Appendix H

Regional Planning Reports



South Georgian Bay/Muskoka Scoping Assessment Outcome Report

November 30, 2020

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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the regional planning process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of the regional planning process for the South Georgian Bay/Muskoka region was completed in August 2017 with the publishing of the Regional Infrastructure Plan (RIP)[1]. A number of needs were identified to arise in the near- and medium-term timeframes. Prior to the completion of the RIP, two Integrated Regional Resource Plans (IRRPs) were produced in December 2016, as the South Georgian Bay/Muskoka area needs were scoped into two sub-regions for further study: the summer-peaking, high-growth Barrie/Innisfil[2] sub-region, and the winter-peaking, slower-growing Parry Sound/Muskoka[3] sub-region.

The IRRPs outlined recommendations to address all near-term needs, and identified mid- to long-term needs to be confirmed in the next planning cycle. Both IRRPs also identified near-term actions to be carried out in advance of the next cycle of regional planning to gather information to better identify options for future needs. This included the completion of Local Achievable Potential Studies (LAPS) for a portion of each sub-region, to help determine the availability and cost of potential non-wires solutions.

The new cycle of the regional planning process for the South Georgian Bay/Muskoka region started on January 30, 2020. The Needs Assessment is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. (Hydro One). This report was finalized on April 30, 2020, and recommended that a number of needs require regional coordination. This need information was an input into the Scoping Assessment to determine the nature of the planning process required.

During the Scoping Assessment, the Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. This process also determined the best geographic grouping of the needs to efficiently carry out the study. It also considered past or ongoing initiatives in the region, such as the findings of the two LAPS triggered in the last planning cycle. These studies, which assessed the cost and feasibility of using distributed energy resources and local demand management options, will inform and support the analysis of non-wires alternatives in the current cycle.

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[1] 2017 RIP: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South_Georgian_Bay-Muskoka_RIP_Final.pdf

[2] 2016 IRRP for the Barrie/Innisfil Sub-region: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Barrie-Innisfil/Barrie-Innisfil-IRRP.pdf?la=en

[3] 2016 IRRP for the Parry Sound/Muskoka Sub-region: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Parry-Sound-Muskoka/PSM-IRRP.pdf?la=en

The Scoping Assessment considers three potential planning approaches for the region/sub-regions, including: an IRRP – where both wires and non-wires options have potential to address needs; a RIP – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs;
- Determines the appropriate regional planning approach and scope for each sub-region where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP if an IRRP is required; and
- Establishes the composition of the Technical Working Group for each sub-region recommended for an IRRP.

2. Study Team

The Scoping Assessment was carried out with the following participants:

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

3. Categories of Needs, Analysis, and Results

3.1 Overview of the Region

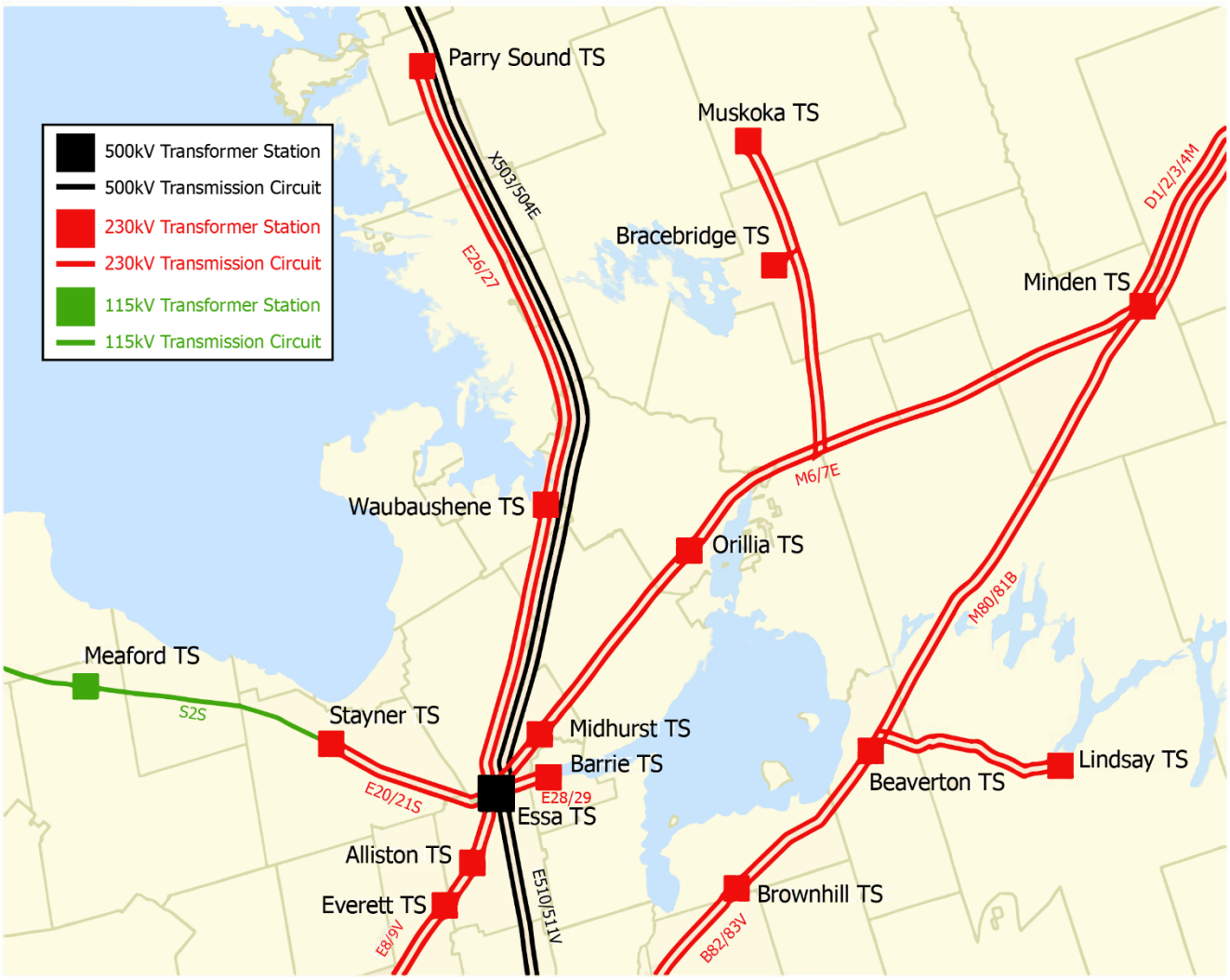
The South Georgian Bay/Muskoka region is located in central Ontario and includes all or part of the following Counties and Districts: the County of Simcoe, County of Dufferin, District of Muskoka, District of Parry Sound, and County of Grey. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

This region also includes the following First Nations and Métis Nation of Ontario (MNO) councils:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- Chippewas of Georgina Island
- Mississaugas of Scugog
- MNO Barrie South Simcoe Métis Council
- MNO Moon River Métis Council
- MNO Georgian Bay Métis Council

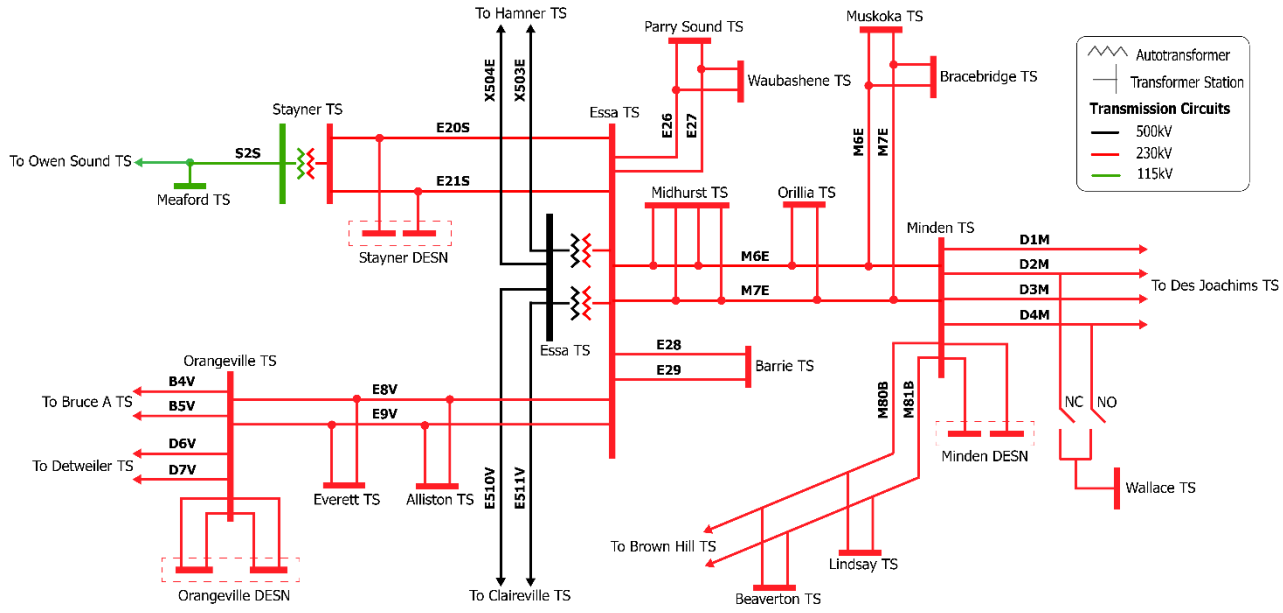
An overview of the South Georgian Bay/Muskoka region and the location of the electrical infrastructure is shown in Figure 3-1. The southern portion of this region is summer-peaking (i.e., electricity demand is highest during the summer months), and is characterized by strong forecast growth, particularly in the south Barrie and Innisfil areas. The northern part of the region is winter-peaking (i.e., electricity demand is highest during the winter months), and growth is forecast to be more gradual.

Figure 3-1 | Overview of the South Georgian Bay/Muskoka Region



The region is currently supplied from 115 kV and 230 kV transmission lines and stations that connect at the Essa transformer station (TS). The 500/230 kV auto-transformers at Essa TS provide the major source of supply to the area. As an outcome of the last planning cycle, the 115 kV supply in the region (from Essa TS to Barrie TS) is being converted to a 230 kV supply in 2022. An overview of the electrical infrastructure that currently supplies the region is provided in the single line diagram in Figure 3-2.

Figure 3-2 | Electricity Infrastructure in the South Georgian Bay/Muskoka Region



3.2 Background of the Previous Planning Process

The regional planning process was formalized by the OEB in August 2013. To prioritize and manage the process, Ontario was organized into 21 regions based on electricity infrastructure boundaries; each of which were assigned to one of three groups based on urgency of need, where Group 1 Regions were being reviewed first. The South Georgian Bay/Muskoka region was part of the Group 2 planning regions.

In March 2015, Hydro One Transmission published the first Needs Assessment report for the South Georgian Bay/Muskoka region. The scope of the report included a review of system capability, reliability assessments, and asset sustainment timelines for the region. The report identified a number of near- and mid-term needs. In June of 2015, the IESO published a Scoping Assessment report for the region, recommending that two IRRPs would be developed to address the identified needs: one for the Barrie/Innisfil sub-region and one for the Parry Sound/Muskoka sub-region.

Within the Terms of Reference for the IRRP for the Barrie/Innisfil sub-region, a need to proceed quickly to address near-term needs at Barrie TS was identified. While the IRRP was still underway in December 2015, the IESO provided a hand-off letter to Hydro One in support of commencing work on uprating Barrie TS to a 230 kV supply to meet the capacity and end-of-life needs identified in south Barrie and Innisfil.

Subsequently in December of 2016, the first IRRP reports for the two South Georgian Bay/Muskoka sub-regions were published. Both IRRPs used a 20-year outlook, allowing the long-term trends in the region to be considered while implementing near-term actions. To address near- and mid-term needs in the first 10 years of the forecast, a number of recommendations were made. Section 3.3.1

documents the status of the near-term transmission reinforcements that were recommended during the first cycle of regional planning for South Georgian Bay/Muskoka.

In addition to the above recommendations, the previous IRRPs also recommended that two LAPS be undertaken in order to better understand the feasibility and cost of potential non-wires alternatives for addressing select mid- and long-term capacity needs. A LAPS was undertaken for the service area of Barrie TS, led by Alectra Utilities and supported by InnPower, and a LAPS was undertaken for the Parry Sound TS and Waubaushene TS service areas, led by Lakeland Power. These studies have now both concluded and will inform the current regional planning cycle.

Following the IRRP, a RIP was published in August 2017 to address transmission needs identified in the Needs Assessment and the IRRP. The plans to address some of these needs were further developed in the RIP. Some of the needs and recommended options that were in the medium- to longer-term time frame were to be re-confirmed in the next regional planning cycle.

This current, second regional planning cycle started with the Needs Assessment report published by Hydro One in April 2020. The needs identified in the Needs Assessment report form the basis of the analysis for this Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. Furthermore, it identified a number of new needs in the South Georgian Bay/Muskoka region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation. Table 3-1 below summarizes this. These projects provide a basis for future assessments and should be accounted for in this planning cycle.

Table 3-1 | Needs Identified in the Previous Cycle and Implementation Plan Update

IRRP	Specific Need	Solution and Timing
Barrie/Innisfil Sub-Region	• Insufficient capacity at Barrie TS and Barrie/Essa 115 kV system • End-of-life Barrie TS, E3/4B circuits, Essa 230/115 kV autotransformers	• BATU project (rebuild and uprate Barrie TS and E3/4B circuits to 230 kV, and retire Essa T1/T2) • In-service in 2022

IRRP	Specific Need	Solution and Timing
Parry Sound/Muskoka Sub-Region	• Insufficient capacity at Parry Sound TS • End-of-life Parry Sound transformers	• Transformer upsizing (new 230/44 kV 83 MVA) • In-service in 2024
	• Load restoration criteria violations under M6E+M7E contingency	• Installation of 230 kV switches on M6E/M7E at Orillia TS • In-service in 2021
	• End-of-life 230/44 kV 42 MVA Minden TS transformers	• Replacement with larger 83 MVA units to address station capacity needs • In-service in 2021

3.3.2 Needs to be Addressed in Current Planning Cycle

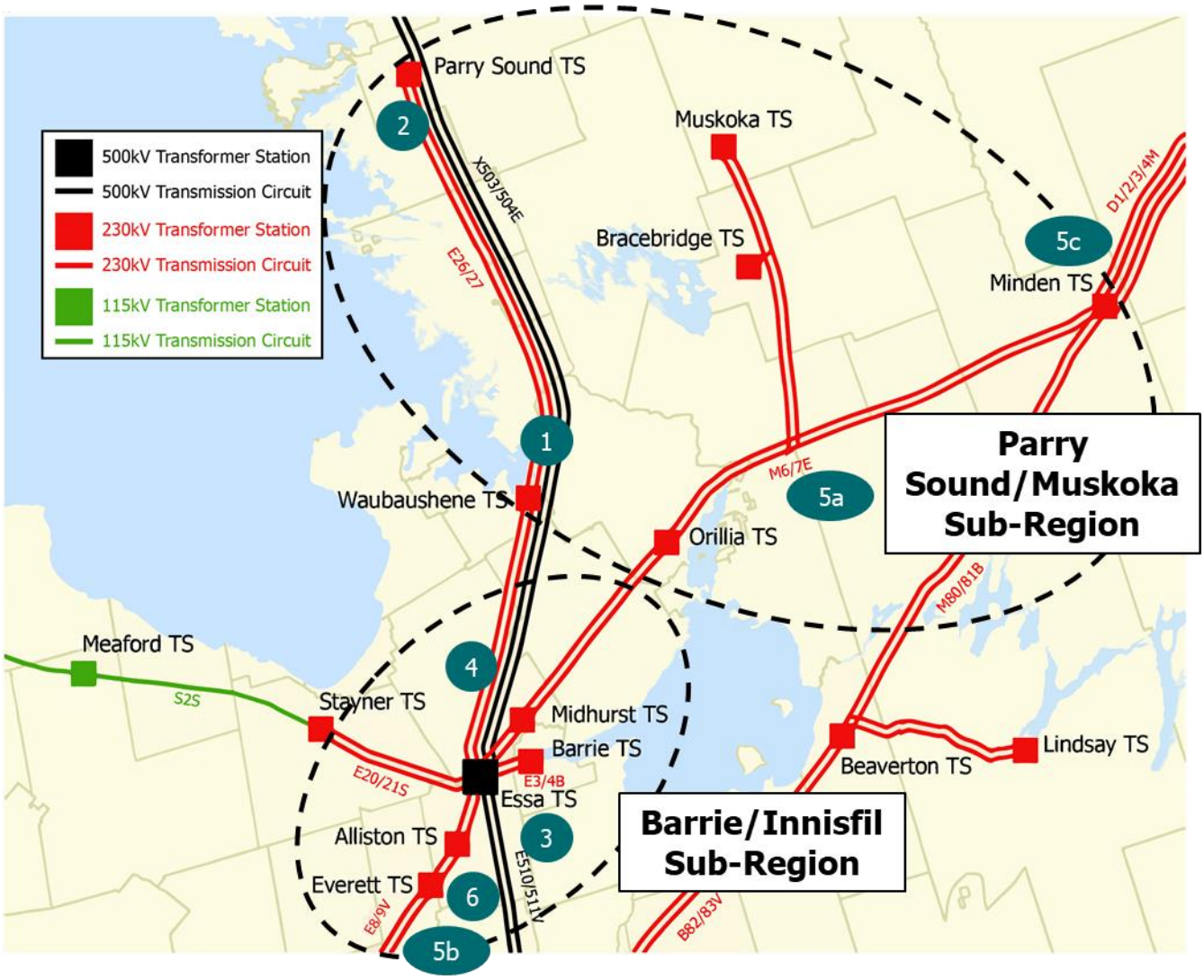
The Needs Assessment then identified new or updated needs in the South Georgian Bay/Muskoka region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated end-of-life asset condition information, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Table 3-2 below lists these regional needs and their timing. Their location is shown in Figure 3-3.

