 6)

Facilitating Growth

Communities are growing across Ontario. When communities grow by attracting new residents or businesses, the local demand for electricity increases, which sometimes results in the need for infrastructure upgrades to build additional system capacity.

Hydro One is required to plan and build its system to provide a safe and reliable supply of energy to all its customers and accommodate load growth. However, Hydro One has some choice over the pacing of these investments.

Hydro One plans infrastructure upgrades to meet both short-term and long-term electricity demand. These plans are adjusted annually in response to the actual demand and are adapted if unexpected events occur.

In its draft plan, Hydro One is proposing to upgrade infrastructure to supply increased forecast electrical demand when equipment approaches its planning limit. This would allow new economic development to proceed as planned and maintain reliability and power quality for existing and new customers. It would also generate revenue for Hydro One that helps offset the costs of building the infrastructure.

Hydro One could also take a more **proactive approach** by upgrading infrastructure *before* equipment planning limits are reached to support regional and economic development in communities looking to grow.

Alternatively, Hydro One could take a more **reactive approach** and upgrade infrastructure *after* equipment is at or exceeding its planning limit.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $400 million to facilitate growth in Ontario.

Distribution: Making Choices (6 of 6)

Replacing Smart Meters

Hydro One is legally mandated to install smart meters, which are a critical component of the infrastructure needed to measure electricity consumption and bill customers accurately.

Between 2009 and 2013, Hydro One installed 1.3 million smart meters. In 2023, many of these meters will begin to surpass the 15-year service life. Hydro One has already started seeing meters failing at an increasing rate.

When a meter fails, it must be replaced, otherwise bills are based on estimates rather than actual consumption, and a Hydro One employee must travel out to the meter every so often to get an accurate read, which is time consuming and costly.

Currently, failing meters are replaced with a similar old technology meter. However, technological advancements have brought prices down, and meter prices on new systems tend to be lower than the current prices. Also, labour costs can be reduced by replacing groups of meters rather than one by one.

Hydro One, therefore, plans to begin replacing the old system in 2023. The new smart metering system has an expected service life of 20 years, and Hydro One will go through a competitive procurement process to select a vendor and purchase a smart metering system at the best price for customers.

While the current smart metering system must be replaced, Hydro One has some choice over how quickly or slowly it replaces the old metering system.

In its draft plan, Hydro One proposes to **spread the meter replacements and associated costs over a 7-year period** (between 2023 and 2029). Alternatively, Hydro One could **speed up** the replacement process and replace all meters over a 5-year period (between 2023 and 2027).

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $550 million to replace the old smart meter system.

Hydro One's Transmission System: Background

Transmission System Reliability

Hydro One's transmission system is the backbone of Ontario's electricity system. Its high voltage transmission lines serve as highways for electricity, transporting power from generation stations like Darlington and Niagara Falls to the distribution network in your community. About 30,000 km of transmission lines and 300 transmission stations ensure that the power flows across Ontario.

Most of Hydro One's transmission system has been built with multiple sources of supply (backup capabilities). This is why outages due to transmission system failures are less frequent than distribution related outages. However, a **transmission system failure can leave thousands without power for days**, as was the case when a severe thunderstorm occurred in the Ottawa region in September 2018, which caused significant damage and impacted over 500,000 Hydro One customers.

How Does Hydro One's Transmission System Reliability Compare to Others?

Hydro One tracks both the average number and duration of interruptions per delivery point—that is the point where power is being transferred from the transmission system to a local distribution system or a transmission connected customer. The average Hydro One delivery point experiences less frequent and shorter interruptions as compared to other utilities in Canada.

Between 2014 and 2018, the typical Hydro One delivery point experienced about 60% fewer interruptions per year than the Canadian average. When it comes to the duration, the typical Hydro One delivery point has been interrupted for 55 minutes each year since 2014—about 38 minutes less than the Canadian average.

Aging and Deteriorating Transmission Infrastructure

Portions of Hydro One's transmission system date back 50 to 100 years. Hydro One has mainly focused on maintaining this infrastructure, but it will soon be time to replace much of it. Aging equipment eventually deteriorates, increasing the risk of equipment failures. Over the past five years, failing equipment has been the biggest contributor to transmission system outages.

Currently, transmission system reliability remains high, but even backup lines are aging and may not always be able to take the load needed. In the long run, reliability is likely to go down if equipment is not replaced.

There are investments that Hydro One can make to ensure the continued high reliability of the transmission system. While these investments reduce the risk of equipment failure, they add to the costs of the system.

Transmission: Making Choices (1 of 2)

Replacing Transmission Lines in Poor Condition

According to an independent review**, 4,000 km (14%) of overhead conductors are currently in poor condition**. This overhead lines equipment is critical to the safe and reliable transmission of power from large generators to end-use customers. To ensure continued safe and reliable transmission service across Ontario, Hydro One needs to replace much of this aging lines equipment in poor condition.

Consequences for customers

Hydro One needs to decide how much of the lines equipment in poor condition to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: As most of the transmission system is built with backup lines, a failure does not necessarily lead to an outage for customers. However, as more lines are deteriorating, it is not guaranteed that a back-up line is always available to carry the load when a line fails. Planned replacements avoid outages in most cases and make the system more resilient to extreme weather, as deteriorating equipment is replaced with newer standards and technology.
- **Safety considerations**: Deteriorating transmission lines pose a safety risk. A broken and dropped conductor will result in an outage to the circuit and endangers all in proximity of its fall. In some cases a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard to its surroundings.
- **Cost considerations**: If Hydro One defers investments in transmission lines equipment, the short-term costs for customers are lower. However, deferring investments further into the future means less cost certainty in the longer run, and likely steeper rate increases in the future.

In its draft investment plan for 2023-2027, Hydro One proposes to replace equipment in poor condition that poses a particular risk to the system and the public. The goal is to maintain the overall reliability of the system and avoid increasing interruptions and safety risk caused by failing equipment. This approach includes targeting single supply radial lines, which are responsible for most interruptions.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $3.85 billion to replace transmission lines in poor condition.

Transmission: Making Choices (2 of 2)

Replacing Aging and Deteriorating Transmission Stations

Hydro One's transmission infrastructure is aging, and close to 25% of transformers (167 units) are currently in poor condition, with additional transformers expected to degrade into poor condition over the next seven years. This equipment is critical to safely and reliably transmit power from large generators to over 5 million end-use customers across Ontario. To maintain the current level of reliability and safety, Hydro One needs to replace much of this aging transmission stations equipment in poor condition.

Consequences for Customers

In terms of timing, Hydro One has some flexibility in how quickly to replace this aging and deteriorating infrastructure. Hydro One must decide how much of this equipment to replace during the 2023-2027 period, and how much to push further into the future.

- **Reliability considerations**: Most transformer stations are built with backup in place, so that a failing transformer does not cause an outage for customers. However, a transformer failure, when there is no backup in place, can leave thousands of customers without power for weeks or months. Depending on its size and location, a transformer replacement takes 6 months on average, but may take 12-18 months if spare parts need to be ordered.
- **Safety considerations**: If a transformer fails, it can cause a fire in the transmission station, which poses environmental and safety risks for customers in the area.
- **Cost considerations**: If Hydro One defers investments in transmission stations equipment, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to address high-risk elements of the transmission stations infrastructure that could pose a risk to the system and the public. The goal is to maintain the overall reliability and safety of the system.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $2.25 billion to replace aging and deteriorating transmission stations.

Hydro One's Joint Rate Application

Municipal Stakeholder Engagement Report (Phase II)

December 2020

Prepared for:

Torys LLP and Hydro One Inc.

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Phase II:
Municipal Engagement

December 2020

Confidentiality

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Torys on behalf of its client Hydro One, in connection with Hydro One's joint rate application. The conclusions drawn and opinions expressed are those of the authors.

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Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged to help design, execute and document the results of Hydro One Inc.'s (Hydro One or HONI) customer engagement, as part of Hydro One's Joint Rate Application (JRAP) to the Ontario Energy Board (OEB) for the years 2023 to 2027.

As part of this engagement, Hydro One sought broad input from its stakeholders on its 2023-2027 Draft Investment Plan through focused in-depth interviews. Hydro One reached out to the Association of Municipalities of Ontario (AMO), inviting AMO representatives from their Board of Directors (a total of 41 mayors and/or municipal leaders) to schedule an interview with INNOVATIVE to share the views of municipalities across Ontario. These interviews were conducted to supplement the findings of Hydro One's direct engagement with customers.

In the fall of 2020, INNOVATIVE conducted 10 interviews with AMO representatives from across Ontario via Zoom teleconferencing or phone calls. Participants represented the following municipalities, some of which are served by Hydro One's distribution system, while others are served by another LDC:

Town of Innisfil	Town of New Tecumseth
Town of Newmarket	United Counties of Prescott and Russell
Town of Marathon	Municipality of Sioux Lookout
City of Greater Sudbury	Middlesex County
City of Brantford	Municipality of Mississippi Mills

The interviews were conducted by a trained moderator and followed a semi-structured discussion guide. 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 strategic direction only. 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.

Key Findings

Most representatives support the objectives of Hydro One's draft investment plan.

All four overall investment objectives—*preserve the electricity system for future generations*, *improve system reliability and safety*, *help customers with poor reliability*, and *enable community growth*—received broad support from municipalities across Ontario. Representatives of rural municipalities were especially pleased with the third objective focusing on customers with poor reliability. All representatives understood the need for infrastructure upgrades, as many were aware of the aging infrastructures servicing their communities. Several representatives noted that they would like to see environmental sustainability as an objective.

On balance, representatives are satisfied with the services that their communities receive from Hydro One.

Interviewees from urban communities appear to be more satisfied with their electricity service than rural participants. Representatives of urban communities reported fewer outages and expressed more satisfaction with the level of service and reliability. Some of the rural representatives voiced concerns about the service they are currently receiving. Some noted being at peak capacity and/or being susceptible to service interruptions due to the nature of the infrastructure servicing their community. Some participants expressed concerned that tthese two factors either currently or will soon be limiting their growth.

Supporting growth by providing critical infrastructure is the key concern for many municipal representatives.

Representatives of communities in more remote locations expressed a desire for more infrastructure investments to improve reliability. Several participants were from communities across Ontario that are forecasting significant growth over the next decade or two. To enable both community and economic growth, they see the need for investments in the electricity system to increase capacity and ensure reliable service. Comments about electrification were less prominent, with those comments mainly pertaining to transportation. Some municipalities indicate they have started to think about ways in which electric vehicles will increase the demand for electricity, and how they can accommodate electric vehicle users in the form of charging stations. Other participants indicated their municipalities are looking into electrifying their municipal fleets and bus systems.

Affordability is seen as a concern for certain segments of the population by some representatives.

Municipal representatives reported that electricity prices are not among the key concerns that they currently hear about from their constituents. However, affordability more generally is an important issue for certain segments of the population—specifically for Ontarians with lower and fixed incomes. While municipal representatives didn't expect the rate increases included in Hydro One's draft plan to affect their average constituents, they voiced some concern that increasing prices may present a challenge for marginalized populations. Several representatives recommended a slow and steady increase of cost, in addition to Hydro One clearly explaining to its customers *why* these costs are incurred, in order to build understanding among their customer base.

Municipalities want to have a more active partnership with Hydro One.

Municipal participants generally report a positive relationship with the company for the most part. However, some municipalities would like to have Hydro One more actively involved in their long-term planning, so that they can better coordinate their plans.

A number of rural community leaders consider Hydro One a potential partner who can help residents get access to broadband internet. In other cases, communities would simply like to see Hydro One collaborate with internet service providers by providing timely access to Hydro One's utility poles.

Hydro One's Draft Investment Plan

Feedback on Plan Objectives

Most representatives agreed with the priorities outlined in Hydro One's draft investment plan. The first two investment objectives—*preserve the electricity system for future generations* and *improve system reliability and safety*—were considered fundamental by participants and did not generate much additional comment. Participants tended to focus on the other two investment objectives—*help customers with poor reliabilit*y and *enable community growth*. Representatives of municipalities with poor reliability were especially pleased with the third objective focusing on customers with poor reliability. There was also strong support for the fourth investment objective to enable community growth, as several municipal representatives expect their communities to grow considerably.

Objective 1: Preserve the electricity system for future generations

All representatives understood the need for infrastructure replacements and upgrades, as many were aware of the aging infrastructure servicing their communities.

> *"The community is in favor of asset replacement… there are generally no issues with regard to increasing costs and replacing old infrastructure."*
>
> *"We need to take care of it…past governments have just been kicking it down the road."*
>
> *"I think the lack of investment in maintaining infrastructure, renewing infrastructure, and building new infrastructure is a sad tale of short-sightedness."*
>
> *"If we don't take care of this stuff, you're going to be without electricity."*

Objective 2: Improve system reliability and safety

Safety concerns were not brought up by any of the respondents during the interviews. There was, however, strong support to improve the system's reliability among the rural and more remote communities. Representatives of urban communities indicated being satisfied with the electricity service in their community; they rarely experienced power interruptions and generally had reliable service. Many made a point of acknowledging the scale that Hydro One operates at and were therefore understanding when they did experience service interruptions.

> *"We're not on the grid, we're at the end of one supply line one–one garden hose–and if that garden hose breaks, we lose our electricity…that line, I would think it's very susceptible to forest fires, to wind storms, to other such things. It's just a point of real weakness."*
>
> *"We have to go 20 to 30 kilometers for a feeder before it reaches the town border. So inherently, these are just power lines on poles. So, there's a lot more risk than having a transmission line. Transmission lines are much more reliable than wires and poles."*
>
> *"Overall, I would say most residents in the city would say that the system is reliable. It's up 99.99% of the time. And when it goes out, it goes out for a moment and then comes back."*

"I've never experienced that you had a line down and the guys weren't there to deal with it in a very expeditious way."

Objective 3: Help customers with poor reliability

The representatives of rural or more remote municipalities expressed a strong desire for increased reliability, so this objective strongly resonated with them. They emphasized that businesses depend on reliable service, and discussed the financial impacts associated with both scheduled and unscheduled outages. For instance, towns with a single supply line have no redundancy of supply, which makes them more susceptible to service interruptions. In order to do the necessary yearly maintenance in one such town, the power needs to be shut off entirely, which has a negative financial impact on the town's economy.

"When I look at Hydro One's Draft Investment Plan at a glance, there were four points or objectives of the plan. And the third one was help customers with poor reliability. So, I would say that speaks to us."

"…what do we need from Hydro One? We need more power and more reliable power."

"…to be able to attract those people, we need to have reliable hydro."

Objective 4: Enable community growth

Representatives from growing municipalities in particular expressed their support for this objective. Some reported how the electrical infrastructure in more rural or remote communities has limiting effects on the amount of power available to a community. This limited capacity, often combined with poor reliability, can severely limit community growth.

Representatives described how they expected Hydro One to increase their capacity and reliability by upgrading transmission lines and building additional transmission stations.

"Building this new infrastructure for growth is the top priority."

"We're expecting the need for more capacity in two ways, like growth, and then also a change in usage or increase in electricity through different usages."

"We're at the limit of power–we have a lot of demand for growth."

"To enable community growth, that's a big priority for us here … and we can't do it unless we have the capacity…and the reliability."

When asked about challenges that their community is facing with respect to electricity, the most frequently cited challenge for Hydro One was them meeting the municipalities' increasing capacity and infrastructure needs in the future.

"Making sure that Hydro One has suitable infrastructure in place to be able to expand service in these areas."

"We need a transmission line going through the town, because right now there's close to 40,000 people. But if we're looking at 30 years out, there's going to be probably over 200,000 people."

"Growth is going to be the number one challenge… making sure the capacity is there. That'll be critical for additional growth and development."

“How do I sign and encourage [new companies] to proceed if I can't guarantee them power?”

A good example of this is Sioux Lookout, which serves as a service center to many northern First Nations communities in Ontario. They are currently at peak capacity and are susceptible to power interruptions. The mayor of Sioux Lookout (who agreed to be identified by name in this report) argued that the cost of new hydro infrastructure to address these challenges should not fall solely on the shoulders of remote communities such as Sioux Lookout, but should at least in part be socialized across the province. This way the burden is not placed entirely on these small remote communities–especially in the case of Sioux Lookout, which functions as a service center to about 20% of the landmass of Ontario and services dozens of First Nations and non-indigenous communities.

“The cost of so many things in so many places across this province has been socialized across everybody's cost. Natural gas is available in 95% of the province, and the main supply/distribution system was a socialized cost–everybody paid for it. Some places were much more expensive than others, more densely populated places. So, as a remote location with a small population, we didn't get in on that deal. Okay. The cost of the hydro transmission lines: hydro transmission is socialized across the province. And now we're telling you that not only the growth of Sioux Lookout, but the growth of Northern Ontario, the First Nations North of us, is dependent on our hydro supply in many ways. … If we die, it won't stop the growth of the North, but boy will it impede it, and to the cost of the entire province. So, I would argue … that the cost that we're going to be faced to upgrade our hydro should be, at least in part, socialized across the province, because it's to the benefit of the whole province that this happens.”

Mayor Lawrence noted that the growth of Northern Ontario is being limited by Sioux Lookout’s electrical capacity constraints, which he considers a detriment to the entire province. Two representatives from other municipalities also specifically noted that the northern communities needed better service.

“[The top priority is] innovation in order to serve Northern communities with proper service levels.”

“Making capacity in particular lines a priority to be able to bring people online.”

Missing Objective

Several representatives noted that Hydro One was missing “**environmental sustainability**" as an objective and commented that this was a missed opportunity for the utility.

“I'm just thinking in terms of planning and communicating to the public about what's going on. That whole green relationship piece, I think is something that a lot of people are concerned about and interested in.”

“An issue that affects us but really affects absolutely everybody is the climate change piece and how that is affecting weather patterns.”

Feedback on Cost Impact of Plan

Municipal representatives reported that electricity prices are not among the key concerns they hear about from their constituents. Representatives expected that a proposed rate increase was likely to garner some negative reactions from rate payers. However, explaining where the money goes and how investments translate into outcomes for customers may help increase understanding and acceptance.

“Have we heard any large issues about the cost of hydro? Not really. I think there has been some things done in the past to get people to understand a little bit better. You know, I think the billing –and I'm just thinking about my own hydro bill– I think the billing is laid out fairly well [so] that you can understand the peak hours or things like that.”

“We try and always take the discussion away from cost and back into value, what you're getting for what you're paying. So, I haven't heard any major complaints about increasing cost of hydro.”

“I’d say it's not such a big local issue. It would be periodically. And we only really hear about it when there's an increase in power rates. That's when you hear about it.”

“I would guess that the majority of people who I represent would roll their eyes. And then would say, ‘Here they go. They're just gonna charge me more, etc.’ …I'm sure if they were experiencing blackouts, like perhaps we see in other parts of the province–and I don't know if they have them a lot or not– I suspect they would probably say, ‘Oh, thank God, we really need it.’ And so, blessings to these investments, if they get more reliable power.”

However, affordability, more generally, is an important issue for certain segments of the population—specifically for Ontarians with lower and fixed incomes. While municipal representatives didn’t expect the rate increases included in Hydro One’s draft plan to affect their average constituents, they voiced some concern that increasing prices may present a challenge for marginalized groups.

“People don't want their bills to go up. They say, ‘my income hasn't gone up by that much.’… people don't like to pay for something they take for granted.”

“It'll go over like a lead balloon that they're gonna have to be paying more money for a system that they still want us to figure out how to get out of.”

“Our system is old. It was among the first in the world of its size and it needs to be brought up to modern day technological levels. But the cost has to come down.”

Arguing that most people take hydro for granted, several representatives indicated their preference for a slow increase of cost, in addition to Hydro One clearly explaining to its customers *why* these costs are incurred in order to build understanding among their customer base.

“People would much rather see a slow, steady rate increase. If it has to be there, then at least keep it manageable.”

“The more information people have, the more informed they are and can make good decisions–and also then understand what the consequences of those decisions are.”

Finally, one representative suggested a “fairness of cost” objective. They pointed out that there are differences in the level of service received by communities throughout Ontario, and that this difference should be reflected in the price.

“I think there should be a pillar that certain specific areas of the province should not be penalized … they should be assisted.”

Other Community Needs and Expectations

Almost all representatives took the time to express their appreciation of Ontario's electricity system and Hydro One's role within it. They noted that their residents often do not realize the sheer scale of the electrical infrastructure that enables them to enjoy hydro in their daily lives.

> *"People don't see the bigger picture."*
>
> *"Hydro is so central to everything we do. And we're so fortunate to have so much of it, that I think it's undervalued."*

Participants reported a good relationship with Hydro One. Interviewees were asked if they commonly interact with Hydro One, and to characterise their relationship with the electricity provider. Only three of the ten representatives said they had been interacting with Hydro One directly; the others indicated that they tended to deal more frequently with their respective local electrical distributors. Despite many representatives describing minimal interaction with Hydro One, their perception of the relationship between their municipality and Hydro One was a positive one. Most mentioned that communication was on an as-needed basis (i.e., if there was an outage or other issue), with many noting that they were satisfied with their communications with Hydro One.

> *"As a governance person, I think the only time I would hear about any sort of utilities questions and issues is if there's a problem."*
>
> *"Anytime that we've ever been in those types of unfortunate circumstances, most of our dealings [were] with [our LDC], some through Hydro One themselves, but…the lines of communication, I think, are generally really good between both parties and the municipality."*
>
> *"In the five years that I've been there, the communication has been fantastic. And I think that's something that's a really good strength between [our LDC], Hydro One and the municipality–there's always a free flow of information. Obviously, they're trying to deal with their issues, we're trying to do with ours, but there's never seemed to be a problem with respect to the communications, which is obviously tremendously appreciated."*
>
> *"The dealings with Hydro One have been wonderful. They've been very, very, very helpful. But the bottom line is, we need to move forward. We need to have some system improvements, and we need help to do it."*
>
> *"With Hydro One, I'd have to say, in a way, it is collaborative. It's not as close as the local power company and the municipality, but it's still collaborative."*

When asked about what their municipality expects from Hydro One, some did not have clear expectations. Others expressed that it would be beneficial for their long-term planning to have Hydro One involved.

> *"It would be beneficial if Hydro One was at least at the table, or at least was knowledgeable as to what was going on. All the member municipalities are obviously involved with the county in that planning process… So, I think if they were involved in that, then that can certainly help them get a better understanding as far as where the growth is going–where the future demand is."*
>
> *"[We want to] increase our level of communication with various utilities and make sure that we're aware of projects coming down the road and things that we have come down the road, so we can*

collaboratively plan for those types of projects, so they're budgeted for appropriately, and the timeframes can be respected"

"We need to work together to make sure that, based on current rates, this is the rate at which we're building. Things may go up or down because of these variables. But within the next time frame, we anticipate this kind of need."

One representative expressed a desire for timely communication in the case of outages. They want to be informed immediately when the power goes off in their ward so they can respond quickly. The municipality is looking for proactive communication from Hydro One, rather than the onus being on them to navigate to a map on the Hydro One website to see if there are any outages in the area at any point in time. Up until now, the municipality has only been made aware of outages through residents in the affected area who contacted them directly.

"I've had concerns over the last couple of years of not being informed that the power has gone out in my ward. It's difficult for the city to respond when we don't know the power's out, like to provide warming centers, etc."

"If we don't live there, we don't know when the power is gone…I don't look at the map."

One representative expressed a wish for Hydro One to act as a partner of the municipality. They would like to see a focus on the customer and their needs–and not just electrical needs. In this representative's primarily rural municipality, there are large challenges with broadband connectivity, in part due to local internet providers having difficulty gaining access to Hydro One's utility poles, both in terms of cost and getting permission to use the poles. Access to broadband internet was also brought up by several other representatives. They all pointed out that access to reliable internet is considered an essential service in today's economy and society.

"I have the expectation of them of being a partner–actually, I think that's a good word–being a partner and being helpful towards the goal of bringing this utility. Because I kind of think of the internet as a utility at this point, because it's as important as hydro."

"[Internet is] a key essential kind of utility."

"I do believe that that fiber needs to be spread out to the northern communities and remote communities that are receiving power, but not necessarily receiving fiber. So anywhere there's lines of electricity, there should be in parallel lines of fiber being built at the same time."

Some representatives noted that their municipalities have started thinking about ways in which electric vehicles will increase the demand for hydro, and how they can accommodate electric car users in the form of charging stations. Others mentioned working on policies to facilitate residents setting up charging plugs at the front of houses.

"Yeah, there's an appetite for it. People want to achieve self-sufficiency, but I tell those people, 'well, that's great. The solar panels on your roof–assuming you've got an economical way of storing it–that'll fire up your TV and your radios and your lights. But what about that electric car you're going to buy four years from now that needs 220 volts service… [Are you] going to power that up off your solar panels? I don't think so.' And so, I would think as we move to electrification, which won't just be in vehicles, we have to move to heating, right, that the need for a centralized delivery of hydro is just gonna grow."

“When we talk about the construction of recreation centers, or other municipal facilities, we do talk about and make sure that staff provide some accommodation for electric charging.”

Other municipalities are looking into electrifying their fleets and bus systems, but they have identified substantial financial challenges with that.

“The problem right now is the price differential. Even when you consider the lifecycle cost, it's probably still 50-60% more expensive, primarily because of upfront capital costs…we're gonna wait until it becomes more economical. And that's probably reflective of decisions individuals are making when they're purchasing vehicles. Which is the range, the charging time, the access to charging stations, and the cost. So, all the same issues that we struggle with, and, of course, a lot of pressure from a portion of Canada. They want us to be electrified for everything right now, [but] we have to be fiscally responsible…We want to be on the leading edge but not the bleeding edge.”

“We want to electrify, but the difficulty right now is [that] it's not an easy thing to shift the buses over. How long can they go before they charge? Whereas right now you fill them up and they go for the day.”

Appendices

Appendix 1: Municipal Dx + Tx Draft Investment Plan (Overview Package)

Appendix 2: Municipal Tx Draft Investment Plan (Overview Package)

Overview:
2023-2027 Draft Investment Plan
Distribution and Transmission Systems

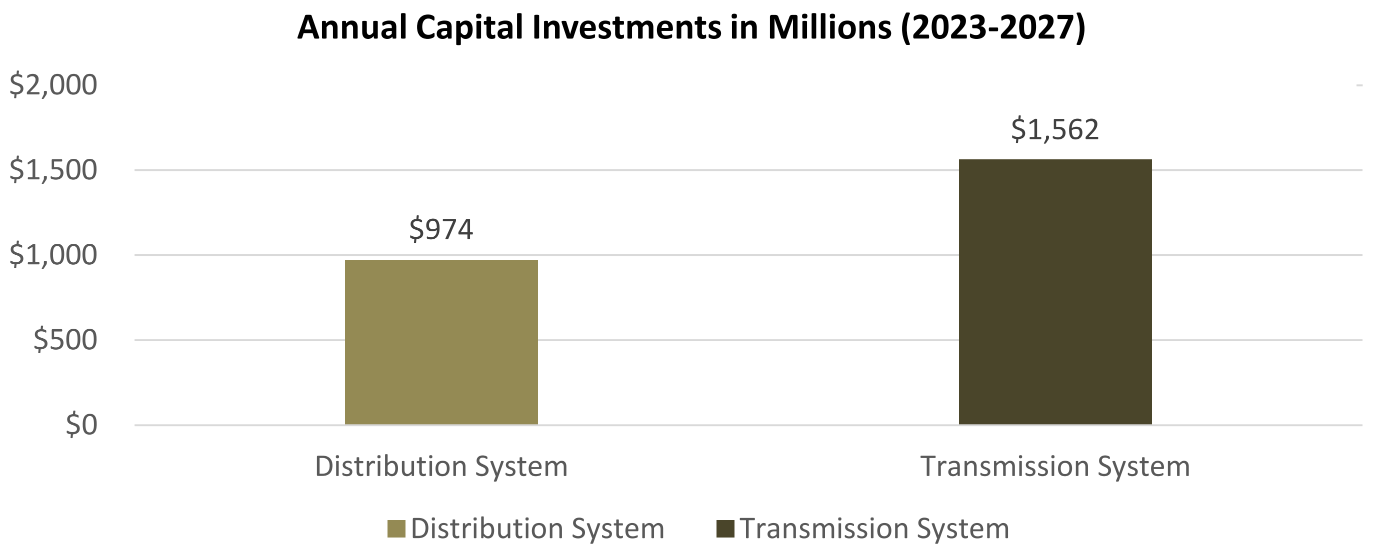
September 2020

Hydro One's Plans: Distribution and Transmission

Hydro One's Draft Investment Plan (2023–2027)

Based on initial customer feedback, information and input from Hydro One's internal engineering and technical experts, and emerging pressures on the electricity system, Hydro One developed its draft investment plan for the years 2023-2027.

This draft investment plan includes significant capital investments in both the distribution and transmission systems. The costs for **distribution system** investments are spread among all of Hydro One's 1.4 million distribution customers. For the **transmission system**, capital investment costs are shared by more than 5 million electricity customers in Ontario.



Hydro One's Draft Investment Plan At A Glance

Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	Proposed Approach
Preserve the electricity system for future generations	Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system
Improve system reliability and safety	Replace equipment that poses the biggest reliability and safety risk
Help customers with poor reliability	Invest in new technology to help restore power faster
Enable community growth	Expand the electricity system to facilitate community growth and economic development

Hydro One's Plans: Distribution and Transmission

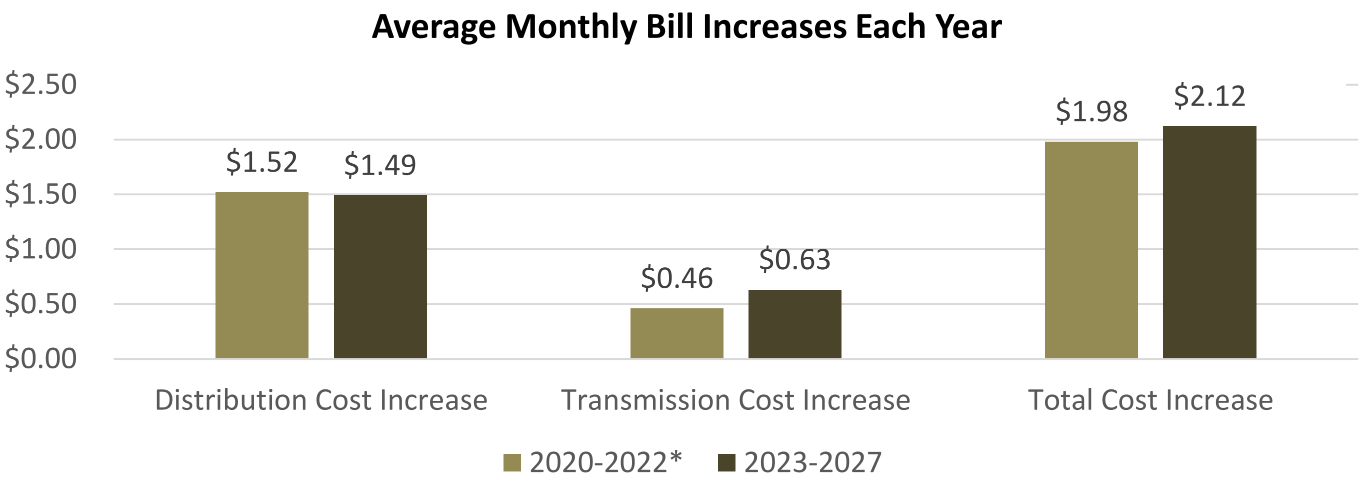
How Much Will Hydro One's Draft Plans Cost Customers?

Residential Customers

If Hydro One continues with its draft investment plan, the **monthly distribution costs** for residential customers are estimated to increase by an average of **$1.49 each year** and the **transmission portion of the monthly bill** is estimated to increase by an average of **$0.63 each year** for the period 2023-2027.

That means the typical residential customer's **monthly bill is estimated to increase by an average of $2.12 (or 1.7%)** each year over the period 2023-2027.

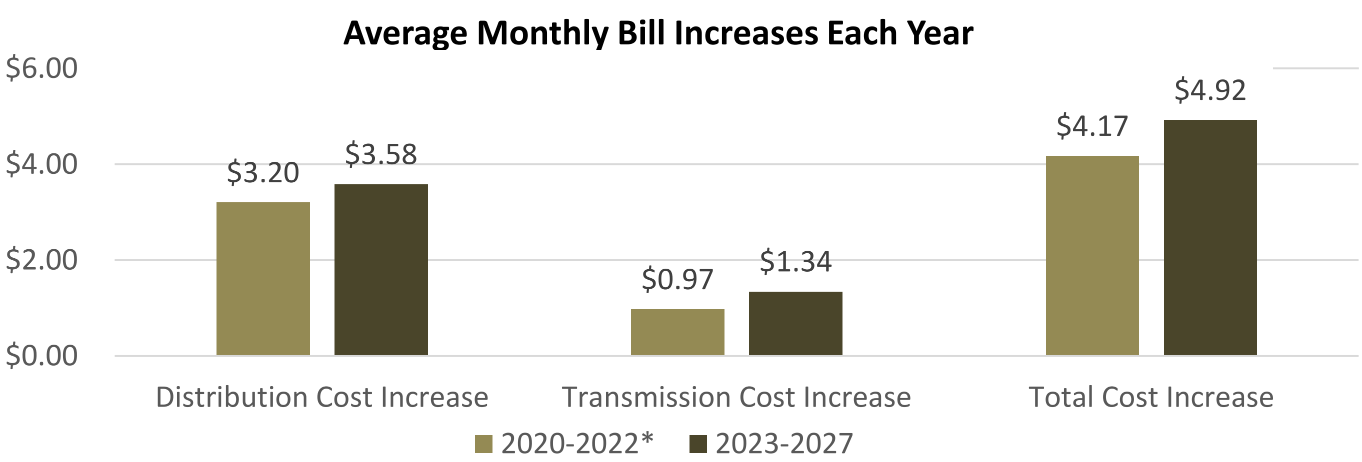
Rural customers benefit from *distribution rate protection* and will <u>not</u> see an increase in distribution costs on their monthly bill. Instead, rural customers will only see an increase in the transmission portion of their monthly bill.