Table 3-2 | Updated Regional Needs Identified in the NA

Need	Station/Circuit	Description of Need
1	Waubaushene TS	• Supply capacity exceeded in 2020
2	Parry Sound TS	• Existing 230/44 kV, 42 MVA transformers reach end-of-life in near-term • Station capacity need between 2020-2024, before larger (230/44 kV, 83 MVA) replacement transformers are in-service
3	Barrie TS/Innisfil Area	• Subsequent to BATU, InnPower has a supply capacity constraint on the 44 kV feeder level starting in 2025 • Up-sized Barrie TS will have a station capacity need arising in 2029

Need	Station/Circuit	Description of Need
4	M6E/M7E	• Thermal overload (exceeding Long-Term Emergency, LTE, rating) between Essa TS x Midhurst TS starting in 2023 (assuming four Des Joachims GS units are out of service)
5	M6E/M7E E8V/E9V D1M/D2M	• Various sections to be refurbished due to end-of-life needs • M6E/M7E: in-service 2026 • E8V/E9V: in-service 2026 • D1M/D2M: in-service 2028
6	Everett TS	• Full utilization of the existing station supply capacity is limited due to a limiting component within the low voltage yard; need arises in 2026 (rather than 2027, as identified in the last IRRP) • CT ratio setting on the low voltage bushing of the transformer breaker can be modified to allow full transformer limited time rating (LTR) capability

Figure 3-3 | Geographic Location of Needs Identified in the Needs Assessment



3.3.3 Analysis of Needs and Identification of Sub-Regions

The Study Team has discussed the needs in the South Georgian Bay/Muskoka region and potential planning approaches to address them. Consistent with the previous planning cycle, two sub-regions, Barrie/Innisfil and Parry Sound/Muskoka, have been identified for further study in the regional planning process (geographic area of the sub-regions is identified in Figure 3-3).

In addition to discussing the planning approach for the identified needs and the division of the sub-regions, the Study Team also discussed the potential impact of the COVID-19 pandemic, as there are supply capacity needs in the region driven by forecast load growth. The Study Team noted that the pandemic may have a temporary and near-term impact on the load growth. However, there is also the potential for certain needs to materialized with greater magnitude (e.g. continued development of housing stock in the south Barrie area). Therefore, the Study Team agreed to assess the needs using the need dates from the Needs Assessments, which was based on the original demand forecast completed prior to the pandemic. Throughout the IRRP process, potential near-term impacts to demand from the COVID-19 pandemic will continue to be monitored.

Barrie/Innisfil Sub-Region

Supplied by Alectra Utilities, InnPower Corporation, and Hydro One Distribution, this sub-region continues to exhibit strong electricity demand growth – particularly in the south Barrie and Innisfil area. The following transmission infrastructure falls within this sub-region's boundaries:

- Transformer stations: Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits: E8/9V, E28/29, M6/7E (Essa-Midhurst section)

Forecast growth is expected to trigger a supply capability need in the south Barrie and Innisfil area after the BATU project is in-service:

1. In the near-term, supply to InnPower's service territory is limited by two 44 kV feeders supplied from Barrie TS, and
2. In the mid-term, the combined load growth in the Barrie area will exceed the station capacity of uprated Barrie TS.

The potential for integrated solutions to address these near- and mid-term capacity needs should be evaluated through an IRRP. Potential wires options may involve a new line, an additional transformer station, a further expansion of Barrie TS, additional feeders, or load transfers. Furthermore, the potential for non-wires alternatives to defer or meet a portion of the sub-region's needs will also be evaluated. Findings from the Barrie TS LAPS recommended from the 2016 IRRP can support and inform this assessment.

In addition to supply capability needs at Barrie TS and in the Innisfil area, network circuits from Essa TS (M6/7E) are expected to be thermally overloaded under certain post-contingency system conditions. Various sections of other nearby circuits (E8/9V, M6/7E, and D1/2M) have also been identified in the Needs Assessment as reaching end-of-life. Needs on these circuits are sensitive to generation output and bulk power system flow assumptions (particularly flows both north and south on the transmission interface (i.e. path) through Essa TS), as well as the region's load level. These types of needs are typically addressed through bulk planning, although coordination is required with the regional planning process to ensure system assumptions are aligned, and potential impacts of solutions from either regional or bulk planning are accounted for in the other plan.

The supply capability need at Everett TS is driven by the current setting of the station equipment, preventing utilization of the full station capacity. As this need has only been advanced by a year and has not otherwise changed since identified in the previous IRRP, the Study Team continues to support the solution recommended in 2016.

Recommendation: The Barrie/Innisfil sub-region has a mixture of urgent, more complex system capacity needs, and mid-term end-of-life and capacity needs. Integrated solutions should be evaluated to meet these regional needs while coordinating with any bulk system assessments. Outcomes of the regional plan are anticipated to have broader impacts and require input from multiple stakeholders (LDCs, transmitter, community members, and municipalities). The Study Team, therefore, proposes that an IRRP is conducted for the Barrie/Innisfil sub-region to identify the most cost-effective and feasible solutions.

For the supply capability need identified on the M6E/M7E circuit, the Study Team recommends that a bulk study be completed and that the results be shared with the Technical Working Group as applicable.

Parry Sound/Muskoka Sub-Region

Supplied by Hydro One Distribution, Lakeland Power, Newmarket-Tay Power, Elexicon Energy, and EPCOR Electricity Distribution Ontario Inc., this winter-peaking sub-region exhibits slower electricity demand growth. The following transmission infrastructure falls within this sub-region's boundaries:

- Transformer stations: Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits: M6/7E, E26/27

According to the Needs Assessment, Waubaushene TS will require additional supply capacity starting 2020, and a total of 10 MW will be required in 2029 when the station is expected to reach end-of-life. The end-of-life need in 2030 provides an opportunity to replace the station transformers with higher rated units, and the 10 MW capacity need prior to 2029 has the potential to be managed by non-wires solutions. In addition, non-wires options have recently been modelled for the Waubaushene area, providing a basis to explore and evaluate any non-wires potential in the area.

During the last cycle of regional planning, re-supplying loads at Waubaushene TS from nearby stations was recommended. According to the 2016 IRRP, 4 MW of load at Waubaushene TS can be supplied by Orillia TS, and another 7 MW from Waubaushene TS can be supplied by Midhurst TS. These options, not yet implemented, will be reassessed in this planning cycle as part of identifying an integrated solution to address the need. This includes coordinating with the impacted LDCs to obtain the appropriate load transfer approvals if required.

Parry Sound TS requires additional supply capacity starting 2020. The transformers at Parry Sound TS have also reached end-of-life and are scheduled to be replaced with higher rated units in 2024. During the previous cycle of the regional plan, this supply capacity need at Parry Sound TS was identified. Transferring 6 MW of load from Parry Sound TS to the nearby Muskoka TS was recommended to manage the loading at Parry Sound TS. This option will be reassessed as part of identifying an integrated solution to address the capacity and end-of-life needs.

Recommendation: There is a need to evaluate integrated solutions to address the sub-region's near- to mid-term capacity and end-of-life needs. Though relatively small in magnitude, these needs will involve multiple stakeholders (LDCs, transmitter, community members, and municipalities) and could trigger investments impacting local ratepayers. Therefore, an IRRP of a smaller scope is proposed to study the Parry Sound/Muskoka sub-region.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- An IRRP be undertaken to address the needs in the Barrie/Innisfil sub-region;
- An IRRP be undertaken to address the needs in the Parry Sound/Muskoka sub-region; and
- A bulk system study be undertaken to assess the need on M6E/M7E.

The Terms of Reference for the Barrie/Innisfil IRRP is attached in Appendix 2. Similarly, the Terms of Reference for the Parry Sound/Muskoka IRRP is found in Appendix 3.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAPS	Local Achievable Potential Study
LDC	Local Distribution Company
MNO	Métis Nation of Ontario
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

Appendix 2 – Barrie/Innisfil Sub-Region IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an Integrated Regional Resource Plan of the Barrie/Innisfil sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

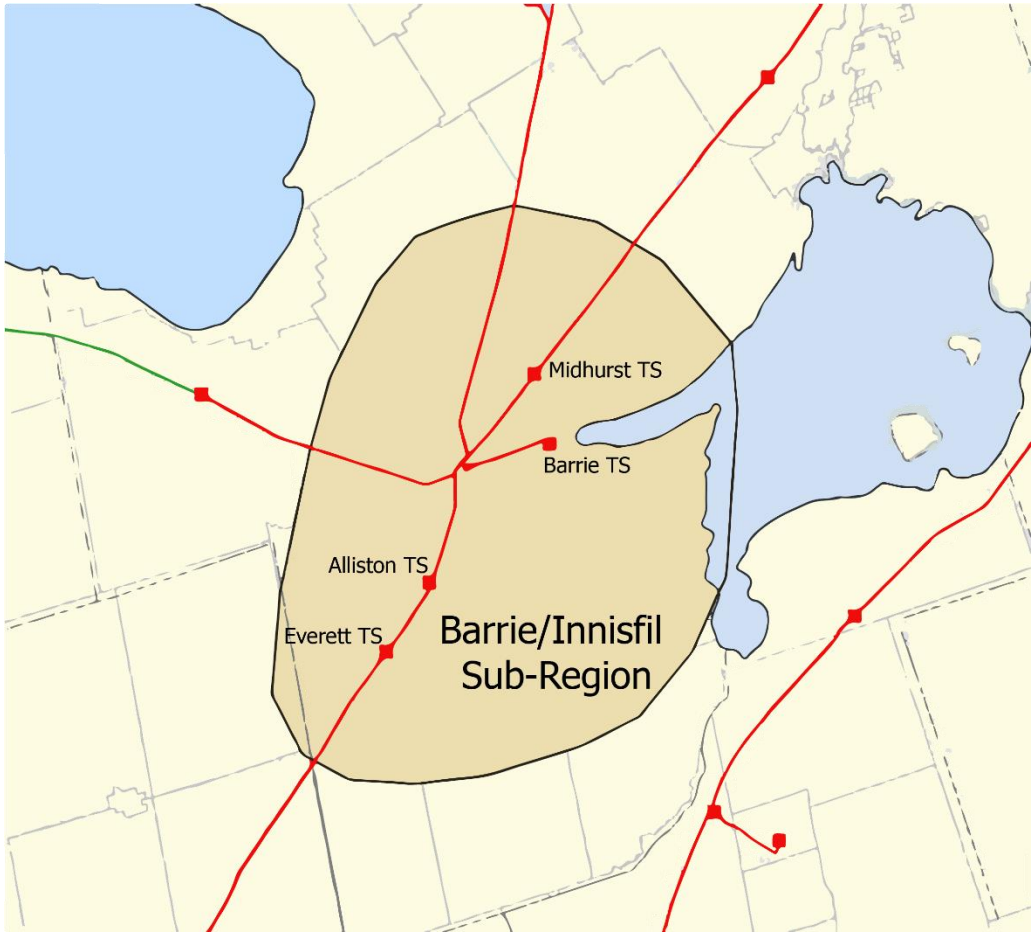
Barrie/Innisfil Sub-Region

The Barrie/Innisfil sub-region is a summer-peaking region that includes the City of Barrie, the Town of Innisfil, and customers in surrounding municipalities supplied from the Barrie, Midhurst, Everett and Alliston transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-1.

The sub-region includes all or part of the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

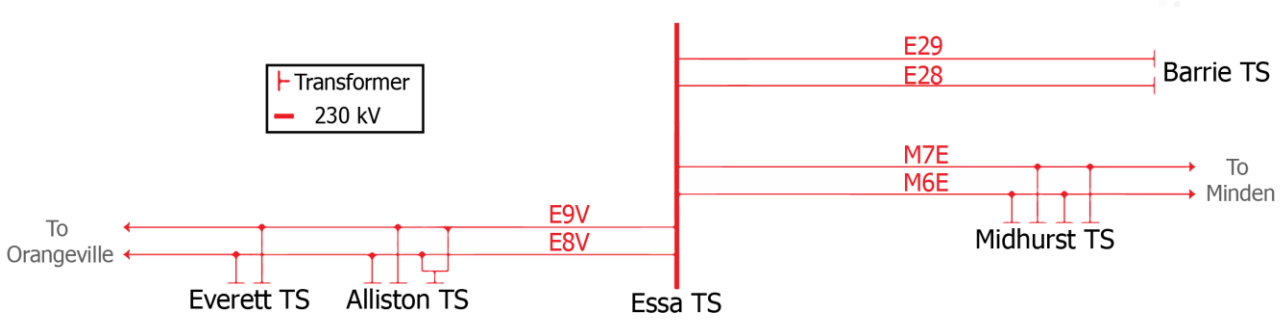
Figure A-1 | Overview of the Barrie/Innisfil Sub-Region



Barrie/Innisfil Electricity System

The electricity system supplying the Barrie/Innisfil sub-region is shown in Figure A-2.

Figure A-2 | Barrie/Innisfil Electricity System



Background

In the last regional planning cycle, the Barrie/Innisfil sub-region IRRP and RIP were published in December 2016 and August 2017, respectively. Studies conducted during the development of these plans triggered a hand-off letter issued to Hydro One Transmission in December 2015. This letter recommended the implementation of the Barrie Area Transmission Upgrade (BATU) project to supply forecast growth in the Barrie and Innisfil areas.

The BATU project, to be in-service in 2022, involves rebuilding and uprating Barrie TS and the E3/4B[4] circuits to 230 kV, as well as retiring Essa auto-transformers T1/T2. This recommendation also included an additional 44 kV feeder supply line to service InnPower load from the uprated Barrie TS. The new 44 kV feeder, as well as InnPower's existing feeder at the time, would be relocated outside of the Hydro One transmission corridor and was expected to help meet InnPower's forecast demand until the mid-2020s.

Long-term recommendations from the previous planning cycle in Barrie/Innisfil included the Barrie TS LAPS (to explore the potential of local demand management resources), as well as continued monitoring of demand growth and local projects to help inform the subsequent planning cycle.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over the next 20 years.
2. To address customer-driven electricity needs by developing a flexible, comprehensive, integrated electricity plan for the Barrie/Innisfil sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Barrie/Innisfil sub-region. The plan is a joint initiative involving Alectra Utilities, InnPower, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement activities. The plan will integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of facilities in the area, relevant community plans, other bulk system developments, and generation uptake, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Barrie/Innisfil area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E28/29, M6/7E (Essa-Midhurst section)

[4] Now designated as E28 and E29

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS and supply capacity needs of M6/7E) will be assessed by the IESO through a separate bulk system planning process, and assumptions will be coordinated between the regional and bulk plans. Results of the bulk study will be shared with the Technical Working Group as they become available.

The Barrie/Innisfil IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe.
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Barrie/Innisfil sub-region, taking into account system reinforcements committed during the last planning cycle, facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices.
- Establish feasible integrated alternatives to address remaining needs, considering a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Barrie/Innisfil sub-region.
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
    - Local Achievable Potential Studies
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements

    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions
- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular end of life segments of 230 kV circuits in the subregion
    - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator (Team Lead for IRRP)
- Hydro One Transmission
- Alectra Utilities
- InnPower
- Hydro One Distribution

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Barrie/Innisfil IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2020
2. Develop the planning forecast, including scenarios for sensitivity analyses, as required		Long-term planning forecast scenarios	Q4 2020 – Q1 2021
Establish historical coincident and non-coincident peak demand information	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast for LDC service areas	LDCs		
Establish existing, committed and potential DG	LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop planning forecast scenarios for sensitivity analyses	IESO		
3. Provide information on load transfer capabilities under normal and emergency conditions	LDCs	Load transfer capabilities under normal and emergency conditions	Q4 2020 – Q1 2021
4. Provide and review relevant community plans, if applicable	LDCs and IESO	Relevant community plans	Q4 2020 – Q1 2021
5. Complete system studies to identify needs over a twenty-year period - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2021
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 – Q3 2021
Develop energy efficiency options, with consideration for previous LAPS findings	IESO and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop local generation options, with consideration for previous LAPS findings	IESO and LDCs		
Develop transmission and distribution options	Hydro One Transmission, and LDCs		
Develop options involving other electricity initiatives (e.g., smart grid, storage)	IESO/ LDCs with support as needed		
Develop portfolios of integrated alternatives	All		
Technical comparison and evaluation	All		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities	Ongoing as required
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	All		
Develop communications materials	All		
Undertake community and stakeholder engagement	All		
Summarize input and incorporate feedback	All		
8. Hand-off wires component of integrated solution	IESO	Hand-off letter to Hydro One	Q1-Q2 2021

Activity	Lead Responsibility	Deliverable(s)	Timeframe
9. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q3 – Q4 2021
10. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q1 – Q2 2022

Appendix 3 – Parry Sound/Muskoka Sub-Region IRRP Terms of Reference

1. Introduction and Background

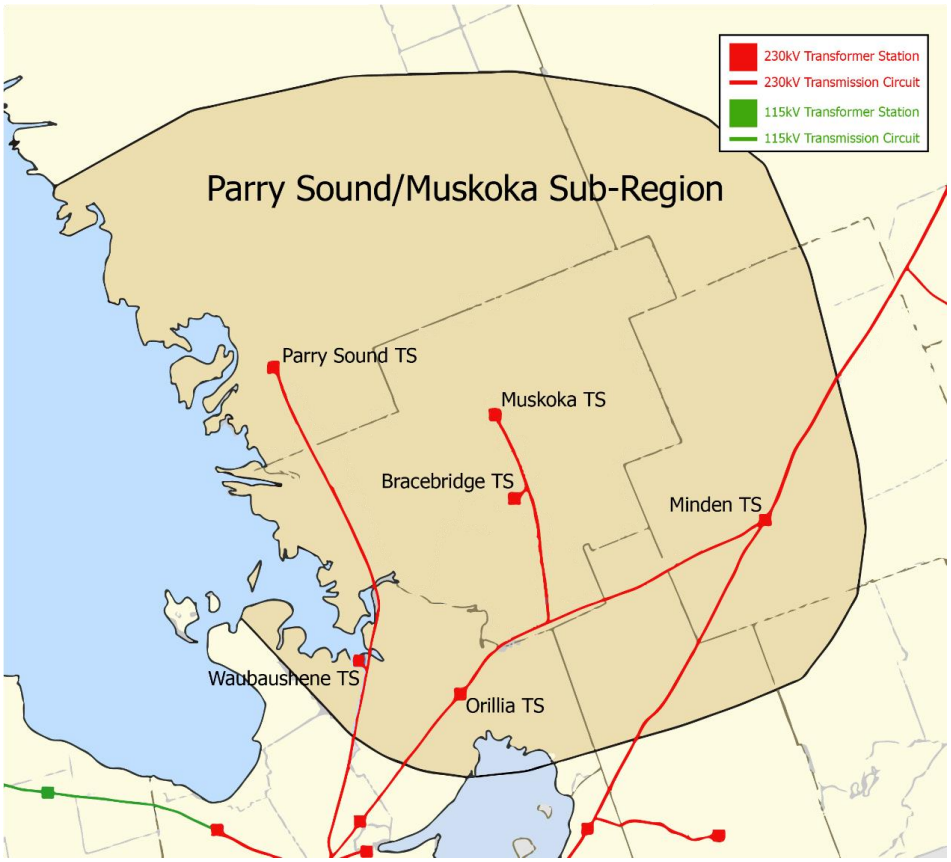
These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an Integrated Regional Resource Plan of the Parry Sound/Muskoka sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Parry Sound/Muskoka Sub-Region

The Parry Sound/Muskoka sub-region is winter-peaking and it roughly encompasses the Districts of The approximate geographical boundaries of the sub-region are shown in Figure A-3.