Small Business Customers

The **monthly distribution costs** for small business customers are estimated to increase by an average of **$3.58 each year** and the **transmission portion of the monthly bill** is estimated to increase by an average of **$1.34 each year** for the period 2023-2027.

That means the typical small business customer's **monthly bill is estimated to increase by an average of $4.92 (or 1.3%)** each year over the period 2023-2027.



*Hydro One's rates until December 31, 2022 were approved by the OEB in an earlier application.

Hydro One's Distribution System: Background

Distribution System Reliability

The Make Up of Hydro One's Distribution System

Hydro One's distribution system serves about 1.4 million customers and covers about 75% of the geographic area of Ontario. A large proportion of Hydro One's distribution infrastructure is aging and is now 50 to 70 years old.

Since most of its customers live in rural areas, Hydro One's distribution system looks different than others in Ontario. Servicing more sparsely populated communities means that more equipment (e.g. wooden poles, transformers and wires) is needed to serve the same number of customers.

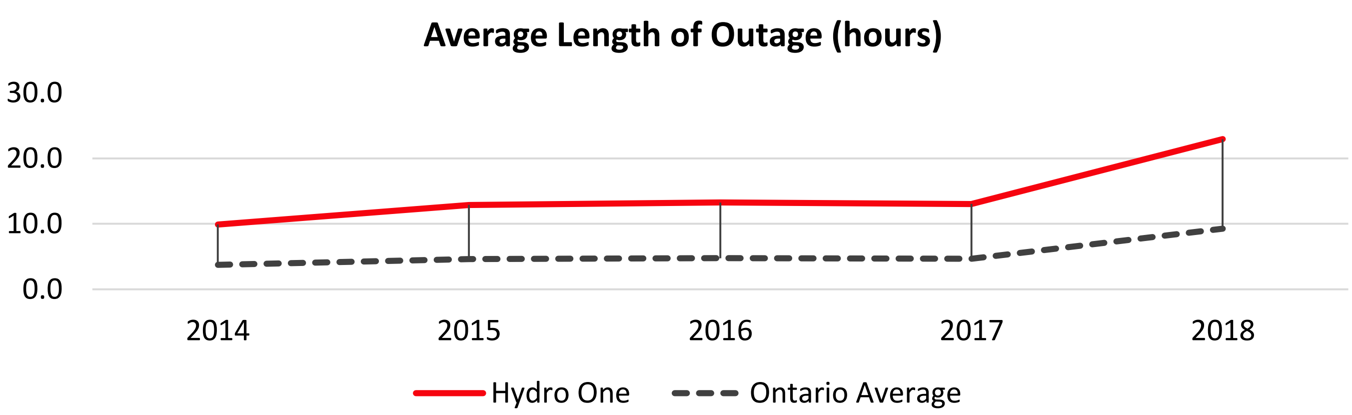
Many rural communities are connected through long lines with only one power source. If there is a disruption of power due to an equipment failure, fallen tree, or other cause, then customers further down the line experience a power interruption. Power can only be restored when the source of the outage is found and repaired.

How Does Hydro One's Distribution System Reliability Compare to Others?

Hydro One tracks both the average number of power outages per customer and how long those outages last. The average Hydro One customer experiences more frequent and longer outages than the average Ontarian.

On average, between 2014 and 2018, the typical Hydro One customer experienced 1.5 more outages per year compared to the Ontario average.

When it comes to total time spent without electricity each year, the typical Hydro One customer, since 2014, has been without power for 14.4 hours each year. That is 9 hours more than the Ontario average.



There are investments that Hydro One can make to improve reliability. While these investments are likely to reduce the length of outages, they add to the costs of the system. Different types of investments to improve reliability are presented on the following pages.

Many of the investments included in the draft plan will help Hydro One to move closer to the Ontario average. With the accelerated option, Hydro One will get there faster, while the slower option includes fewer investments to close this gap but keeps rates lower in the short term.

Distribution: Making Choices (1 of 6)

Replacing Poles in Poor Condition

Hydro One owns and maintains about 1.6 million wood poles. Some of these poles serve single households, while others supply electricity to over 5,000 customers.

The majority of Hydro One's poles are currently in good condition. However, **a significant number of wood poles (approximately 124,000) are expected to be in poor condition by the end of 2027 unless they are replaced**. These poles are more likely to fail and cause unplanned outages for customers served by these lines, and they have to be replaced at some point.

Consequences for Customers

For the current investment plan, Hydro One's planners need to decide how many poles to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If a pole fails, customers served by this pole experience an outage that lasts an average of 9 hours. A planned pole replacement doesn't necessarily lead to an outage, but if an interruption occurs, it lasts an average of 2 hours.
- **Cost considerations**: If Hydro One defers investments in poles, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to replace poles at a pace that would maintain the overall health of the system and reduce the likelihood of long outages caused by pole failures. The proposed approach prioritizes poles that serve a larger number of customers.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $650 million to replace poles in poor condition.

Distribution: Making Choices (2 of 6)

Replacing Power Transformers in Poor Condition

Hydro One owns close to 1,200 power transformers that are used to step down the voltage supplied by high-voltage lines before the electricity is distributed to households and businesses.

While the majority of these transformers are currently in good (38%) or fair (28%) working condition, Hydro One expects that **about 600 transformers will deteriorate into poor condition by the end of 2027** if they are not replaced.

Most transformers in poor condition don't require immediate replacement, but they can deteriorate quickly, at which point they must be replaced. Hydro One regularly monitors their condition with the goal to replace deteriorating transformers before they fail.

Consequences for Customers

Hydro One needs to determine how many transformer replacements to plan for in the 2023—2027 period, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If Hydro One can replace a transformer before it fails, the customers served by it experience a short outage that usually lasts a few minutes. However, if a transformer fails and needs to be replaced on an unplanned basis, customers served by the station lose power for an average of 12 hours.
- **Cost considerations:** If Hydro One defers investments in transformers, the short-term costs for customers are lower. However, pushing more replacements into the future means more uncertain costs and likely steeper cost increases in the future.

In its draft investment plan, Hydro One proposes to continue its current pace of planned transformer replacements. Alternatively, it could increase the number of planned replacements or reduce them.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to replace power transformers in poor condition.

Distribution: Making Choices (3 of 6)

Improving Reliability Through Grid Modernization

Hydro One's service territory includes challenging terrain and old infrastructure, making it prone to outages. In the past, there were few cost-effective investments Hydro One could make to significantly improve reliability and bring it closer to the Ontario average.

Technology has advanced in recent years, offering solutions that would allow Hydro One to detect, repair and restore power more quickly than in the past. This would reduce the length of time customers are without power, as Hydro One crews would be able to locate the problem and restore power faster. In some cases, Hydro One would also be able to remotely restore power.

Parts of Hydro One's distribution system are already equipped with these technologies. However, compared to other large distributors in Ontario, Hydro One's system has less.

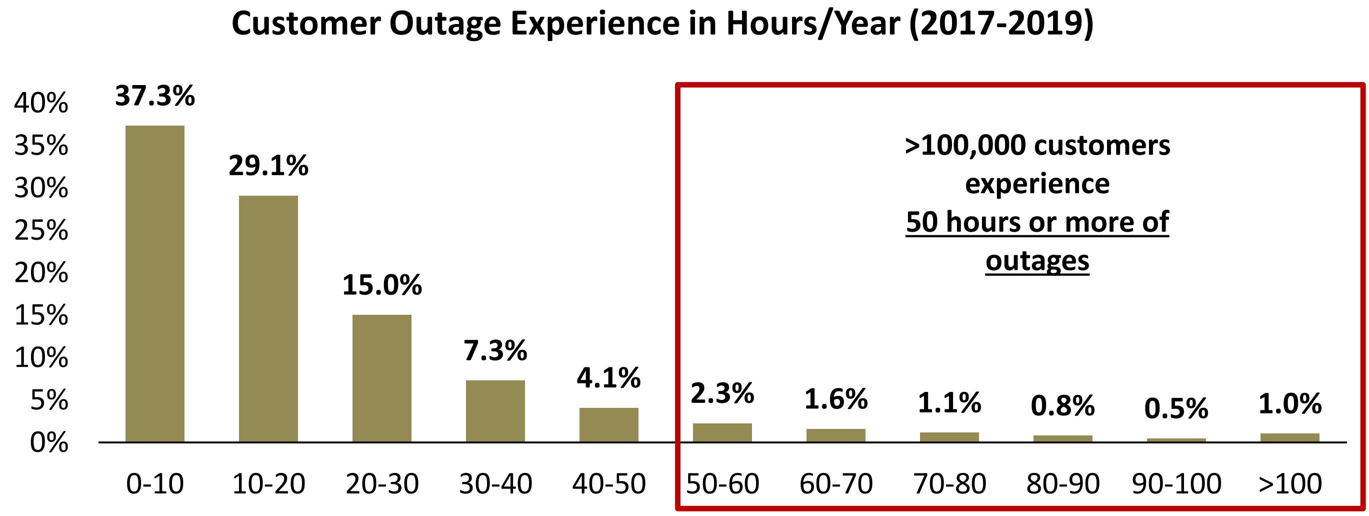
In its draft plan, Hydro One is proposing to install smart devices to help restore power more quickly. Hydro One would target these investments at lines that have historically had high interruptions affecting a large number of customers. Hydro One's planners estimate that **these investments would lead to a 40% average reduction in the duration of power outages per year** for customers served by the lines addressed in this plan.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to improve reliability through grid modernization.

Distribution: Making Choices (4 of 6)

Battery Energy Storage Solutions

Outage experiences vary across Hydro One's service territory, and some customers experience more or longer outages than others. While some Hydro One customers didn't experience any outages between 2017 and 2019, over 100,000 customers were without power for more than 50 hours per year. Some communities experienced up to 150 hours of outages.



Recent advancements in technology and battery systems have provided better options to help these customers. These batteries store electricity and automatically provide backup if a power line experiences an interruption. Hydro One is currently testing some of these solutions in pilot projects, including:

- Centralized battery storage stations that serve a whole community
- Battery storage units that serves as a backup for a small group of customers
- Single-household battery storage installed within a customer's home (*pending OEB approval*)

In 2023-2027, Hydro One is planning a larger roll-out of these energy storage solutions that would improve reliability for customers experiencing about 50 hours of interruptions per year or more. Hydro One's planners estimate that these investments would lead to a **60% to 80% average reduction in the duration of power outages** per year for customers served by battery systems.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $150 million to improve reliability through battery energy storage solutions.

Distribution: Making Choices (5 of 6)

Facilitating Growth

Communities are growing across Ontario. When communities grow by attracting new residents or businesses, the local demand for electricity increases, which sometimes results in the need for infrastructure upgrades to build additional system capacity.

Hydro One is required to plan and build its system to provide a safe and reliable supply of energy to all its customers and accommodate load growth. However, Hydro One has some choice over the pacing of these investments.

Hydro One plans infrastructure upgrades to meet both short-term and long-term electricity demand. These plans are adjusted annually in response to the actual demand and are adapted if unexpected events occur.

In its draft plan, Hydro One is proposing to upgrade infrastructure to supply increased forecast electrical demand when equipment approaches its planning limit. This would allow new economic development to proceed as planned and maintain reliability and power quality for existing and new customers. It would also generate revenue for Hydro One that helps offset the costs of building the infrastructure.

Hydro One could also take a more **proactive approach** by upgrading infrastructure *before* equipment planning limits are reached to support regional and economic development in communities looking to grow.

Alternatively, Hydro One could take a more **reactive approach** and upgrade infrastructure *after* equipment is at or exceeding its planning limit.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $400 million to facilitate growth in Ontario.

Distribution: Making Choices (6 of 6)

Replacing Smart Meters

Hydro One is legally mandated to install smart meters, which are a critical component of the infrastructure needed to measure electricity consumption and bill customers accurately.

Between 2009 and 2013, Hydro One installed 1.3 million smart meters. In 2023, many of these meters will begin to surpass the 15-year service life. Hydro One has already started seeing meters failing at an increasing rate.

When a meter fails, it must be replaced, otherwise bills are based on estimates rather than actual consumption, and a Hydro One employee must travel out to the meter every so often to get an accurate read, which is time consuming and costly.

Currently, failing meters are replaced with a similar old technology meter. However, technological advancements have brought prices down, and meter prices on new systems tend to be lower than the current prices. Also, labour costs can be reduced by replacing groups of meters rather than one by one.

Hydro One, therefore, plans to begin replacing the old system in 2023. The new smart metering system has an expected service life of 20 years, and Hydro One will go through a competitive procurement process to select a vendor and purchase a smart metering system at the best price for customers.

While the current smart metering system must be replaced, Hydro One has some choice over how quickly or slowly it replaces the old metering system.

In its draft plan, Hydro One proposes to **spread the meter replacements and associated costs over a 7-year period** (between 2023 and 2029). Alternatively, Hydro One could **speed up** the replacement process and replace all meters over a 5-year period (between 2023 and 2027).

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $550 million to replace the old smart meter system.

Hydro One's Transmission System: Background

Transmission System Reliability

Hydro One's transmission system is the backbone of Ontario's electricity system. Its high voltage transmission lines serve as highways for electricity, transporting power from generation stations like Darlington and Niagara Falls to the distribution network in your community. About 30,000 km of transmission lines and 300 transmission stations ensure that the power flows across Ontario.

Most of Hydro One's transmission system has been built with multiple sources of supply (backup capabilities). This is why outages due to transmission system failures are less frequent than distribution related outages. However, a **transmission system failure can leave thousands without power for days**, as was the case when a severe thunderstorm occurred in the Ottawa region in September 2018, which caused significant damage and impacted over 500,000 Hydro One customers.

How Does Hydro One's Transmission System Reliability Compare to Others?

Hydro One tracks both the average number and duration of interruptions per delivery point—that is the point where power is being transferred from the transmission system to a local distribution system or a transmission connected customer. The average Hydro One delivery point experiences less frequent and shorter interruptions as compared to other utilities in Canada.

Between 2014 and 2018, the typical Hydro One delivery point experienced about 60% fewer interruptions per year than the Canadian average. When it comes to the duration, the typical Hydro One delivery point has been interrupted for 55 minutes each year since 2014—about 38 minutes less than the Canadian average.

Aging and Deteriorating Transmission Infrastructure

Portions of Hydro One's transmission system date back 50 to 100 years. Hydro One has mainly focused on maintaining this infrastructure, but it will soon be time to replace much of it. Aging equipment eventually deteriorates, increasing the risk of equipment failures. Over the past five years, failing equipment has been the biggest contributor to transmission system outages.

Currently, transmission system reliability remains high, but even backup lines are aging and may not always be able to take the load needed. In the long run, reliability is likely to go down if equipment is not replaced.

There are investments that Hydro One can make to ensure the continued high reliability of the transmission system. While these investments reduce the risk of equipment failure, they add to the costs of the system.

Transmission: Making Choices (1 of 2)

Replacing Transmission Lines in Poor Condition

According to an independent review**, 4,000 km (14%) of overhead conductors are currently in poor condition**. This overhead lines equipment is critical to the safe and reliable transmission of power from large generators to end-use customers. To ensure continued safe and reliable transmission service across Ontario, Hydro One needs to replace much of this aging lines equipment in poor condition.

Consequences for customers

Hydro One needs to decide how much of the lines equipment in poor condition to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: As most of the transmission system is built with backup lines, a failure does not necessarily lead to an outage for customers. However, as more lines are deteriorating, it is not guaranteed that a back-up line is always available to carry the load when a line fails. Planned replacements avoid outages in most cases and make the system more resilient to extreme weather, as deteriorating equipment is replaced with newer standards and technology.
- **Safety considerations**: Deteriorating transmission lines pose a safety risk. A broken and dropped conductor will result in an outage to the circuit and endangers all in proximity of its fall. In some cases a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard to its surroundings.
- **Cost considerations**: If Hydro One defers investments in transmission lines equipment, the short-term costs for customers are lower. However, deferring investments further into the future means less cost certainty in the longer run, and likely steeper rate increases in the future.

In its draft investment plan for 2023-2027, Hydro One proposes to replace equipment in poor condition that poses a particular risk to the system and the public. The goal is to maintain the overall reliability of the system and avoid increasing interruptions and safety risk caused by failing equipment. This approach includes targeting single supply radial lines, which are responsible for most interruptions.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $3.85 billion to replace transmission lines in poor condition.

Transmission: Making Choices (2 of 2)

Replacing Aging and Deteriorating Transmission Stations

Hydro One's transmission infrastructure is aging, and close to 25% of transformers (167 units) are currently in poor condition, with additional transformers expected to degrade into poor condition over the next seven years. This equipment is critical to safely and reliably transmit power from large generators to over 5 million end-use customers across Ontario. To maintain the current level of reliability and safety, Hydro One needs to replace much of this aging transmission stations equipment in poor condition.

Consequences for Customers

In terms of timing, Hydro One has some flexibility in how quickly to replace this aging and deteriorating infrastructure. Hydro One must decide how much of this equipment to replace during the 2023-2027 period, and how much to push further into the future.

- **Reliability considerations**: Most transformer stations are built with backup in place, so that a failing transformer does not cause an outage for customers. However, a transformer failure, when there is no backup in place, can leave thousands of customers without power for weeks or months. Depending on its size and location, a transformer replacement takes 6 months on average, but may take 12-18 months if spare parts need to be ordered.
- **Safety considerations**: If a transformer fails, it can cause a fire in the transmission station, which poses environmental and safety risks for customers in the area.
- **Cost considerations**: If Hydro One defers investments in transmission stations equipment, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to address high-risk elements of the transmission stations infrastructure that could pose a risk to the system and the public. The goal is to maintain the overall reliability and safety of the system.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $2.25 billion to replace aging and deteriorating transmission stations.

Overview:
2023-2027 Draft Investment Plan
Transmission System

September 2020

Hydro One’s Plan: The Transmission System

Hydro One’s Draft Investment Plan (2023–2027)

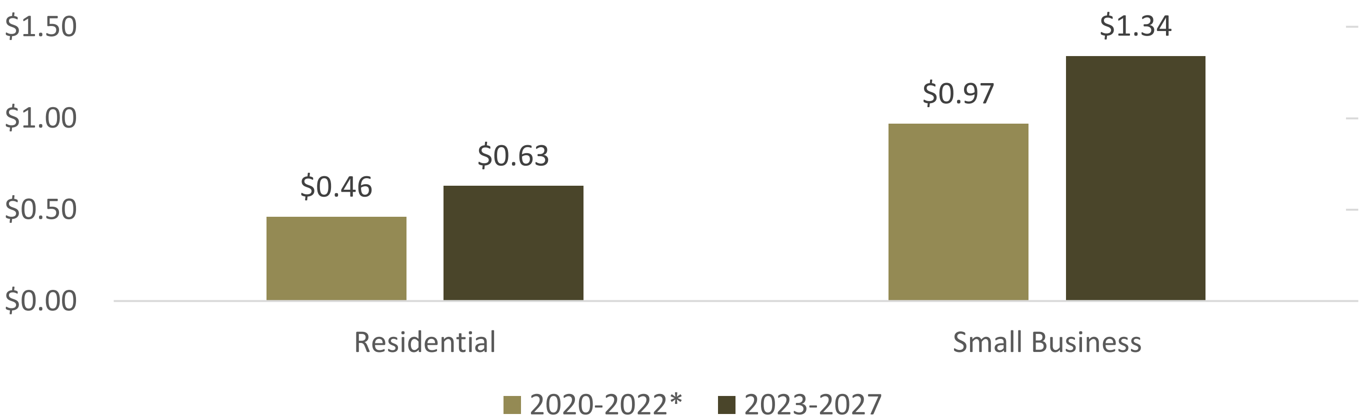
Based on initial customer feedback, information and input from Hydro One’s internal engineering and technical experts, and emerging pressures on the electricity system, Hydro One developed its draft investment plan for the years 2023-2027.

This draft investment plan includes significant capital investments of approximately **$1,562 million per year in the transmission system**. Capital investment costs are shared by more than 5 million electricity customers in Ontario.

If Hydro One continues with its draft investment plan, the **transmission portion of the monthly bill** is estimated to increase by an average of **$0.63 each year** for the period 2023-2027.

The **monthly transmission costs** for small business customers are estimated to increase by an average of **$1.34 each year** for the period 2023-2027.

Average Monthly Bill Increases Each Year



*Hydro One’s rates until December 31, 2022 were approved by the OEB in an earlier application.

Hydro One’s Draft Investment Plan At A Glance

Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	Proposed Approach
Preserve the electricity system for future generations	Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system
Improve system reliability and safety	Replace equipment that poses the biggest reliability and safety risk
Help customers with poor reliability	Invest in new technology to help restore power faster
Enable community growth	Expand the electricity system to facilitate community growth and economic development

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Portions of Hydro One's transmission system date back 50 to 100 years. Hydro One has mainly focused on maintaining this infrastructure, but it will soon be time to replace much of it. Aging equipment eventually deteriorates, increasing the risk of equipment failures. Over the past five years, failing equipment has been the biggest contributor to transmission system outages.

Currently, transmission system reliability remains high, but even backup lines are aging and may not always be able to take the load needed. In the long run, reliability is likely to go down if equipment is not replaced.

There are investments that Hydro One can make to ensure the continued high reliability of the transmission system. While these investments reduce the risk of equipment failure, they add to the costs of the system.

Transmission: Making Choices (1 of 2)

Replacing Transmission Lines in Poor Condition

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Consequences for customers

Hydro One needs to decide how much of the lines equipment in poor condition to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: As most of the transmission system is built with backup lines, a failure does not necessarily lead to an outage for customers. However, as more lines are deteriorating, it is not guaranteed that a back-up line is always available to carry the load when a line fails. Planned replacements avoid outages in most cases and make the system more resilient to extreme weather, as deteriorating equipment is replaced with newer standards and technology.
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In its draft investment plan for 2023-2027, Hydro One proposes to replace equipment in poor condition that poses a particular risk to the system and the public. The goal is to maintain the overall reliability of the system and avoid increasing interruptions and safety risk caused by failing equipment. This approach includes targeting single supply radial lines, which are responsible for most interruptions.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $3.85 billion to replace transmission lines in poor condition.

Transmission: Making Choices (2 of 2)

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Hydro One's transmission infrastructure is aging, and close to 25% of transformers (167 units) are currently in poor condition, with additional transformers expected to degrade into poor condition over the next seven years. This equipment is critical to safely and reliably transmit power from large generators to over 5 million end-use customers across Ontario. To maintain the current level of reliability and safety, Hydro One needs to replace much of this aging transmission stations equipment in poor condition.

Consequences for Customers

In terms of timing, Hydro One has some flexibility in how quickly to replace this aging and deteriorating infrastructure. Hydro One must decide how much of this equipment to replace during the 2023-2027 period, and how much to push further into the future.

- **Reliability considerations**: Most transformer stations are built with backup in place, so that a failing transformer does not cause an outage for customers. However, a transformer failure, when there is no backup in place, can leave thousands of customers without power for weeks or months. Depending on its size and location, a transformer replacement takes 6 months on average, but may take 12-18 months if spare parts need to be ordered.
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In its draft plan, Hydro One is proposing to address high-risk elements of the transmission stations infrastructure that could pose a risk to the system and the public. The goal is to maintain the overall reliability and safety of the system.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $2.25 billion to replace aging and deteriorating transmission stations.

Hydro One's Joint Rate Application

Stakeholder Engagement Report (Phase II)

December 2020

Prepared for:

Torys LLP and Hydro One Inc.

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Phase II:
Stakeholder Engagement

December 2020

Confidentiality

This report and all of the information and data contained within may not be released, shared, or otherwise disclosed to any other party, without the prior, written consent of Torys LLP (Torys) or Hydro One Inc. (Hydro One).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Torys on behalf of its client Hydro One, in connection with Hydro One's joint rate application. The conclusions drawn and opinions expressed are those of the authors.

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Methodology

Innovative Research Group Inc. (INNOVATIVE) was engaged to help design, execute and document the results of Hydro One's customer engagement, as part of Hydro One Inc.'s (Hydro One or HONI) Joint Rate Application (JRAP) to the Ontario Energy Board (OEB) for the years 2023 to 2027.

As part of this engagement, Hydro One sought broad input from its stakeholders on its 2023-2027 Draft Investment Plan through focused in-depth interviews. Hydro One sent an email to 25 of its various stakeholders, inviting representatives to schedule an interview with INNOVATIVE to share the views of their organizations and/or members. These interviews were conducted to supplement the findings of Hydro One's direct engagement with customers.

In the fall of 2020, INNOVATIVE conducted 10 interviews with stakeholders from across Ontario via Zoom teleconferencing or telephone call. INNOVATIVE also received a written response from a stakeholder unable to participate in an interview session (see **Appendix 1**). Participating stakeholders represented the following organizations:

Association of Major Power Consumers in Ontario	Ontario Waterpower Association
Association of Power Producers of Ontario	Prospectors & Developers Association of Canada
Christian Farmers Federation of Ontario	Tourism Industry Association of Ontario
Consumers Council of Canada	United Way Bruce Grey
Ontario Chamber of Commerce	United Way Eastern Ontario
Ontario Forest Industries Association	

A package outlining Hydro One's draft investment plan was shared with all stakeholder representatives (see **Appendix 2**).

About this Report

The interviews were conducted by a trained moderator and followed a semi-structured discussion guide. 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 strategic direction only. 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.

Key Findings

Stakeholders support the objectives of Hydro One's draft investment plan.

All four overall investment objectives—*preserve the electricity system for future generations*, *improve system reliability and safety*, *help customers with poor reliability*, and *enable community growth*—received broad support by the stakeholders interviewed for this report. Overall, stakeholders understand the need for investments in the system. For stakeholders representing business interests, the third objective (*help customers with poor reliability)* was most closely aligned with their members' priorities. The need for reliability improvements was primarily discussed in the context of getting reliable power in more remote areas. Several stakeholders added that agricultural and industrial growth could be given more importance in the plan.

Ensuring reliable and affordable service is a key concern for stakeholders.

Receiving consistently reliable electricity service was considered a must by all stakeholders. Manufacturing businesses and generators noted that they rely on reliable service to operate effectively and have a competitive edge over others. At the same time, most stakeholders also noted the need for electricity to be affordable for businesses in Ontario to remain competitive with companies in other jurisdictions. Fairness in pricing, incentivized rates for major hydro users, and competitive rates across regional borders were emphasized by several stakeholders.

Affordability of electricity is also an issue for residential customers. Especially Ontarians on low and fixed incomes struggle to pay their electricity bills. More targeted relief programs were proposed to help those falling behind.

Stakeholders expect new, alternative energy options to be incorporated in future planning.

Most of the interviews also covered the future of the electricity system, including anticipated opportunities and challenges. There was an expectation among the stakeholders that Hydro One should be a leader when it comes to innovation and enabling new solutions. Specifically, some stakeholders expressed the wish for Hydro One to provide new, alternative energy options in the future to help businesses in remote regions that are currently still reliant on diesel generators.

Stakeholders want to have a more active partnership with Hydro One.

Stakeholders report an overall positive relationship with Hydro One. Several representatives would like to see more frequent communication with Hydro One–particularly with regards to how their draft investment plan and other future plans would affect their organization.

Hydro One is expected to be transparent and accountable.

Several stakeholders emphasized that one of their key expectations of Hydro One was for the utility to be transparent and accountable. Besides transparency on rates, there was also an expectation of Hydro One to proactively report on their performance, and to show how they had incorporated previous customer and stakeholder feedback in their business plan.

Hydro One's Draft Investment Plan

Feedback on Plan Objectives

All representatives broadly agreed with the priorities outlined in Hydro One's draft investment plan. Depending on the types of customers they represented, they stressed the importance of one objective over another. Some interviewees were looking for additional details and more explicit information on how some of the specific goals outlined in the draft investment plan would be achieved.

> *"They're all pretty important. I can understand where they've come from, especially the modernization and the upkeep question are key."*
>
> *"I would say that, generally speaking, the overview is pretty good. It's hard to argue with its basic objectives."*
>
> *"I have no difficulty with any of those. Those seem like appropriate objectives."*
>
> *"…But what would that new technology be like? … it'd be really nice to know some further details."*

Objective 1: Preserve the electricity system for future generations

All interviewees saw the need for investments in aging and deteriorating infrastructure. There was widespread agreement among the organizations that the preservation of the electrical system for future generations was a key objective.

> *"They're the steps that need to happen to kind of keep the business viable, and again, preserve the grid for future generations as stated."*
>
> *"I think everything I've talked about in terms of climate change, resiliency and so forth, that would fall into one of those buckets probably. I'd say it'll probably be subsumed into either 'preserving the system for future generations' or 'responsive to communities.'"*
>
> *"They have a responsibility to ensure that they are both profitable, but as well growing in their capabilities to deliver that infrastructure."*

Objective 2: Improve system reliability and safety

The importance of improving system reliability was emphasized by participants representing businesses across Ontario. For generators and manufacturing businesses, having a consistently reliable supply of electricity was considered a must to operate efficiently.

One representative stressed that having reliable and consistent service is of paramount importance for the day-to-day production, and that power interruptions can have serious negative consequences for businesses.

> *"It is a just a huge part of … production. We need consistency in the delivery."*

Another representative brought up the negative effects of stray voltage on some rural farms in Ontario. Addressing this issue was considered a top priority for this organization. Since this issue originates from the electrical system, the organization expressed the hope that Hydro One would commit to simultaneously dealing with this issue as they are replacing aging infrastructures around the province–even though this would add to the overall cost of system upgrades.

> *"We would hope that when they replace the aging infrastructure, or replace equipment that poses the biggest reliability and safety risks, that they would add something in there to resolve the stray current or stray voltage challenge that we have in some rural areas of the province."*

Objective 3: Help customers with poor reliability

All stakeholders interviewed for this report agreed with this priority. Many were quick to note that the level of reliability is highly dependent on geographical location. While those in higher density areas tend to have good reliability, customers in more remote locations often experience poor or very poor reliability. This is a comment they would frequently hear from their members.

Two organizations specifically noted the lack of infrastructure in place in the northern part of the province, and how there are considerable costs associated with being disconnected from infrastructure by anything more than a few kilometers.

> *"…the amount of connectivity and energy connectivity in the northern part of the province is very minimal for industry to be able to connect to, so I think that's probably one of the biggest discrepancies we see as industry: the lack of infrastructure in [the] northern part of the province."*

> *"They're responsible for certain amounts of infrastructure across the province. And in being able to support our member companies' business in a reliable and affordable way is kind of the expectation that we would have."*

Several respondents furthermore mentioned that they expect Hydro One to provide new, alternative energy options in the future. Some pointed out that clients operating in remote regions who do not have access to Hydro One energy are currently reliant on diesel generators, which comes with emissions. Since the industry is looking to reduce their overall environmental footprint, this reliance on diesel power is a costly impediment to these companies.

> *"The industry has been caught between a rock and a hard place of having to…maintain operations, but doing so without options for access to energy, and in an environment of being told that they need to reduce emissions and reduce the overall amount of petroleum being used for fuels being used on site."*

> *"We've got some pretty significant directives from government, saying 'you need to get to net zero by 2050. Those will be legislated next week.' And all those things come with costs. So, I can understand, you're going to have to do rate hikes; you're going to have to get pretty creative in being able to create the capital to do that."*

> *"…identification of what gaps or extra steps may be necessary to integrate new energy options with current infrastructure."*

> *"I don't hear much about innovation in there beyond maintaining the current system. So arguably, there's maybe a lack of innovative foresight in what new technologies should be brought in to play?"*

One stakeholder mentioned being encouraged by Ontario's general support of small modular reactors as a low-carbon energy alternative but noted that Hydro One would have to be a significant player in this strategic plan going forward.

"Given that there needs to be good integration with any new developments with respect to power generation in Ontario and Hydro infrastructure, they would need to be a critical player in any strategic planning that's undertaken by the province or the federal government."

Objective 4: Enable community growth

Participants representing businesses in Ontario felt the draft investment plan should provide greater emphasis on economic growth and industrial development. They wanted to see more initiatives to help businesses strive and remain competitive.

"I find it interesting that both Economic Development and Community Growth are packaged together. You know, they almost seem to have their own equal importance. And it seems like industrial capacity seems fairly diminished in that statement, or almost a secondary thought."

"I don't see much about supporting a competitive, manufacturing kind of jurisdiction."

"Anything that we would consider from a community growth standpoint should be considering industrial growth, because they should be going hand in hand."

Feedback on Cost Impact of Plan

The cost of electricity in Ontario was a topic that was raised in every interview. Some stakeholders representing residential customers described that they saw higher numbers of clients who are struggling to pay their bills due to income loss because of the COVID-19 pandemic. Those stakeholders expressed concern that for customers with low and fixed incomes, cost increases are expected to be a challenge. However, slow and steady increases were considered a lot more manageable than larger and unpredictable increases.

One stakeholder representing vulnerable Ontarians noted that because of Hydro One's role and presence in the sector, they ought to exercise some public policy leadership and be more discerning in who they give support to. Rather than providing support to *all* Ontarians, they suggested Hydro One should more actively target those customers who are genuinely struggling. They argued that this approach may even help Hydro One save money in the process.

"We've chosen simplicity of delivery, ease of delivery, over the efforts required to better target. Because it's easier to put up a website and say, 'Please apply here if you've got trouble with your bill,' and just sit back and wait and see what happens."

For business customers, both cost and reliability were top priorities. Sacrificing reliability for lower prices was not considered a viable option, especially for manufacturing businesses. The core issue for businesses regarding prices is one of maintaining competitiveness vis-à-vis companies in other jurisdictions with lower electricity costs. One stakeholder specifically emphasized the importance of incentivized rates for major hydro users in the industrial sector in order to maintain competitiveness across provincial borders.

"Certainly, for all of our members, maintaining costs will be top of mind."

"Is there an opportunity to, you know, lower the price or reduce the cost of production? I think so. But those are all long-term projects. So long as they don't see money being wasted."

"When it comes to industrial development in Ontario, providing those incentivized rates for major users is something that would need to be codified going forward or maintain going forward."

One organization brought up fairness in pricing for price-taking industries. They explained that any increase in hydro cost must be absorbed by the company, as they are not able to adjust the product price to reflect this increase.

> *"We are not a price setter; we are a price taker. So, what that means is that when there's added cost to our production, we cannot add that to our final product. So often our product–the price that we get paid—is set by somebody else, and we cannot influence that. So, when all of a sudden there's an increase in hydro rates, it increases the cost of production, and we cannot recoup that cost.*

Several stakeholders mentioned that their members generally support investments in the electricity system, if these investments provide good value for money. They also expect efficient operations and want Hydro One to demonstrate that they operate and invest in a cost-conscious way.

Other Needs and Expectations

While most interviewees report they are generally satisfied with Hydro One, also they indicate their relationships tend to be limited. Participants indicated they can reach the right contact when they need to get in touch. That said, several participants raised some specific issues.

Some pointed out opportunities for improved communications between their own organization and Hydro One. They were looking for more active communication from Hydro One, while others expected more transparency about Hydro One's future plans.

> *"We'd like to see far more openness and transparency and better engagement with stakeholders."*
>
> *"What resources are available from an industrial standpoint in terms of understanding what this new strategic plan or this new five-year path forward will look like?"*

Besides several stakeholders requiring transparency on rates, one added that they also wanted Hydro One to proactively report on their performance, and to show how they had incorporated previous feedback in their investment plan. It was suggested that these reports could be pushed out to the public by including a link on customers' bills that would take them directly to Hydro One's annual performance reports.

> *"By and large, whether it's hydro or anything else: consistency, transparency and understanding what future rates, future constructs, future contractual agreements may look like."*
>
> *"A lot of stuff you read in annual reports and performance sounds more like propaganda than it is what I call real performance. Because God, wouldn't it be kind of refreshing if Hydro One, not just Hydro One, but others say, 'this is where we fell short, and this is why?' Think about it."*
>
> *"How do you actually demonstrate performance value added to stakeholders, which goes beyond profit, which goes beyond your immediate shareholders, into environmental, social responsibility?"*

The need for collaboration to create the grid of the future was brought up by several representatives. Some suggested pursuing partnerships with other utilities or private companies to achieve further electrification. Others suggested Hydro One should enable more customers to feed electricity back into the grid.

> *"Some of our members also produce electricity back to the grid. Hopefully, we can see that expand as well."*
>
> *"Collaboration is something that I didn't hear here with respect to potentially neighboring regions…collaboration on [the] integration of infrastructure is very important…given the cooperative balance that the system needs to have."*

One interviewee wished for Hydro One to take on more of a leadership role to ensure all its customers are included in Hydro One's plan for a more reliable and capable system. That participant suggested that a more explicit objective should be included in the draft that recognizes the need for collaboration with others to achieve this inclusion.

> *"If there was anything, I would encourage of Hydro One it is … some perspective about inclusion of migrating to this energy future, ensuring that their growth doesn't leave behind too many of their customers or any of their customers. So, there's a sense of inclusion for that."*

Appendices

Appendix 1: Written Submission

a) Tourism Industry Association of Ontario

Appendix 2: Stakeholder Draft Investment Plan Package

Appendix 1

tiao
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Association of Ontario

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Alex Phillips
Senior Manager, Policy and Partnerships
Hydro One Networks Inc
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Ref: Consultation on Hydro One's Preliminary Invesment Plan for 2023 - 2027

Dear Alex,

Thank you for the opportunity to offer comment on Hydro One's preliminary investment plan for 2023-2027.

The Tourism Industry Association of Ontario (TIAO) is the authoritative voice of the tourism industry in Ontario. We represent an industry of over 200,000 businesses and 400,000 jobs. The businesses we represent range from the smallest family run B & B, to internationally renowned attractions spread across the province. Ensuring a reliable and affordable source of electricity is vital to the economic future of our industry and by definition the economic viability of local economies across the province.

At TIAO, we recognize the challenges faced by Hydro One in ensuring the best value for the customer. We understand that prudent investment in infrastructure is vital to ensure the future of the network, and that in turn protects customers from unexpected expenditures because of the failure of an ageing network.

TIAO believes that it is imperative that the essential investments are made to keep the system safe, the power on and at the lowest possible price for the consumer.

We recognize the need to replace key pieces of Ontario's energy infrastructure that in some places is over 100 years old. We welcome and recognize the cost efficiencies that can be realized through the harnessing of new technologies. We believe prudent investments in our infrastructure and energy delivery systems will help the businesses we represent have a reliable and safe access to energy and help support the growth of tourism in every corner of our province.

It is in that spirit that TIAO supports the aims established in the consultation document and we therefore make the following recommendations:

- TIAO supports Hydro One's plans to target investment into the replacement of wooden poles that serve larger communities. However, TIAO asks that Hydro One also reviews and includes commercial enterprises to be included in that program of works.
- TIAO is concerned by the number of power transformers that are classified as being in a poor condition (34%). TIAO supports Hydro One's plan to replace defective transformers before they fail. However, TIAO believes that Hydro One should reflect on the cost benefit of replacing these transformers more urgently by comparing the cost of replacing failed transformers and past

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likelihood of poor condition transformers failing. If the cost of replacing failed transformers far exceeds replacement before failure, TIAO recommends expediating the replacement program.

- TIAO supports plans to modernize the grid to improve reliability by harnessing technological advances. TIAO strongly welcomes the proposed $200 million investment in smart devices.
- TIAO welcomes the decision to run limited pilot studies on battery energy storage solutions and a report into their performance at a later date.
- TIAO supports Hydro One's intention to replace infrastructure that can no longer facilitate expected increases in demand. TIAO believes it is imperative that Hydro One is proactive in this monitoring process and ensures that no community is left behind by an anticipated increase in demand.
- TIAO welcomes Hydro One's ambitious plans to replace all smart meters over a seven-year period. TIAO notes the alternative to replace all metres over a five-year period and recommends the program is built in such a way that if labour and technological costs reduce, the plan can be adapted and completed in five years.
- TIAO supports Hydro One's plan to replace all transmission lines that are currently in a poor condition.
- TIAO believes that replacing deteriorating transmission stations should be a high priority for Hydro One and supports plans in the draft strategy to ensure safety and security of the system and the public. TIAO believes that the long-term implications on supply and health and safety dangers must be properly addressed. TIAO believes that customers would expect technical experts should be given proper authority to make these decisions free of interference.

Thank you for the opportunity to present our feedback at this stage. We look forward to the next phase of the process and revisiting the revised parts of the investment plan.

Yours sincerely,

Beth

Beth Potter
President and CEO
Tourism Industry Association of Ontario

Overview:
2023-2027 Draft Investment Plan

Distribution and Transmission Systems

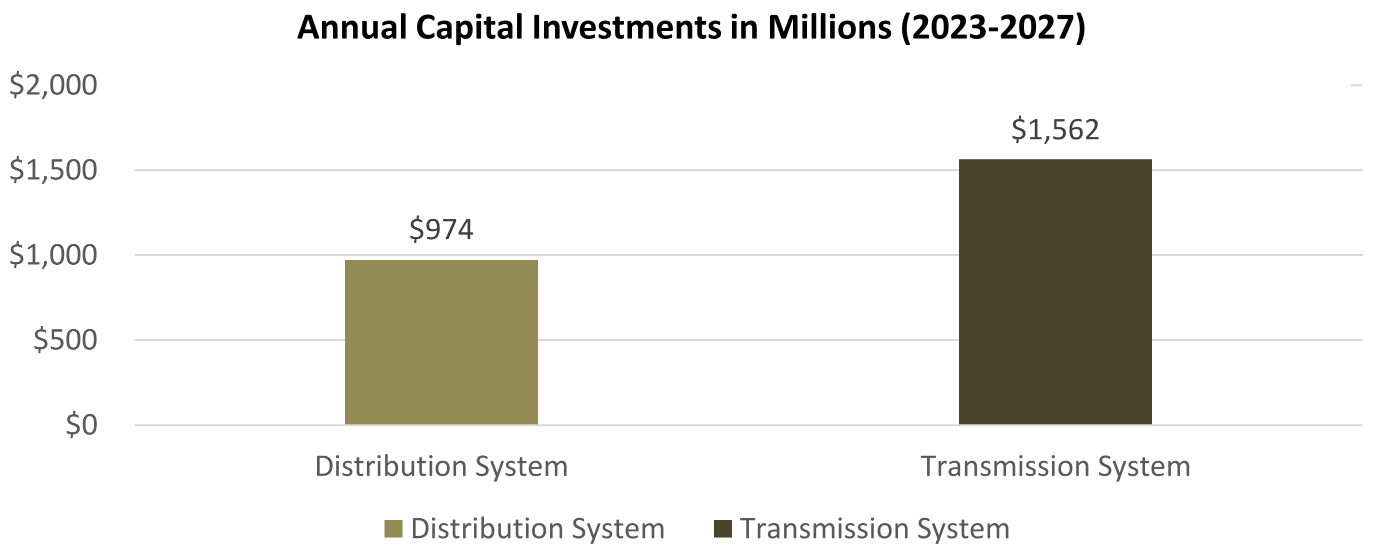
September 2020

Hydro One's Plans: Distribution and Transmission

Hydro One's Draft Investment Plan (2023–2027)

Based on initial customer feedback, information and input from Hydro One's internal engineering and technical experts, and emerging pressures on the electricity system, Hydro One developed its draft investment plan for the years 2023-2027.

This draft investment plan includes significant capital investments in both the distribution and transmission systems. The costs for **distribution system** investments are spread among all of Hydro One's 1.4 million distribution customers. For the **transmission system**, capital investment costs are shared by more than 5 million electricity customers in Ontario.



Hydro One's Draft Investment Plan At A Glance

Hydro One has developed a draft plan that is responsive to the needs and preferences of its customers. It also responds to challenges and pressures caused by aging and deteriorating infrastructure, the occurrence of extreme weather events, community growth across the province, and evolving regulatory requirements. Below are some of the highlights of this draft plan.

Objectives of the Plan	Proposed Approach
Preserve the electricity system for future generations	Replace aging infrastructure in poor condition to maintain the overall health and condition of the electricity system
Improve system reliability and safety	Replace equipment that poses the biggest reliability and safety risk
Help customers with poor reliability	Invest in new technology to help restore power faster
Enable community growth	Expand the electricity system to facilitate community growth and economic development

Hydro One's Distribution System: Background

Distribution System Reliability

The Make Up of Hydro One's Distribution System

Hydro One's distribution system serves about 1.4 million customers and covers about 75% of the geographic area of Ontario. A large proportion of Hydro One's distribution infrastructure is aging and is now 50 to 70 years old.

Since most of its customers live in rural areas, Hydro One's distribution system looks different than others in Ontario. Servicing more sparsely populated communities means that more equipment (e.g. wooden poles, transformers and wires) is needed to serve the same number of customers.

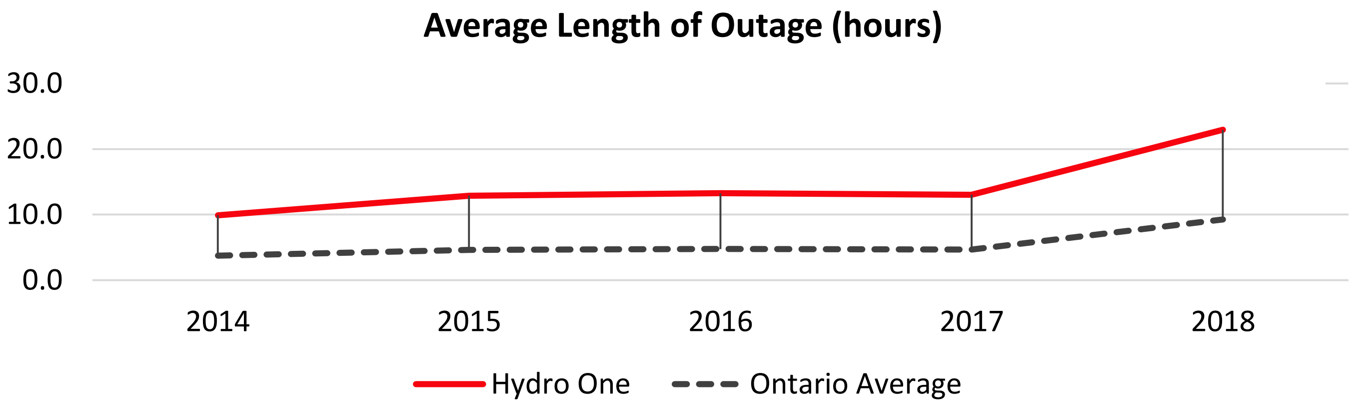
Many rural communities are connected through long lines with only one power source. If there is a disruption of power due to an equipment failure, fallen tree, or other cause, then customers further down the line experience a power interruption. Power can only be restored when the source of the outage is found and repaired.

How Does Hydro One's Distribution System Reliability Compare to Others?

Hydro One tracks both the average number of power outages per customer and how long those outages last. The average Hydro One customer experiences more frequent and longer outages than the average Ontarian.

On average, between 2014 and 2018, the typical Hydro One customer experienced 1.5 more outages per year compared to the Ontario average.

When it comes to total time spent without electricity each year, the typical Hydro One customer, since 2014, has been without power for 14.4 hours each year. That is 9 hours more than the Ontario average.



There are investments that Hydro One can make to improve reliability. While these investments are likely to reduce the length of outages, they add to the costs of the system. Different types of investments to improve reliability are presented on the following pages.

Many of the investments included in the draft plan will help Hydro One to move closer to the Ontario average. With the accelerated option, Hydro One will get there faster, while the slower option includes fewer investments to close this gap but keeps rates lower in the short term.

Distribution: Making Choices (1 of 6)

Replacing Poles in Poor Condition

Hydro One owns and maintains about 1.6 million wood poles. Some of these poles serve single households, while others supply electricity to over 5,000 customers.

The majority of Hydro One's poles are currently in good condition. However, **a significant number of wood poles (approximately 124,000) are expected to be in poor condition by the end of 2027 unless they are replaced**. These poles are more likely to fail and cause unplanned outages for customers served by these lines, and they have to be replaced at some point.

Consequences for Customers

For the current investment plan, Hydro One's planners need to decide how many poles to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If a pole fails, customers served by this pole experience an outage that lasts an average of 9 hours. A planned pole replacement doesn't necessarily lead to an outage, but if an interruption occurs, it lasts an average of 2 hours.
- **Cost considerations**: If Hydro One defers investments in poles, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to replace poles at a pace that would maintain the overall health of the system and reduce the likelihood of long outages caused by pole failures. The proposed approach prioritizes poles that serve a larger number of customers.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $650 million to replace poles in poor condition.

Distribution: Making Choices (2 of 6)

Replacing Power Transformers in Poor Condition

Hydro One owns close to 1,200 power transformers that are used to step down the voltage supplied by high-voltage lines before the electricity is distributed to households and businesses.

While the majority of these transformers are currently in good (38%) or fair (28%) working condition, Hydro One expects that **about 600 transformers will deteriorate into poor condition by the end of 2027** if they are not replaced.

Most transformers in poor condition don't require immediate replacement, but they can deteriorate quickly, at which point they must be replaced. Hydro One regularly monitors their condition with the goal to replace deteriorating transformers before they fail.

Consequences for Customers

Hydro One needs to determine how many transformer replacements to plan for in the 2023—2027 period, and how many replacements can be pushed further into the future.

- **Reliability considerations**: If Hydro One can replace a transformer before it fails, the customers served by it experience a short outage that usually lasts a few minutes. However, if a transformer fails and needs to be replaced on an unplanned basis, customers served by the station lose power for an average of 12 hours.
- **Cost considerations:** If Hydro One defers investments in transformers, the short-term costs for customers are lower. However, pushing more replacements into the future means more uncertain costs and likely steeper cost increases in the future.

In its draft investment plan, Hydro One proposes to continue its current pace of planned transformer replacements. Alternatively, it could increase the number of planned replacements or reduce them.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to replace power transformers in poor condition.

Distribution: Making Choices (3 of 6)

Improving Reliability Through Grid Modernization

Hydro One's service territory includes challenging terrain and old infrastructure, making it prone to outages. In the past, there were few cost-effective investments Hydro One could make to significantly improve reliability and bring it closer to the Ontario average.

Technology has advanced in recent years, offering solutions that would allow Hydro One to detect, repair and restore power more quickly than in the past. This would reduce the length of time customers are without power, as Hydro One crews would be able to locate the problem and restore power faster. In some cases, Hydro One would also be able to remotely restore power.

Parts of Hydro One's distribution system are already equipped with these technologies. However, compared to other large distributors in Ontario, Hydro One's system has less.

In its draft plan, Hydro One is proposing to install smart devices to help restore power more quickly. Hydro One would target these investments at lines that have historically had high interruptions affecting a large number of customers. Hydro One's planners estimate that **these investments would lead to a 40% average reduction in the duration of power outages per year** for customers served by the lines addressed in this plan.

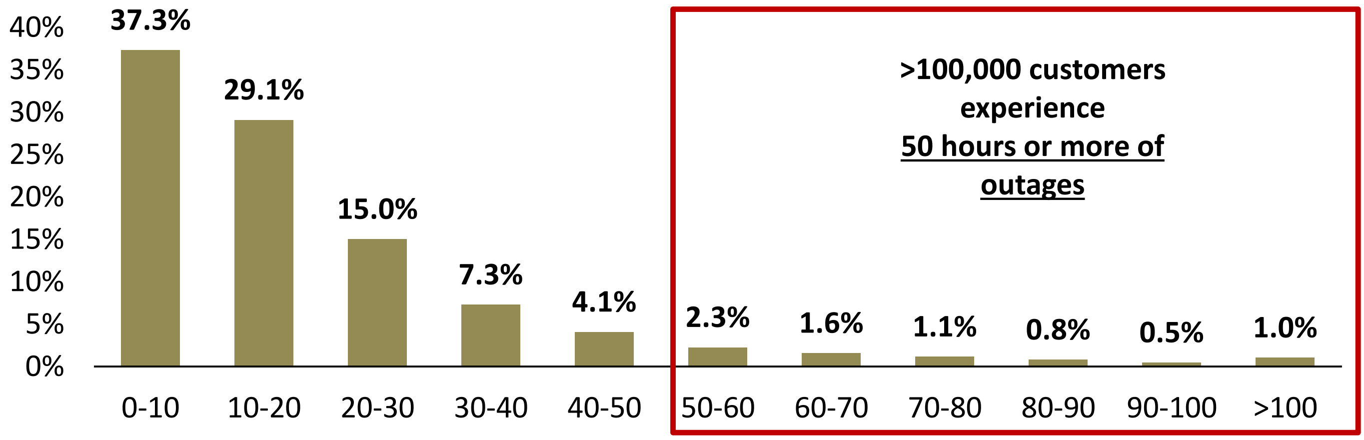
Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $200 million to improve reliability through grid modernization.

Distribution: Making Choices (4 of 6)

Battery Energy Storage Solutions

Outage experiences vary across Hydro One's service territory, and some customers experience more or longer outages than others. While some Hydro One customers didn't experience any outages between 2017 and 2019, over 100,000 customers were without power for more than 50 hours per year. Some communities experienced up to 150 hours of outages.

Customer Outage Experience in Hours/Year (2017-2019)



Recent advancements in technology and battery systems have provided better options to help these customers. These batteries store electricity and automatically provide backup if a power line experiences an interruption. Hydro One is currently testing some of these solutions in pilot projects, including:

- Centralized battery storage stations that serve a whole community
- Battery storage units that serves as a backup for a small group of customers
- Single-household battery storage installed within a customer's home (*pending OEB approval*)

In 2023-2027, Hydro One is planning a larger roll-out of these energy storage solutions that would improve reliability for customers experiencing about 50 hours of interruptions per year or more. Hydro One's planners estimate that these investments would lead to a **60% to 80% average reduction in the duration of power outages** per year for customers served by battery systems.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $150 million to improve reliability through battery energy storage solutions.

Distribution: Making Choices (5 of 6)

Facilitating Growth

Communities are growing across Ontario. When communities grow by attracting new residents or businesses, the local demand for electricity increases, which sometimes results in the need for infrastructure upgrades to build additional system capacity.

Hydro One is required to plan and build its system to provide a safe and reliable supply of energy to all its customers and accommodate load growth. However, Hydro One has some choice over the pacing of these investments.

Hydro One plans infrastructure upgrades to meet both short-term and long-term electricity demand. These plans are adjusted annually in response to the actual demand and are adapted if unexpected events occur.

In its draft plan, Hydro One is proposing to upgrade infrastructure to supply increased forecast electrical demand when equipment approaches its planning limit. This would allow new economic development to proceed as planned and maintain reliability and power quality for existing and new customers. It would also generate revenue for Hydro One that helps offset the costs of building the infrastructure.

Hydro One could also take a more **proactive approach** by upgrading infrastructure *before* equipment planning limits are reached to support regional and economic development in communities looking to grow.

Alternatively, Hydro One could take a more **reactive approach** and upgrade infrastructure *after* equipment is at or exceeding its planning limit.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $400 million to facilitate growth in Ontario.

Distribution: Making Choices (6 of 6)

Replacing Smart Meters

Hydro One is legally mandated to install smart meters, which are a critical component of the infrastructure needed to measure electricity consumption and bill customers accurately.

Between 2009 and 2013, Hydro One installed 1.3 million smart meters. In 2023, many of these meters will begin to surpass the 15-year service life. Hydro One has already started seeing meters failing at an increasing rate.

When a meter fails, it must be replaced, otherwise bills are based on estimates rather than actual consumption, and a Hydro One employee must travel out to the meter every so often to get an accurate read, which is time consuming and costly.

Currently, failing meters are replaced with a similar old technology meter. However, technological advancements have brought prices down, and meter prices on new systems tend to be lower than the current prices. Also, labour costs can be reduced by replacing groups of meters rather than one by one.

Hydro One, therefore, plans to begin replacing the old system in 2023. The new smart metering system has an expected service life of 20 years, and Hydro One will go through a competitive procurement process to select a vendor and purchase a smart metering system at the best price for customers.

While the current smart metering system must be replaced, Hydro One has some choice over how quickly or slowly it replaces the old metering system.

In its draft plan, Hydro One proposes to **spread the meter replacements and associated costs over a 7-year period** (between 2023 and 2029). Alternatively, Hydro One could **speed up** the replacement process and replace all meters over a 5-year period (between 2023 and 2027).

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $550 million to replace the old smart meter system.

Hydro One's Transmission System: Background

Transmission System Reliability

Hydro One's transmission system is the backbone of Ontario's electricity system. Its high voltage transmission lines serve as highways for electricity, transporting power from generation stations like Darlington and Niagara Falls to the distribution network in your community. About 30,000 km of transmission lines and 300 transmission stations ensure that the power flows across Ontario.

Most of Hydro One's transmission system has been built with multiple sources of supply (backup capabilities). This is why outages due to transmission system failures are less frequent than distribution related outages. However, a **transmission system failure can leave thousands without power for days**, as was the case when a severe thunderstorm occurred in the Ottawa region in September 2018, which caused significant damage and impacted over 500,000 Hydro One customers.

How Does Hydro One's Transmission System Reliability Compare to Others?

Hydro One tracks both the average number and duration of interruptions per delivery point—that is the point where power is being transferred from the transmission system to a local distribution system or a transmission connected customer. The average Hydro One delivery point experiences less frequent and shorter interruptions as compared to other utilities in Canada.

Between 2014 and 2018, the typical Hydro One delivery point experienced about 60% fewer interruptions per year than the Canadian average. When it comes to the duration, the typical Hydro One delivery point has been interrupted for 55 minutes each year since 2014—about 38 minutes less than the Canadian average.

Aging and Deteriorating Transmission Infrastructure

Portions of Hydro One's transmission system date back 50 to 100 years. Hydro One has mainly focused on maintaining this infrastructure, but it will soon be time to replace much of it. Aging equipment eventually deteriorates, increasing the risk of equipment failures. Over the past five years, failing equipment has been the biggest contributor to transmission system outages.

Currently, transmission system reliability remains high, but even backup lines are aging and may not always be able to take the load needed. In the long run, reliability is likely to go down if equipment is not replaced.

There are investments that Hydro One can make to ensure the continued high reliability of the transmission system. While these investments reduce the risk of equipment failure, they add to the costs of the system.

Transmission: Making Choices (1 of 2)

Replacing Transmission Lines in Poor Condition

According to an independent review**, 4,000 km (14%) of overhead conductors are currently in poor condition**. This overhead lines equipment is critical to the safe and reliable transmission of power from large generators to end-use customers. To ensure continued safe and reliable transmission service across Ontario, Hydro One needs to replace much of this aging lines equipment in poor condition.

Consequences for customers

Hydro One needs to decide how much of the lines equipment in poor condition to replace between 2023 and 2027, and how many replacements can be pushed further into the future.

- **Reliability considerations**: As most of the transmission system is built with backup lines, a failure does not necessarily lead to an outage for customers. However, as more lines are deteriorating, it is not guaranteed that a back-up line is always available to carry the load when a line fails. Planned replacements avoid outages in most cases and make the system more resilient to extreme weather, as deteriorating equipment is replaced with newer standards and technology.
- **Safety considerations**: Deteriorating transmission lines pose a safety risk. A broken and dropped conductor will result in an outage to the circuit and endangers all in proximity of its fall. In some cases a broken conductor can remain energized, which presents an added danger of electrocution and fire hazard to its surroundings.
- **Cost considerations**: If Hydro One defers investments in transmission lines equipment, the short-term costs for customers are lower. However, deferring investments further into the future means less cost certainty in the longer run, and likely steeper rate increases in the future.

In its draft investment plan for 2023-2027, Hydro One proposes to replace equipment in poor condition that poses a particular risk to the system and the public. The goal is to maintain the overall reliability of the system and avoid increasing interruptions and safety risk caused by failing equipment. This approach includes targeting single supply radial lines, which are responsible for most interruptions.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $3.85 billion to replace transmission lines in poor condition.

Transmission: Making Choices (2 of 2)

Replacing Aging and Deteriorating Transmission Stations

Hydro One's transmission infrastructure is aging, and close to 25% of transformers (167 units) are currently in poor condition, with additional transformers expected to degrade into poor condition over the next seven years. This equipment is critical to safely and reliably transmit power from large generators to over 5 million end-use customers across Ontario. To maintain the current level of reliability and safety, Hydro One needs to replace much of this aging transmission stations equipment in poor condition.

Consequences for Customers

In terms of timing, Hydro One has some flexibility in how quickly to replace this aging and deteriorating infrastructure. Hydro One must decide how much of this equipment to replace during the 2023-2027 period, and how much to push further into the future.

- **Reliability considerations**: Most transformer stations are built with backup in place, so that a failing transformer does not cause an outage for customers. However, a transformer failure, when there is no backup in place, can leave thousands of customers without power for weeks or months. Depending on its size and location, a transformer replacement takes 6 months on average, but may take 12-18 months if spare parts need to be ordered.
- **Safety considerations**: If a transformer fails, it can cause a fire in the transmission station, which poses environmental and safety risks for customers in the area.
- **Cost considerations**: If Hydro One defers investments in transmission stations equipment, the short-term costs for customers are lower. However, pushing replacements into the future also means less cost certainty in the long run, and likely steeper increases in the future.

In its draft plan, Hydro One is proposing to address high-risk elements of the transmission stations infrastructure that could pose a risk to the system and the public. The goal is to maintain the overall reliability and safety of the system.

Over the 2023-2027 period, Hydro One's draft plan includes capital investments of approximately $2.25 billion to replace aging and deteriorating transmission stations.

Customer Engagement Planning Placemat (Phase II)

Dx Investment Trade-Offs

	Residential	Small Business	Commercial & Industrial	Large Dx Accounts	First Nations (on-reserve)
Replacing Poles in Poor Condition					
Across all customer segments, there is strong support for the draft plan.					
Accelerated Pace	43%	39%	22%	22%	38%
The Draft Plan	43%	45%	61%	67%	41%
Slower Pace	14%	15%	17%	11%	21%
Replacing Power Transformers in Poor Condition					
Residential customers tend to favour an accelerated pace, while business customers overall lean towards the draft plan.					
Accelerated Pace	48%	44%	34%	17%	41%
The Draft Plan	41%	44%	54%	78%	43%
Slower Pace	11%	11%	12%	6%	16%
Improving Reliability Through Grid Modernization					
On balance, the accelerated pace is the preferred option across customer segments.					
Accelerated Pace	47%	42%	40%	39%	40%
The Draft Plan	36%	39%	41%	28%	42%
Slower Pace	16%	19%	19%	33%	18%
Battery Energy Storage Solutions					
Customers support investments in battery energy storage solutions at the level proposed in the draft plan.					
Accelerated Pace	35%	29%	16%	6%	34%
The Draft Plan	47%	49%	57%	50%	48%
Slower Pace	19%	21%	27%	44%	17%
Facilitating Growth					
A majority of customers across all segments prefers the draft plan over an accelerated or slower pace.					
Accelerated Pace	29%	28%	21%	17%	33%
The Draft Plan	56%	57%	64%	67%	51%
Slower Pace	15%	14%	15%	17%	16%
Replacing Smart Meters					
Residential and small business customers have a clear preference for the draft plan.					
Accelerated Pace	36%	29%	--	--	40%
The Draft Plan	64%	71%	--	--	60%

November 2020

INNOVATIVE RESEARCH GROUP

Customer Engagement Planning Placemat (Phase II)

Tx Investment Trade-Offs

Replacing Transmission Lines in Poor Condition

Residential customers tend to favour an accelerated pace, while the draft plan is the preferred option among business customers.

	Residential	Small Business	Commercial & Industrial	Large Dx Accounts	Large Tx Accounts	First Nations
Accelerated Pace	44%	42%	30%	28%	27%	40%
The Draft Plan	41%	43%	57%	61%	67%	46%
Slower Pace	15%	15%	13%	11%	6%	15%

Replacing Aging and Deteriorating Transmission Stations

Customers support investments in transmission stations at the level included in the draft plan.

	Residential	Small Business	Commercial & Industrial	Large Dx Accounts	Large Tx Accounts	First Nations
Accelerated Pace	42%	40%	27%	6%	31%	34%
The Draft Plan	45%	46%	60%	94%	59%	52%
Slower Pace	14%	14%	13%	0%	10%	13%

Support for Hydro One's Draft Investment Plan

Supported Bill Impact and Investment Level

Customers support investments at or above the level of Hydro One's draft plan and are willing to accept bill increases in return.

	Residential	Small Business	Commercial & Industrial	Large Dx Accounts	Large Tx Accounts	First Nations
Increase Above Draft Plan	49%	44%	32%	28%	18%	40%
Increase of Draft Plan	29%	28%	31%	28%	59%	33%
Increase Below Draft Plan	12%	17%	19%	11%	8%	13%
Other	4%	5%	6%	22%	14%	3%
Don't know	5%	6%	12%	11%	2%	11%

Methodology: Hydro One's Online Workbook (Phase II)

The main mode used to gather customer feedback was an online workbook. The first part of the workbook was designed to provide information about Hydro One's role in the electricity system and the draft investment plan. The second part asked customers to provide their feedback on the draft plan as well as specific investment trade-offs, covering both distribution and transmission systems.

All Hydro One customers were invited to complete the online workbook, which was customized for different customer types. Separate versions were created for Hydro One residential (primary and seasonal), small business (GS<50 kW), C&I, LDA, and on-reserve residential First Nations customers. LTX customers, as well as Ontario residential and small business rate payers that are outside of Hydro One's distribution network received a version that only included transmission-related questions. The Tx residential and small business samples combine customers who receive their electricity bill from Hydro One and rate payers who are served by other LDCs and are weighted to be representative of Hydro One's transmission territory.

Interpreting the Results

To ensure that these findings are representative of Hydro One's broader customer base, INNOVATIVE conducted a rigorous sample validation process during Phase I. This process included comparing the online sample to the broader customer base on known variables, such as region and usage (where available). The results for LDA customers should be interpreted with some caution, given the small sample size (n=18).

Customer Segment	Dx Sample Size	Tx Sample Size
Residential	N=35,000	N=2,500
Small business	N=1,000	N=800
C&I	N=200	N=200
LDA	N=18	N=18
LTX	--	N=51
First Nations residential customers (on-reserve)	N=261	N=261

INNOVATIVE RESEARCH GROUP

2023-2027 Customer Engagement COVID Pulse-Check Survey (Residential and Small Business)

June 2020

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R&SB Customers

Methodology

Introduction
Customer Engagement Methodology

Hydro One's 2023-2027 Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Hydro One Inc. (Hydro One) to assist in meeting Hydro One's customer engagement commitments under the *Renewed Regulatory Framework for Electricity Distributors*. The information contained within this report was obtained through an online survey among Hydro One's low volume distribution customers in June 2020. Tracking numbers come from the online workbook completed by the same customer types during Phase I of the customer engagement.