Figure A-3 | Overview of the Parry Sound/Muskoka Sub-Region



The sub-region includes all or part of the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan
- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin
- Township of Severn
- Township of Strong

- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

The Parry Sound/Muskoka sub-region also includes the following First Nations and Métis Nation of Ontario councils:

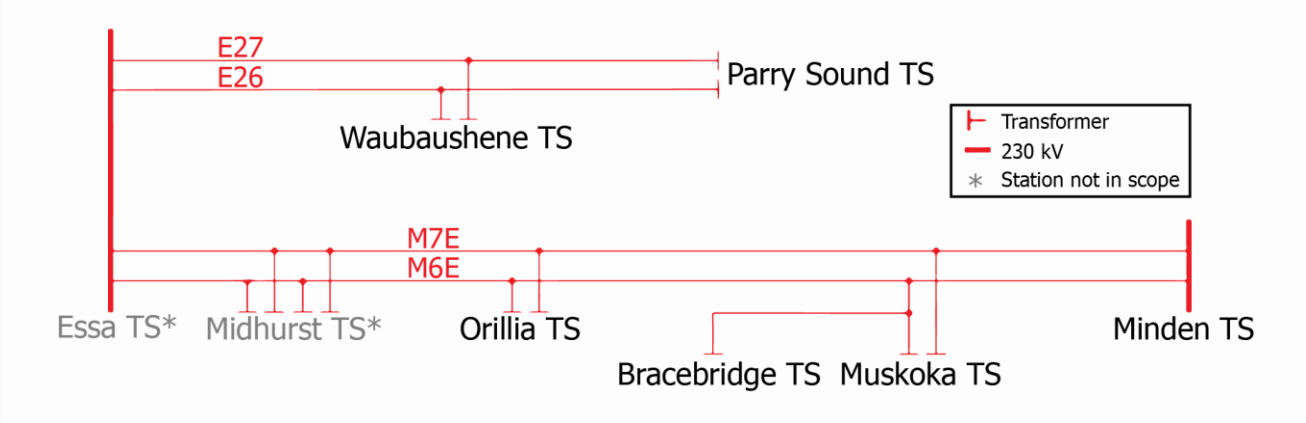
- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- MNO Barrie South Simcoe Métis Council
- MNO Moon River Métis Council
- MNO Georgian Bay Métis Council

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Parry Sound/Muskoka Electricity System

The electricity system supplying the Parry Sound/Muskoka sub-region is shown in Figure A-4.

Figure A-4 | Parry Sound/Muskoka Electricity System



Background

In the last regional planning cycle, the Parry Sound/Muskoka sub-region IRRP and RIP were published in December 2016 and August 2017, respectively. Studies conducted during the development of these plans triggered a hand-off letter issued to Hydro One Transmission in March 2017. This letter recommended the implementation of two 230 kV motorized switches on the 230 kV circuits M6/7E at Orillia TS to improve the load restoration capability to the Muskoka and Orillia areas. These switches are expected to be in-service in 2021.

The previous planning studies also recommended the replacement of end-of-life Minden TS transformers (in-service in 2021), the upsizing of the end-of-life Parry Sound TS transformers in 2024, and various distribution-level load transfers between stations (Waubaushene TS to Orillia TS or Midhurst TS; Parry Sound TS to Muskoka TS) to maximize the use of the region's existing electricity system.

Long-term recommendations from the previous planning cycle in Parry Sound/Muskoka included the Parry Sound and Waubaushene LAPS (to explore the potential of local demand management resources), as well as continued monitoring of demand growth and local projects to help inform the subsequent planning cycle.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Parry Sound/Muskoka sub-region over the next 20 years.
2. To develop a flexible, comprehensive, integrated electricity plan for the Parry Sound/Muskoka sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Parry Sound/Muskoka sub-region. The plan is a joint initiative involving Lakeland Power, Newmarket-Tay Power, Alectra Utilities, Elexicon, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and generation uptake, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Parry Sound/Muskoka area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS and supply capacity needs of M6/7E) will be assessed by the IESO through a separate bulk system planning process, and assumptions will be coordinated between the Regional and Bulk plans. Results of the bulk study will be shared with the Technical Working Group as they become available.

The Parry Sound/Muskoka IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Parry Sound/Muskoka sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Parry Sound/Muskoka sub-region
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.

    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
    - Local Achievable Potential Studies
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records

    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions
- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular end of life segments of 230 kV circuits in the subregion
    - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Hydro One Distribution
- Alectra Utilities
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Parry Sound/Muskoka IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2020
2. Develop the planning forecast for Parry Sound TS and Waubaushene TS		Long-term planning forecast scenarios	Q4 2020 – Q1 2021
Establish historical coincident and non-coincident peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed and potential DG	LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop planning forecast scenarios for sensitivity analyses	IESO		
3. Reconfirm load transfer capabilities from Parry Sound TS and Waubaushene TS	LDCs	Load transfer capabilities under normal and emergency conditions	Q4 2020 – Q1 2021

Activity	Lead Responsibility	Deliverable(s)	Timeframe
4. Provide and review relevant community plans, if applicable	LDCs, First Nations and IESO	Relevant community plans	Q4 2020 – Q1 2021
5. Complete system studies to identify needs - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2021
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 – Q3 2021
Develop energy efficiency options, with consideration for previous LAPS findings	IESO and LDCs		
Develop local generation/demand management options, with consideration for previous LAPS findings	IESO and LDCs		
Confirm the transmission and distribution alternatives: advancement of EOL transformer replacement plans and/or load transfers	IESO, Hydro One Transmission and LDCs		
Develop portfolios of integrated alternatives	All		
Technical comparison and evaluation	All		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	All		
Develop communications materials	All		
Undertake community and stakeholder engagement	All		
Summarize input and incorporate feedback	All		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q3 – Q4 2021
9. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q1 – Q2 2022

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South Georgian Bay-Muskoka

REGIONAL INFRASTRUCTURE PLAN

December 16, 2022

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

With support from:

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

Disclaimer

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

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

Technical Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The participants of the South Georgian Bay-Muskoka Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangevile Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

This RIP is the final phase of the second cycle of the South Georgian Bay-Muskoka Regional Planning (RP) process. It follows the completion of the South Georgian Bay-Muskoka Integrated Regional Resource Plan ("IRRP") which was subdivided into two sub-regions; Barrie Innisfil and Parry Sound/Muskoka both completed in May 2022. This also follows completion of the South Georgian Bay-Muskoka Needs Assessment ("NA") and Scoping Assessment ("SA") in April 2020 and November 2020, respectively.

The South Georgian Bay-Muskoka RIP provides a consolidated summary of needs and recommended plans for the region over a 10-year planning horizon (2022-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer term needs and trend. All needs for this long-term horizon will be reviewed again and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in August 2017 with the publication of the South Georgian Bay-Muskoka RIP report, which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

I. Update on the needs identified during the previous regional planning cycle

The following needs and projects identified in the previous regional planning cycle have been completed:

- Orillia TS M6E/M7E Switches (2021) - Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS (2021) – Replacement of end-of-life (EOL) 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units.

The following needs and projects identified in the previous regional planning cycle are currently underway:

- Parry Sound TS (2023) - Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment.

- Barrie TS (2023) Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

- Orangeville TS (2023)- Replace existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Also replace and upgrade T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate additional capacity.

II. Newly Identified needs:

The major infrastructure investments in this 2nd cycle recommended by the TWG in the South Georgian Bay-Muskoka Region over the near and medium-term (2022-2032) period are given in Table 1 below, along with their planned in-service date and budgetary estimate for planning purposes.

Table 1. South Georgian Bay-Muskoka Region - Recommended Plans over the 2022-2032 Study Period

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[1]	Cost ($M)[2]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal - Transmission Line	M6E / M7E (Orillia TS x Coopers Fls)	Replace end- f-life (EOL) transmission line conductor (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace EOL transmission line conductor and associated assets (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace EOL transmission line conductor and associated assets (62 km)	HONI	2028	70
Asset Renewal - Transmission Station	Wallace TS	Replace existing EOL 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units	HONI	2025	25
	Midhurst TS	Replace existing 230/44kV 125MVA EOL transformer (T4) with a new 230/44kV 125MVA unit	HONI	2026	12
	Orillia TS	Replace existing EOL 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing EOL 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing EOL 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

The South Georgian Bay-Muskoka TWG recommends that Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 1 while keeping the TWG apprised of project status.

[1] Planned in-service dates are tentative and subject to change

[2] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The next regional planning cycle for the South Georgian Bay-Muskoka Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will start in Q2 2025. However, the next regional planning cycle can be started earlier if required to address any emerging needs.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

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

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders. Figure 1-1 represents the South Georgian Bay-Muskoka Region Map.

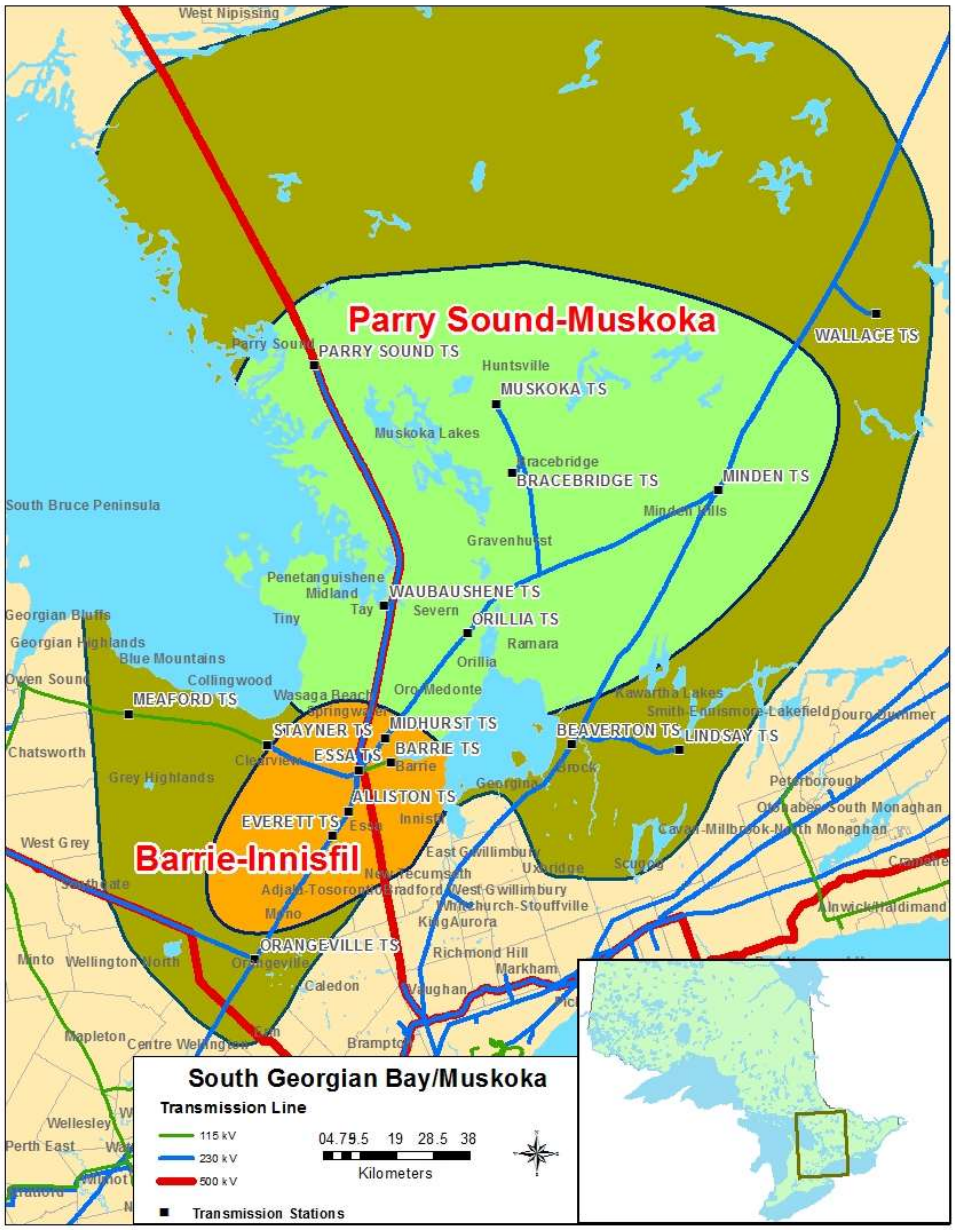


Figure 1-1 South Georgian Bay-Muskoka Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the South Georgian Bay-Muskoka Region. Its objectives are to:

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2022-2032) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2022-2032 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the South Georgian Bay-Muskoka IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

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

2. REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) determines whether further regional coordination is necessary to address them. If no further regional coordination is required to address the need(s), further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer to develop a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straightforward wires solution. The TWG considers various factors in determining that a LP is the appropriate planning approach.

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

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

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

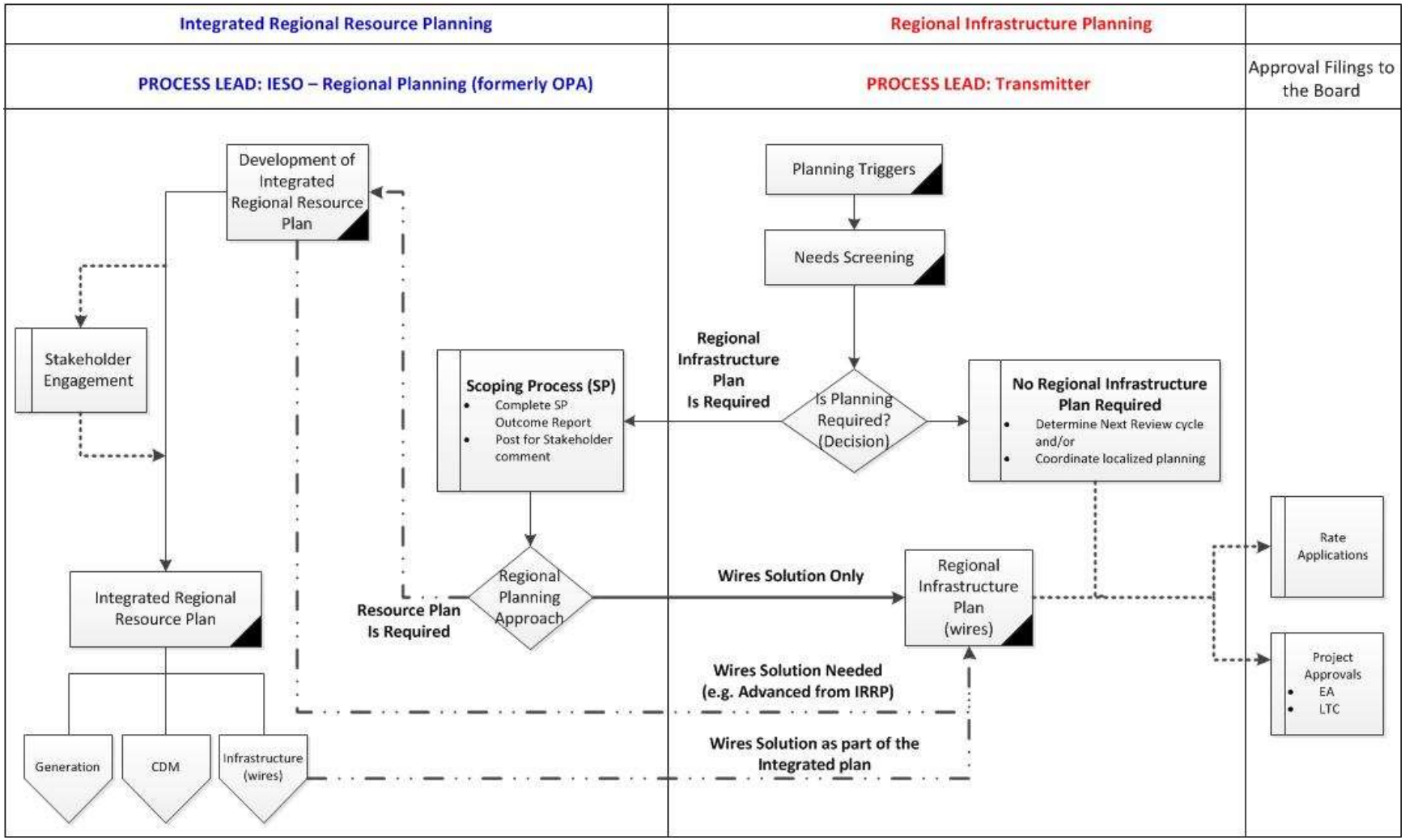


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

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

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

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

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

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

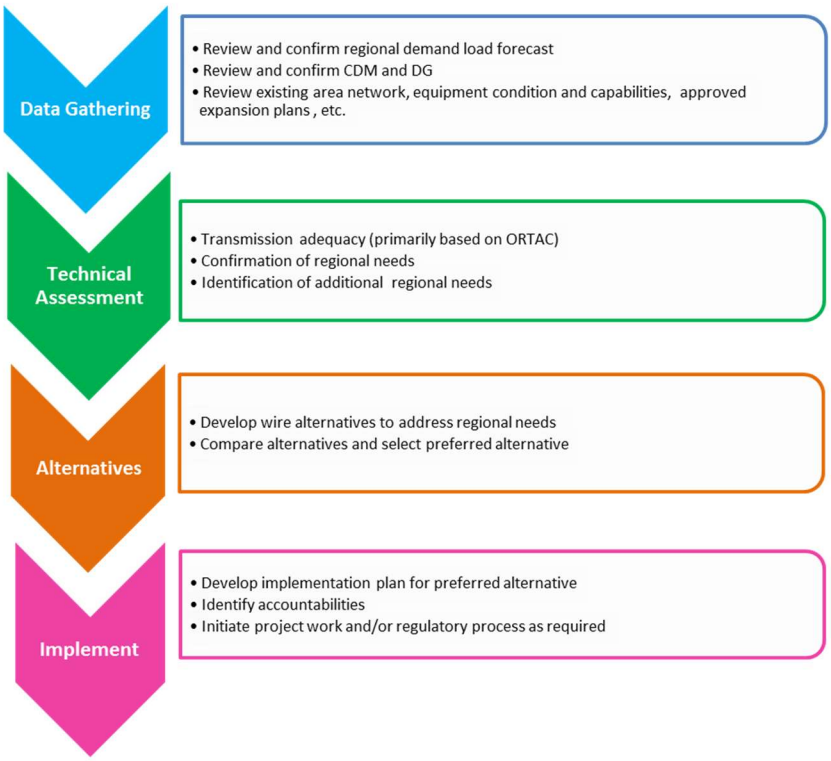


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230KV CIRCUITS E8V AND E9V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this report.

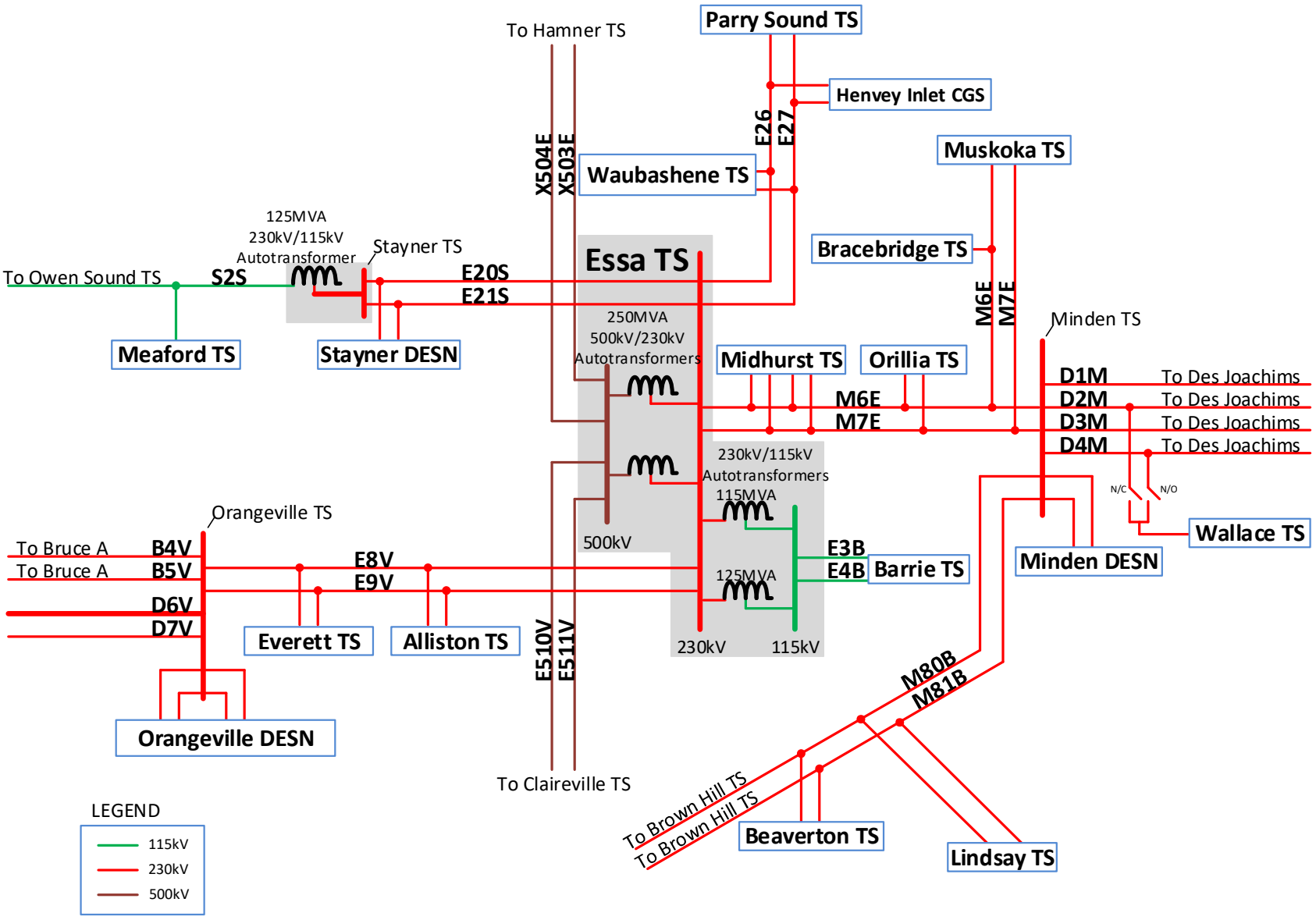
There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The April 2020 South Georgian Bay/Muskoka Region second cycle NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region.

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

This Parry Sound/Muskoka sub-region roughly encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS, and transmission circuits M6E/M7E and E26/E27.
The following circuits are not included in the South Georgian Bay/Muskoka Region:

- The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
- The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.



Note: BATU project will convert E3B/E4B to 230kV and connect Barrie TS directly to Essa TS 230kV bus (In-Service 2023)

Figure 3-1 South Georgian Bay-Muskoka Region Single Line Diagram

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

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

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

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44kV, 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (two banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and defer the overload on circuit M6E.

  Meaford TS Transformer Replacement (2015) – The 115/44 kV, 25/42 MVA T1/T2 transformers were at end-of-life (EOL) and replaced like-for-like.

- Orillia TS M6E/M7E Switches (2021) – Loss of M6E and M7E resulted in violation of ORTAC load restoration criteria based on the peak load forecast. Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS Transformer Replacement (2021) – The 230/44kV, 42MVA T1/T2 transformers were at EOL and replaced with new 230/44kV 83MVA units.

The following projects are underway:

- Barrie TS (2023) – This investment will convert the existing 115kV E3B/E4B circuits to 230kV and connect directly to the Essa 230kV bus. Barrie TS will be rebuilt with new 230/44kV 75/125MVA transformers and connect to the new 230kV E28/E29B circuits. The 230/115kV autotransformers at Essa TS will also be removed as part of this investment.

- Orangeville (2023) – Based on asset condition assessment the existing T3/T4 230/44kV 83MVA transformers will be replaced with new 125MVA units and also, the existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) be replaced with new dual winding 230/27.6, 83MVA units. This investment also involves reconfiguration of low voltage equipment and transfering existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

- Parry Sound TS (2023) - Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to their asset conditions. Hydro One will be installing new 230/44kV 83MVA transformers units to address both end of life and capacity needs at this station.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

During the study period, the load in the South Georgian Bay-Muskoka Region is expected to grow at an average annual rate of approximately 2% (summer) and 1.8% (winter) from 2022 to 2032.

Figure 5-1 shows the South Georgian Bay-Muskoka Region extreme summer weather net load forecast from 2022 to 2042. The load forecasts from the Barrie Innisfil sub-region IRRP and Parry Sound/Muskoka sub-region IRRP were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.
Non-coincident forecast for the individual stations in the region is available in Appendix D and is used to determine any need for station capacity relief.

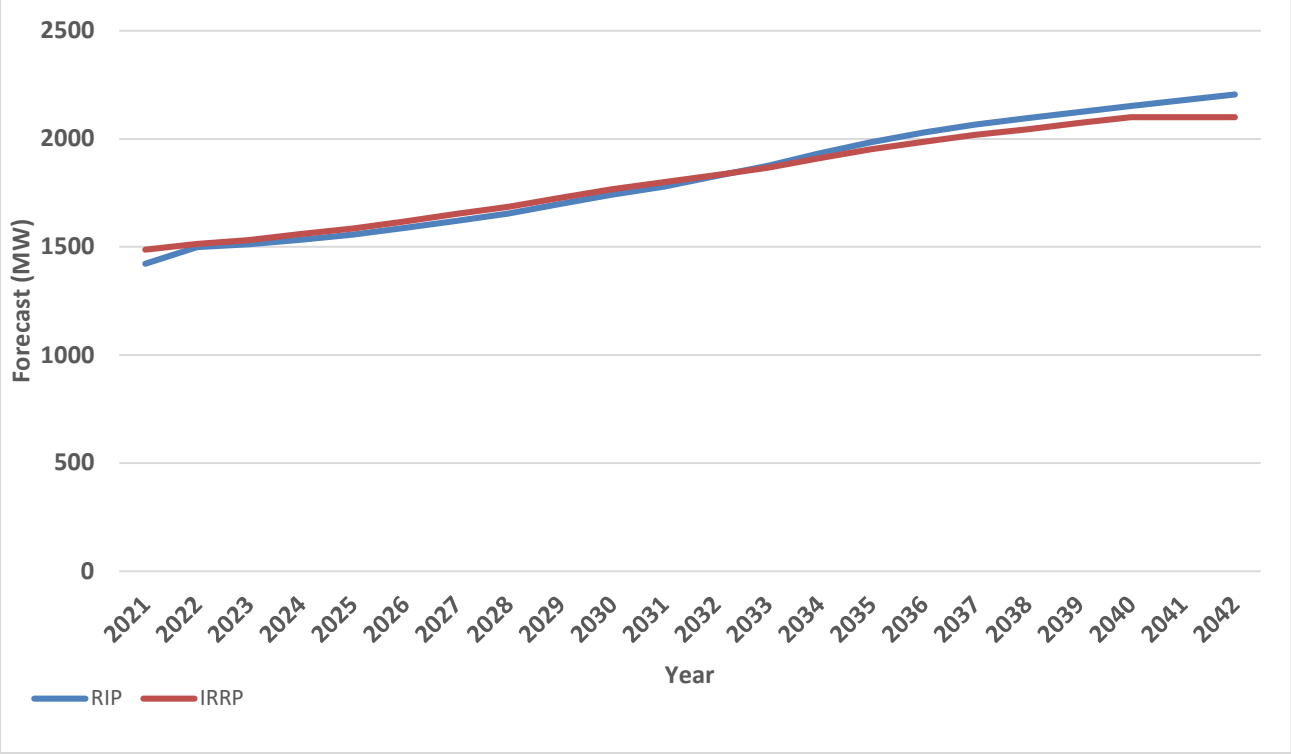


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

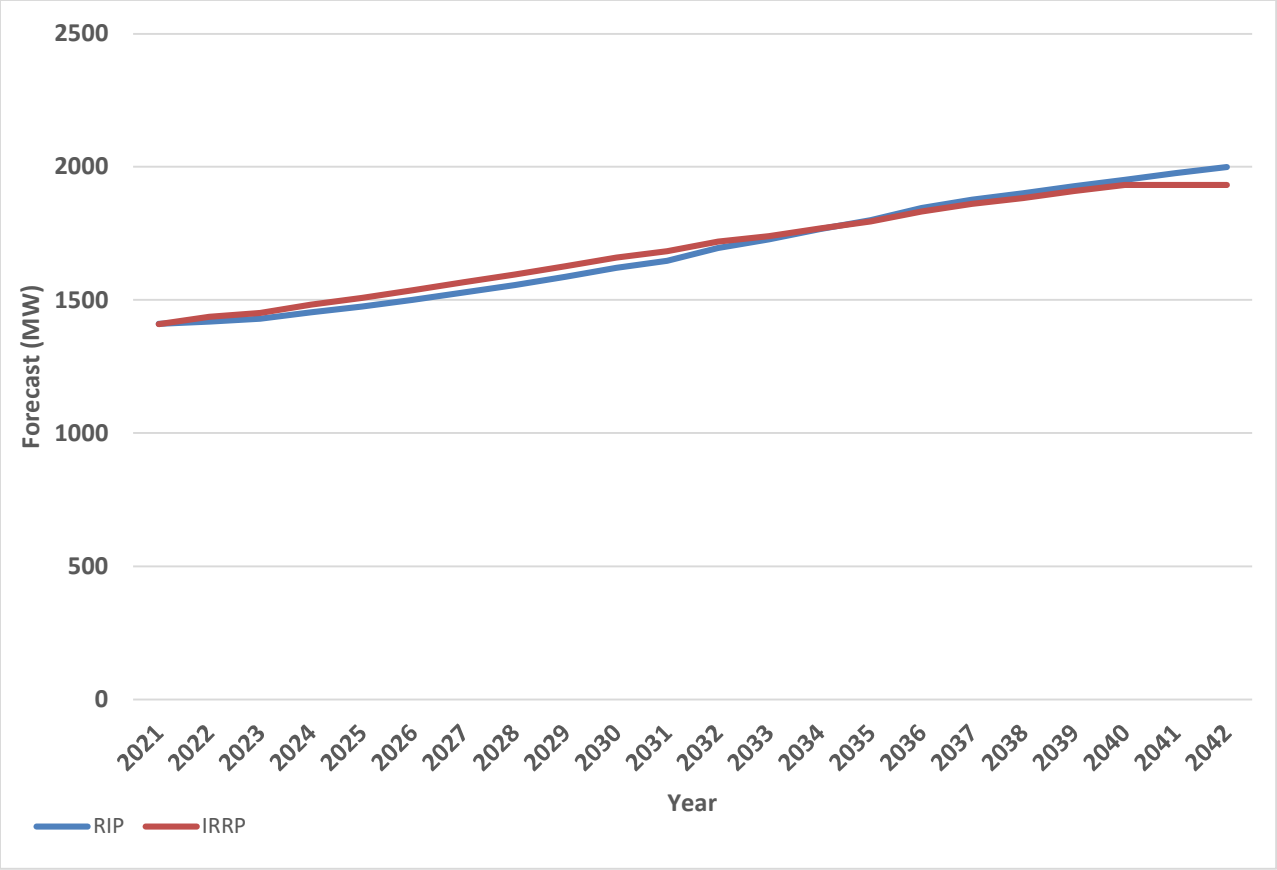


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the IESO's Barrie Innisfil sub-region and Parry Sound/Muskoka sub-region IRRPs.
- LDCs reconfirmed load forecasts up to 2040. The additional two years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Both summer and winter loads were considered to assess line and transformer loadings.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY-MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the South Georgian Bay-Muskoka Region. The findings of these assessments are inputs to this RIP. These assessments are:

1) South Georgian Bay-Muskoka Region second cycle Needs Assessment (NA) Report, April 2020
2) South Georgian Bay/Muskoka second cycle Scoping Assessment Outcome Report, November 2020
3) Barrie/Innisfil sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022
4) Parry Sound/Muskoka sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near to mid-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the South Georgian Bay/Muskoka Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service and specifically, the Barrie Area Transmission Reinforcement project and Orangeville/Parry Sound transformer replacements are in-service by 2023.

Sections 6.1- 6.3 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the South Georgian Bay-Muskoka Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system. The 230 kV circuits also serve local area stations within the region and the power flow on these circuits vary depending on the bulk system transfers as well as the local area loads.

6.1.1 500/230 kV Transformation Facilities

Bulk power supply to the South Georgian Bay-Muskoka Region is provided by 500/230 kV autotransformers at Essa TS which serves as a hub for major power flows between Hanmer TS (Sudbury) and Clairville TS (Toronto). Additional support for the region is provided from the 230 kV generation facilities (Des Joachims GS, Henvey Inlet CGS)

6.1.2 230 & 115 kV Transmission Circuits

The 230kV circuits in the region are as follows;

- E20S/E21S (Essa TS x Stayner TS)
- E26/E27 (Essa TS x Parry Sound TS)
- M6E/M7E (Essa TS x Minden TS)
- D1M/D2M/D3M/D4M (Minden TS x Des Joachims)
- 115 kV - S2S (Stayner TS x Owen Sound TS)

Table 6-1 below highlights the line section(s) and violations identified in the IRRP and reaffirmed in this RIP.