Phase I (September 2019 – February 2020)

Hydro One is developing its joint rate application for the period covering the years 2023 to 2027, including both a consolidated Distribution System Plan and Transmission System Plan. Between September 2019 and February 2020, INNOVATIVE (on behalf of Hydro One) reached out to a range of Hydro One customers to identify customer needs and outcomes valued by customers.

Both distribution and transmission connected customers were invited to provide their feedback. 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. Ontario ratepayers outside of Hydro One's distribution network were only presented with transmission related questions.

The goal of this first phase was to obtain feedback from a representative sample of customers and assess their needs and outcome preferences. Only a random sub-sample of customers was invited to participate in this phase. All customers will have the opportunity to participate in Phase II.

"Pulse-Check" Online Survey (June 2020)

Phase I of customer engagement was completed before the COVID-19 outbreak. In June 2020, Hydro One reached out to a random sample of residential and small business customers to see if their needs and outcome preferences had changed as a result of the pandemic.

All responses were collected using unique survey URLs which were sent directly to customers, using a Hydro One email address administered by INNOVATIVE. The Pulse-Check Survey was customized for primary residential, seasonal residential, small business (GS<50 kW) customers.

Interpreting the Results

Links to the Pulse-Check Survey were distributed to customers with an email address on file. To ensure that these findings are representative of Hydro One's broader customer base, INNOVATIVE relied on a rigorous sample validation process conducted in Phase I and weighted the online results by region and usage.

Sampling Methodology
Coverage and Consumption Analysis

Comparing the email samples to the overall population in each rate class, we can see that the email samples are largely representative of the overall customer base with regard to consumption and regional distribution.

Overall Email Coverage

Coverage is highest in the groups with higher usage, but even among the group with the lowest coverage, 44% of customers have an email on file.

Customer Type	Full Population	Email Coverage	
Primary Residential	1,070,319 records	522,120 records	**49%**
Seasonal Residential	144,489 records	63,765 records	**44%**
Small business (GS<50)	111,749 records	57,665 records	**52%**

Average Electricity Consumption

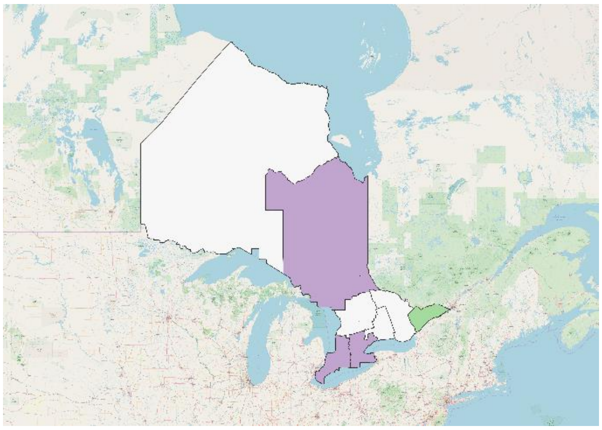
Across most rate classes, the sample of customers with email addresses on file use more power than the overall sample on average.

Customer Type	Full Population	Those with email addresses	Difference
Primary Residential	960 kWh	977 kWh	**+2%**
Seasonal Residential	1,001 kWh	1,170 kWh	**+17%**
Small business (GS<50)	2,298 kWh	2,550 kWh	**+11%**

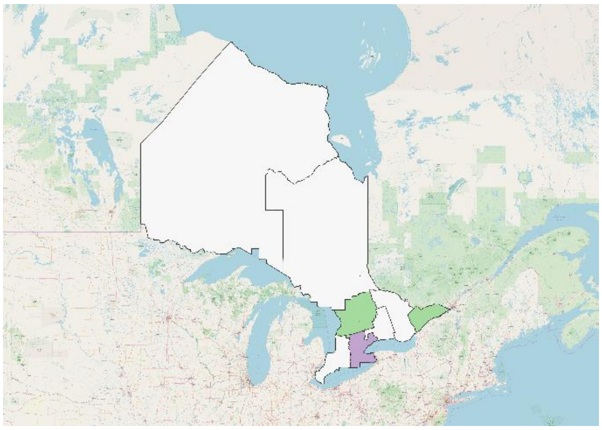
Sampling Methodology

Regional Analysis

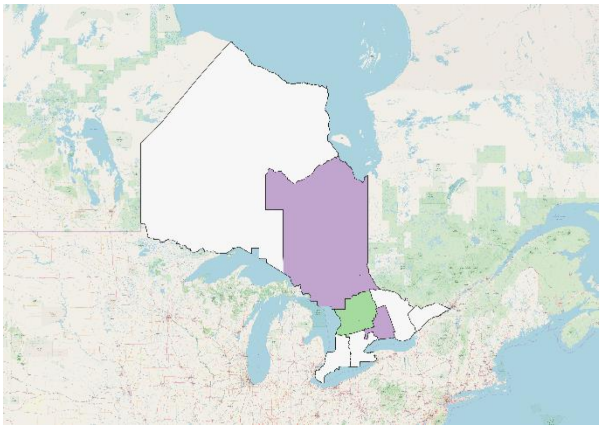
Primary Residential



GS<50



Seasonal Residential



Difference between email sample and full population
More than -1.5%
-1.5% to -0.5%
-0.5% to +0.5%
+0.5% to +1.5%
More than +1.5%

These charts show the difference between the share of the full population that is from a given region, and the share of the email sample from that region.

The difference between groups does not exceed more than 1.5 percentage points for any region across all rate classes, and in most regions the difference is no more than 0.5 percentage points.

Final results are weighted by region to ensure results are representative across the province.

Note: The regions represented in the charts are graphical approximations of the regions used by Hydro One's distribution system planners. Customers are grouped by the region they are classified in by Hydro One.

Sampling Methodology

Residential and Small Business Completes & Weighting

Online Survey Completes

Customer Type	Full Population	Emails Sent Out	Unweighted Completes	Weighted Completes
Primary Residential	1,070,319 records	20,000 records	n=1,360	n=1,400
Seasonal Residential	144,489 records	2,000 records	n=155	
Small business	111,749 records	9,981 records	n=262	n=250

Residential Pulse-Check Survey

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Southern	5.7%	6.7%	7.0%	7.1%	26.5%	6.5%	7.7%	7.8%	7.3%	29.3%
Central	6.9%	7.2%	7.5%	7.9%	29.5%	6.9%	6.2%	6.8%	7.9%	27.7%
Eastern	6.9%	9.4%	9.6%	6.9%	32.7%	7.1%	8.0%	7.8%	6.8%	29.6%
Northern	3.2%	2.3%	2.6%	3.2%	11.3%	3.9%	3.1%	3.0%	3.4%	13.3%
Total	22.6%	25.6%	26.7%	25.1%	100.0%	24.4%	24.9%	25.3%	25.4%	100.0%

Small Business Pulse-Check Survey

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Southern	4.6%	5.7%	5.7%	8.8%	24.8%	8.5%	8.3%	8.1%	8.6%	33.5%
Central	4.6%	7.6%	3.8%	6.9%	22.9%	5.7%	5.8%	5.8%	5.7%	23.0%
Eastern	7.6%	9.2%	4.2%	6.5%	27.5%	6.7%	6.9%	6.6%	6.3%	26.5%
Northern	5.3%	8.4%	3.4%	7.6%	24.8%	4.2%	4.1%	4.5%	4.4%	17.1%
Total	22.1%	30.9%	17.2%	29.8%	100.0%	25.0%	25.0%	25.0%	25.0%	100.0%

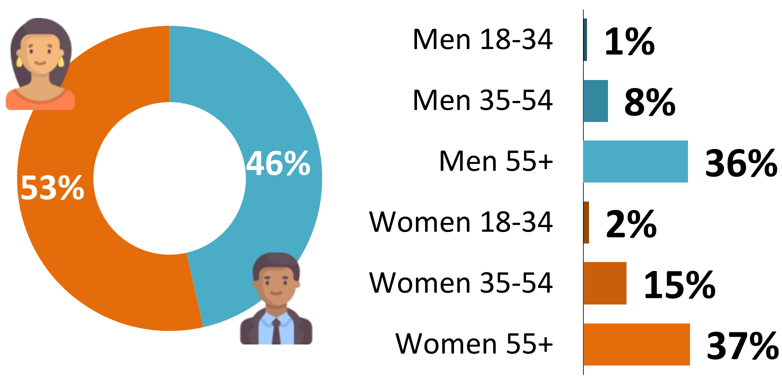
Survey Results

Residential Customers

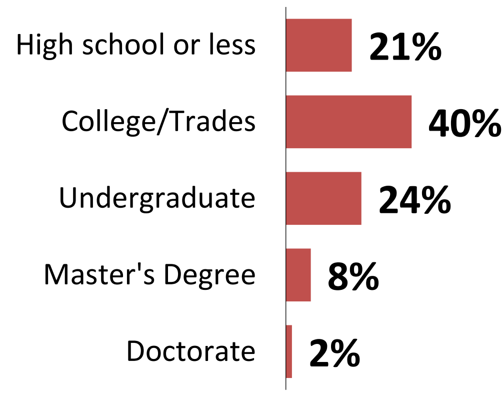
Pulse-Check Survey
Demographics

Residential

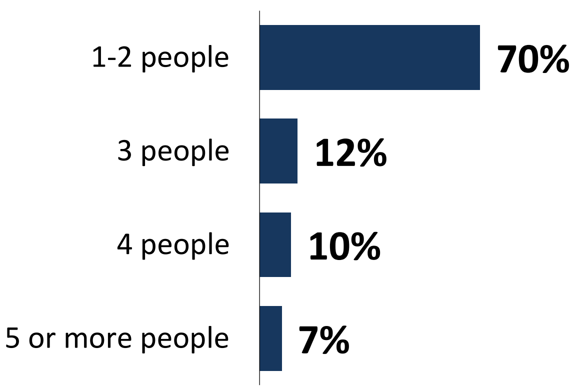
Gender & Age



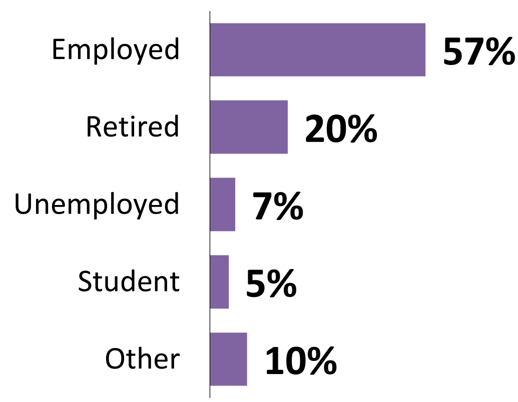
Education



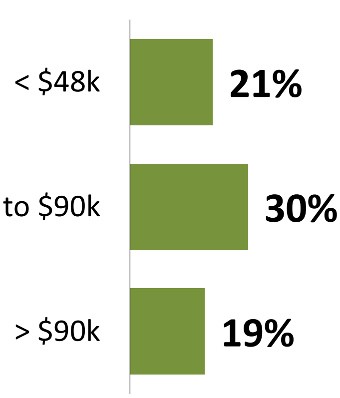
Household Size



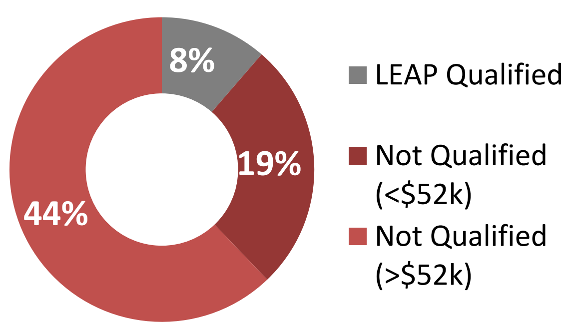
Employment Status



Household Income



Leap Qualification

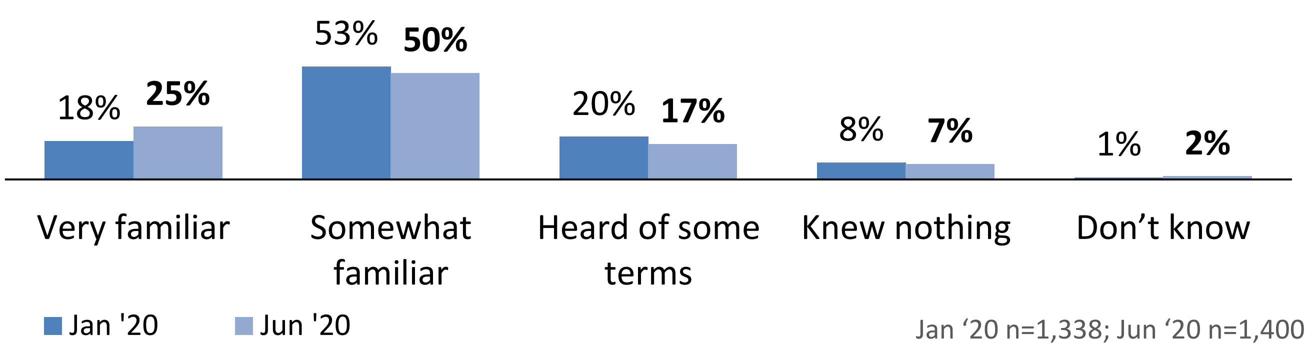


Note: Sums added before rounding. “Prefer not to say/Don’t know” not shown.

Pulse-Check Survey
Electricity 101

Residential

Q Before today, how familiar were you with Hydro One and its role in Ontario's electricity system?



June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Very familiar and could explain the details	25%	25%	26%	24%	23%	25%	28%
Somewhat familiar with the system but could not explain all the details	50%	49%	55%	44%	54%	53%	48%
Had heard of some of the terms and organizations mentioned	17%	17%	11%	20%	13%	16%	18%
I knew nothing about how the provincial electricity system works	7%	7%	9%	10%	8%	5%	5%
Don't know	2%	2%	-	2%	1%	1%	2%

Pulse-Check Survey

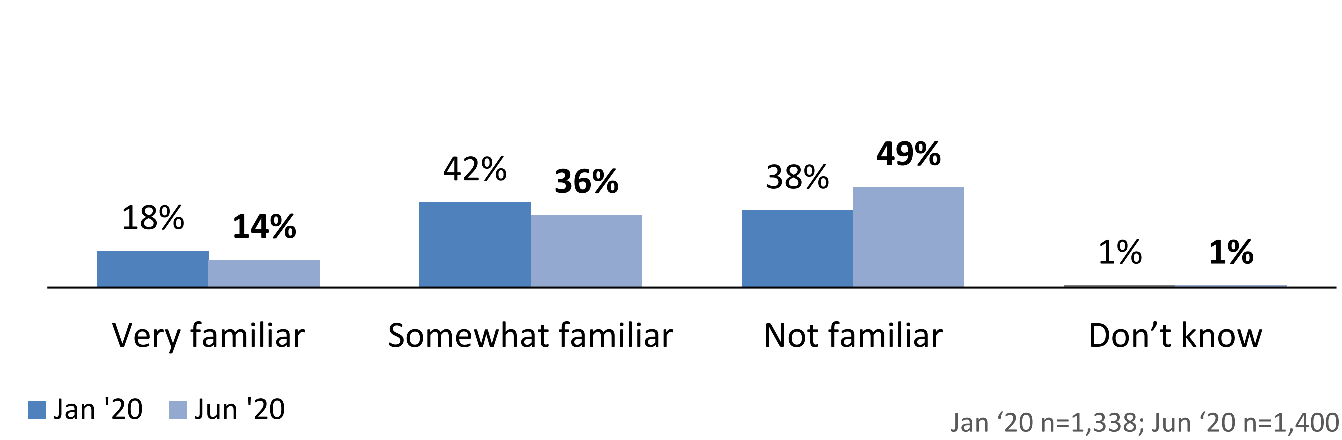
How much of my bill goes to Hydro One?

Residential

Q

While Hydro One is responsible for collecting payment for the entire electricity bill, it keeps about 28% of the average residential customer's bill. This amount is split into 21% for distribution, and 7% for transmission*. The rest of the bill goes to power generation companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?



June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Very familiar	14%	14%	9%	13%	12%	13%	19%
Somewhat familiar	36%	36%	38%	37%	37%	36%	33%
Not familiar	49%	49%	52%	49%	51%	50%	48%
Don't know	1%	1%	1%	1%	1%	1%	1%

*Seasonal customers survey version:
While Hydro One is responsible for collecting payment for the entire electricity bill, it only keeps about 50% of the average seasonal customer's bill. This amount is split into 47% for distribution, and 3% for transmission.

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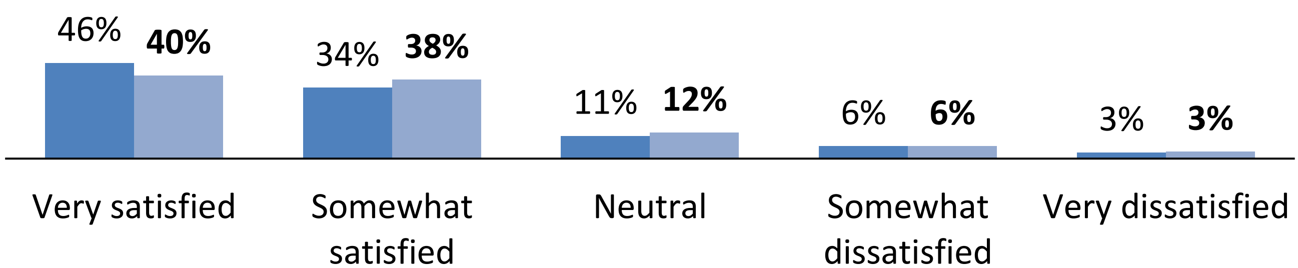
Pulse-Check Survey

Satisfaction with Hydro One's Services

Residential

Q Thinking specifically about the services provided to you and your community by Hydro One, overall, how satisfied or dissatisfied are you with the services that you receive?



Note: Don't know (<1%) not shown.

Jan '20 n=1,338; Jun '20 n=1,400

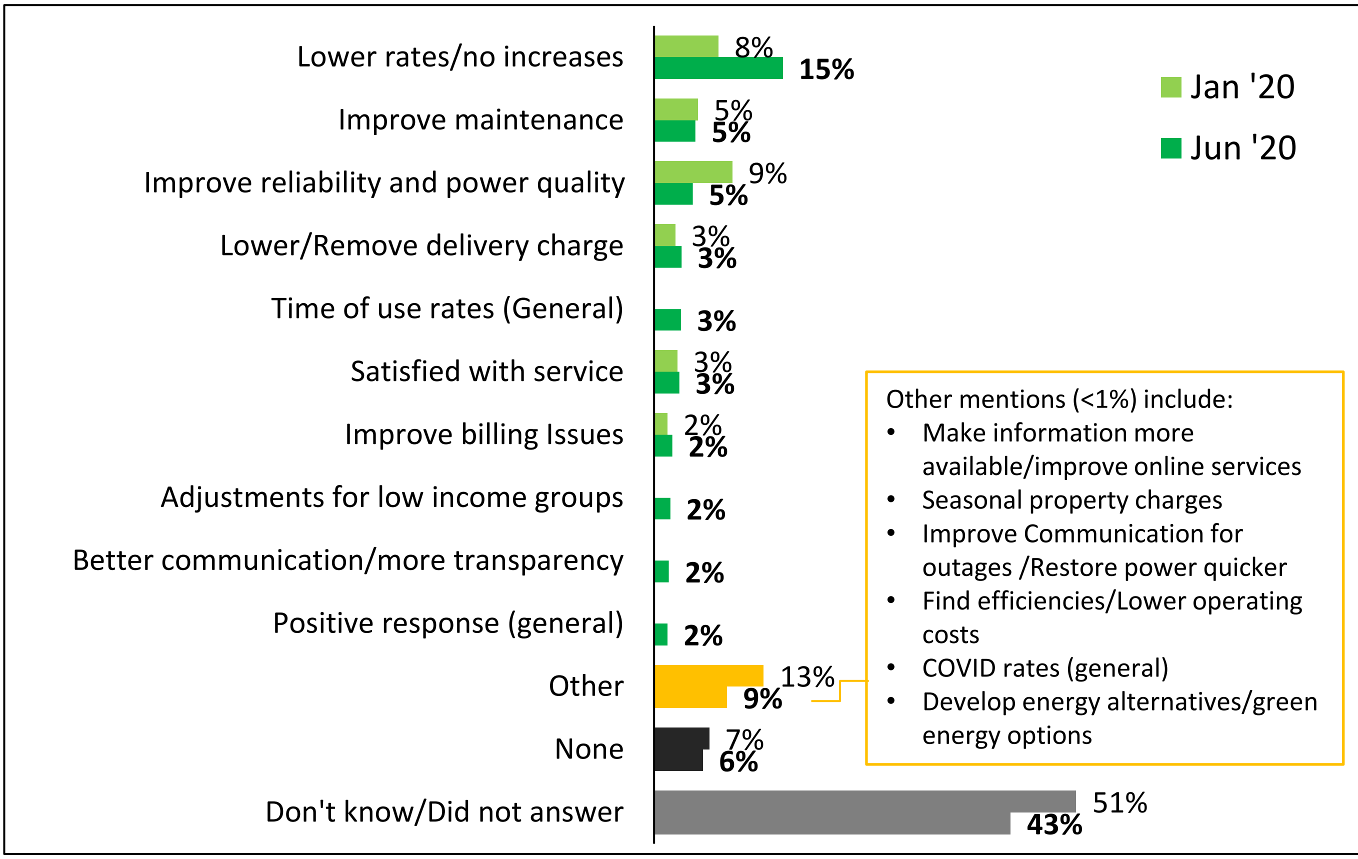
June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Very satisfied	40%	41%	34%	39%	40%	42%	37%
Somewhat satisfied	38%	38%	40%	39%	40%	35%	37%
Neutral	12%	13%	10%	14%	10%	12%	15%
Somewhat dissatisfied	6%	5%	11%	5%	6%	7%	5%
Very dissatisfied	3%	3%	7%	2%	4%	3%	5%
Don't know	0%	0%	-	0%	0%	0%	1%
Overall satisfied	**78%**	**78%**	**73%**	**78%**	**80%**	**77%**	**74%**
Overall dissatisfied	**9%**	**8%**	**17%**	**8%**	**10%**	**10%**	**10%**

Pulse-Check Survey

Satisfaction with Hydro One's Services

Residential

Q Is there anything in particular you would like Hydro One to do to improve its services to you?



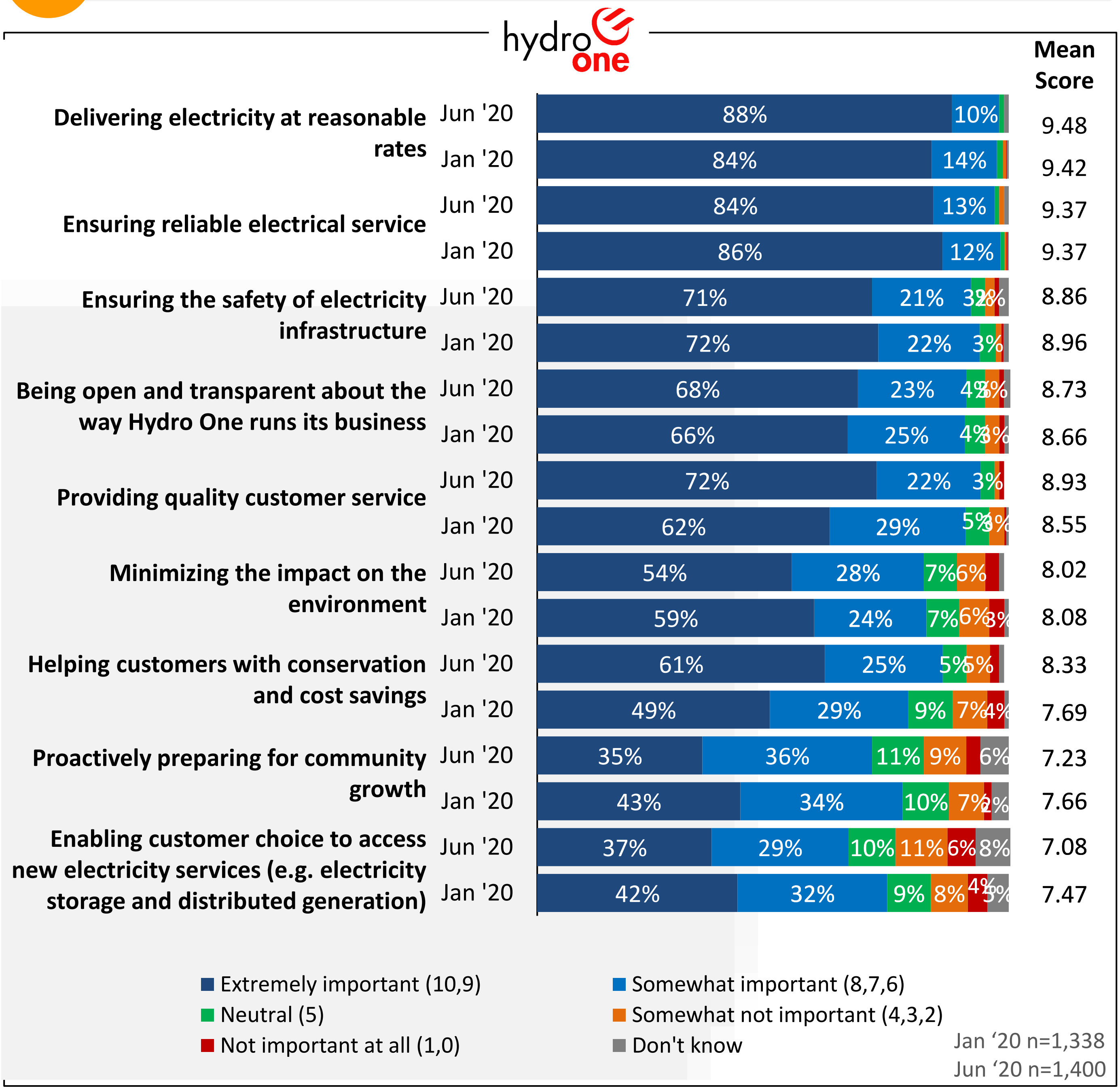
Pulse-Check Survey

Outcome Priorities

Residential

Through previous customer research and contacts, a number of outcomes were identified by customers as priorities for Hydro One. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

Q How important are each of the following Hydro One priorities to you as a customer?



INNOVATIVE RESEARCH GROUP

Pulse-Check Survey

Outcome Priorities

Residential

Through previous customer research and contacts, a number of outcomes were identified by customers as priorities for Hydro One. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

Q How important are each of the following Hydro One priorities to you as a customer?
BY **Mean Score**

June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Delivering electricity at reasonable rates	9.48	9.51	9.28	9.49	9.49	9.43	9.57
Ensuring reliable electrical service	9.37	9.37	9.37	9.31	9.39	9.40	9.38
Ensuring the safety of electricity infrastructure	8.86	8.87	8.76	8.87	8.80	8.89	8.86
Being open and transparent about the way Hydro One runs its business	8.73	8.75	8.53	8.69	8.69	8.79	8.74
Providing quality customer service	8.93	8.93	8.93	8.97	8.92	8.90	8.96
Minimizing the impact on the environment	8.02	8.04	7.84	8.01	7.91	8.01	8.24
Helping customers with conservation and cost savings	8.33	8.36	8.06	8.56	8.22	8.28	8.21
Proactively preparing for community growth	7.23	7.29	6.74	7.38	7.24	7.17	7.03
Enabling customer choice to access new electricity services (e.g. electricity storage)	7.08	7.07	7.14	7.31	6.98	6.75	7.56

INNOVATIVE RESEARCH GROUP

Pulse-Check Survey

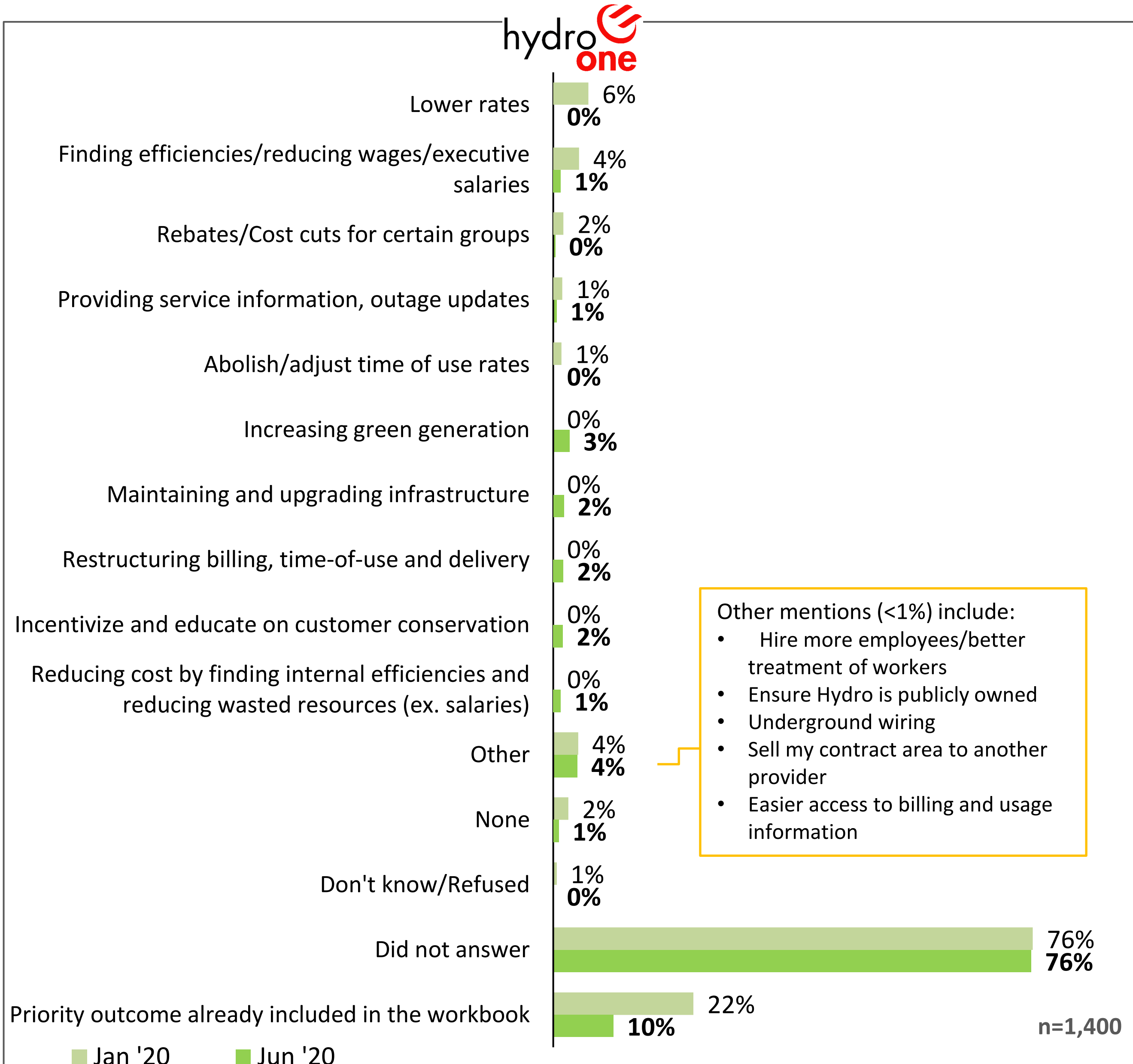
Outcome Priorities

Residential

Through previous customer research and contacts, a number of outcomes were identified by customers as priorities for Hydro One. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

Q

The list above may not include all the outcomes that matter to you. Are there any other important priorities that Hydro One should be focusing on that weren't included in the list above?