Table 6-1 South Georgian Bay-Muskoka Region - Lines Sections Exceeding ratings

No.	Line	Section	Contingency	Year Line Rating exceeded
1	M6E/M7E	Essa TS x Midhurst TS	N-1[1]	2034
2	M6E	Minden x Coopers Fls JCT	N-1[2]	2038
3	M6E	Minden x Coopers Fls JCT	N-1-1[3]	2040

[1] Loss of one of either M6E or M7E will result in overload of the companion circuit.
[2] Minden TS HL7 breaker fail.
[3] M7E O/S followed by loss of Essa TS T3

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Step-Down Transformation Facilities

There are sixteen (16) step-down transformer stations in the South Georgian Bay-Muskoka Region as listed in Table 6-2.

Table 6-2 South Georgian Bay-Muskoka Region - Step-Down Transformer Stations

Alliston TS	Everett TS	Minden TS	Parry Sound TS
Barrie TS	Lindsay TS	Muskoka TS	Stayner TS
Beaverton TS	Meaford TS	Orangeville TS	Wallace TS
Bracebridge TS	Midhurst TS	Orillia TS	Waubaushene TS

This RIP reviewed the step-down transformation capacity for the stations within the South Georgian Bay-Muskoka Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the 2022-2032 study period are shown in Table 6-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) 10-day LTR.

Table 6-3 South Georgian Bay-Muskoka Region - Stations Requiring Relief in the study period (2022-2032)

Station	Capacity (MW)	2022 Loading (MW)	Need Date
Everett TS	86	85	Immediate
Barrie TS	162[3]	98	2027
Waubaushene TS	94	90	2027

Further, based on the load forecast, the stations requiring relief beyond the study period are listed below:

- Midhurst TS (T1/T2) – 2033
- Midhurst TS (T3/T4) – 2034

6.3 Asset Renewal for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period as listed in Table 6-4 below.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as (but not limited to):

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

The major high voltage equipment considered includes the following:

1. 230/115kV autotransformers;
2. 230 and 115kV load serving step-down transformers;
3. 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
4. 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
5. 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

[3] After completion of the BATU project

Table 6-4 South Georgian Bay-Muskoka Region - Planned Replacement Work

No.	Station / Line Section	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS (T1/T2)	2023
2	Orangeville TS (T1/T2 & T3/T4)	2023
3	Parry Sound TS (T1/T2)	2023
	In Development	
4	Wallace TS (T3/T4)	2025
5	Midhurst TS (T4)	2026
6	Orillia TS (T2)	2025
7	Bracebridge TS (T1)	2026
8	Waubaushene TS T5/T6	2027
9	Alliston TS (T3/T4)	2030
10	M6E/M7E – Cooper Falls Jct x Orillia TS	2026
11	E8V/E9V – Orangeville TS x Essa Jct	2027
12	D1M/D2M – Otter Creek Jct x Minden TS	2028

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

6.4 Load Security and Load Restoration

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

Further, loads are to be restored in the restoration times[4] specified as follows:

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

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

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

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The electrical infrastructure needs for the South Georgian Bay-Muskoka Region are summarized in Table 7-1. These needs include those previously identified in the NA for the South Georgian Bay-Muskoka Region and IRRPs for the Barrie/Innisfil and the Parry Sound/Muskoka Sub-Regions as well as any new needs identified during the RIP phase. All estimated costs included in the altnerative analysis are considered as planning budgetary estimates and are used for comparative purposes only.

Table 7-1 South Georgian Bay-Muskoka Region – Near, Medium and Long Term Needs

Type	Section	Needs	Timing
Station Capacity	7.1	Everett TS	2023
		Barrie TS	2027
		Waubaushene	2027
		Midhurst TS	2033/2034
		Minden TS	2036
Supply Capacity	7.2	M6E/M7E (Essa x Midhurst)	2034
		M6E/M7E (Minden x Coopers Fls)	2038
Asset Renewal for Major HV Transmission Equipment	7.3.1	M6E/M7E (Orillia x Coopers Fls)	2026
		E8V/E9V (Orangeville TS x Essa Jct)	2027
		D1M/D2M (Otter Creek Jct x Minden TS)	2028
	7.3.2	Wallace TS (T3/T4)	2025
		Midhurst TS (T4)	2026
		Orillia TS (T2)	2025
		Bracebridge TS (T1)	2026
		Waubaushene TS (T5/T6)	2027
		Alliston TS (T3/T4)	2030
Load Security/Restoration	7.4	None Identified in this planning cycle	-

7.1 Station Capacity Needs

7.1.1 Everett TS

Everett TS is 230/44kV 50/83MVA transformer station with a summer and winter 10-Day LTR of 86MW. Load at this station is forecasted to increase up to 105MW by the end of 2032. Supply capacity is presently limited by a current transformer (CT) ratio setting on the transformer breaker bushing, thereby restricting the ability to utilize the full supply capability of the transformers.

Table 7-2 Everett TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Everett TS	86	85	86	87	88	90	92	93	95	97	100	105

The following alternatives were considered to address Everett TS capacity need:

Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.

Alternative 2 – Replace and upgrade T1/T2 with new 75/125MVA units: Under this alternative the existing T1/T2 transformers will be replaced with new 75/125MVA transformers. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire the T1/T2 transformers. These transformers remain in acceptable condition are not scheduled to be replaced by Hydro One within the study period.

Alternative 3 – Modify the CT Ratio: This alternative would require modifying the CT ratio of the low voltage transformer breaker CTs to realize the full supply capacity of the transformers.

The TWG recommends Alternative 3 as the preferred and cost effective alternative for addressing the need. CT ratios are established based on expected loading at a station and typically lower when transformer stations are initially constructed. As the load increases these ratios must be adjusted to ensure protection, control and metering continue to operate as intended. This solution utilizes existing assets without incurring additional high capital expenditures and will allow the station LTR to increase to 108MW (summer) and 177MW (winter) once completed. The budgetary cost for this alternative is expected to be $0.5M

7.1.2 Barrie TS

The Barrie Area Transmission Upgrade (BATU) project is presently underway and scheduled to be in-service in 2023. Barrie TS will be upgraded to a new 230/44kV 125MVA transformer station with 8 feeder positions (six for Alectra Utilities and two for Hydro One Distribution with InnPower as an embedded customer).

Barrie TS will have a 10-Day LTR of 162MW and the forecasted load will exceed its normal supply capacity in 2028 based on the summer demand forecast (see Table 7-3 below). Coincident with the station capacity violation, Hydro One distribution and its embedded LDC (InnPower) will also see a supply capacity constraint on their two 44kV feeders in 2028. Minor capacity increases can be accommodated on the 44kV system, but only on an emergency basis and cannot be used as a permanent supply solution for increased load growth. InnPower will

need new supply capacity into the Innisfil service territory to service its load growth beyond the 2-feeder capacity that Barrie TS can supply.

An Innisfil supply study was completed to evaluate supply options for InnPower and consequently help to offload demand from Barrie TS. Results of this study are described in the alternatives below.

Table 7-3 Barrie TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Barrie TS	162	98	119	128	141	154	161	163	164	167	170	174

Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address future station capacity restrictions at Barrie TS, nor does it provide InnPower with the mid-term supply capacity required for load growth in their service territory.

Alternative 2 – Inn Power to connect to existing Alectra Feeder as embedded customer:

This solution was initially discussed by the TWG in the first planning cycle to provide increased supply to InnPower without additional station work at Barrie TS. Spare feeder capacity is not available and thus, this alternative fails to meet the full supply needs within the study period and will need to be combined with alternate solutions. This alternative was rejected on this basis, and thus costs have not been explored further.

Alternative 3 – Install an Additional 44kV feeder position from Barrie TS:

This solution was discussed with the TWG and closely relates to Alternative 2. A new dedicated feeder position for InnPower will provide up to 25MW supply capacity, however this solution would still fail to meet the full supply needs of InnPower within the study period, and the increased load will still be seen at Barrie TS triggering a capacity need in 2028. This solution will need to be combined with alternate solutions to relieve Barrie TS.
The combined transmission and distribution costs to install and construct a new distribution line from Barrie TS is estimated to cost $20M, however this alternative is rejected as it does address capacity needs at Barrie TS.

Alternative 4 – Load existing 44kV supply feeders beyond normal capacity

This alternative was explored by the TWG to increase supply on the two 44kV feeders from Barrie TS beyond the normal supply capacity. This solution requires increased voltage support on the distribution system along the feeders and will provide up to 20MW increased supply capacity (10MW/feeder). Distribution costs to facilitate increased feeder loading is estimated to cost $8M, however this alternative is rejected as it still does address Capacity needs at Barrie TS.

Alternative 5 – Provide 230kV tap connection to Innisfil service territory for new transformer station

This alternative involves construction of a 230/27.6kV 50/83MVA transformer station in Innisfil to supply the increased load demand forecast. This station will connect directly to the 230kV E28B/E29B circuits which will be completed in 2023 as part of the Barrie Area Transmission Upgrade project. A new 9km double circuit 230kV transmission line will be constructed to connect this new transformer station.

This alternative will provide increased supply capacity for InnPower within the study period and allow for load growth in the future. This alternative can be utilized as a standalone solution to meet the needs without additional interim investments or in conjunction with other alternatives presented above. This solution also allows InnPower to transfer load to this station which would otherwise be connected to Alliston TS. This transfer of load helps to mitigate a capacity need during the study period which would see an additional expenditure to increase supply capacity on the T3/T4 DESN at Alliston TS.
The estimated cost for this investment is expected to be $44M which is comprised of $14M for transmission line construction and $30M for a new transformer station.

The TWG recommends proceeding with Alternative 5. This alternative provides a robust transmission solution to meet InnPower's demand forecast and will also allow for future load growth beyond the study period. This solution will also help to relieve Barrie TS which will see a capacity need in 2028. Based on findings in the Needs Assessment and IRRP, Hydro One and InnPower have commenced development work on this alternative to meet the 2028 need date and TWG recommends continuing with this work.

7.1.3 Waubaushene TS

Waubaushene TS presently has 230/44 83MVA transformers (T5/T6) with a summer LTR of 94MW. This station will exceed its normal supply capacity in 2028 (see Table 7-4 below).

Summer overloading at this station continues to be of concern and the TWG agrees that a solution is required to address this need. Hydro One Distribution has permanently transferred 10MW of load from Waubaushene TS to Midhurst TS to help with recent summer loading concerns, however a solution is required to further address the upcoming supply capacity need.

Table 7-4 Waubaushene TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Waubaushene TS	94	90	90	91	92	93	94	96	97	99	100	102

Alternative 1 - Maintain Status Quo: This solution is not recommended as it does not address the supply capacity need at the station. This solution will prevent load growth at this station beyond 2027.

Alternative 2 – Load Transfer to neighboring stations

This solution was explored during the NA and IRRP phase. Hydro One distribution assessed transfer capability to other stations and determined that a maximum of 10MW of load could be transferred, and this was completed in Q1 2022. Further transfers are not feasible without significant distribution construction costs and regulators on the low voltage network estimated to be $ 5-10 M depending on feeder construction and voltage regulation.

Alternative 3 – Replace End-of-Life Waubaushene TS T5/T6 transformers with upgraded 125MVA units.

Replace and upgrade existing T5/T6 transformers with larger 75/125MVA units. This solution will increase supply capacity to allow load to continue to grow as per the demand forecast.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative for addressing the need. The existing T5/T6 transformers at Waubaushene TS have been identified by Hydro One as requiring replacement based on their asset condition and is planned for replacement in 2027. This date coincides with the supply capacity need timing as shown in Table 7.4 and thus the TWG agrees this is the ideal scenario to address the capacity need and right size the transformers. The budgetary cost for the replacement and upgrade of the transformers is expected to be $20M. Hydro One will follow Ontario Energy Board (OEB) approved procedures to determine appropriate cost allocation as this project addresses both a sustainment and capacity upgrade need.

7.1.4 Midhurst TS and Minden TS

As identified in Table 7-1, the stations listed below will require capacity relief beyond 2032. Based on the long-term horizon of these needs the load at these stations will be reviewed in the next regional planning cycle. The timing for capacity relief of these stations is shown below:

- Midhurst TS T1/T2: 2033 and Midhurst TS T3/T4: 2034
- Minden TS T3/T4: 2036

7.2 Supply Capacity Needs

The M6E/M7E circuits are a 230kV double circuit transmission line forming a critical path between Essa TS and Minden TS. These circuits are approximately 120 km long and serve to provide connection to load serving stations and provide a path for network flows. Based on the coincident load forecast of the stations in the region, sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The two circuit sections are described below:

1. Essa TS x Midhurst TS (10km) – For the loss of M6E or M7E, the companion circuit will exceed its Long-Term Emergency (LTE) rating as early as 2034 based on theload forecast.

2. Minden TS x Coopers Falls JCT (51km) – This section of transmission line will experience Long-Term Emergency (LTE) rating violations as early as 2038 for a Minden TS HL7 breaker failure, and Essa T3 contingency with M7E out of service.

Based on the long-term horizon of these needs solutions to address them will be further explored in the next regional planning cycle. Flows on this line and its violations are heavily influenced by area resource assumptions and demand forecast of the transformer stations connected to this circuits. IESO has also identified that incremental cost effective CDM, storage and other non-wires alternatives will be explored to address this need. The TWG will review this need in the next regionalplanning cycle and initiate an investment should this violation be advanced due to changing system conditions.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

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

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

7.3.1 Transmission Line Refurbishment

The following transmission line sections were identified by Hydro One as requiring refurbishment over the study period based on asset condition assessment:

1. M6E/M7E Orillia x Coopers Fls – This is a 50km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2026.

2. E8V / E9V Orangeville TS X Essa JCT – This is a 112km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2027.

3. D1M / D2M Otter Creek JCT x Minden TS – This is a 124km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2028.

7.3.2 Transmission Station Refurbishment

Hydro One identified a number of step-down transformers as requiring replacement over the study period based on asset condition assessment. Details of the planned work as recommended by the TWG are given in Table 7-5 below.

Table 7-5 Asset Renewal Plan-Transmission Stations

No.	Station	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV. This investment is also known as Barrie Area Transmission Upgrade (BATU) and will include replacement of end of life equipment at Essa TS, in addition to increasing both station and supply capacity to the area.	2023
2	Orangeville TS Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 230/44kV 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. This replacement plan will decrease the risk of equipment failure and contribute to maintaining supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	2023
3	Parry Sound TS Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment. Replacement of these power transformers will help to maintain the reliability of supply and provide increased supply capacity to customers in the area by right sizing to 83MVA units.	2024
	In Development	
4	Wallace TS Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units. Replacement of Oil circuit breakers will also be part of this investment. This investment will help maintaining reliability of supply to Hydro One Distribution customers and reduce the risk of interruptions caused by station equipment failure.	2025

5	Midhurst TS Replace existing 230/44kV 125MVA T4 transformer with a new like-for-like unit. The T3/T4 DESN presently supplies load to Alectra though 8 x 44kV feeders. T4 is the sole unit that has been identified as requiring replacement due to poor asset condition. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure. Load growth in the area will be reviewed in the next regional planning cycle. The TWG will ensure solutions to increase supply capacity in the region are explored in advance of the need date.	2026
6	Orillia TS Replace existing 230/44kV 125MVA T2 transformer with a new like-for-like 230/44kV 125MVA unit. The T1 transformer was replaced in 2015 after failure and does not require replacement during this study period. This investment will help maintain reliability of supply to Hydro One Distribution customersand decrease the risk of interruptions caused by failure of transformer T2.	2025
7	Bracebridge TS Replace existing 230/44kV 83MVA transformer (T1) with new like-for-like 230/44kV 83MVA unit. Bracebridge TS presently has one transformer (T1) and is used to supply 2 x 44kV feeders and a backup for industrial pipeline operation. The load at this station is not expected to trigger installation of a second transformer and thus like-for-like replacement of T1 will be sufficient during the study period. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2026
8	Waubaushene TS Replace existing 230/44 83MVA transformers (T5/T6) with new 125MVA units. This investment will help to maintain reliability of supply to area customers and provide increased supply capacity to meet demand forecast.	2027
9	Alliston TS Replace existing 230/44kV 83MVA transformers (T3/T4) with new like-for-like 230/44kV 83MVA units.	2030

	This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure and removal of legacy obsolete equipment.	

*The planned in-service year is tentative and is subject to change.

The above asset replacement plans have taken "right sizing" into consideration. All transformer replacements in the development phase are planned to be replacewith like-for-like units based on the load forecast in the study period and Hydro One standard equipment. The TWG recommends that Hydro One proceed with the above station sustainment work to ensure system reliability is maintained.

7.4 Load Security / Restoration

As indicated in section 6.4 there are no load security or restoration violations in the SGB-Muskoka region over the study period. The TWG will continue to monitor and take corrective action as needed.

7.5 Long Term Considerations

Like many other regions in Ontario, load growth in the SGB-Muskoka region will be directly impacted by new energy programs specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near and medium-term planning horizon (2022-2032) are provided in Table 8-1 below, along with their planned in-service dates and budgetary estimates for planning purposes.

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

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[5]	Cost ($M)[6]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and extend and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing end-of-life 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal Needs for Major HV Transmission Equipment	M6E / M7E (Orillia TS x Coopers Fls)	Replace transmission line conductor and associated assets. (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace transmission line conductor and associated assets. (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace transmission line conductor and associated assets. (62km)	HONI	2028	70
	Wallace TS	Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units.	HONI	2030	25
	Midhurst TS	Replace existing 230/44kV 125MVA transformer (T4) with a new 230/44kV 125MVA unit.	HONI	2026	12
	Orillia TS	Replace existing 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

[5] The planned in-service dates are tentative and subject to change.

[6] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The South Georgian Bay-Muskoka TWG recommends Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 8-1. All the other identified needs/options in the long-term will be further reviewed by the TWG in the next regional planning cycle.

9. REFERENCES

[1] Independent Electricity System Operator, Barrie/Innisfil IRRP (2022)

[2] Independent Electricity System Operator, Parry Sound Muskoka IRRP (2022)

[3] Hydro One, South Georgian Bay/Muskoka Needs Assessment (2020)

[4] Hydro One, South Georgian Bay/Muskoka RIP (2017)

[5] Independent Electricity System Operator, Barrie/Innisfil IRRP (2016)

[6] Independent Electricity System Operator, Parry Sound/Muskoka IRRP (2016)

[7] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 August 07, 2007

[8] Ontario Energy Board, Transmission System Code (2018)

[9] Ontario Energy Board, Distribution system Code (2022)

APPENDIX A. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS

No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubaushene TS	230/44

APPENDIX B. SOUTH GEORGIAN BAY-MUSKOKA REGION - TRANSMISSION LINES

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

APPENDIX C. SOUTH GEORGIAN BAY-MUSKOKA REGION - DISTRIBUTORS

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd.	DX
9.	Wasaga Distribution Inc.	DX

APPENDIX D. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	74.7	44	44	44	44	45	45	45	45	46	46	47	48	48	49	50	51	51	52	53	54	55
Alliston TS	T3/T4	112	100.8	76	80	83	86	90	93	91	91	91	92	92	93	93	93	93	93	94	94	94	94	94
Barrie TS	T1/T2	170	162.0	98	119	128	141	154	161	163	164	167	170	174	178	183	189	195	203	213	222	232	233	233
Beaverton TS	T3/T4	204	193.8	69	69	69	69	70	70	71	71	71	72	73	75	78	82	82	83	83	86	87	87	87
Bracebridge TS	T1	83	74.7	27	27	27	27	27	27	27	27	28	28	28	28	28	29	29	29	29	29	29	30	30
Everett TS	T1/T2	86	77.4	85	86	87	88	90	92	93	95	97	100	105	111	119	130	140	149	156	164	171	171	172
Lindsay TS	T1/T2	169	160.6	84	85	85	85	86	87	88	89	89	90	92	94	97	100	101	101	102	103	104	105	105
Meaford TS	T1/T2	55	52.3	33	33	33	33	33	34	34	34	34	35	37	38	38	38	38	38	39	39	39	40	40
Midhurst TS	T1/T2	171	163	150	151	153	154	156	157	159	160	162	162	163	166	167	169	170	171	173	174	175	176	176
Midhurst TS	T3/T4	166	149.4	123	107	111	115	118	122	125	129	133	136	140	144	151	156	160	163	167	171	175	176	176
Minden TS	T1/T2	58	52	44	44	44	44	44	45	45	45	46	46	46	47	47	48	48	52	52	53	53	53	53
Muskoka TS	T1/T2	179	170.1	113	114	113	113	114	115	116	117	125	125	126	127	130	132	133	134	135	136	137	137	137
Orangeville TS	T1/T2	113	101.7	49	49	52	53	53	54	55	55	56	57	59	60	62	62	63	64	65	65	66	67	67
Orangeville TS	T3/T4	170	161.5	90	91	97	98	99	100	102	103	104	106	110	111	114	116	117	119	120	122	123	124	124
Orillia TS	T1/T2	162	153.9	105	106	106	107	107	108	109	119	120	121	122	123	128	130	131	132	133	134	135	135	135
Parry Sound TS	T1/T2	113	101.7	45	46	45	47	48	50	50	51	54	54	55	55	56	56	56	57	57	58	58	58	59
Stayner TS	T3/T4	191	181.5	129	130	130	131	133	135	136	138	140	143	145	147	150	152	159	161	163	166	168	170	171
Wallace TS	T3/T4	54	48.6	36	36	36	36	36	36	36	36	36	37	37	37	37	38	38	38	38	38	38	39	40
Waubaushene TS	T5/T6	99	94.1	90	90	91	92	93	94	96	97	99	100	102	107	108	111	113	114	115	116	117	117	117

Winter Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LV Cap	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	N	74.7	32	32	32	32	32	33	33	33	34	34	35	35	36	36	37	37	38	38	39	40	40
Alliston TS	T3/T4	128	N	115.2	80	69	74	78	81	85	88	87	86	87	87	87	88	88	88	88	88	89	89	89	88
Barrie TS	T1/T2	200	Y	190.0	74	88	97	109	119	127	127	129	131	133	136	140	144	149	153	160	168	176	184	185	186
Beaverton TS	T3/T4	224	Y	212.8	77	78	78	78	79	79	80	80	81	81	81	82	82	83	84	84	85	88	88	89	90
Bracebridge TS	T1	83	N	74.7	34	34	34	34	34	34	34	35	35	35	35	35	35	35	36	36	36	36	36	37	38
Everett TS	T1/T2	95	N	85.5	60	61	62	63	64	65	66	67	69	71	75	81	88	99	109	118	125	132	139	139	140
Lindsay TS	T1/T2	192	Y	182.4	92	93	94	94	95	96	97	98	98	99	100	101	102	102	103	104	105	105	107	106	107
Meaford TS	T1/T2	62	Y	58.9	43	44	44	44	44	44	44	45	45	45	52	52	53	53	53	54	54	54	54	55	56
Midhurst TS	T1/T2	194	Y	184.3	116	116	117	118	119	120	121	122	123	124	125	126	127	128	128	129	130	131	132	132	133
Midhurst TS	T3/T4	191	N	171.9	96	85	88	90	93	95	98	101	103	106	108	111	114	117	119	122	125	127	130	131	132
Minden TS	T1/T2	64	N	58	55	55	55	55	55	56	56	56	57	57	57	58	58	58	59	63	63	63	64	64	65
Muskoka TS	T1/T2	209	Y	198.6	146	146	146	147	148	150	151	151	158	159	160	161	162	163	164	165	166	167	168	168	169
Orangeville TS	T1/T2	133	N	119.7	42	42	45	46	46	46	47	47	47	48	52	52	55	55	56	56	56	57	57	58	58
Orangeville TS	T3/T4	200	Y	190.0	78	78	84	85	86	86	87	87	88	89	97	97	102	103	103	104	104	105	106	107	107
Orillia TS	T1/T2	184	Y	174.8	108	109	110	111	112	112	113	123	123	124	125	126	127	128	129	130	131	132	133	133	134
Parry Sound TS	T1/T2	133	N	119.7	59	60	60	62	64	65	66	66	69	69	70	70	71	71	72	73	73	74	74	75	76
Stayner TS	T3/T4	213	Y	202.4	135	136	137	138	139	141	142	144	145	147	148	150	152	154	167	169	171	173	175	176	178
Wallace TS	T3/T4	60	N	54.0	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40	40	41	41	41	42	42
Waubaushene TS	T5/T6	109	Y	103.6	74	75	76	76	77	78	79	80	80	81	82	83	84	85	86	86	87	88	89	89	90

APPENDIX E. LIST OF ACRONYMS

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



Integrated Regional Resource Plan

Barrie/Innisfil
May 2022

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List of Acronyms

APO	Annual Planning Outlook
BKF	Breaker Failure
CEP	Community Energy Plan
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
GHG	Greenhouse Gas
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Electricity Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-Wires Alternatives
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RO	Reliability Outlook
SIA	System Impact Assessment

SGBM	South Georgian Bay Muskoka
TS	Transformer Station

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

This IRRP was prepared on behalf of the Technical Working Group of the Barrie/Innisfil sub-region which is composed of the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Alectra Utilities
- InnPower Corporation

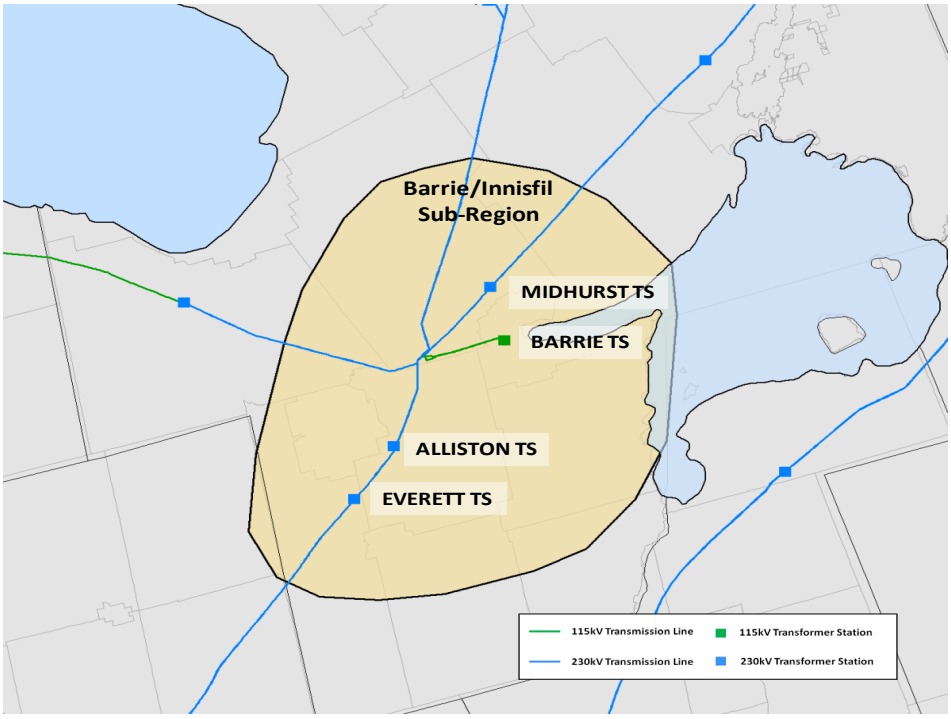
The Technical Working Group assessed the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Barrie/Innisfil Technical Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to appropriate community engagement and consultations and obtaining necessary regulatory approvals.

1. Introduction

This IRRP for Barrie/Innisfil sub-region addresses the regional electricity needs over the study period, i.e., from 2021 to 2040. The Barrie/Innisfil sub-region is located in the South Georgian Bay Muskoka region and it encompasses the City of Barrie, the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury, and the townships of Essa, Springwater, Clearview, Mulmur and Adjala-Tosorontio. Figure 1 shows the overview of the Barrie/Innisfil sub-region.

Figure 1 | Overview of the Barrie/Innisfil Sub-Region and Transmission System[1]



The sub-region is electricity supplied by the following three local distribution companies (LDC), namely: Hydro One Networks Inc. (Distribution), Alectra Utilities and Innpower Corporation. The transmission asset owner is Hydro One Networks (Transmission). This IRRP report was prepared by the IESO on behalf of the Technical Working Group composed of the three Local Distribution LDCs and transmitter.

[1] Barrie TS is currently being upgraded to 230 kV supply

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is conducted through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for each of the province's 21 electricity planning regions, including the South Georgian Bay Muskoka region, at least once every five years.

This is the second cycle of regional planning for the Barrie/Innisfil sub-region. This cycle began in 2020 with the publication of the South Georgian Bay Muskoka Needs Assessment Report. This was followed by a Scoping Assessment which identified needs that should be addressed through the IRRP process and recommended two IRRPs; one for Parry Sound/Muskoka sub-region and another for Barrie/Innisfil sub-region. A Technical Working Group was then formed for Barrie/Innisfil to gather data, identify electricity needs and develop options and recommendations which are included in this IRRP.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Barrie/Innisfil sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Barrie/Innisfil sub-region and the study scope are discussed in Section 4;
- The demand forecast and conservation and demand management (CDM) and distributed generation (DG) assumptions are described in section 5;
- Electricity needs in the Barrie/Innisfil sub-region are presented in Section 6;
- Alternatives and recommendations for addressing needs are described in Section 7;
- A summary of engagement activities is provided in section 8; and
- The plan conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The Barrie/Innisfil IRRP provides recommendations to address the electricity needs of the sub-region over the next 20 years. The needs were identified based on the sub-region's demand forecast and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that considers: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from communities and stakeholders.

The Barrie/Innisfil IRRP recommendations below are organized under a near/medium-term plan and a longer-term plan. The near/medium-term timeframe is seven to ten years out while the longer-term timeframe is beyond ten years. The timeframe distinction reflects the different levels of forecast certainty, lead time for development and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on the investments that will be needed in a near future while remaining flexible to new information.

2.1 Near/Medium-Term Plan

Table 1 below lists the recommended actions to address the sub-region's needs together with the details of their implementation for the near/medium-term. The recommendations are further discussed below.

Table 1 | Summary of Near/Medium-term Plan for Barrie/Innisfil IRRP

Need Description	Recommendation	Lead Responsibility	Required by
Barrie TS to reach its summer 10-day LTR and supply capacity constraint at 44 kV feeder level	Construct a new 230/27.6 kV transformer substation	Hydro One and InnPower	2025
Everett TS to reach its summer 10-day LTR	Adjust the CT ratio of transformer breakers	Hydro One	2025
Sections of E8V/E9V circuits to reach end-of-life	Like for like replacement	Hydro One	2027

2.1.1 Transformer CT Ratio Adjustment at Everett TS and New 230/27.6 kV Transformer at Barrie TS

Everett TS and Barrie TS are both expected to reach their summer 10-day LTR in the near/medium-term timeframe.

Everett TS peak demand forecast will exceed its rating by 2025. The recommended solution for this need is to adjust the CT ratio of the transformer breakers[2]. This will provide the ability to utilize the full supply capability of the transformers at Everett TS and alleviate the need.

Barrie TS peak demand forecast will exceed its rating by 2027. Also, there is a supply constraint on the distribution level at the 44 kV feeder starting in 2025. For this distribution level need, minor capacity increases can be accommodated on the 44 kV system but only on an emergency basis. The recommended solution is to construct a new 230/27.6 kV transformer substation which would connect to the upgraded circuits E28B/E29B that will be in place once the Barrie Area Transmission Upgrade (BATU) reinforcements are in-service[3].

2.1.2 E8V/E9V Like-for-Like Replacement

Sections of circuits E8V/E9V will reach end-of-life by 2027. A like-for-like approach is recommended for the replacement of these assets from a regional perspective.

2.2 Longer-Term Plan

In addition to the near/medium-term plan above there are the following items to monitor and develop in the longer-term.

2.2.1 Monitor Growth at Midhurst TS and Alliston TS

Midhurst TS and Alliston TS are expected to reach capacity by 2035 and 2037 respectively. Given the timing of the need, no firm recommendation is required at this time. The Technical Working Group will continue to monitor demand growth in the area and revisit these needs in the next cycle of regional planning.

2.2.2 Consider CDM in Next Cycle of Regional Planning for M6E/M7E Essa x Midhurst circuit

There is a thermal capacity need on one MxE 230 kV circuit section between Essa and Midhurst for the loss of the companion MxE circuit starting in 2034. While this need is expected to arise in the longer-term, potential options were contemplated to inform future plans.

---

[2] Current transformers are instrument transformers used for measurements for metering/loading data or for generating signals for protective devices. Since the current on the actual system is usually too high to be either economically or practically measured or to supply a signal to a protective device, the current transformer lowers the current to an acceptable level. The ratio between these two current values is the "CT ratio"

[3] The BATU project involves rebuilding and uprating Barrie TS and the E3/4B circuits to 230 kV circuits E28/29 and retiring Essa T1/T2

The analysis showed that incremental, cost-effective CDM is potentially a good candidate to defer this need, when considering the need characteristics. Given the time of the need, no firm recommendation is required at this time; however, it is recommended to continue to consider incremental, cost-effective CDM as an option in between planning cycles and bring these insights into the next cycle of regional planning for the region.

2.2.3 Supporting Community Energy Plans and Monitoring Energy Efficiency and Electrification Trends

There are two Community Energy Plans (CEP) identified in the Barrie/Innisfil sub-region. The first is the Barrie Community Energy and Green House Gas (GHG) Emission Reduction Plan which was presented to Council in March 2022. This plan will help the community better understand current energy consumption, identify energy efficiency opportunities and help meet the community's climate priorities.

The second plan is for the Town of Innisfil. The Community Strategic Plan: Innovative Innisfil 2030 was approved by Council in October 2019. This plan will guide projects across the Town of Innisfil over the next ten years to help Innisfil become a unique and innovative community.

While the IRRP seeks to align with these plans where possible, not all of the objectives fall within the scope of the regional planning nor the IESO's mandate. For example, absent of provincial government policy, the IESO is technology agnostic and will generally choose the most economic option that adequately resolves the need and meets applicable reliability standards. Greenhouse gas emissions are considered in the IRRP's options analysis by accounting for the carbon price associated with emitting resources, but the IESO does not have emission reduction targets unless directed by government policy. Furthermore, while regional planning is responsible for ensuring electricity ratepayer value and minimizing electricity costs, the IESO relies on government policy for broader socioeconomic considerations.

There are three CEP objectives that the IESO and regional planning can play a role in supporting. First, the IESO recognizes that distributed energy resources (DER) are becoming increasingly prevalent and features prominently in many CEPs. DERs can provide benefits to both customers as well as the distribution and transmission systems. By enabling DERs to provide wholesale services, system costs can be reduced and opportunities for customers and investors can be increased. The IESO's Enabling Resources Program (ERP) will produce a 5-10 year plan to enable resources to provide services they cannot or cannot fully currently provide. The ERP has identified storage, hybrids, and DERs as high-priority opportunities. The IESO developed a DER roadmap in the fall of 2021 to provide clarity on IESO objectives, initiatives, and timing for DER integration and is completing a DER Potential Study by June 2022. More information can be found on the Distributed Energy Resource Roadmap engagement page.