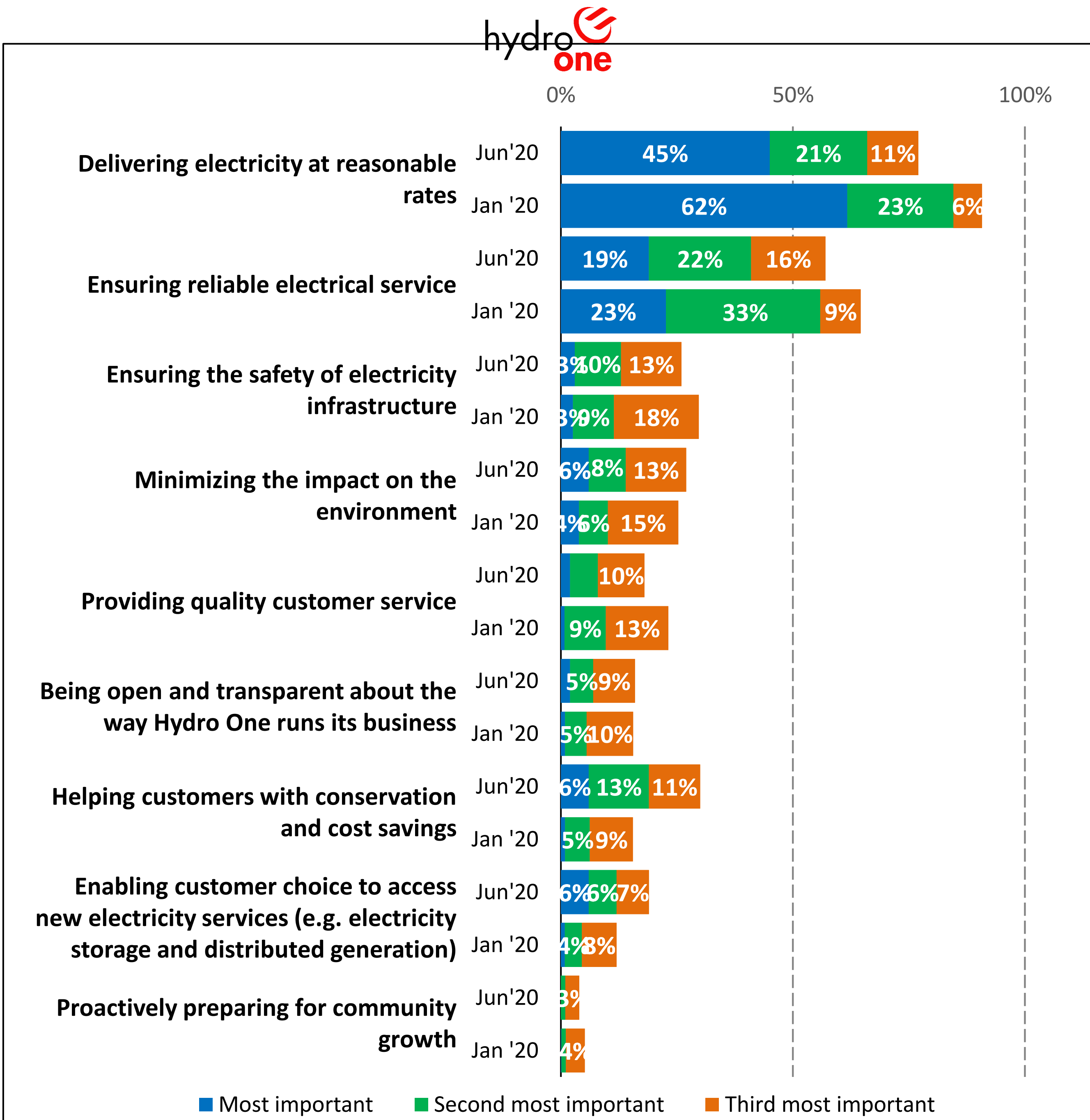


Online Workbook

Outcome Priorities

Residential

Q Thinking again about the things Hydro One should be focusing on, please rank your top 3 priorities—where “1” would be the most important, “2” the second most important, and “3” the third most important.



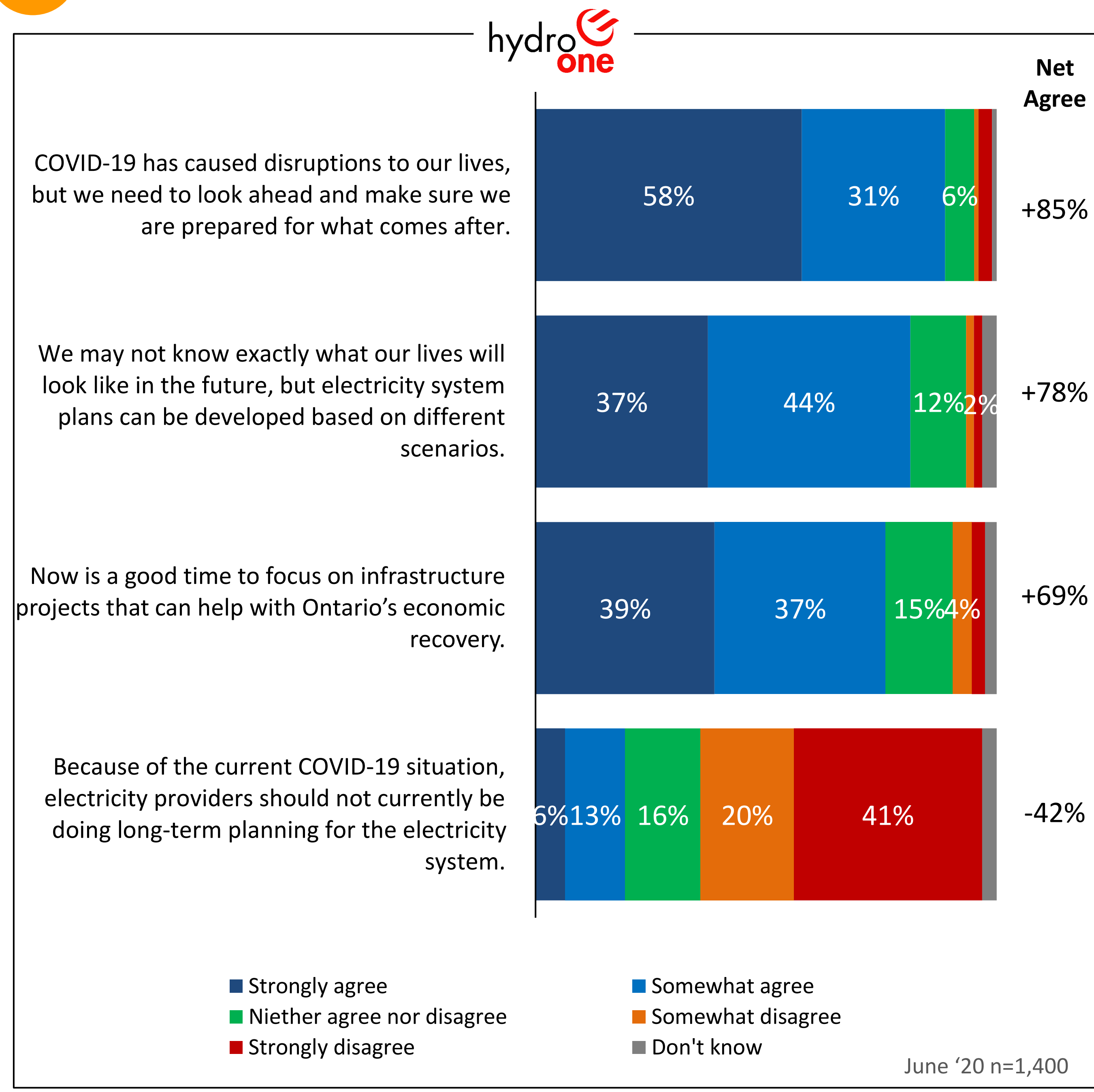
Jan ‘20 n=1,338
Jun ‘20 n=1,400

Pulse-Check Survey

Planning for the Future

Residential

Q To what extent do you agree or disagree with the following statements?



INNOVATIVE RESEARCH GROUP

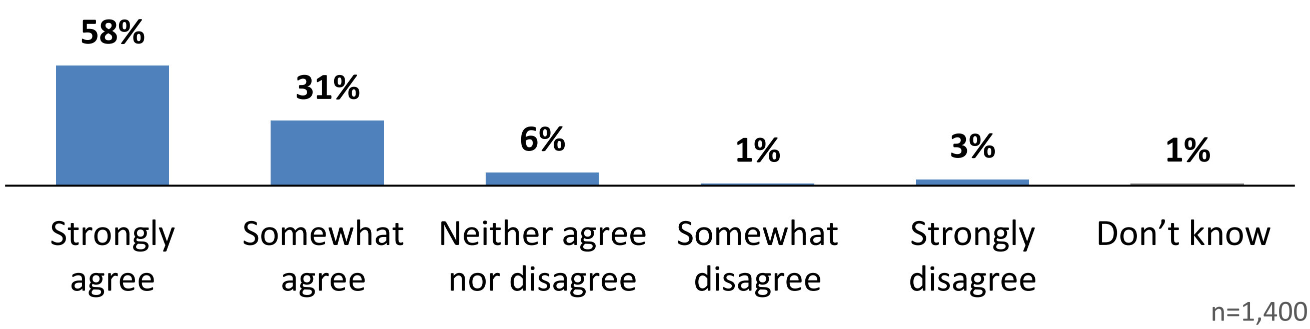
Pulse-Check Survey

Planning for the Future

Residential

Q

To what extent do you agree or disagree with the following statements?
COVID-19 has caused disruptions to our lives, but we need to look ahead and make sure we are prepared for what comes after.



June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	58%	57%	66%	54%	61%	56%	61%
Somewhat agree	31%	32%	22%	32%	29%	32%	31%
Neither agree nor disagree	6%	6%	7%	7%	5%	8%	3%
Somewhat disagree	1%	1%	1%	1%	1%	0%	1%
Strongly disagree	3%	3%	4%	4%	3%	2%	3%
Don't know	1%	1%	1%	1%	0%	1%	2%
Overall agree	**89%**	**89%**	**88%**	**87%**	**90%**	**88%**	**92%**
Overall disagree	**4%**	**4%**	**4%**	**5%**	**4%**	**3%**	**4%**
Net agree	**85%**	**85%**	**83%**	**81%**	**86%**	**86%**	**88%**

Pulse-Check Survey

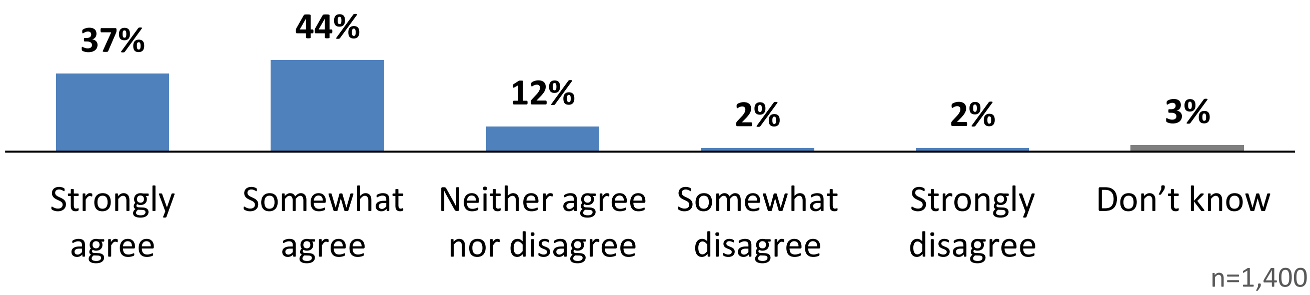
Planning for the Future

Residential

Q

To what extent do you agree or disagree with the following statements?
We may not know exactly what our lives will look like in the future, but electricity system plans can be developed based on different scenarios.

hydro one



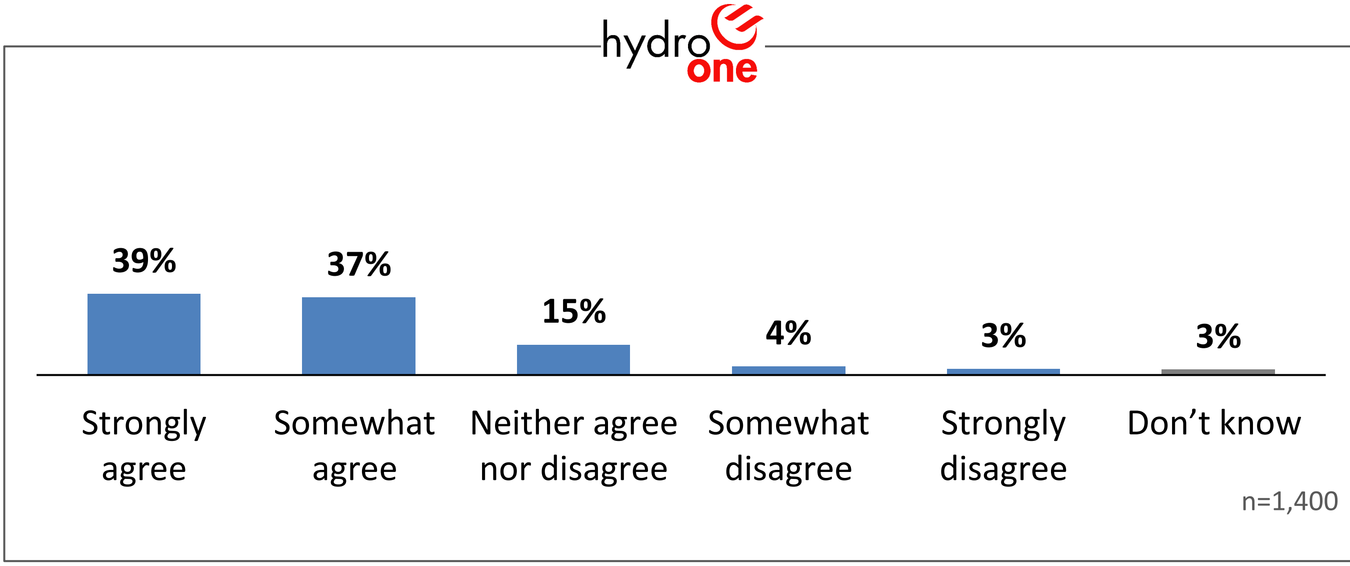
June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	37%	36%	49%	34%	38%	40%	38%
Somewhat agree	44%	45%	31%	45%	45%	41%	46%
Neither agree nor disagree	12%	12%	13%	13%	11%	13%	11%
Somewhat disagree	2%	2%	1%	2%	2%	2%	
Strongly disagree	2%	2%	3%	2%	1%	2%	2%
Don't know	3%	3%	4%	4%	2%	3%	3%
Overall agree	**81%**	**81%**	**80%**	**79%**	**84%**	**80%**	**84%**
Overall disagree	**3%**	**3%**	**3%**	**5%**	**3%**	**4%**	**2%**
Net agree	**78%**	**78%**	**77%**	**74%**	**81%**	**77%**	**82%**

Pulse-Check Survey

Planning for the Future

Residential

Q To what extent do you agree or disagree with the following statements?
Now is a good time to focus on infrastructure projects that can help with Ontario's economic recovery.



June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	39%	39%	36%	38%	41%	37%	40%
Somewhat agree	37%	36%	44%	36%	40%	36%	35%
Neither agree nor disagree	15%	15%	14%	15%	13%	16%	14%
Somewhat disagree	4%	4%	1%	5%	3%	5%	3%
Strongly disagree	3%	3%	2%	3%	2%	3%	4%
Don't know	3%	3%	3%	2%	2%	2%	5%
Overall agree	**76%**	**75%**	**80%**	**75%**	**80%**	**74%**	**74%**
Overall disagree	**7%**	**7%**	**3%**	**9%**	**5%**	**8%**	**6%**
Net agree	**69%**	**68%**	**77%**	**66%**	**75%**	**66%**	**68%**

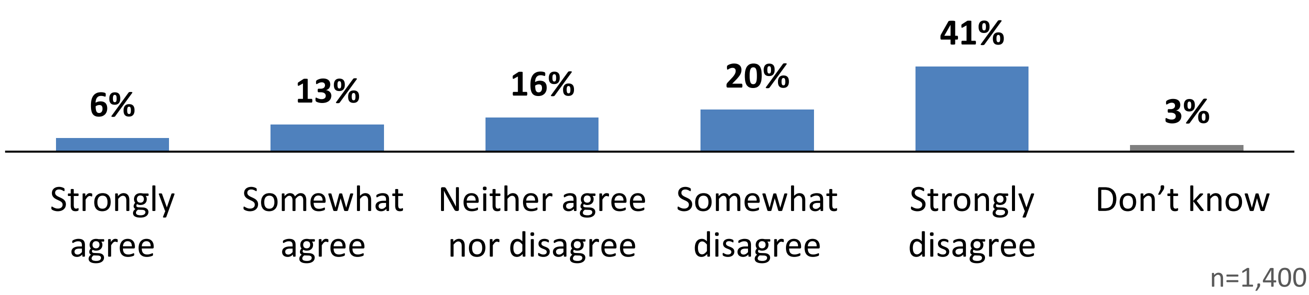
Pulse-Check Survey

Planning for the Future

Residential

Q

To what extent do you agree or disagree with the following statements?
Because of the current COVID-19 situation, electricity providers should not currently be doing long-term planning for the electricity system.



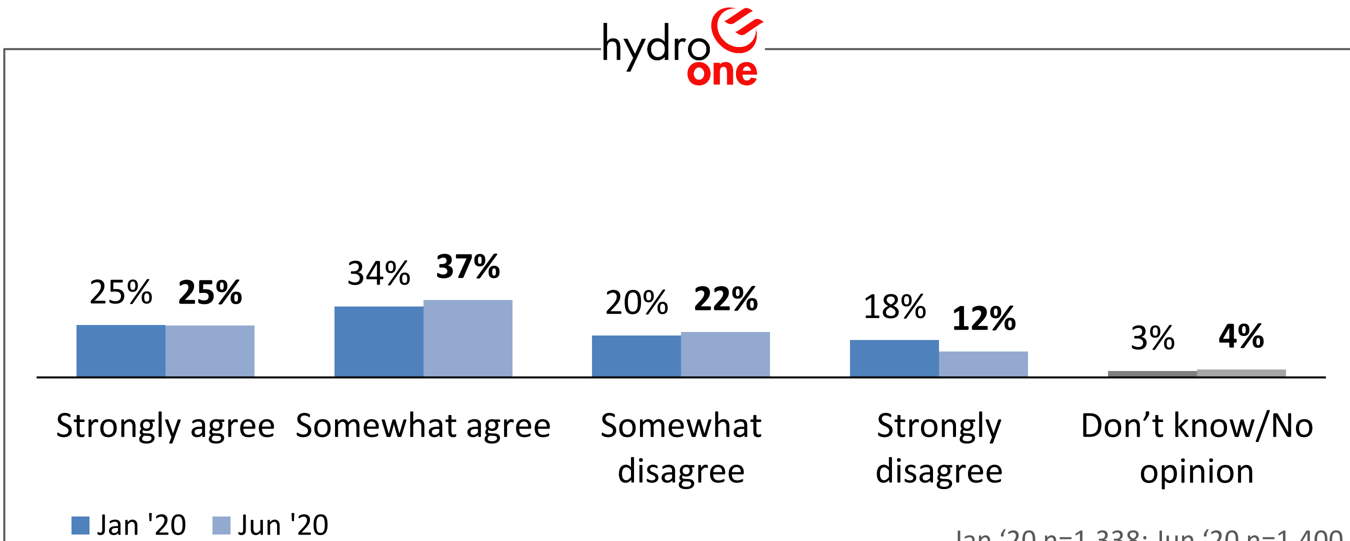
June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	6%	7%	2%	6%	5%	6%	12%
Somewhat agree	13%	13%	10%	14%	12%	13%	13%
Neither agree nor disagree	16%	17%	12%	17%	19%	14%	15%
Somewhat disagree	20%	20%	18%	21%	19%	22%	17%
Strongly disagree	41%	39%	56%	40%	43%	41%	38%
Don't know	3%	3%	3%	3%	3%	4%	4%
Overall agree	**19%**	**20%**	**12%**	**20%**	**17%**	**19%**	**26%**
Overall disagree	**61%**	**60%**	**73%**	**61%**	**62%**	**63%**	**55%**
Net agree	**-42%**	**-39%**	**-61%**	**-41%**	**-45%**	**-45%**	**-29%**

Pulse-Check Survey

Environmental Controls

Residential

Q To what extent do you agree or disagree with the following statements?
The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



Jan ‘20 n=1,338; Jun ‘20 n=1,400

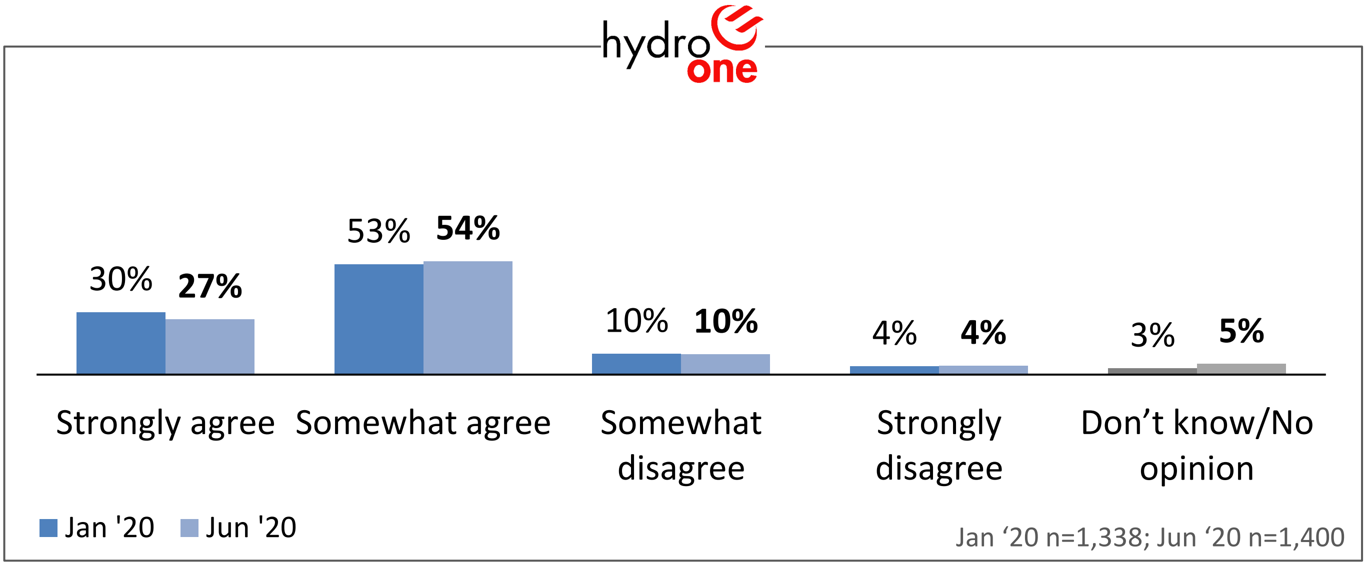
June ’20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	25%	26%	18%	23%	24%	22%	37%
Somewhat agree	37%	38%	35%	38%	38%	39%	30%
Somewhat disagree	22%	21%	25%	22%	23%	22%	17%
Strongly disagree	12%	12%	16%	12%	12%	13%	11%
Don’t know/No opinion	4%	4%	6%	4%	3%	4%	5%
Overall agree	**62%**	**63%**	**53%**	**61%**	**62%**	**61%**	**68%**
Overall disagree	**34%**	**33%**	**41%**	**35%**	**35%**	**35%**	**28%**

Pulse-Check Survey

Environmental Controls

Residential

Q To what extent do you agree or disagree with the following statements?
Customers are well served by the electricity system in Ontario.



June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	27%	27%	25%	27%	30%	24%	24%
Somewhat agree	54%	55%	54%	55%	53%	57%	51%
Somewhat disagree	10%	10%	10%	8%	10%	10%	12%
Strongly disagree	4%	4%	6%	4%	4%	5%	5%
Don't know/No opinion	5%	5%	5%	7%	4%	4%	8%
Overall Agree	**81%**	**81%**	**79%**	**82%**	**83%**	**81%**	**76%**
Overall Disagree	**14%**	**14%**	**16%**	**12%**	**13%**	**15%**	**17%**

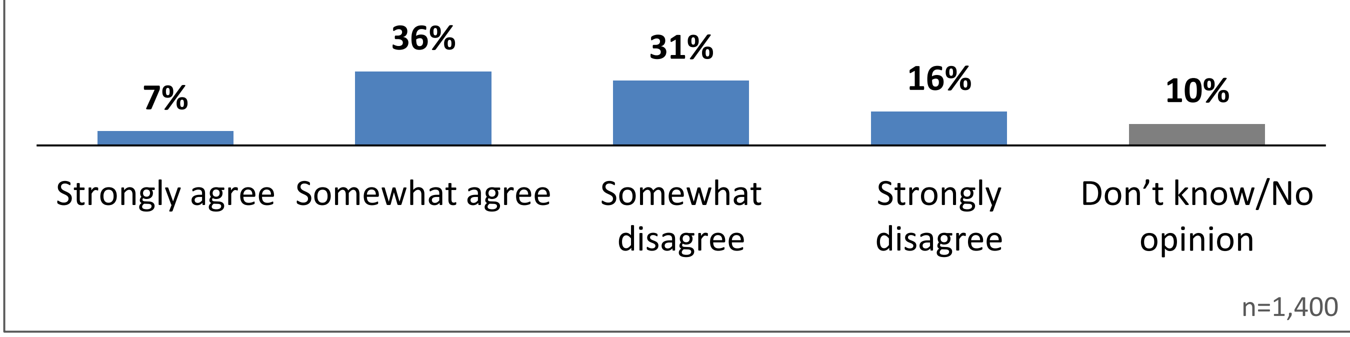
Pulse-Check Survey

Environmental Controls

Residential

Q

To what extent do you agree or disagree with the following statements?
Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.

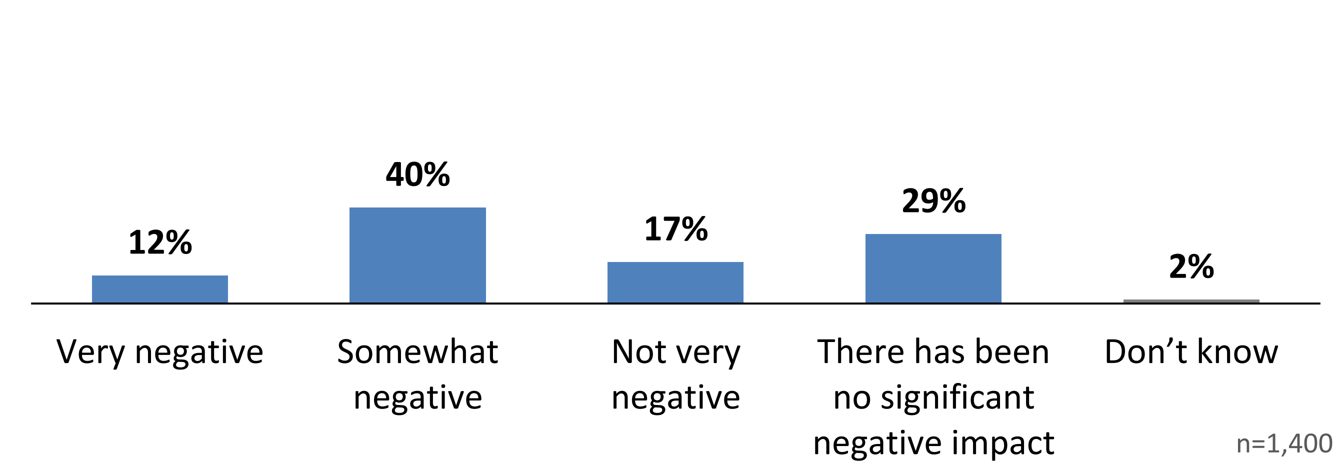


June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Strongly agree	7%	7%	5%	6%	8%	6%	8%
Somewhat agree	36%	36%	36%	35%	38%	36%	31%
Somewhat disagree	31%	31%	29%	32%	29%	33%	28%
Strongly disagree	16%	16%	19%	14%	16%	16%	22%
Don't know/No opinion	10%	10%	12%	12%	9%	9%	10%
Overall Agree	**42%**	**43%**	**40%**	**41%**	**46%**	**42%**	**39%**
Overall Disagree	**47%**	**47%**	**48%**	**46%**	**45%**	**49%**	**50%**

Pulse-Check Survey
Personal Finances

Residential

Q How big of a negative financial impact has the COVID-19 outbreak had on your household finances?



June '20	Total	Primary Residential	Seasonal Residential	Southern	Central	Eastern	Northern
Very negative	12%	12%	10%	12%	12%	10%	15%
Somewhat negative	40%	40%	38%	40%	41%	40%	40%
Not very negative	17%	17%	17%	17%	17%	18%	17%
There has been no significant negative impact	29%	29%	34%	30%	28%	31%	27%
Don't know	2%	2%	1%	2%	2%	1%	1%

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Survey Results

Small Business Customers

Pulse-Check Survey

Firmographics

Small Business

Company Size	N-size	%
1 person	22	9%
2 to 5 people	60	24%
6 to 10 people	27	11%
11 to 25 people	38	15%
26 to 50 people	21	9%
More than 50 people	53	21%

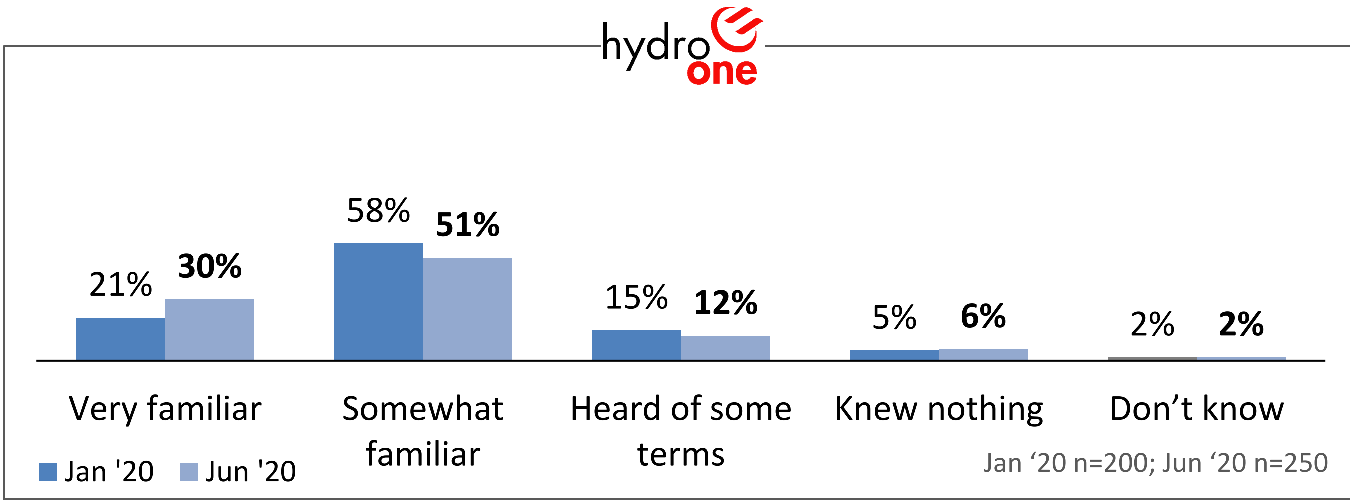
Company Type	N-size	%
Commercial	20	8%
Manufacturing/Industrial	23	9%
Hospitality	19	8%
Restaurant/Tavern	7	3%
Warehouse	27	11%
Real Estate	10	4%
Other	121	49%

Note: Sums added before rounding. “Prefer not to say/Don’t know” not shown.

Pulse-Check Survey

Electricity 101

Q Before today, how familiar were you with Hydro One and its role in Ontario's electricity system?



June '20	Total	Southern	Central	Eastern	Northern
Very familiar and could explain the details	30%	36%	22%	29%	32%
Somewhat familiar with the system but could not explain all the details	51%	48%	61%	41%	56%
Had heard of some of the terms and organizations mentioned	12%	8%	12%	19%	8%
I knew nothing about how the provincial electricity system works	6%	5%	5%	8%	3%
Don't know	2%	3%	-	2%	-

Pulse-Check Survey

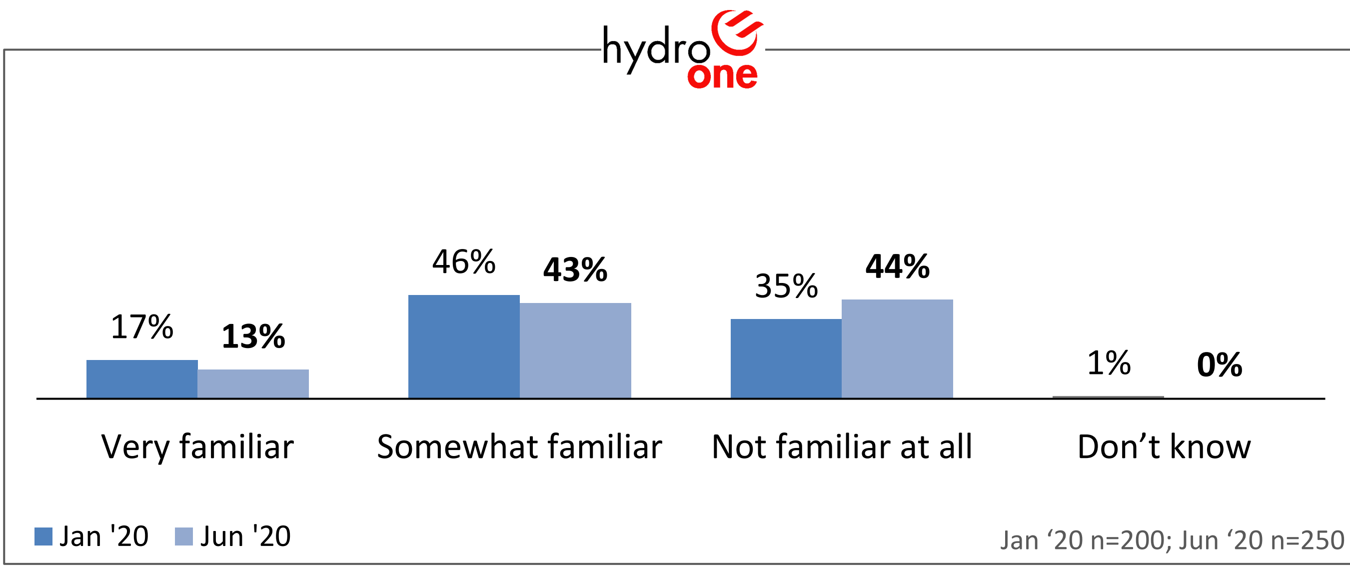
How much of my bill goes to Hydro One?