Second, the Technical Working Group will continue to support and monitor energy efficiency uptake. Conservation expected to be achieved through codes, standards, and program delivery has already been included in the planning forecast as described in Section 5.4. On September 30, 2020, the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensures energy efficiency can continue to play a role in meeting the region's needs. The Technical Working Group will monitor uptake of the CDM framework as well as energy efficiency initiatives in CEPs and assess the impact of these additional savings on the timing of local reliability needs.

Finally, the Technical Working Group will monitor electrification trends and their impact on the demand forecast. The Technical Working Group recognizes that many CEPs are calling for ambitious electrification targets as a means to achieve carbon emission reductions. It is not yet clear how impactful electrification will be to the load forecast in the near-term but it could drive significantly higher demand in the long term that will necessitate new electricity supply into the area. While it is still difficult to establish when firm investments or infrastructure reinforcements will be needed, it is prudent to prepare for a future where electricity demand could potentially be significantly higher than forecast.

2.3 Bulk Area Needs

One of the needs identified as part of this IRRP is linked to the bulk transmission system in the broader region. This need is a thermal capacity need on one of the Essa 500/230 kV autotransformers for loss of the companion autotransformer arising in 2022. For loss of Essa T4, Essa T3 is at 100% of its 10-day summer Limited Time Rating (LTR) in 2022. This will be considered as part of IESO's bulk planning process.

3. Development of the IRRP

3.1 The Regional Planning Process

In 2013, the OEB created a formal process for regional planning which is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The regional planning formal process sets out 21 different electricity planning regions for the province. Regional planning assesses the interrelated needs of a region over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, demand forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the largest transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;

3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A Regional Infrastructure Plan (RIP), led by the transmitter, which provides further details on recommended wires solutions.

Further details on the components of the regional planning process in Ontario and the IESO's approach to regional planning can be found in Appendix A.

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues whereas distribution network planning considers the supply of electricity within an LDC's system Regional planning is the intersection of those two.

A review of the regional planning process was finalized in 2021 following the completion of the first cycle of regional planning for all 21 regions. The Regional Planning Process Review Final Report is published on the IESO's website.

3.2 Barrie/Innisfil and IRRP Development

The process to develop the Barrie/Innisfil IRRP was initiated following the publication of Hydro One's South Georgian Bay Muskoka Needs Assessment report in April 2020 and the IESO's Scoping Assessment report in November 2020. The Scoping Assessment report recommended that the needs identified for the Barrie/Innisfil sub-region be considered through an IRRP in a coordinated regional

approach. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options and recommend solutions in the sub-region.

4. Background and Study Scope

This is the second cycle of regional planning for the Barrie/Innisfil sub-region. During the first cycle of regional planning, a Needs Assessment was conducted for the South Georgian Bay Muskoka Region in March 2015 that was led by Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination should be considered and a Scoping Assessment was published in June 2015 which recommended coordinated planning through an IRRP. Subsequently, the IRRP for Barrie/Innisfil was published in December 2016 and the RIP was published in August 2017.

This regional planning cycle started with a Needs Assessment published by Hydro One in April 2020, which identified several needs requiring further regional coordination. This was followed by a Scoping Assessment published in November 2020. The report recommended that an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2021.

4.1 Study Scope

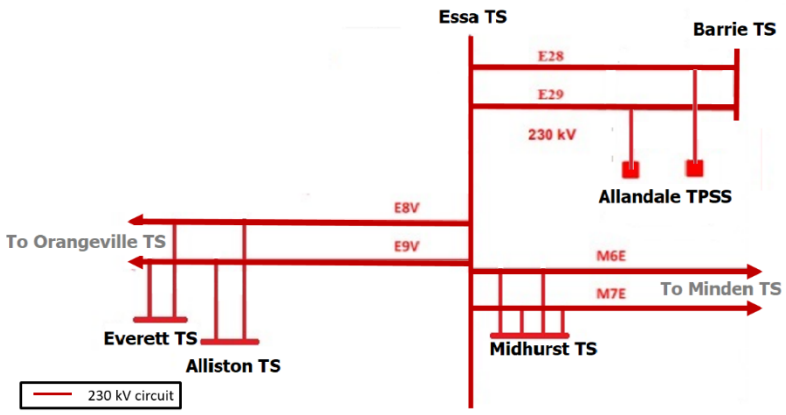
This IRRP develops and recommends options to meet the electricity needs of the Barrie/Innisfil sub-region. The plan was prepared by the IESO on behalf of the Technical Working Group. The plan includes consideration of forecast electricity demand growth, CDM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The needs addressed in this IRRP include adequacy, security and relevant end-of-life asset considerations.

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

- 230/115 kV autotransformers at Essa Transformer Station (TS)
- Stations: Alliston TS, Barrie TS, Everett TS, Midhurst TS
- Transmission circuits: E8V/9V, E28/29, M6/7E (Essa to Midhurst section)

The single line diagram of the Barrie/Innisfil sub-region studied is shown in Figure 2 below.

Figure 2 | Single Line Diagram of Barrie/Innisfil Sub-Region



The Barrie/Innisfil sub-region is supplied from the two 500/230 kV autotransformers at Essa TS. These transformers form part of the bulk transmission system, as they are impacted by changes in the broader Ontario electricity system, in addition to the local distribution system. Specifically, the autotransformers are impacted by bulk power system flows on the north-south transmission interface, driven by changing generation and demand patterns in northern and southern Ontario. Therefore, regional needs pertaining to these autotransformers must also be considered from a bulk system perspective and coordinated accordingly.

The Barrie/Innisfil IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the Load Meeting Capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs are established by applying ORTAC and NERC planning criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO controlled grid as described in section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

4.2 Related Bulk System Planning Studies

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV autotransformers at Essa TS) will be assessed by the IESO through a separate bulk system planning process, and assumptions will be coordinated between the regional and bulk plans.

5. Electricity Demand Forecast

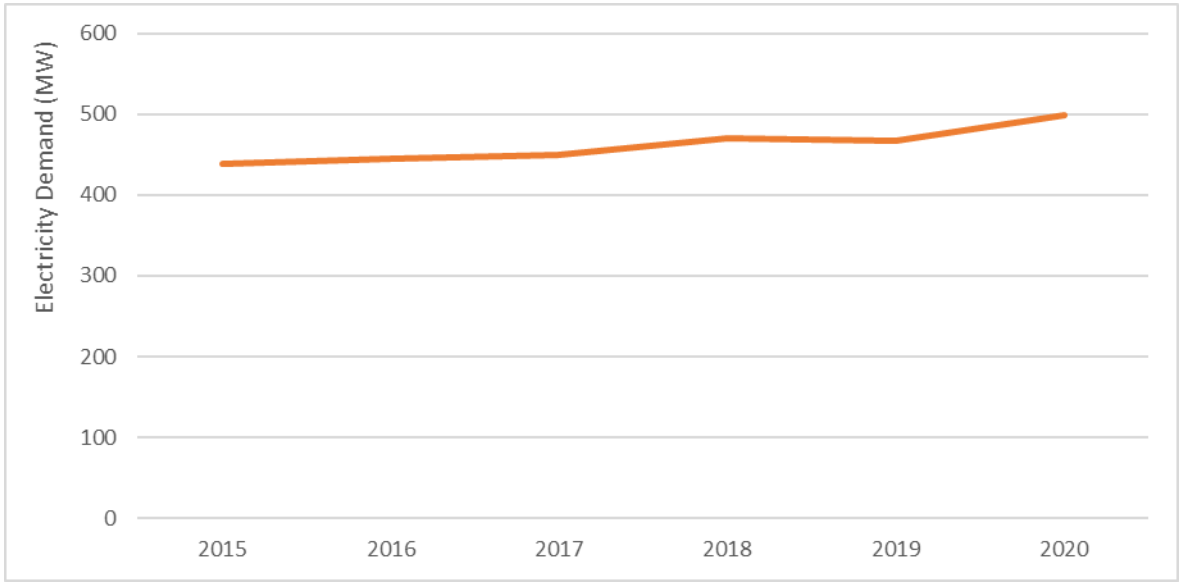
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the Barrie/Innisfil sub-region. It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Barrie/Innisfil sub-region, the peak loading hour for each year occurs in the summer.

5.1 Historical Electricity Demand

In the Barrie/Innisfil sub-region, electricity demand is primarily driven by residential and commercial customers and typically peaks during the summer months. In the summer, air conditioning plays a significant role in contributing to peak electricity demand. The historical demand is shown in Figure 3 and has been adjusted for weather-related impacts. The figure below shows a steady increase in the summer electricity demand needs of the sub-region, reaching a peak of 500 MW in 2020; notably, there is a significant increment from 2019 to 2020 impacted primarily by the weather conditions. The Technical Working Group determined 2020 to be the base year to be used for developing the planning demand forecast.

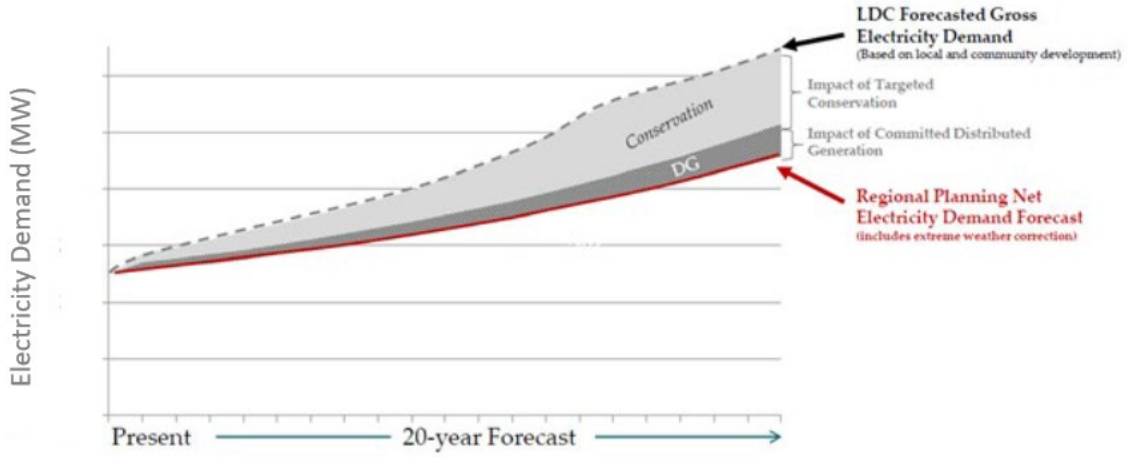
Figure 3 | Historical Summer Peak Demand – Barrie/Innisfil Sub-region



5.2 Demand Forecast Methodology

A 20-year regional peak demand forecast was developed to assess reliability needs for the Barrie/Innisfil sub-region; Figure 4 shows the steps taken to develop this. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions i.e., normal weather, were provided by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation savings and DG contracted through previous provincial programs such as FIT and microFIT. The forecasts were then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix B.

Figure 4 | Development of the Demand



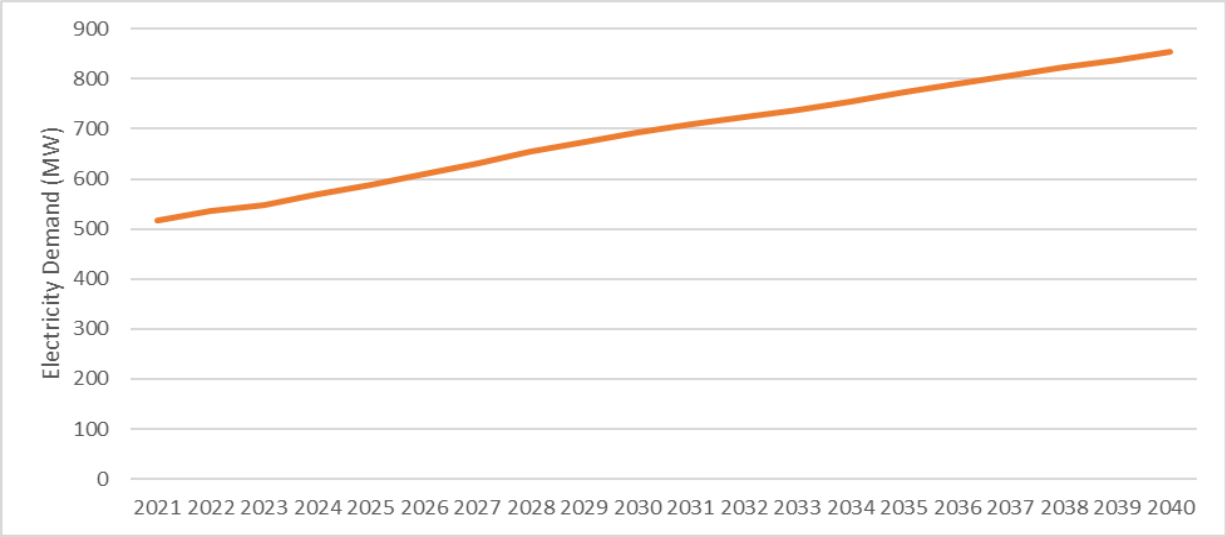
5.3 Gross LDC Forecast

All participating LDCs in the Barrie/Innisfil sub-region provided a gross demand forecast at the station level or at the station bus level for multi-bus stations. LDCs have a better understanding of future local demand growth and drivers than the IESO since they have more direct involvement with their customers. The LDC gross demand forecasts include known connection applications and account for increases in demand due to new or intensified development, economic growth, changes in consumer behaviour, etc. Increases in demand due to new or intensified development were captured through a sensitivity analysis. An example of this is the new Allandale Traction Power Substation (TPSS) (47.2 MW), which will be supplied from uprated circuits E28/E29.

Most LDCs cited alignment with municipal and regional official plans and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for later in the process. The gross LDC forecast assumes median on-peak weather conditions. More information on the LDCs' demand forecast methodology can be found in Appendix B.

The total gross coincident LDC forecast in the next 20 years for both summer and winter weather is shown in Figure 5 below.

Figure 5 | LDC Coincident Gross Summer Demand Forecast – Median Weather



5.4 Contribution of Conservation to the Demand Forecast

CDM helps in meeting Ontario's electricity needs by reducing demand. This is achieved through a mix of codes and equipment standards amendments as well as CDM program-related activities.

Demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers. Program-related activities include Save on Energy programs, as well as those that are being implemented as part of the 2021-2024 CDM framework.

For the Barrie/Innisfil sub-region, the total forecast conservation savings at the time of summer peak are shown in Table 2 for a selection of the forecast years. These savings are subtracted from the gross median demand forecast as described in Section 5.6. Additional information is provided on Appendix B.

Table 2 | MW Savings from Conservation and Demand Management

Year	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040
Summer Savings (MW)	12	25	32	37	41	42	43	44	46	47

5.5 Contribution of Distributed Generation to Demand Forecast

In addition to conservation resources, DG in the Barrie/Innisfil sub-region is also forecasted to offset peak demand requirements. The resources that were included in the DG forecast reflect resources that have contracts with the IESO as a result of previous procurement programs, such as the FIT and microFIT programs. In the Barrie/Innisfil sub-region, the contracted DG resources are all solar projects. The effective capacity, i.e., the MW output at the time of regional peak, was determined at a resource level, and the data was aggregated at a station level in order to put together a forecast specifying the estimated peak demand reduction due to DG output.

From 2021 to 2033, the expected annual peak demand contribution of contracted DG in the Barrie/Innisfil sub-region is 5.8 MW, going down to 2.35 MW in 2034 and 0 MW in 2040.

The DGs included in the Barrie/Innisfil IRRP are distributed connected from the following stations:

- Alliston TS
- Barrie TS
- Everett TS
- Midhurst TS

5.6 Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the sub-region and is used to carry out system studies for identifying potential needs in the Barrie/Innisfil sub-region. This forecast is created in three steps:

1. The gross median weather forecast, provided by the LDCs, is adjusted to extreme weather conditions, according to the methodology described in Appendix B. The result is the gross extreme weather forecast.
2. The impacts of forecast CDM savings and DGs output are added to the gross extreme weather forecast which results in a net extreme weather forecast, or planning forecast.
3. A coincidence factor is applied to convert the forecast to non-coincident. The coincidence factor is based on the contribution of each station to the group's coincident peak over the past five years. Non-coincident station forecasts are utilized for assessing the capacity adequacy of each transformer station in the sub-region.

Figure 6 and Figure 7 below show the net extreme weather winter and summer forecasts for the Barrie/Innisfil sub-region. The figures also show the median gross weather forecast and the extreme gross forecast.