Small Business

Q

While Hydro One is responsible for collecting payment for the entire electricity bill, it keeps about 28% of the average residential customer's bill. This amount is split into 21% for distribution, and 7% for transmission/it only keeps about 50% of the average seasonal customer's bill. This amount is split into 47% for distribution, and 3% for transmission. The rest of the bill goes to power generation companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to Hydro One?



June '20	Total	Southern	Central	Eastern	Northern
Very familiar	13%	14%	23%	8%	6%
Somewhat familiar	43%	38%	44%	40%	54%
Not familiar at all	44%	48%	32%	52%	40%
Don't know	0%	-	1%	-	-

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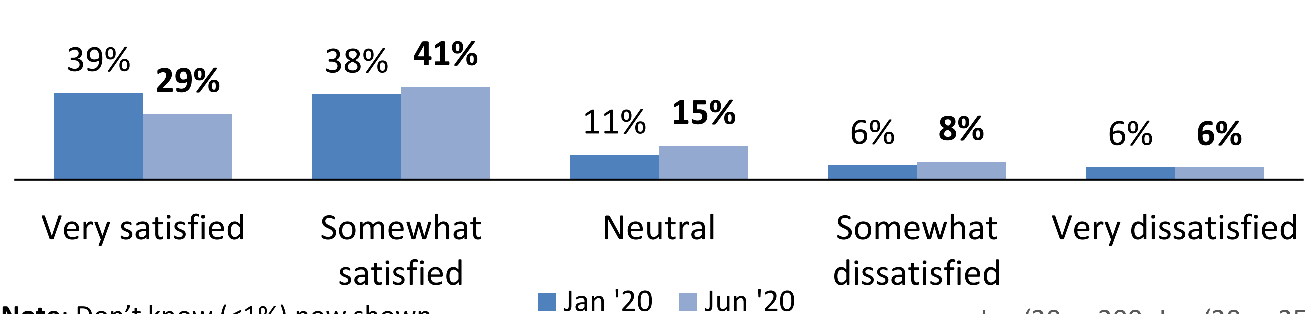
Pulse-Check Survey

Satisfaction with Hydro One's Services

Small Business

Q Thinking specifically about the services provided to you and your community by Hydro One, overall, how satisfied or dissatisfied is your organization with the services that you receive?



Note: Don't know (<1%) now shown.

Jan '20 n=200; Jun '20 n=250

June '20	Total	Southern	Central	Eastern	Northern
Very satisfied	29%	31%	24%	40%	18%
Somewhat satisfied	41%	43%	44%	34%	46%
Neutral	15%	15%	17%	15%	15%
Somewhat dissatisfied	8%	9%	4%	6%	14%
Very dissatisfied	6%	3%	11%	6%	4%
Don't know	0%				2%
Overall satisfied	**71%**	**74%**	**68%**	**73%**	**65%**
Overall dissatisfied	**14%**	**12%**	**15%**	**12%**	**18%**

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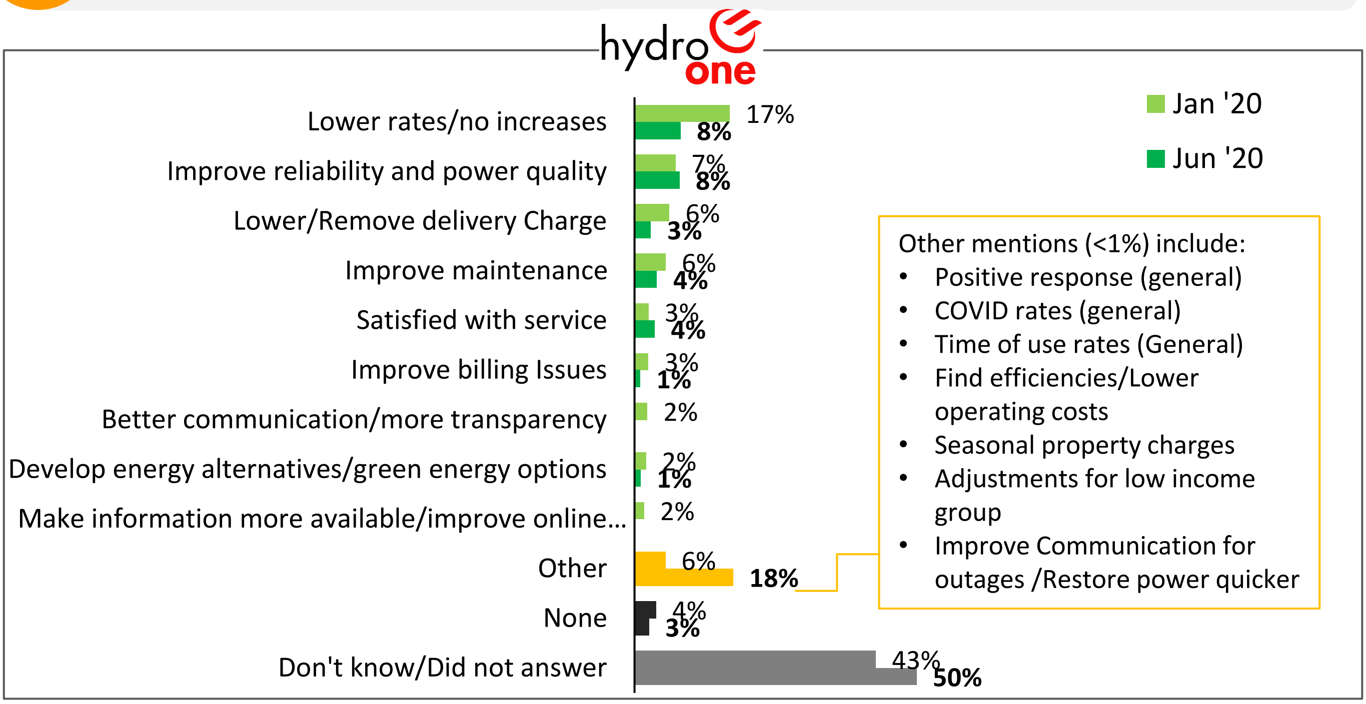
Pulse-Check Survey

Satisfaction with Hydro One's Services

Small Business

Q Is there anything in particular you would like Hydro One to do to improve its services to your organization?



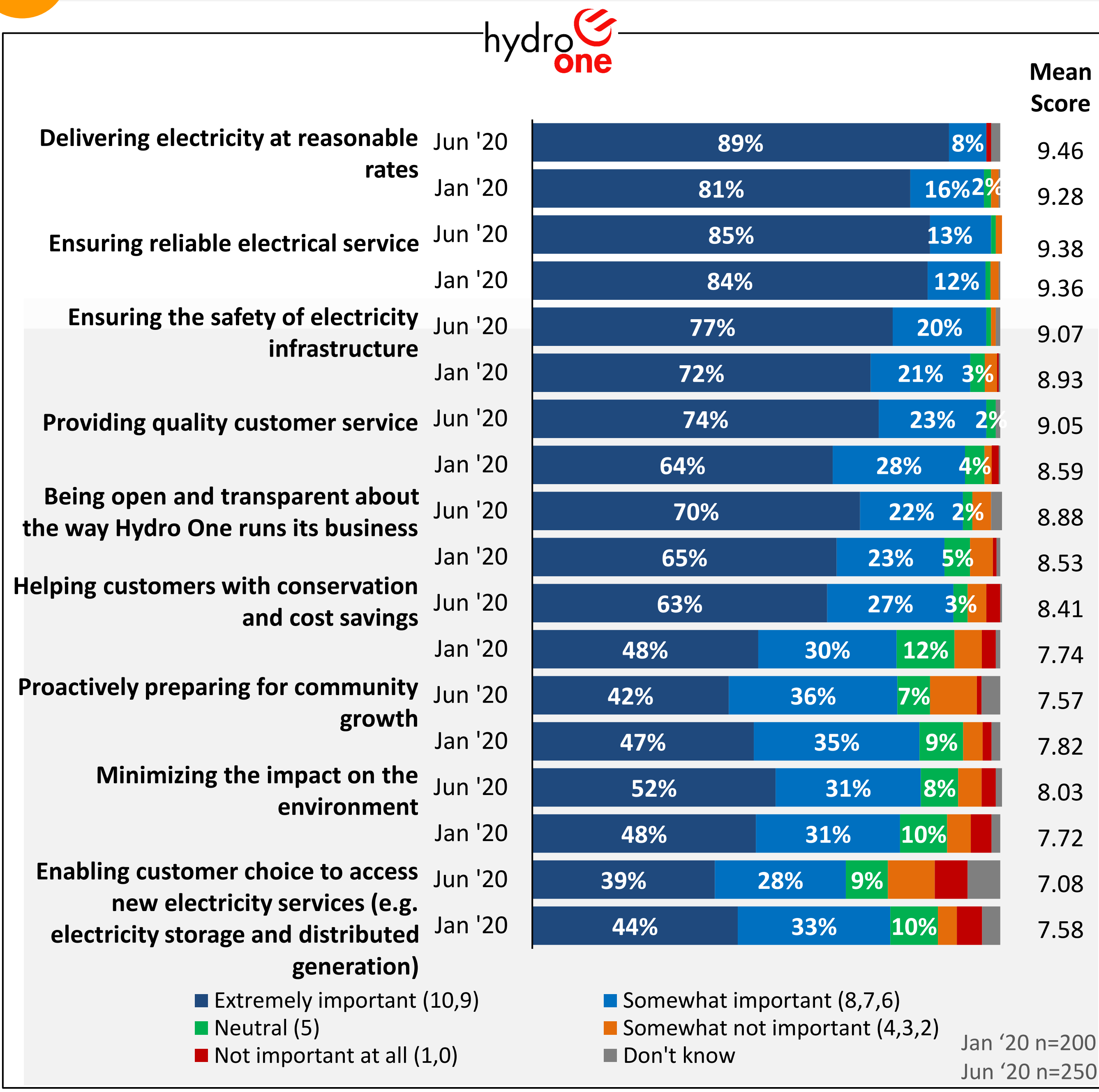
Pulse-Check Survey

Outcome Priorities

Small Business

Through previous customer research and contacts, a number of outcomes were identified by customers as priorities for Hydro One. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

Q How important are each of the following Hydro One priorities to you as a customer?



Pulse-Check Survey
Outcome Priorities

Small Business

Through previous customer research and contacts, a number of outcomes were identified by customers as priorities for Hydro One. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

Q How important are each of the following Hydro One priorities to you as a customer?
BY **Mean Score**

June '20	Total	Southern	Central	Eastern	Northern
Delivering electricity at reasonable rates	9.46	9.23	9.44	9.60	9.72
Ensuring reliable electrical service	9.38	9.46	9.12	9.37	9.58
Ensuring the safety of electricity infrastructure	9.07	8.93	8.94	9.16	9.39
Providing quality customer service	9.05	8.93	9.00	9.04	9.39
Being open and transparent about the way Hydro One runs its business	8.88	8.72	9.08	8.96	8.83
Helping customers with conservation and cost savings	8.41	8.13	8.18	8.60	8.99
Proactively preparing for community growth	7.57	7.35	7.56	7.51	8.13
Minimizing the impact on the environment	8.03	7.55	8.35	8.22	8.25
Enabling customer choice to access new electricity services (e.g. electricity storage)	7.08	6.84	7.21	6.68	8.00

n=250

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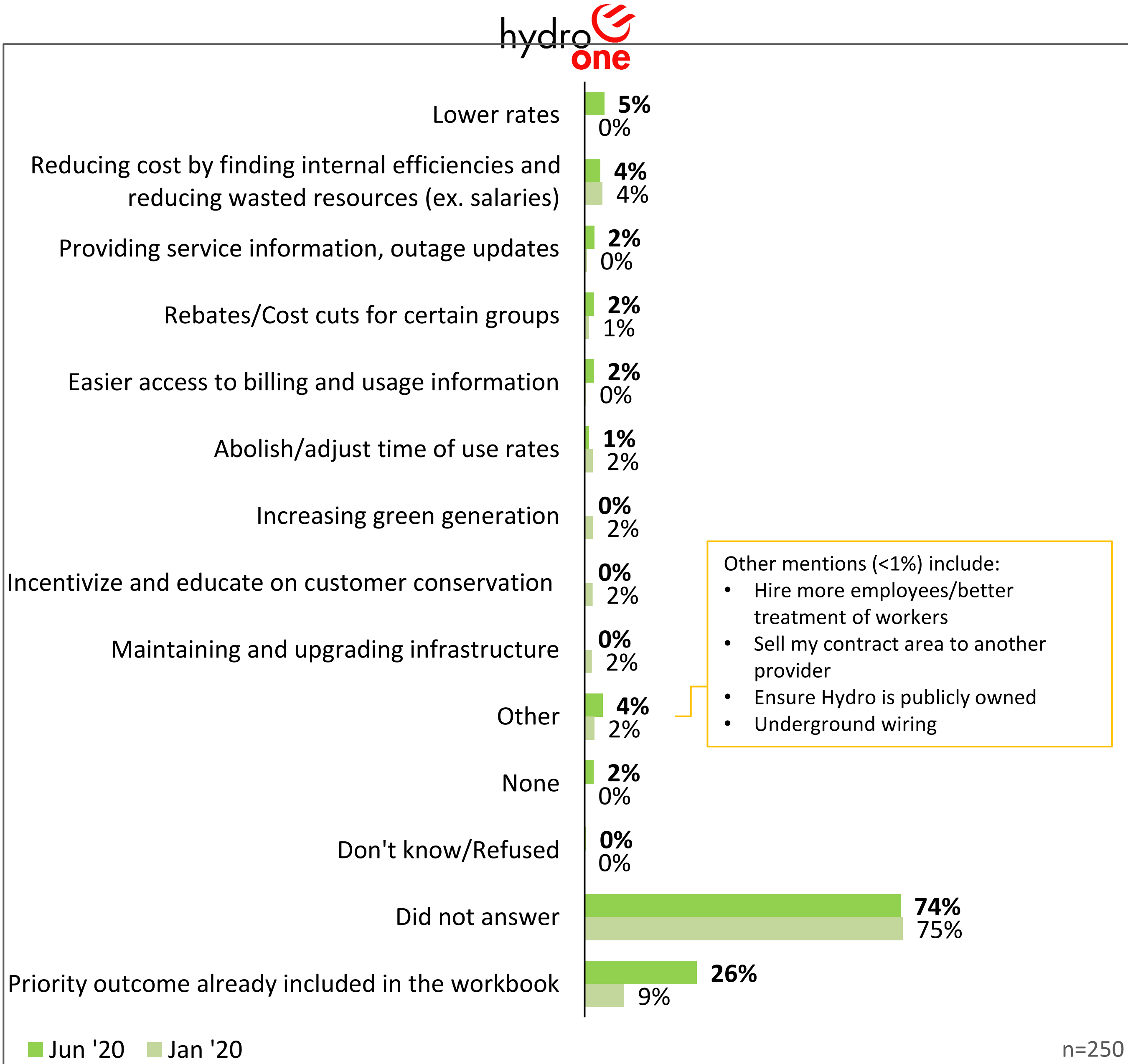
Pulse-Check Survey

Outcome Priorities

Through previous customer research and contacts, a number of outcomes were identified by customers as priorities for Hydro One. We would like to check that list with you to ensure it is complete. We also want to understand the priorities you give to different outcomes.

Q

The list above may not include all the outcomes that matter to you. Are there any other important priorities that Hydro One should be focusing on that weren't included in the list above?

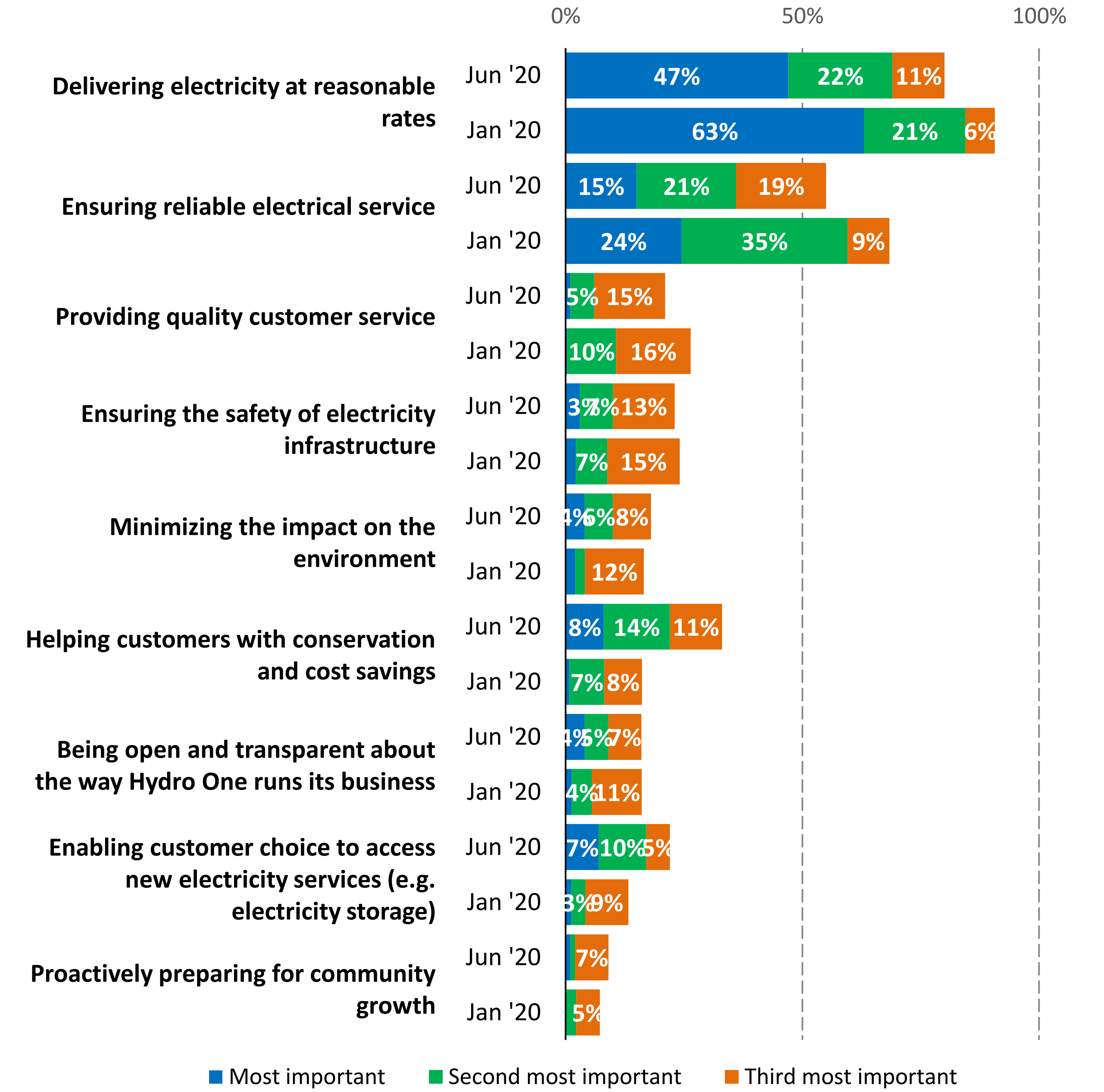


Pulse-Check Survey

Outcome Priorities

Small Business

Q



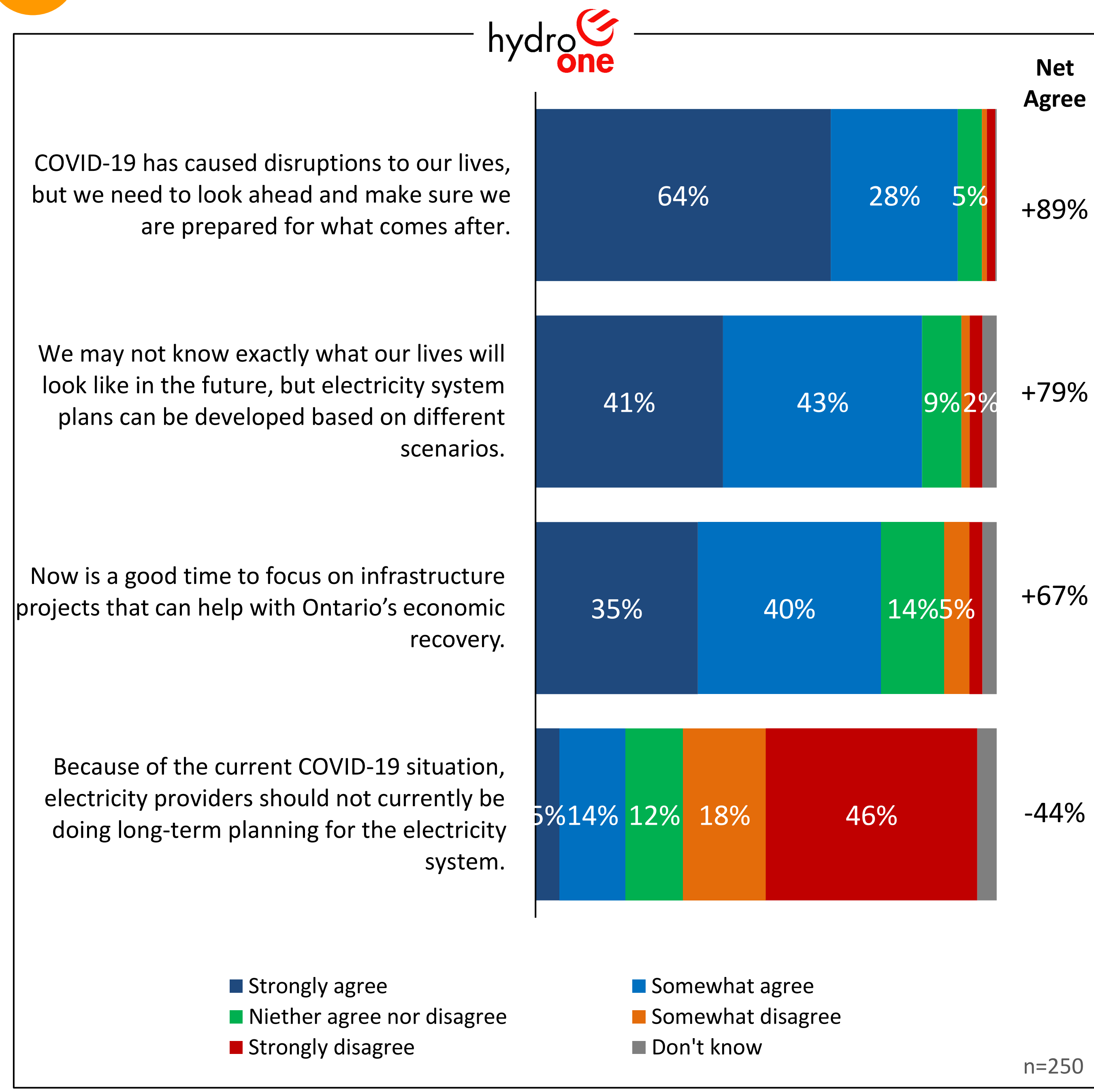
Jan ‘20 n=200
Jun ‘20 n=250

Pulse-Check Survey

Planning for the Future

Small Business

Q To what extent do you agree or disagree with the following statements?



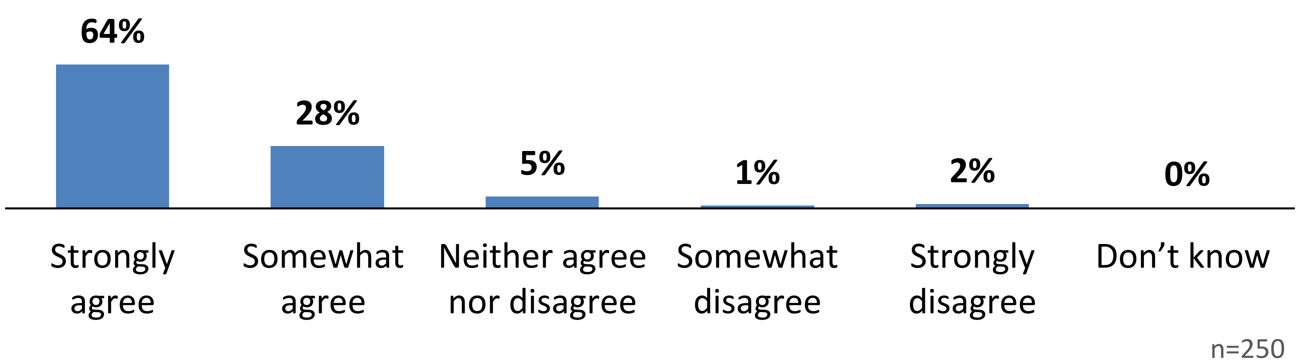
Pulse-Check Survey

Planning for the Future

Small Business

Q

To what extent do you agree or disagree with the following statements?
COVID-19 has caused disruptions to our lives, but we need to look ahead and make sure we are prepared for what comes after.



June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	64%	58%	61%	69%	71%
Somewhat agree	28%	33%	27%	22%	26%
Neither agree nor disagree	5%	8%	5%	4%	2%
Somewhat disagree	1%	-	2%	1%	2%
Strongly disagree	2%	1%	5%	2%	-
Don't know	0%	-	-	1%	-
Overall agree	**92%**	**91%**	**88%**	**92%**	**97%**
Overall disagree	**3%**	**1%**	**7%**	**3%**	**2%**
Net agree	**89%**	**90%**	**82%**	**89%**	**95%**

Pulse-Check Survey

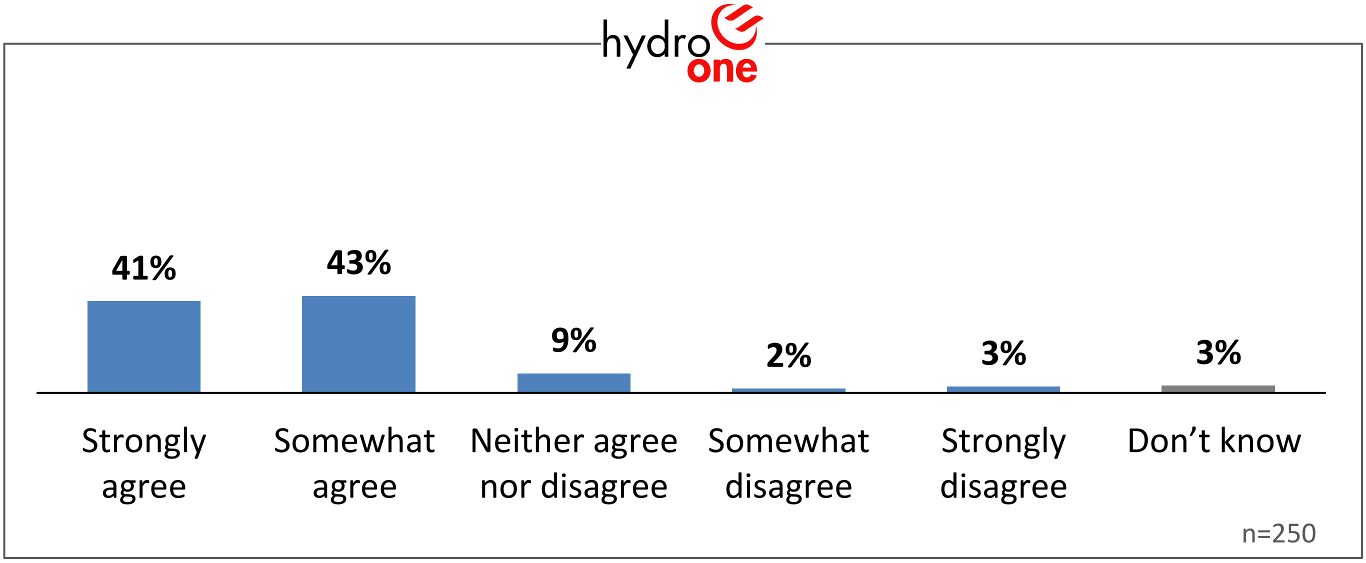
Planning for the Future

Small Business

Q

To what extent do you agree or disagree with the following statements?

We may not know exactly what our lives will look like in the future, but electricity system plans can be developed based on different scenarios.



June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	41%	39%	37%	47%	40%
Somewhat agree	43%	46%	38%	39%	49%
Neither agree nor disagree	9%	10%	13%	6%	3%
Somewhat disagree	2%	1%	2%	3%	2%
Strongly disagree	3%	1%	9%	1%	
Don't know	3%	3%	1%	4%	6%
Overall agree	**84%**	**85%**	**75%**	**86%**	**89%**
Overall disagree	**5%**	**2%**	**11%**	**4%**	**2%**
Net agree	**79%**	**83%**	**65%**	**82%**	**87%**

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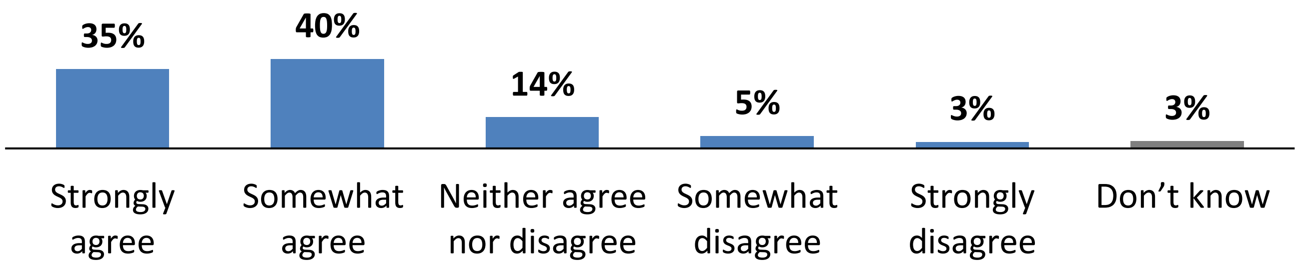
Pulse-Check Survey

Planning for the Future

Small Business

Q

To what extent do you agree or disagree with the following statements?
Now is a good time to focus on infrastructure projects that can help with Ontario's economic recovery.



June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	35%	33%	37%	31%	45%
Somewhat agree	40%	50%	31%	38%	34%
Neither agree nor disagree	14%	13%	17%	16%	6%
Somewhat disagree	5%	2%	5%	8%	8%
Strongly disagree	3%		8%	2%	2%
Don't know	3%	1%	2%	5%	6%
Overall agree	**75%**	**83%**	**67%**	**69%**	**79%**
Overall disagree	**8%**	**2%**	**14%**	**10%**	**9%**
Net agree	**67%**	**80%**	**54%**	**59%**	**69%**

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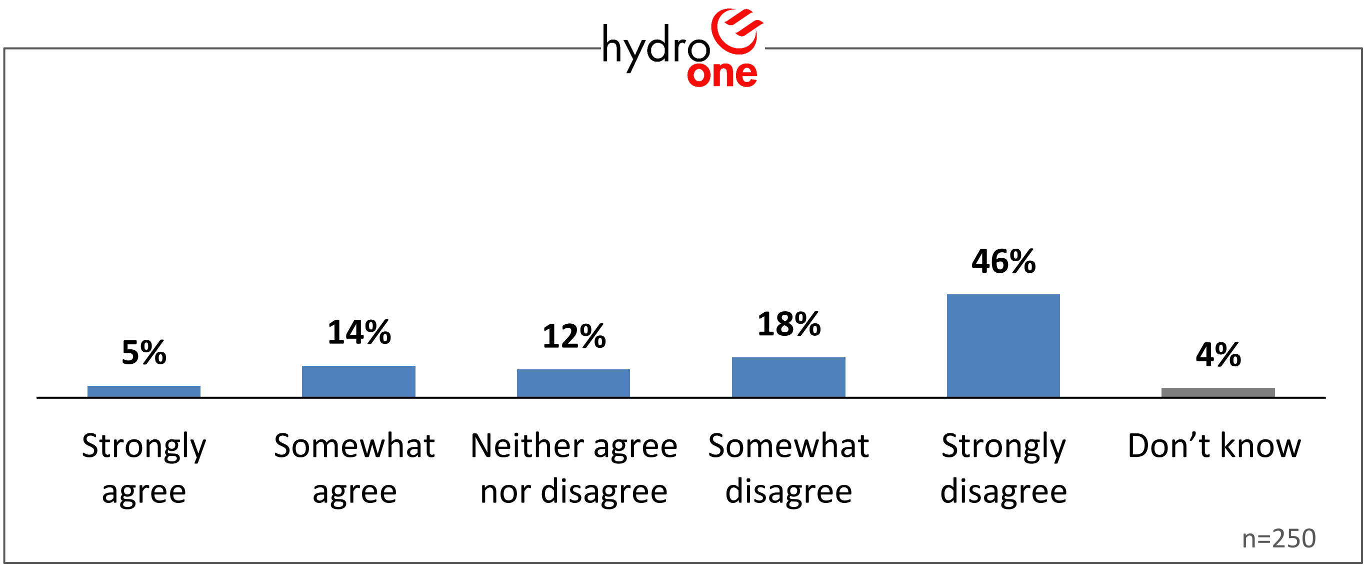
Pulse-Check Survey
Planning for the Future

Small Business

Q

To what extent do you agree or disagree with the following statements?
Because of the current COVID-19 situation, electricity providers should not currently be doing long-term planning for the electricity system.



June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	5%	3%	6%	6%	8%
Somewhat agree	14%	14%	15%	12%	17%
Neither agree nor disagree	12%	13%	13%	11%	12%
Somewhat disagree	18%	22%	21%	14%	12%
Strongly disagree	46%	45%	37%	52%	48%
Don't know	4%	3%	7%	5%	3%
Overall agree	**19%**	**17%**	**21%**	**18%**	**25%**
Overall disagree	**64%**	**67%**	**58%**	**66%**	**60%**
Net agree	**-44%**	**-50%**	**-37%**	**-48%**	**-36%**

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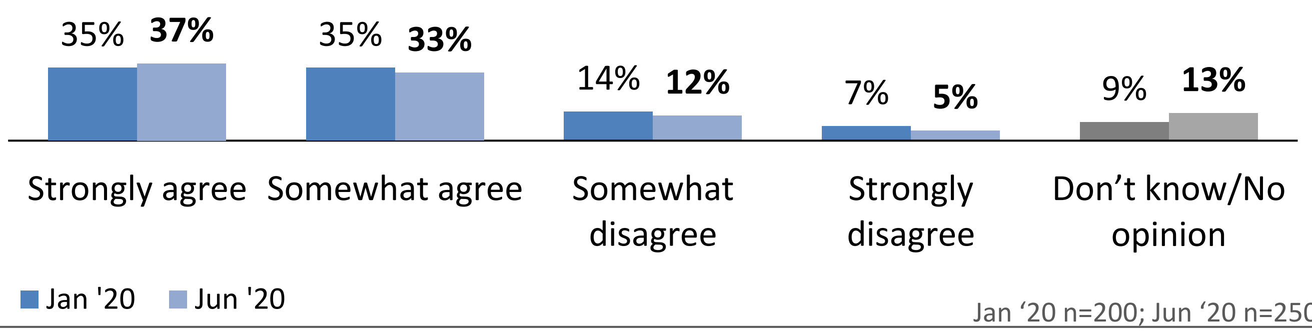
Pulse-Check Survey
Environmental Controls

Small Business

Q

To what extent do you agree or disagree with the following statements?
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.



June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	37%	32%	48%	32%	40%
Somewhat agree	33%	36%	24%	34%	35%
Somewhat disagree	12%	11%	12%	9%	18%
Strongly disagree	5%	8%	7%	3%	-
Don't know/No opinion	13%	12%	9%	22%	7%
Overall Agree	**70%**	**69%**	**72%**	**66%**	**75%**
Overall Disagree	**17%**	**19%**	**19%**	**12%**	**18%**

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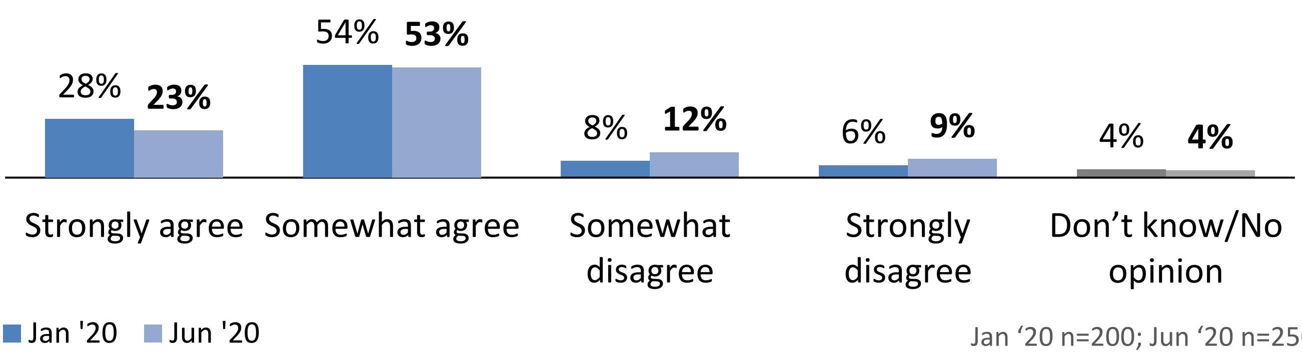
Pulse-Check Survey

Environmental Controls

Small Business

Q To what extent do you agree or disagree with the following statements?
Customers are well served by the electricity system in Ontario.



Jan '20 n=200; Jun '20 n=250

June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	23%	27%	21%	26%	11%
Somewhat agree	53%	61%	47%	50%	51%
Somewhat disagree	12%	5%	15%	13%	20%
Strongly disagree	9%	5%	13%	8%	13%
Don't know/No opinion	4%	3%	4%	3%	6%
Overall Agree	**75%**	**87%**	**68%**	**76%**	**61%**
Overall Disagree	**21%**	**10%**	**28%**	**21%**	**33%**

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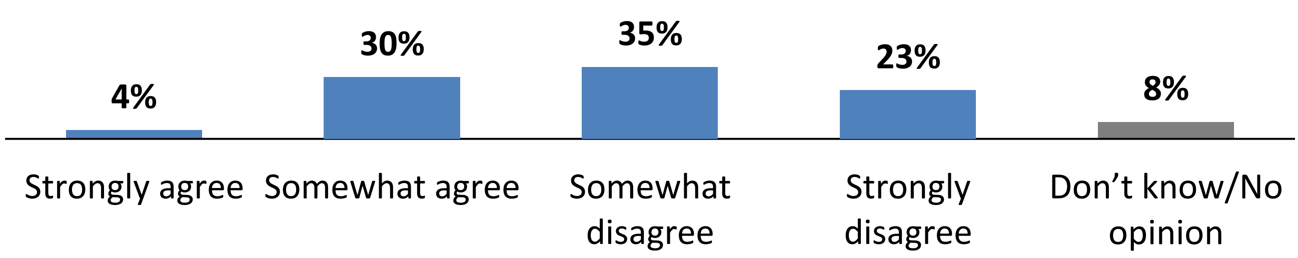
Pulse-Check Survey
Environmental Controls

Small Business

Q

To what extent do you agree or disagree with the following statements?
Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.



June '20	Total	Southern	Central	Eastern	Northern
Strongly agree	4%	7%	4%	4%	
Somewhat agree	30%	30%	28%	28%	35%
Somewhat disagree	35%	31%	36%	37%	36%
Strongly disagree	23%	27%	26%	17%	24%
Don't know/No opinion	8%	6%	6%	15%	5%
Overall Agree	34%	37%	32%	32%	35%
Overall Disagree	58%	57%	62%	54%	60%

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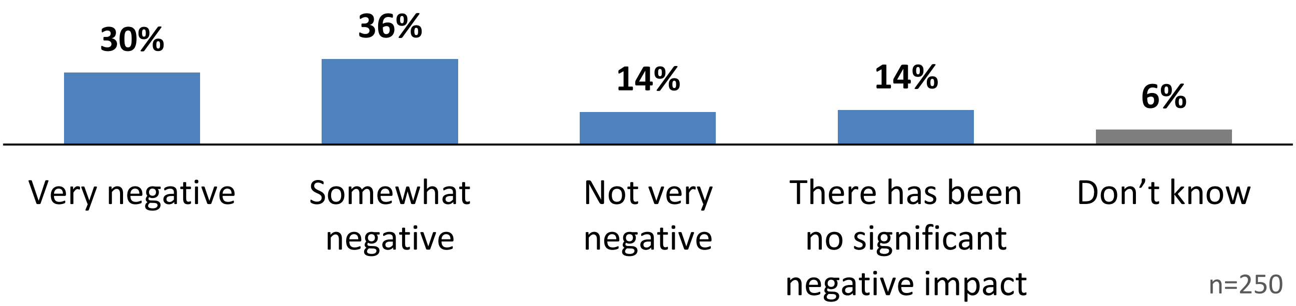
Pulse-Check Survey

Personal Finances

Small Business

Q How big of a negative financial impact has the COVID-19 outbreak had on your organization's finances?



June '20	Total	Southern	Central	Eastern	Northern
Very negative	30%	27%	35%	24%	39%
Somewhat negative	36%	36%	39%	38%	28%
Not very negative	14%	16%	10%	14%	14%
There has been no significant negative impact	14%	12%	14%	18%	13%
Don't know	6%	9%	2%	6%	6%

Building Understanding.

For more information, please contact:

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SECTION 1.7 – SPF – INVESTMENT PLANNING PROCESS

1.7.1 OVERVIEW

This schedule describes the system planning processes that underlie the planned investments in in the Transmission System Plan (TSP), Distribution System Plan (DSP), and General Plant System Plan (GSP) that comprise the System Plans. Section 1.7.1 of this schedule provides an overview of this integrated system planning process.

Consistent with the revised system planning process presented in the last Transmission application (EB-2019-0082), 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) Strategy and Context, (ii) Asset Management, and (iii) Investment Planning.

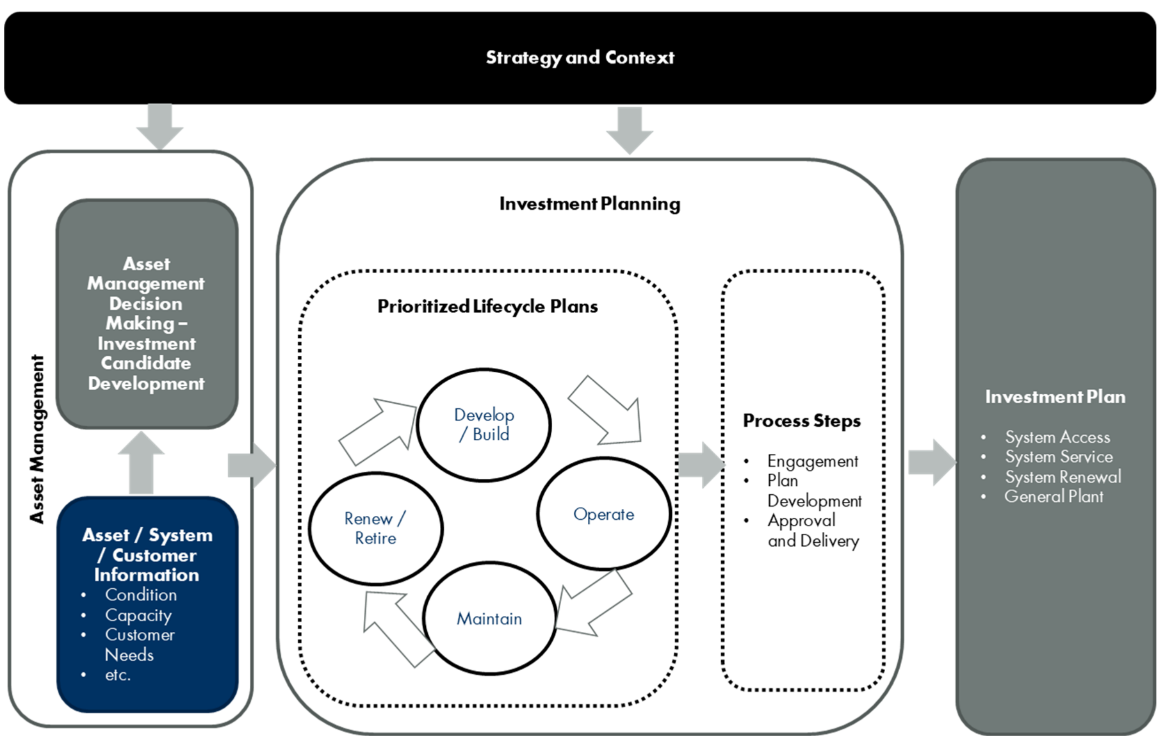

Figure 1: System Planning Process Diagram

Strategy and Context: Hydro One identifies long-term system needs within the context of asset condition, customer priorities, and customer and system load profiles and is informed by the Company's Strategic Priorities, the Company's alignment with the OEB's Renewed Regulatory Framework outcomes, and Phase 1 of the customer engagement process described in section 1.6 of the SPF. Further information on the Strategy and Context underlying the investments in the System Plans is provided in Section 1.7.2 below.

Asset Management: During the asset management process, Hydro One assesses the current state of its assets, evaluates specific asset condition and system requirements, formulates potential options and develops a list of candidate investments. This lifecycle management approach balances asset performance, costs and associated risks during the asset service life. Further information on the Asset Management approach that Hydro One has employed when preparing the System Plans is provided in Section 1.7.3 below.

Investment Planning: Based on the candidate investments, Hydro One uses its investment planning process to identify, prioritize and optimize investments. Risk taxonomies guide the assessment of candidate investments, based on safety, reliability and environmental consequences. 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.

The results of Hydro One's Phase 2 customer engagement process informed the identification of investments for this plan. Following the development of three draft investment scenarios for each of Transmission and Distribution, Hydro One returned to customers and external stakeholders to ask about their preferences between specific investment decisions. Hydro One also solicited feedback from internal business units on cost and execution considerations. The combined output of these engagements informed this investment plan. Further information on the Investment Planning process used to prepare the System Plans is included in Section 1.7.4 below.

1.7.1.1 2023-2027 INVESTMENT PLANNING TIMELINE

The material events contributing to the development of the System Plans and Business Plan are set out below.

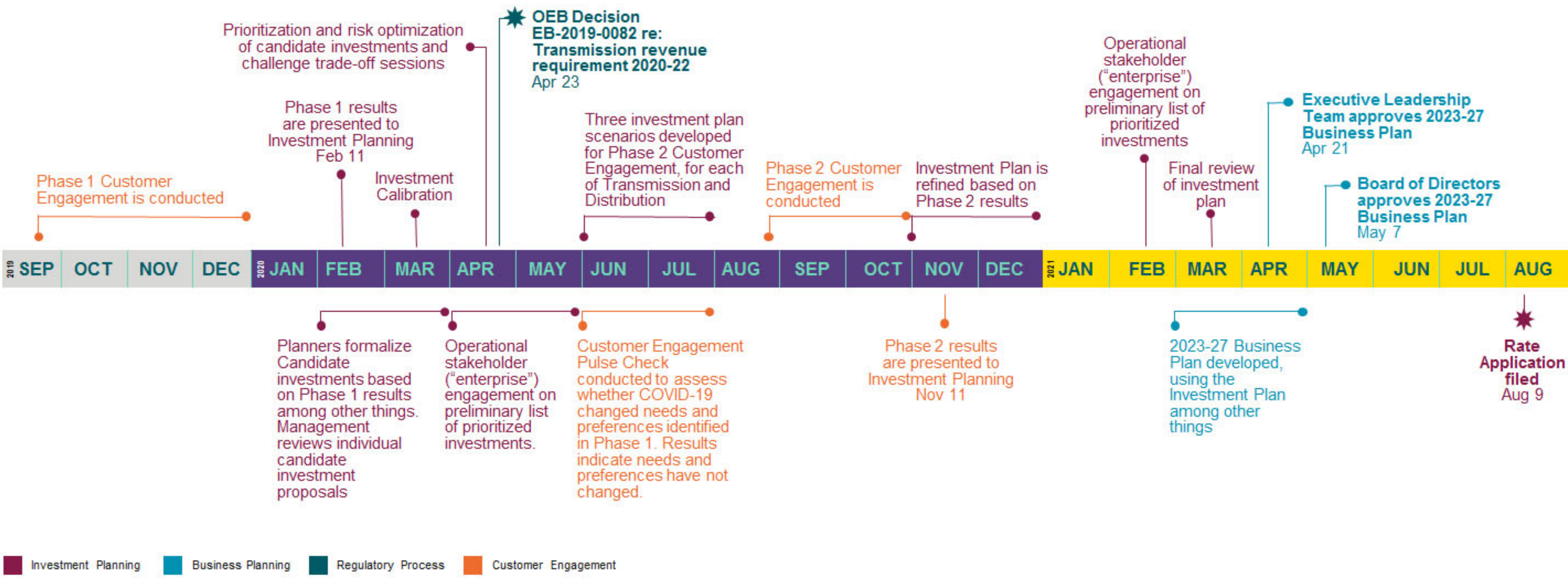

Figure 2: Investment Planning Timeline

1.7.1.2 APPROACH TO TRANSMISSION AND DISTRIBUTION SEGMENTS

Hydro One prioritizes transmission and distribution system investments separately for both segments, consistent with separate OEB approvals and separate revenue requirements. Common corporate costs and general plant investments are allocated based on the result of the Black & Veatch shared asset allocation study provided in E-04-08 and are included within each segment based on business needs.

The discrete drivers that inform the eventual system plans vary across the Transmission 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
- Transmission projects are large, complex, multi-year tasks that require extensive coordination with other power system entities (customers, generators, system operator)
- Much of the transmission system has been constructed to include redundancies, whereas the distribution system is largely radial in nature. This design difference impacts the outcomes experienced by customers.

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. Mandatory 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.

1.7.2 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.

Strategic Priorities:

- We will **plan, design, and build a grid for the future** that is reliable, resilient, and flexible; doing it in a way that delivers value for customers; and balances our environmental responsibility.
- We will be **the safest and most efficient utility** through transformation and improvements to our culture; enabling field operations to drive productivity and reliability; optimizing corporate support; and driving efficient capital delivery.
- We will **advocate for our customers and help them make informed decisions** based on their unique needs, improving customer experience, providing customers with actionable insights, and access to third-party products and services.
- We will **be a trusted partner**, building and strengthening trust-based partnerships with government and industry stakeholders, Indigenous peoples, and other customers to continue to provide essential services to Ontarians.
- We will **innovate and grow** the business to provide value for our customers, shareholders, and other stakeholders through responsible and prudent investment and pursuit of innovative opportunities that present value.

Figure 3: Hydro One's Strategic Priorities and Objectives

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 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 Hydro One's plan outcomes are aligned with the RRF outcomes.

Table 1 - Hydro One's RRF Performance Outcome Objectives

Renewed Regulatory Framework Performance Outcomes		**Plan Outcomes**
Customer Focus	Customer Satisfaction	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Deliver industry-leading customer service, in response to identified customer preferences
Operational Effectiveness	Cost Control	• Focus on continuous improvement to enhance efficiency, productivity, and reliability
	Safety	• Achieve top-tier safety performance and eliminate serious injuries
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Maintain top tier Transmission reliability performance and improve long-term Transmission and Distribution reliability
Public Policy Responsiveness	Public Policy Responsiveness	• Deliver on obligations mandated by government through legislation and regulatory requirements
	Environment	• Lower Hydro One's environmental footprint through greenhouse gas reduction
Financial Performance	Financial Performance	• Responsible investment in rate base assets to ensure the safety and reliability of the grid • Manageable and stable rate impacts over the course of the planning period

1.7.2.3 CUSTOMER ENGAGEMENT PHASE 1

The investment planning process is also informed by customer engagement. Hydro One's full spectrum of customer engagement initiatives is designed to:

- increase the company'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 with the Hydro One services.

As described in Section 1.6 of the SPF and in Section 1.7.4 below, Hydro One is committed to proactive, consistent and transparent engagement with its customers and stakeholders to understand their needs, preferences and priorities. As such, Hydro One conducted an extensive customer engagement exercise in 2019 and 2020 to inform the investment plans underlying this application. The engagement process was conducted by Innovative Research Group Inc. (IRG) and is the most comprehensive customer engagement in Hydro One's history, the results of which directly informed the transmission and distribution investments in the planning period. For the first time, investment planning and the customer engagement processes were integrated over two phases as summarized below in Figure 4.

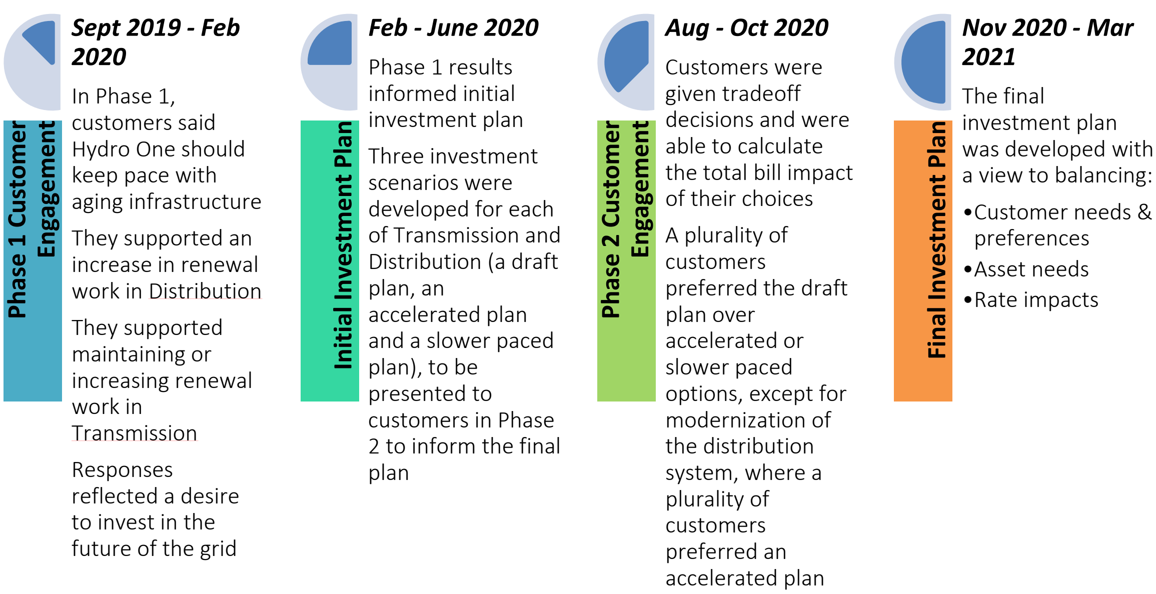

Figure 4: Integrated Customer Engagement and Investment Planning Process

Customer feedback from Phase 1 of the engagement process was provided as an initial input into the System Plans, and set the context for the subsequent development of the investment plans. Three investment scenarios were prepared for each of Transmission and Distribution to reflect initial feedback in Phase 1. These scenarios were later presented to customers in Phase 2 of the customer engagement process to test which scenario best reflected customer needs and preferences. This approach allowed Hydro One to develop a final investment plan for 2023-2027 that is directly responsive to customers' needs.

As part of Phase 1, customer priorities and outcomes were identified, within the context of indicative investment envelopes and preferred outcomes, summarized through Customer Engagement Planning Placemats, included as Attachment 6 to section 1.6 of the SPF.

Through Phase 1, Hydro One surveyed a representative group of its distribution and transmission customers through focus group sessions, phone surveys, in-depth interviews and an online survey using a workbook that asked customers about their priorities and what trade-offs they were willing to make between rate increases and levels of investment and service outcomes.

Distribution customers prioritized reasonable rates and reliable service. In respect of reliability outcomes, they prioritized reductions to the length of time to restore power after extreme weather, and fewer outages during extreme weather. With respect to trade-offs:

- A clear majority of customers preferred a more proactive approach to replacing aging infrastructure, when or before it starts to deteriorate. Most wanted Hydro One to invest in reliability but were divided over the level of investment, between maintaining and improving
- The majority supported investments in hardening the system, either as part of ongoing system renewal or as proactive investments.
- Almost all want to help those with poor reliability, by either shifting or increasing spending.
- Customers were divided over funding additional spending on building capacity to enable economic growth.
- Most customers want investments to keep the business running safely and reliably.

Transmission customers prioritized reasonable rates and reliable service. In respect of reliability outcomes, they generally prioritized reductions to the length of time to restore power after extreme weather, and fewer outages during extreme weather. With respect to trade-offs:

- A clear majority wanted to maintain or increase the current level of investment to replace aging transmission infrastructure.
- Most wanted investments in a more reliable transmission system, either as part of ongoing renewal or as proactive investments.
- The majority wanted Hydro One to make investments to improve power quality.

Hydro One developed a clear and specific understanding of the outcomes that its customers 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 plan. The feedback received from customers through the Phase 1 customer engagement process is an important and direct input into Hydro One's asset management and investment planning process.

1.7.2.4 ECONOMIC PLANNING ASSUMPTIONS

Hydro One relied on the following economic assumptions in the investment planning process:

- Inflation is based on the Ontario Consumer Price Index (CPI)
- Exchange rates (CDN:USD) are based on the November 2020 Global Insight Forecast

1.7.3 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 output of the asset management process is a key component of the investment planning process.

1.7.3.1 CURRENT STATE ASSESSMENT

Hydro One monitors and assesses the current state of the system and its assets on an ongoing basis as part of its asset management and system planning process. The development of candidate investments is underpinned by a comprehensive needs assessment, which considers several dimensions including (i) asset-specific investment needs, particularly condition, (ii) customer needs and preferences, (iii) system needs (including regional and bulk planning considerations), (iv) operational needs, and (v) other external influences. Each of these components is discussed in the sections that follow.

ASSET NEEDS ASSESSMENT

Hydro One planners perform an asset needs assessment to identify the drivers in the development of 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 prerequisite of, and critical input into, the investment planning process. The output of the asset needs assessment is a portfolio of investment candidates that reflects asset-related needs and risks, particularly on the basis of asset condition. The investment candidates are further scored and prioritized through the investment planning process (as described in Section 1.7.4.3 below) to achieve the optimal balance of risk and benefits.

The asset needs assessment processes are 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 (ex: transformers, conductors, breakers, and protection and control systems) and distribution (ex: station transformers, poles) that directly affect system reliability. This process drives effective planning decisions by ensuring 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 defined using different criteria for different assets. For example, the condition of a transmission or distribution station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test. While methods to evaluate condition vary, the condition of all assets of a given type is evaluated consistently based upon objective criteria. Assets of a given type that have a high condition risk are candidates for refurbishment or replacement.
- **Criticality** – 'Criticality' is the impact the failure of a specific asset would have on the transmission or distribution system. Criticality is primarily used to show the relative importance of an asset compared to other assets of the same type. 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** - Risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized. The relative deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. 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 of the breaker. Therefore, the asset utilization risk for transformers and circuit breakers considers their relative deterioration based on available loading and operational history, respectively.
- **Performance** - Risk that reflects the historical performance of an asset, derived from the frequency and duration of outages. Past performance can be a good indicator of

expected future performance. Therefore, assets with a relatively 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.

On-site assessments with field personnel are conducted to validate and confirm asset condition, 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 actually reflect the condition of the assets in the field.

Many system renewal investments in the System Plans are informed by the asset needs assessment process, largely driven by asset condition. Material planned investments to address asset needs include:

- D-SR-04 – Distribution Station Refurbishments – to address poor condition station transformers
- D-SR-07 – Distribution Pole Replacements – to address poor condition wood poles
- D-SR-12 – Advance Meter Infrastructure 2.0 – to address poor performing and obsolete first generation meters
- T-SR-01 - Transmission Station Renewal - Network Stations – to address poor condition, end-of-life assets at transmission network stations part of the bulk electricity system
- T-SR-02 – Transmission Air Blast Circuit Breaker Replacements – to address poor condition and poor performing air blast circuit breakers
- T-SR-03 - Transmission Station Renewal - Connection Stations – to address poor condition, end-of-life assets at transmission connection stations that directly supply customers, including local distribution companies and industrial customers

- T-SR-19 – Transmission Line Refurbishments – to address poor condition overhead conductors and related infrastructure

CUSTOMER NEEDS

Understanding customer needs is critical to Hydro One's business and investment planning processes. Hydro One's ongoing process mechanisms help the Company quickly and proactively identify customer needs. The needs of new customers are most 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 by continuous monitoring of the power system and engagement with major customers (ex: transmission connected local distribution companies, transmission connected industrials, large distribution accounts).

Planned System Access investments are largely informed by specific customer needs and requests, including:

- T-SA-01 – New Customer Connection Stations near Richview and Parkway
- T-SA-04 – Connect Metrolinx Traction Substations
- T-SA-10 - Build Leamington Area Transformer Stations
- D-SA-02 – New Load Connections and Upgrades
- D-SA-03 – Connecting Distributed Energy Resources

SYSTEM NEEDS

System needs relate to work that is necessary to maintain and operate the transmission and distribution system to adequately and reliably deliver supply to customers, driven by the requirement to meet current and forecast requirements resulting from the connection of new load customers, generation facilities and other distributed energy resources. System needs include:

- Provision of adequate capacity to reliably deliver electricity to the local areas connected to Hydro One's system;

- Address 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);
- Provision for regional transmission facility needs identified as part of the regional planning process; and
- Local distribution upgrades and enhancements to relieve system capacity constraints and meet forecast load growth, consistent with the requirements of the Distribution System Code.

Under the electricity industry 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 (e.g., through the Long Term Energy Plan), 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 as 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.

System needs assessments, regional planning, and larger bulk planning processes result in the identification of system service investments, including:

- D-SS-01 – System Upgrades driven by Load Growth – to address local and regional capacity constraints
- T-SS-03 – Merivale x Hawthorne Upgrades – to increase capacity to meet future demand requirements
- D-GP-01 – Capital Contributions to Hydro One Transmission – capital contributions to increase transmission capacity to accommodate forecast distribution load growth.

- G-GP-14 – Network Management System Investments – to sustain centralized monitoring and control functions for the transmission system

EXTERNAL AND OTHER INFLUENCES

Hydro One uses information on industry best practices, trends and benchmarking to compare its operations and performance to other utilities within the industry. Technical studies performed on the system provide further insight into the state of the asset base and support the decisions regarding which assets are candidates for investment. A description of the benchmarking studies and the resulting recommendations are included in SPF section 1.3.

1.7.3.2 INVESTMENT CANDIDATE DEVELOPEMENT

Throughout the assessment of individual asset and system needs, 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 refurbishment 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 candidate investments. The candidate investments are considered further during the Investment Planning process and are evaluated and justified 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 1.7.4.1 below. Risks related to asset condition, performance and utilization inform the probability score, and risks relating to asset criticality directly inform the consequence score.

1.7.4 INVESTMENT PLANNING

1.7.4.1 INVESTMENT CANDIDATE LIFECYCLE RISK ASSESSMENT

Following the investment candidate identification process described above, candidates 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]

[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.

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 taxonomies that have been developed to classify safety, reliability and environmental risks.[2] Each risk taxonomy features clear definitions and consistent assessments, which permits a proper comparison between candidate investments. These risk taxonomies exclude extreme events such as extreme natural hazards or health pandemics.

Hydro One assesses proposed candidate investments on the consequence and probability of the safety, reliability and environmental risks that they are designed to mitigate. These taxonomies 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 taxonomy has seven consequence levels upon which each investment is assessed. The seven consequence levels are based on the financial impact of the WRDI and are quantified to the same scale for each of the three risk taxonomies. The assessments are calibrated across taxonomies. For example, a score of "6" in the reliability consequence taxonomy is equivalent and comparable in severity to a

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[2] Reliability consequences can be classified in terms of unsupplied energy, 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.

score of “6” in safety and environmental taxonomies. Figures 5 to 8 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 9 below) is an assessment of the likelihood of a failure event happening in a given year or during a specified period of time based on the WRDI 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.

FLAGGING

Hydro One utilizing a "flagging" process to account for special considerations and to ensure stakeholder perspectives are consistently included in the evaluation of investments. 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. To incorporate key customer and regulatory outcomes into its evaluation of projects, Hydro One's flags enable it to identify investments that address key customer priorities such as improving power quality, and investments that align to strategic priorities and objectives.

Flags are classified as either "mandatory" or "non-mandatory." The flagging 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 net result of this process is more efficient investment prioritization and optimization, which eventually leads to lowered costs for customers.

Flagging is guided by specific and defined categories which are common and consistent across proposed investments. As risk scoring cannot always capture all relevant considerations, flags are applied to investments when such other considerations ought to be material drivers of the funding decision.

The following flags have been established to provide clear guidance and a more rigorous definition of what constitutes a mandatory investment:

- **Immediate / Short-term Compliance** – Explicit obligation to a regulatory agency (e.g., OEB requires work to be done within a year with immediate risk of legal breach, or there is a two to five-year risk of regulatory or legal breach);
- **Third party requests** – Explicit connection request by a city, county, agency, or customer, with a one to five-year risk of breaking the utility obligation to serve;
- **Contractual** – Signed, fixed-sum contracts with third parties for services such as IT support, facility support, etc.; and
- **In-Flight** – Project already under construction.

The following flags are used for non-mandatory investments and represent factors that are important to Hydro One and its customers:

- **Customer Engagement** – Influence of customer engagement/consultation; response to specific customer needs and preferences, including those described in greater detail in Section 1.6 of the SPF. These were flagged after Phase 1 of the Customer Engagement process;
- **Productivity** – Contains committed productivity savings, as tracked by the company, or facilitates future productivity savings;

- **Corrective Maintenance/Demand Replacements** – A risk identified by Hydro One or other utilities that requires near-term action (e.g., break/fix);
- **Preventive Maintenance/System Renewal** – Opportunity to prolong asset life with planned and condition-based maintenance, or renew the asset based on condition considerations, consistent with asset management practices;
- **Strategic** – Codified goal by leadership team or explicit request by senior leadership;
- **Political Commitments** – Explicit statement by Hydro One officer to non-agency parties such as politicians, media or through official public statement, etc.; and
- **First Nation Communities** – Investment to address needs identified with respect to facilities serving First Nation communities.

1.7.4.2 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 scorers and management from across the organization together to compare approaches, assumptions and quality of data used in scoring investments. The sessions ensure that all stakeholders have applied the scoring process consistently. After the session, investment owners have an opportunity to revise their scores consistent with feedback received at the session.

1.7.4.3 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 10 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 consequence 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 (broken into mandatory versus non-mandatory groups) are ranked according to risk mitigation achieved per dollar or the risk-spend efficiency.

CHALLENGE SESSIONS

Challenge sessions are facilitated discussions among a broad set of stakeholders to (i) review an integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g., strategic, 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, aimed at defining the funded investments portfolio, with the focus on ensuring that the most valuable work to customers 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 other non-risk parameters (i.e., qualitative flags). 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.

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): Which investments need to be funded for non-risk merits?
- The consideration of both risk efficiency and risk mitigated per dollar supports the making of prudent and data-driven trade-off decisions.

1.7.4.4 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. Externally, the second phase of customer engagement is undertaken to further solicit customer feedback on specific investment decisions. The results of both engagement activities are taken into consideration as part of the development of the final plan.

ENTERPRISE ENGAGEMENT

The enterprise engagement process is held to ensure that the investment plan is properly reviewed and updated, where needed, by the executing lines of business. The goal is to create a realistic and up-to-date version of the investment plan to be considered at the final challenge session. 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 investment scope. Enterprise review also identifies interim milestones for investment definition stages that will set the organization up for success by providing the ability to monitor the associated milestones and identify potential challenges earlier in the process.

Adjustments may be made to reflect emerging execution or asset management risks based on discussions during enterprise engagement sessions.

PHASE 2 CUSTOMER ENGAGEMENT

Customer needs and preferences from Phase 1 were used to develop three investment plans for each of Transmission and Distribution between February and June 2020. Each investment plan included a different level of investment and service outcome, with a corresponding rate impact, that reflected the direction provided by customers in Phase 1 as follows:

- **Scenario 1: Slower Pace –** prioritizes low cost/managing rate impacts, by deferring the replacement of assets in poor condition to a future rate period, and thus resulting in higher system risk and rates in the long term
- **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 while managing costs and rate increases now and in the future
- **Scenario 3: Accelerated Pace –** responds to the needs of the system and assets, and delivers the outcomes prioritized by customers, allowing Hydro One to replace more of its aging infrastructure; costs under this plan are higher but long term risk and rates are lower as a result of accelerated equipment replacement

Hydro One presented these scenarios to customers in Phase 2 of customer engagement. Customer feedback on those scenarios was incorporated in the System Plans, as discussed further in section 1.7.4.4 below.

Phase 2 provided customers with an opportunity to identify the outcomes that they value, as well as the level of spending and mix of investments that customers would most like to see included in Hydro One's investment plan. Consequently, Hydro One's capital expenditure plan, as set out in the System Plans, is closely aligned with and highly responsive to the customer needs and preferences that Hydro One has identified.

Tables 2 and 3 below summarize the distribution and transmission trade-offs presented to customers.

Table 2 – Phase 2 Distribution Trade-offs

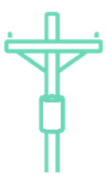
Segment	Option	Scenario 1 (Slower Pace)	Scenario 2 (Draft Plan)	Scenario 3 (Accelerated Pace)
Distribution 	1. Replacing poles in poor condition	Slow the proposed pole replacement program, focusing on larger poles serving >400 customers	Replace all poles in poor condition that serve at least 100 customers	Replace all poles in poor condition that serve >30 customers
	2. Replacing poor condition station transformers	Reduce the pace of replacement, leading to high risk of outages and fleet deterioration	Maintain current approach; results in slight deterioration of fleet condition	Increase the rate of replacement, improving the overall fleet condition
	3. Grid modernization	Deploy smart devices to improve reliability for ~200k customers	Deploy smart devices to improve reliability for ~400k customers	Deploy smart devices to improve reliability for ~600k customers
	4. Battery Energy Storage	Deploy battery storage to improve reliability for ~500 customers	Deploy battery storage to improve reliability for ~4,000 customers	Deploy battery storage to improve reliability for ~8,000 customers
	5. Facilitating Growth	Delay community growth & economic development in rural areas, impacting reliability & power quality	Allow new economic development to proceed, maintaining reliability and power quality	Enable regional and economic development, maintaining reliability and power quality.
	6. Replacing Smart Meters	Not applicable. Replacing at a slower rate could lead to higher costs	Replace meters over a 7-year period	Replace meters over a 5-year period

Table 3 – Phase 2 Transmission Trade-offs

Segment	Option	Scenario 1 (Slower Pace)	Scenario 2 (Draft Plan)	Scenario 3 (Accelerated Pace)
Transmission	7. Replacing poor condition transmission lines	Slightly lower the current level of safety and reliability performance of transmission lines	Maintain the current level of safety and overall health of transmission lines	Moderately improve the current level of safety and overall health of transmission lines
	8. Replacing poor condition transmission stations	Replacing only the most critical infrastructure, which will increases performance and environmental risks and creates need for higher investment levels later on	Maintain the overall health of transmission station infrastructure and sustain current performance and environmental risk	Improve the overall health of transmission station infrastructure and reduce the risk of equipment failure

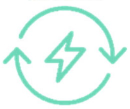
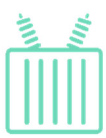
All Distribution customers were invited to complete an online workbook covering the draft plans for both the Distribution and the Transmission system. Large Transmission customers and indirect customers served by other Distribution companies also had the opportunity to provide feedback on the draft Transmission plan. First Nation communities and the Métis Nation of Ontario were engaged through separate online workbooks and in-depth interviews, and municipalities and key stakeholders were invited to provide feedback through one-on-one interviews. Through Phase 2 of Customer Engagement, over 43,000 customers completed the online workbook.

In general, a plurality of customers preferred the draft plan (Scenario 2) over accelerated or slower paced options, except for modernization of the distribution system, where a plurality of customers preferred an accelerated plan (Scenario 3).

Following the conclusion of Phase 2 of customer engagement, Hydro One analyzed the results and considered the alignment between asset needs, customer needs and preferences and overall costs, making select adjustments to its investment plan to strike an appropriate balance. Hydro One held further cross-functional sessions to roll out the results of the surveys, and inform the finalization of the investment plan.

The specific customer inputs resulting from Phase 2 ultimately informed the investment plan, as summarized in Table 4 below:

Table 4 – Implementation of Customer Inputs to the Investment Plan

	Customer Inputs	**How it appears in our investment plans**
System Access 	Requirements for timely access and grid service Growth: A majority of customers across all segments prefer the draft plan over an accelerated or slower pace	Provide customers timely access to the network through customer connections and paced regional expansions
System Service 	**Distribution** <u>Grid Modernization</u>: Across all customer types, the accelerated pace is the preferred option <u>Battery Storage</u>: There is a clear preference for the draft plan, with less appetite for an accelerated pace than in other investment categories	Deliver improved reliability to our customers, pursuing safe, cost effective solutions to meet their needs, including deployment of over 1,000 smart devices/year and batteries to support ~800 customers/year.
System Renewal 	**Distribution** <u>Poles</u>: Across all customer types, the draft plan is the preferred option. <u>Transformers</u>: Residential customers favour an accelerated replacement pace, while business customers lean towards the draft plan. <u>Smart Meters</u>: Both residential and small business customers have a clear preference for the draft plan (7-year deployment)	• Address critical asset needs, including renewing the current fleet of assets, replacing and refurbishing ~65k wood poles and replacing ~24 distribution station transformers/year consistent with customer feedback • Accelerated the replacement of smart meters to a 5-year deployment over a 7-year horizon, in response to third party study findings indicating a faster failure rate of old meters than anticipated
	Transmission <u>Lines</u>: Across all customer types, the draft plan is the preferred option. Residential and small business customers show a greater interest in the accelerated pace <u>Stations</u>: Across all customer types, the draft plan is the preferred option	• System reinvestment to address verified, condition-based asset and system needs, including replacement of ~25 poor condition transformers/year, refurbishment of ~300 km/year of deteriorated and at-risk conductors and related components

Hydro One adjusted its draft plan to incorporate outcomes that were valued by customers, including increased distribution station transformer replacement, accelerated deployment of grid modernization, and marginal increases to transmission renewal programs.

The outcome of this exercise, informed the final composition of the investment plan.

1.7.4.5 INVESTMENT PLAN DEVELOPMENT

Based on the feedback provided by customers in Phase 2 of Customer Engagement, the final investments are developed, incorporating internal feedback and customer preferences on trade-offs and pacing. Those investments incorporate the following:

- **Feedback from Phase 2 of Customer Engagement** – incorporate customer feedback and reprioritize investments based on cost-outcome considerations specified by customers
- **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 and scheduled maturity, permitting completion of more/less proposed investments that are on the margin, in consideration of execution feasibility. In this regard, certain earlier assumptions around project maturity (which in turn impact planned pacing and costs for the 2023-2027 period) were modified to reflect updated information.

Additional considerations that resulted in refinements to the investment plan included: (i) updated allocation of common assets between Transmission and Distribution, and (ii) updated load forecast based on latest IESO information (which also led to higher forecast customer connection volumes).

1.7.4.6 INVESTMENT PLAN APPROVAL AND DELIVERY

Hydro One closely monitors the execution of its investment plan to ensure it is effectively delivered. Once the Board of Directors approves the plan, the execution team takes ownership for delivery. The plan is reviewed throughout the execution phase as new information on asset condition and risks becomes available. If needed, resources can be redeployed through the redirection process.

INDIVIDUAL INVESTMENT APPROVAL

Individual investments are further reviewed and approved through the business case process, 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 Sections 2.10, 3.10, and 4.10.

MONITORING & CONTROL

Hydro One monitors year-to-date expenditures and accomplishments, as well as projected year-end expenditures, on a monthly basis. Variances from the plan are identified and managed through a variance and redirection process. The approval of the variance proposal is in accordance with the limits set out in the expenditure authority register based on the cost and criticality of the investment.

REDIRECTION OF FUNDS

As changes to investments or other circumstances occur during the year, Hydro One reprioritizes during execution as new information may change one or more projects' expected value, timing, cost, customer needs, and other factors. A Redirection Committee oversees the operational redirection of funds and authorizes additional spending as necessary. Redirection or allocation allows prudent and timely adjustments to be made to the work originally identified in the investment plan. These redirection decisions take place separately within the transmission and distribution segment, with the exception of common shared asset investments.

Hydro One's Redirection Committee[3]: (i) oversees the redirection process where investment changes are approved, documented, systemized and communicated to the relevant stakeholders; (ii) provides advice and direction on investment adjustments to address emerging business needs or risks; and (iii) ensures an enterprise-wide understanding regarding issues affecting the execution of Hydro One's investment plan.

Following the review and recommendation of plan adjustments, investment level decisions are documented and communicated to appropriate stakeholders, including the recommended change and rationale. Updates regarding significant Redirection Committee decisions, as well as recommendations related to reprioritization options that require an approval authority that exceeds that of members of the committee are communicated to the ELT.

PERFORMANCE REPORTING

The final stage of the planning process is monitoring performance of the approved Investment Plan by tracking actual outcomes, measuring performance, and benchmarking. Hydro One compares actual investment costs and accomplishments to the proposed investment plan. In this Application, Hydro One is proposing to include a set of key performance measures in its scorecard to track the company's performance. Hydro One also benchmarks its performance against other utilities on the basis of specific accomplishments and costs for each investment as indicators. Details of Hydro One's benchmarking activities that informed this Application can be found in SPF section 1.3.

[3] The Committee includes the VP Planning, VP Transmissions & Stations, VP Distribution, VP Shared Services, VP System Operations, SVP Corporate Finance, CIO, VP Customer Service, and VP Regulatory and Chief Risk Officer.

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SECTION 1.8 – SPF – CLIMATE CHANGE

1.8.1 OVERVIEW

Over the 2023-2027 period, Ontario's changing climate will continue to affect the way that Hydro One builds and maintains its networks, and how the company operates its business. Section 1.8.2 of this schedule summarizes the growing risks and recent impacts of climate change on Hydro One's networks. Section 1.8.3 summarizes Hydro One's responses to climate change, which include both adaptation (i.e., investing in reliability and resiliency[1]) and mitigation (i.e., moderating the company's greenhouse gas (GHG) emissions).

Hydro One is committed to transmitting and distributing electricity in a safe, environmentally and socially responsible manner to meet the needs of the people of Ontario. Responding to Climate Change is one of the company's Environmental, Social and Governance priorities and is also integral to Hydro One's strategic priority to plan, design and build a grid for the future.[2]

Hydro One's focus on climate change is consistent with the priorities of Hydro One customers. The investment plan set out in this SPF is based on a comprehensive, two-phase customer engagement process conducted in 2019 and 2020 (SPF Section 1.6). During the first phase of that engagement, customers were surveyed regarding needs, preferences and priorities, including those related to reliability and responses to extreme weather events. Distribution customers' top reliability priorities were (i) reducing the length of time to restore power during extreme weather events, and (ii) reducing the number of outages during extreme weather events.[3] When asked about high-level priority areas for investment, over 90% of distribution

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[1] Reliability is an outcome which is reflective of the design, construction, maintenance and operation of the transmission and distribution to provide stable and adequate supply, while resiliency is a related concept, representing the system's ability to withstand and recover from disruptions, including the impacts of severe weather.

[2] Hydro One Inc., Hydro One 2019 Sustainability Report (July 2020) – page 22 (https://www.hydroone.com/Sustainability/Documents/CSR_2019/HydroOne_CSR_2019.pdf)

[3] Innovative Research Group, Hydro One Customer Engagement Report (December 2020) – SPF Section 1.6 Attachment 1, page 16

customers indicated that Hydro One should invest in making the system more resilient to severe weather, either as part of ongoing renewal (31%) or on a proactive basis (60%) to reduce the length and number of outages caused by severe weather.[4] Similarly, customers were surveyed regarding transmission strategies related to improving reliability and resilience; over 80% of customers supported investment in a more reliable transmission system, either as part of ongoing renewal (43%) or on a proactive basis (38%).[5]

The results of this customer engagement indicated that customers understand and value reliability and resilience, indicating that Hydro One should pursue approaches that:

- Improve the grid's ability to withstand and recover from extreme weather events.
- Improve restoration times through increased coordination, enhanced response, and reduced human error.
- Prevent, minimize and restore power outages to continue to provide safe and reliable power to customers.

1.8.2 CLIMATE CHANGE IMPACTS AND RISKS

Ontario's electricity grid is critical infrastructure, comprised of systems and services that are essential to the daily life and economy of the province. Loss of supply and outage events can have far-reaching impacts on Hydro One's customers and, in extreme events, on the effective functioning of the province as a whole.

Hydro One's networks, and the broader electricity sector in general, are vulnerable to climate risks. Changing meteorological conditions, such as temperature, precipitation and wind, and extreme weather, have already affected continuity of supply, and system operations. In recent years, weather has impacted Hydro One system performance on both the transmission and distribution systems.

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[4] Innovative Research Group, Hydro One Customer Engagement Report (December 2020) – SPF Section 1.6 Attachment 1, page 18
[5] Innovative Research Group, Hydro One Customer Engagement Report (December 2020) – SPF Section 1.6 Attachment 1, page 19

On the transmission system, over the last 25 years, flooding and tornados have been the most significant weather related cause of energy losses, driven in large part by catastrophic flooding in the greater Toronto area in 2013 and a significant tornado event in the Ottawa area in 2018 (as depicted in Figure 1 below).

Figure 1: Aftermath of the September 21, 2018 tornado outbreak at the Merivale Transmission Station

As displayed in Figure 2 below, the distribution system has experienced an increasing trend of force majeure and storm days since 2014, illustrating the frequency with which some of the events may impact the system. Further discussion of reliability performance is included in TSP Section 2.5 and DSP Section 3.5.

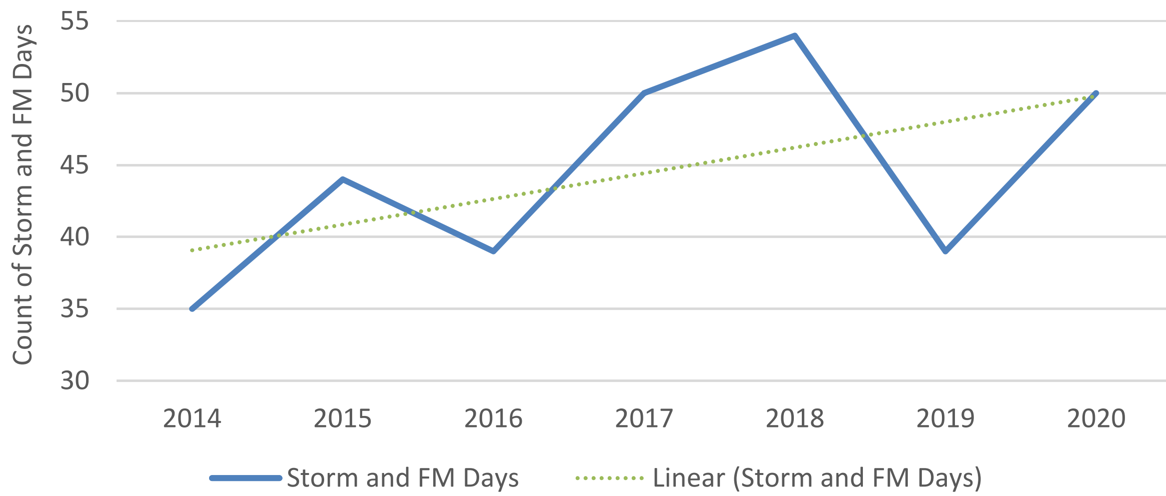

Figure 2: Storm and Force Majeure Days between 2014 and 2020

Responding to severe weather is also costly. Hydro One invests approximately $100M annually on distribution storm and trouble response, an investment which has steadily increased over the last 10 years.

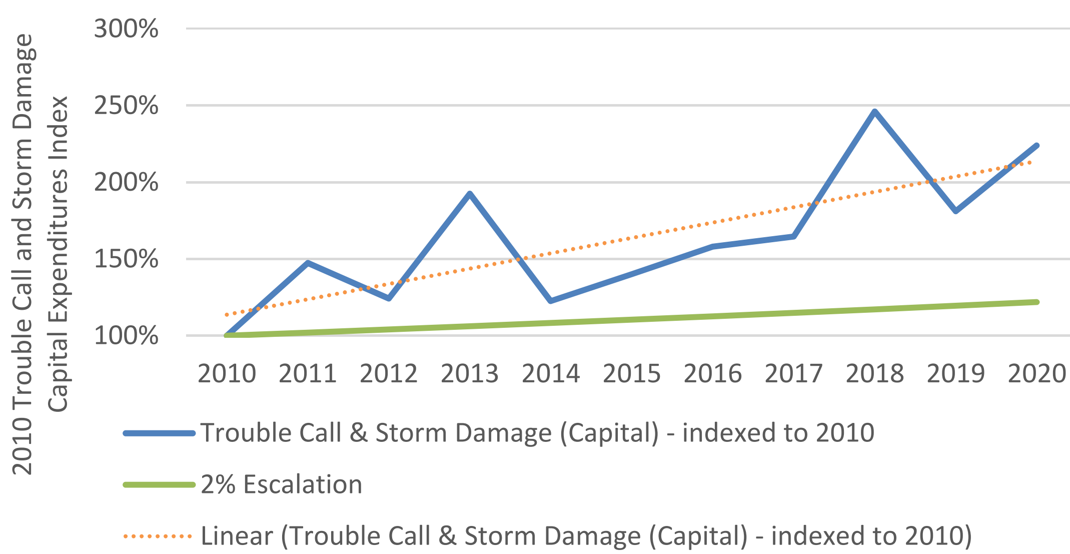

Figure 3: Trouble Call and Storm Damage Capital Expenditures

The breadth and variety of Hydro One's transmission and distribution systems expose the company's networks to climate-related risks, and increasing reliability risks posed by a variety of weather events. Collectively, the company's transmission and distribution systems span over 961,000 square kilometers of Ontario, much of it in heavily forested and rugged terrain, and in some cases located in constrained space in urban areas. Due to the broad geographic span and varied climatic conditions of the company's assets, weather and regional temperature differences have significant impacts on the planning, design, asset management and operation of the transmission and distribution systems.

Climate change presents new risks and perpetuates existing vulnerabilities for Hydro One's networks. Effects of the changing climate, including severe weather, may affect the safe and reliable operations of the electricity grid, and may interrupt the continuity of supply to customers. In its 2019 *Canada's Changing Climate Report*, Environment and Climate Change Canada determined that temperature warming in Canada is, on average, double that seen globally.[6] Northern Canada has warmed at more than double the global rate. The report observed that effects of this warming are occurring in Ontario: extreme heat, less extreme cold, longer growing seasons, shorter snow cover, and earlier spring peak streamflow. The report anticipates that these trends will continue in the future. The Government of Ontario's 2018 *Made-in-Ontario Environment Plan* predicted that, by 2050, temperatures in the province would raise by up to 4°C in summer and 7°C in winter (as compared to 1986-2005 averages) with the most significant increases occurring in the north of the province.[7] Environment and Climate Change Canada also reported the summer precipitation and extreme weather events have become more frequent and intense. The Northern Tornado Project (Western University) reported 39 tornadoes in Ontario during 2020, the highest number on record for the province.

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[6] Government of Canada, Canada's Changing Climate Report (2019) – page 5 (www.ChangingClimate.ca/CCCR2019).

[7]Ministry of the Environment, Conservation and Parks, Preserving and Protecting our Environment for Future Generations : A Made in Ontario Environment Plan (November 2018) – page 16 (https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf)

Ten tornadoes were reported during one extreme weather event that crossed central Ontario in June 2020. [8]

Hydro One has recognized that manifestations of a changing climate will impact the company's vegetation management practices and infrastructure. Longer and more vigorous growing seasons resulting from climate changes will impact the frequency of vegetation management on Hydro One's infrastructure corridors. Existing infrastructure contains equipment which was designed for historical climate norms and conditions, and may be more vulnerable to predicted temperature changes and weather extremes. Critical electrical equipment assets in some Northern Ontario locations are malfunctioning due to summer temperature increases. Distribution system equipment and poles were destroyed as a result of the June 2020 extreme weather and tornado events reported by the Northern Tornado Project. Flooding related to increased precipitation, streamflow, and surface water level has required Hydro One to remove and relocate critical equipment from subsurface infrastructure.

Changing meteorological conditions, including an increased frequency of severe weather events, may result in increased asset failures and extended recovery time. Other adverse impacts on the management and operation of assets include electrical equipment malfunction, accelerated corrosion of steel components, more rapid wood decay, wildfire hazards, mudslides, flooding, reduced opportunity for live line maintenance, delays in recovery operations, and reduced transmission transfer capability.

1.8.3 HYDRO ONE'S RESPONSES TO CLIMATE CHANGE

Hydro One's responses to climate change are based on two-pronged approach: adapt and mitigate. "Adaptation" actions reduce negative impacts of temperature changes and extreme weather, and take advantage of new opportunities. Hydro One's adaptation efforts are

[8] Instant Weather, Breaking : 39 Confirmed Tornadoes Breaks the All Time Ontario Record of 37 in One Season (October 2020) (https://instantweatherinc.com/news/2020/10/20/breaking-39-confirmed-tornadoes-breaks-the-all-time-ontario-record-of-37-in-one-season)

summarized in section 1.8.3.1 below. “Mitigation” actions reduce production of GHG that retain atmospheric heat. Mitigation actions can include process changes, asset replacement, and methods of capturing or containing GHG. The company’s mitigation strategy and actions are summarized in section 1.8.3.2 below.

Hydro One’s planned climate change adaptation and mitigation actions do not impose incremental costs to customers, as the investments are required to address other needs and would be necessary and prudent notwithstanding associated climate change adaptation and mitigation benefits.

1.8.3.1 ADAPTING TO CLIMATE CHANGE THROUGH GRID RESILIENCY

Hydro One considers climate change adaptation in planning decisions as part of the company’s efforts to renew and modernize existing infrastructure through the design and construction of a grid that resilient, reliable and flexible. A reliable grid minimizes the occurrence of outages but is also resilient and restores quickly from events.

Hydro One continues to review impacts of severe weather and adapt its operations to withstand severe events. Hydro One also continues to adapt its design and equipment standards and implementations to address the impacts of severe weather, by taking the following actions:

- automating the grid and deploying solutions to ensure resiliency against severe weather events;
- evaluating existing lines and station design standards against historic climate trend data to ensure the standards can meet the challenges of changing climate conditions;
- modifying and reinforcing existing facilities, as part of planned renewal, and incorporate updated work practices to improve resiliency;
- hardening existing facilities against climate change where possible, considering financial and physical limitations that may be inherent to existing facilities; and
- constructing new facilities with consideration of climate hardening design philosophies from the outset.

Hydro One's planned investments address the networks' resiliency and reliability.[9] While climate change adaptation is not a primary driver of the company's expenditures or investments, many planned maintenance and capital expenditures are linked to climate change adaptation for both the transmission and distribution systems. These expenditures and investments include:

- **Vegetation Management** (Exhibit E-02-02 for transmission | Exhibit E-03-02 for distribution) – Helping ensure appropriate vegetation management for rights-of-way to minimize risk of tree contacts and fall-ins during wind and weather events.
- **Distribution Grid Modernization of Worst Performing Feeders** (DSP Section 3.11, D-SS-05) - Deploying remotely controllable switches and communicating faulted circuit indicators to allow rapid location and sectionalisation of outages to enable restoring power to as many customers as possible following extreme weather events.
- **Distributed Energy Resources** (DSP Section 3.11, D-SS-04) - Deploying distributed energy resources in the form of battery energy storage to provide a backup power to customers impacted by outages due to extreme weather events.
- **Lines and Stations System Renewal** (TSP Section 2.11, T-SR-01, T-SR-02, T-SR-03, and T-SR-18| DSP Section 3.11, D-SR-04, D-SR-07, D-SR-10, and D-SR-11) - Incorporating new design criteria to prepare for future grid resiliency by designing and implementing solutions and functionality to improve "withstand-capability" and restoration times following extreme natural events.
- **Intertie / Interconnection reinforcements** (TSP Section 2.11, T-SR-01, T-SR-02, and T-SS-02) - Renewing interconnections with critical supply sources to ensure network supply adequacy in the event of regional disruptions, including reinvestments at facilities such as the Bruce complex, St. Lawrence, and Keith TS.
- **Telecommunication reinforcements/renewal** (TSP Section 2.11, T-SR-11, T-SR-14, and T-SR-17 | DSP Section 3.11, D-SR-12) – Helping ensure robust telecommunication capabilities to communication and situational awareness during emergency

[9] As the concepts of resiliency and reliability are closely linked, a number of these measures may further reliability measures first, but also provide secondary resiliency considerations, in the event of severe weather events.

restorations, including the replacement of the transmission provincial mobile radio system and the distribution telecommunication network supporting the advance metering infrastructure network.

- **Transmission and distribution engineering standards** (Exhibit E-02-03 for transmission| E-03-03 for distribution) - Evaluating and revising existing transmission and distribution line and station design standards against historic climate trend data to ensure our standards can meet the challenges of changing climate conditions, including incorporation of hardening considerations and new technologies.
- **Spare equipment** (TSP Section 2.11, T-SR-09 | DSP Section 3.11, D-SR-02) – Helping ensure back up/ spares inventories are adequate for major equipment, including mobile transformers, in the event of a catastrophic loss.

1.8.3.2 MITIGATING HYDRO ONE'S CONTRIBUTIONS TO CLIMATE CHANGE

With an unprecedented number of countries and companies committing to lowering their emissions, Hydro One is making efforts to mitigate its own contributions to GHG emissions. In 2015, the world came together and established the Paris Agreement, a global framework to avoid dangerous climate change by limiting global warming to below 2°C. Under the Paris Agreement, Canada has committed to reducing its GHG emissions by 30% below 2005 levels by 2030, and achieving net zero by 2050[10]. The energy sector's commitment to reducing its emissions will be an important factor in allowing Canada to achieve its commitment. In April 2021, Prime Minister Trudeau increased Canada's 2030 emission target to 40-45% by 2030.

Hydro One tracks and reports Scope 1 and 2 emissions. Scope 1 Emissions are direct emissions from sources owned or controlled by Hydro One (e.g., use of fossil fuels in the company's owned and operated fleet vehicles, fossil fuel based electricity generation in Hydro One Remote Communities operations, sulfur hexafluoride (SF_6)). Scope 2 Emissions are indirect emissions

[10]Environment and Climate Change Canada, United Nations Framework Convention on Climate Change and the Paris Agreement (January 2020) - page 3 (https://www.canada.ca/en/environment-climate-change/corporate/international-affairs/partnerships-organizations/united-nations-framework-climate-change.html)

from the generation of acquired and consumed electricity, steam, heat, or cooling from sources owned or controlled by an external organization (e.g., energy purchased to use in our facilities and line losses). Hydro One's Scope 1 and Scope 2 emissions for 2018 to 2020 are presented below in Figure 4.

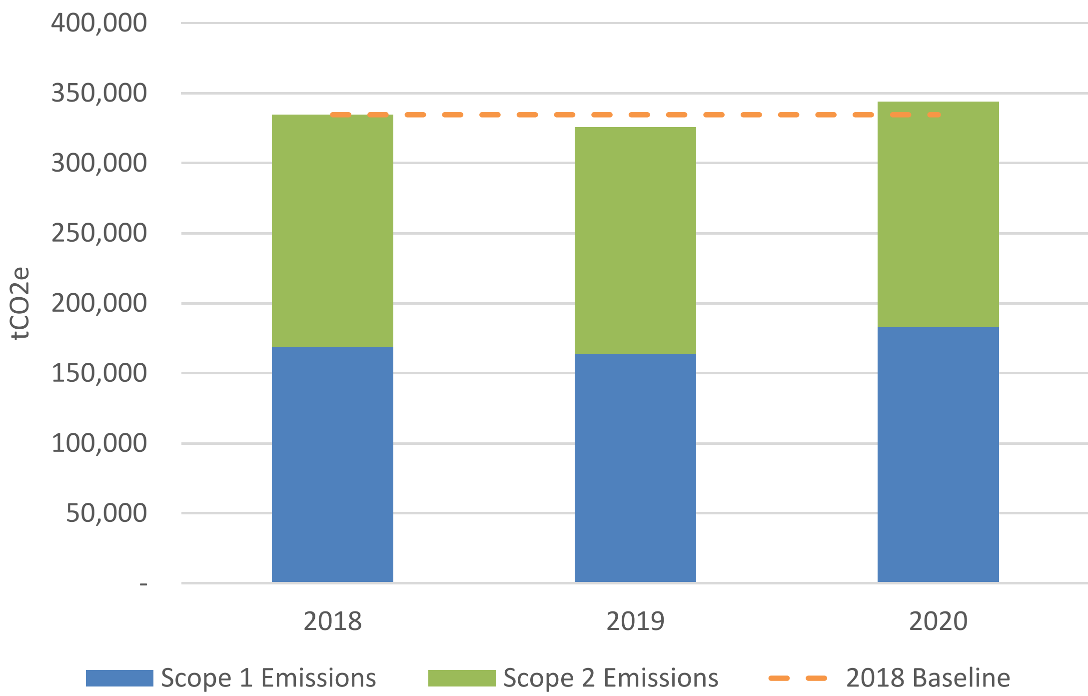

Figure 4: Hydro One Limited Greenhouse Gas Emissions from 2018 – 2020

In 2020, Hydro One teams worked to identify programs and best practices with strong returns on investment to reduce GHG emissions, which are summarized through mitigation efforts described below.

Hydro One is implementing staged actions to mitigate the impacts of climate change through GHG reduction efforts, working towards a long-term, sustainable carbon footprint reduction of 30% by 2030 and striving towards net zero carbon emissions in 2050. While GHG mitigation is not a driver of Hydro One's investments, the company looks for opportunities to prudently mitigate GHGs when identifying investments. Investments that will contribute towards lower overall GHG emissions include:

- **Transport and Work Equipment renewal** (GSP Section 4.11, G-GP-01) – Hydro One's commercial fleet is beginning the gradual transition to low or zero emission technology, increasing the rate of electric vehicles from an estimate 5% of the renewal forecast in 2021 to 50% by 2030. The rate of vehicle replacement will be done as needed to maintain an optimized fleet, and the total cost of ownership of an electric vehicles versus conventional fuel-based has no significant incremental cost.
- **Facilities & Real Estate** (GSP Section 4.11, G-GP-03) – Hydro One is implementing energy savings initiatives at Operations and Service Centres, including installation of high-efficiency equipment (e.g., HVAC units, generators and lighting) and the Remote Command Centre program which monitors energy consumption remotely and allows Hydro One to take the appropriate actions required to minimize energy consumption. In addition to prudently addressing business needs, these investments have the added benefit of contributing to GHG emissions reductions.
- **Reduction of SF_6 Emissions** (Exhibit E-02-02) – Hydro One is enabling the reduction of SF_6 emissions through planned investments addressing defective and leaking SF_6 and gas insulated equipment. This will be accomplished through planned equipment refurbishments, targeted leak reduction efforts, and corrective maintenance to reduce SF_6 releases.

Other investments in equipment upgrades contribute indirectly to emissions reduction through impacts on Scope 2 GHG emissions. These contributions to emission reductions are important but harder to quantify. As an example, line losses (i.e., the loss of electricity during the process of transmitting and distributing the electricity through any electrical distribution system) come from the processes needed to "step-down" and "step-up" power levels to ensure safe transit, as well as the physical loss of heat energy from the wires themselves. Line losses cannot be avoided but they can be reduced through upgrade and modernization of transmission and distribution equipment and by optimizing load on the distribution lines. For example, as part of the procurement process for new transformers, Hydro One evaluates the lifetime cost of the transformer reflecting the cost of energy losses and other costs, in addition to other performance, safety, environmental and technical requirements, as part of bid selection.

Accordingly, investment in equipment upgrades contributes to reduction of these Scope 2 emissions. Further, the connection of customer owner distributed energy resources, including solar, wind and water, (DSP Section 3.11 D-SA-03 and TSP Section 2.11 T-SA-06) benefit Ontario's overall supply of a clean energy mix, which may also contribute to reduction of Hydro One's Scope 2 emissions.