Figure 6 | Summer Net Extreme Weather Demand Forecast

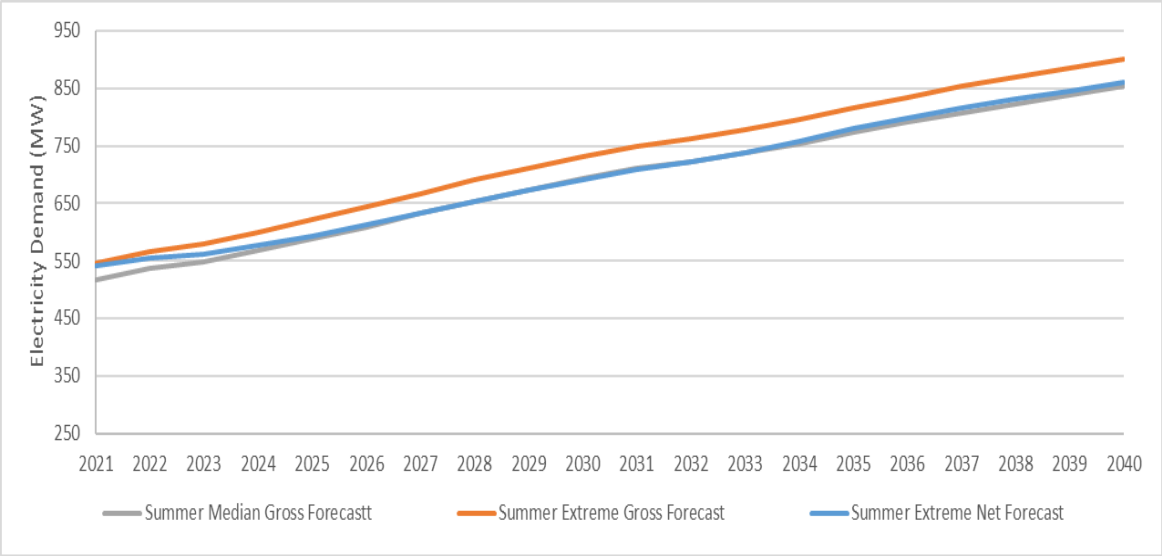
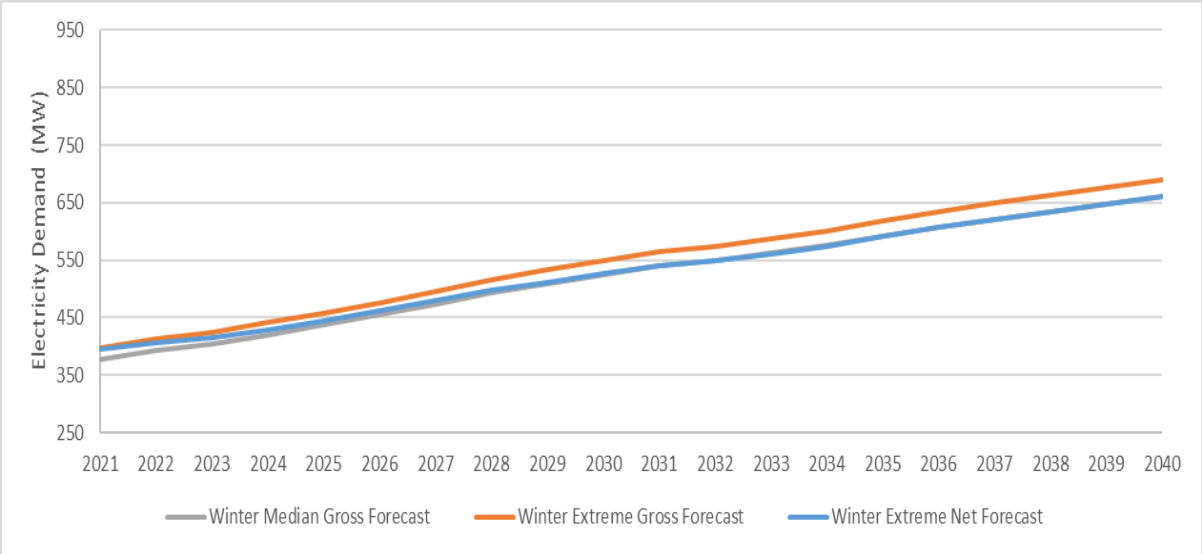


Figure 7 | Winter Net Extreme Weather Demand Forecast



5.7 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over 20 year forecast horizon) for a number of stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of non-wires alternatives options.

Additional load profile details including summary tables and hourly heat maps for each need can be found in Appendix B.

5.8 Sensitivity Scenario

A sensitivity scenario was performed for higher demand. This higher demand scenario is to take into account a variety of factors that could drive demand higher; these include but are not limited to electric vehicles charging infrastructures and electrified space heating installations in the sub-region. For this, a growth factor of 5% was applied equally to each LDC's station in the sub-region to determine the impact this would have on the need dates identified in system studies.
The higher demand scenario will not be used to drive any firm recommendations for this IRRP; however, it will help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can be useful for communities conducting Community Energy Plans, for the TWG in determining areas to monitor in future cycles of regional planning, and for communities and stakeholders as they think about various projects in the sub-region.

6. Electricity System Needs

6.1 Needs Assessment Methodology

Based on the net extreme weather planning demand forecast, the transmitter's identified end-of-life asset replacement plans and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Technical Working Group identified electricity needs for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results can be found in Appendix D. The needs identified are discussed in the section below.

6.2 Needs Identified

Table 3 below summarizes the needs identified for the Barrie/Innisfil sub-region.

Table 3 | Summary of Needs for Barrie/Innisfil Sub-Region

No.	Need	Need Description	Need Date
1	Alliston Station Capacity	Alliston TS demand forecast will exceed summer 10-day LTR	2037
2	Barrie Station Capacity	Barrie TS demand forecast will exceed summer 10-day LTR	2027
3	Everett Station Capacity	Everett TS demand forecast will exceed summer 10-day LTR	2025
4	Midhurst Station Capacity	Midhurst TS demand forecast will exceed summer 10-day LTR	2035
5	M6E/M7E Supply Capacity	After a loss of either M6E or M7E, the remaining circuit will exceed its LTE	2034
6	End-of-Life refurbishments	Sections of M6E/M7E and E8V/E9	various
7	Essa Bulk System Supply	Essa transformer overload of loss of remaining 500/230 kV autotransformer	Today

Figure 8 below summarizes the location of the needs in the Barrie/Innisfil sub-region.

Figure 8| Location of Needs in Barrie/Innisfil Sub-region



6.2.1 Station Capacity Needs

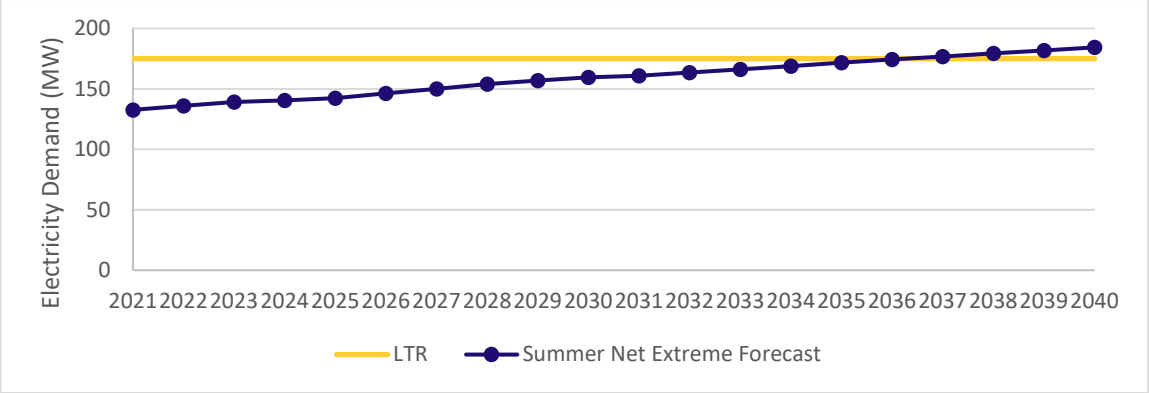
Table 4 and Figure 9 to Figure 12 below show transformer capacity limitations for the Barrie/Innisfil sub-region. In the near/mid-term, there are capacity limitations at Barrie TS and Everett TS. There is also a supply capacity constraint at the 44 kV feeder level for Barrie TS starting in 2025 at the distribution level. The summer demand forecast will exceed the 10-day LTR by 2027 for Barrie TS and 2025 for Everett TS. In the long-term there are capacity needs for Alliston TS in 2037 and Midhurst in 2035.

In the higher demand sensitivity scenario, the station capacity need is advanced by one year for Barrie TS and three years for Everett TS.

Table 4 | Step-down Station Summer 10-day LTR Rating and Peak Demands

Station	10-day LTR Rating (MW)	2022 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Alliston TS	175.0	136.1	142.3	159.5	184.3
Barrie TS	172.8[4]	105.3	157.2	225.7	254.5
Everett TS	86.0	83.1	86.2	94.8	167.9
Midhurst TS[5]	311.0	275.0	263.2	284.7	339.1

Figure 9| Alliston TS Capacity Need



[4] This summer LTR rating is post-BATU

[5] Midhurst TS consists of 2 Dual Element Spot Network (DESN) transformers

Figure 10| Barrie TS Capacity Need

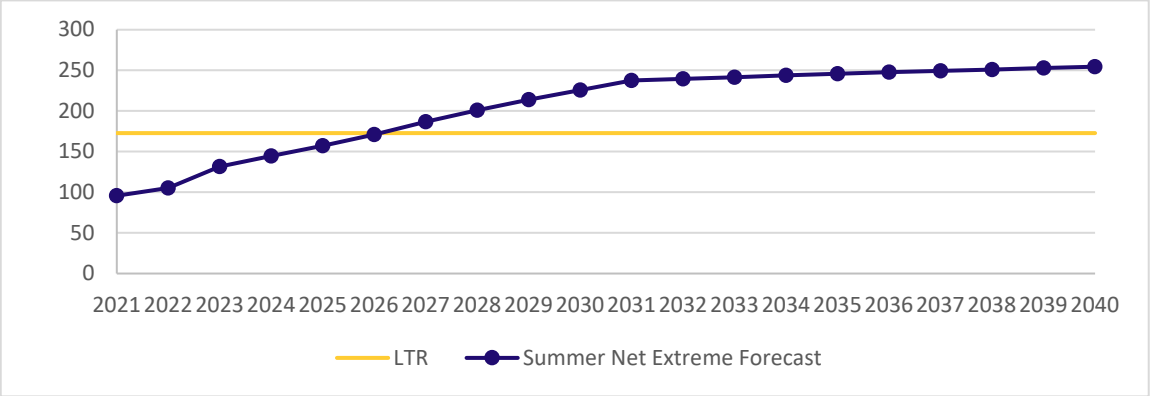


Figure 11| Everett TS Capacity Need

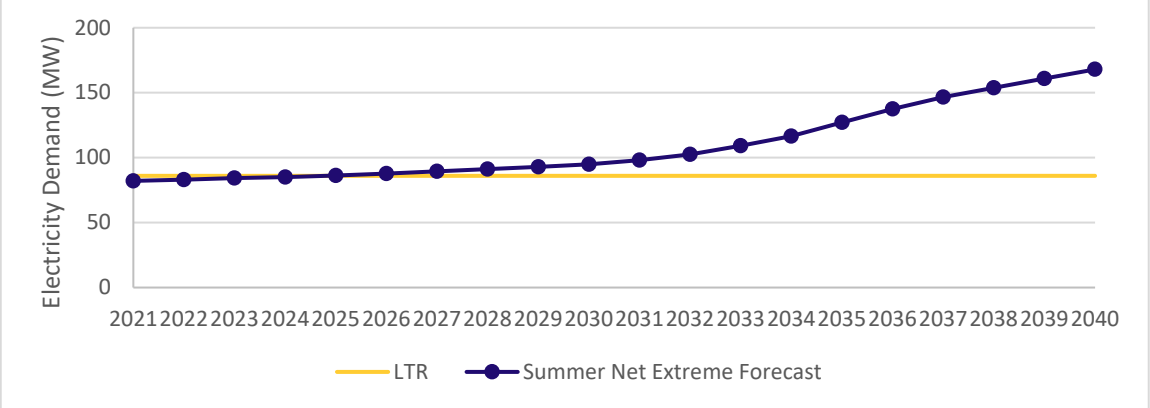
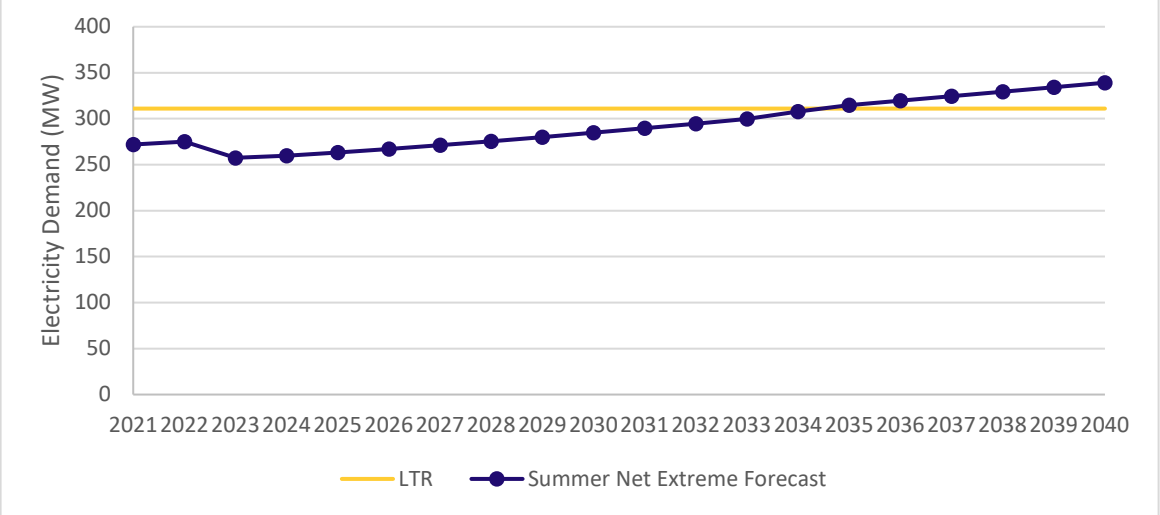


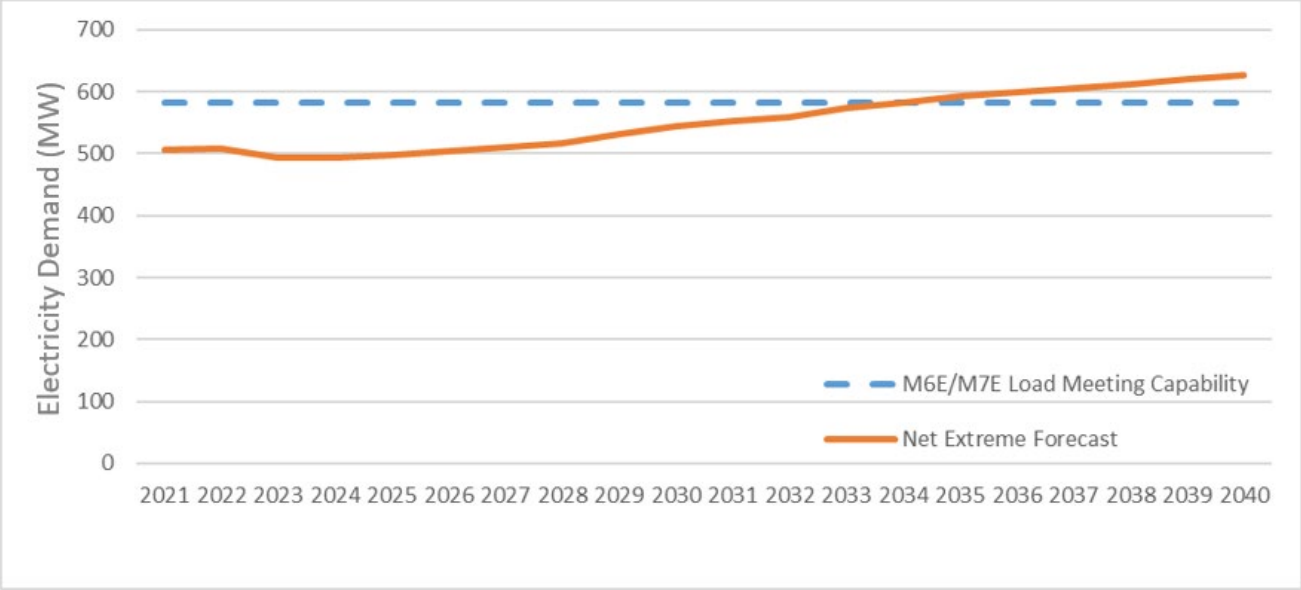
Figure 12| Midhurst TS Capacity Need



6.2.2 Supply Capacity Needs

The circuits M6E and M7E form a 230 kV double circuit from Essa TS to Minden TS. These circuits provide supply to Midhurst, Orillia, Bracebridge and Muskoka. The section between Essa TS to Midhurst TS belongs to the Barrie/Innisfil sub-region. This need occurs for section Essa TS to Midhurst TS. The M6E section between Essa TS to Midhurst TS (10.3 km) will exceed its LTE for loss of M7E or for an Essa HL7 or Essa L7L20 breaker failure starting in 2034. This need is worsened with local generation out of service. Also, the M6E section between Essa TS to Midhurst TS will exceed its LTE with M7E out of service pre-contingency and a contingency to D1M, D3M or D4M. The need is illustrated in Figure 13 below. Note that in the higher demand scenario, this need is advanced by two years.

Figure 13| M6E/M7E Supply Capacity Needs



6.2.3 End-of-Life Refurbishment Needs

Sections of circuits E8V/E9V are reaching end-of-life and need replacement. Information provided by Hydro One Transmission indicated that the in-service date will be 2027 to refurbish 56 km of 230 kV transmission line from Orangeville TS to Essa TS. With no criteria violations identified as part of system studies, there are no needs from a regional perspective that should be coordinated with Hydro One's sustainment plans for a section of circuits E8V/E9V.

6.2.4 Load Security and Restoration Needs

There are no load security or restoration needs identified in the planning time frame.

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the system needs in the Barrie/Innisfil sub-region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

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

- Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as "non-wires" alternatives (NWA) and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need.

The screening process resulted in NWA being considered for all of the near/medium-term needs to be addressed by the IRRP, except the end-of-life needs. A like-for-like sustainment plan is appropriate for the end-of-life needs given that the system studies did not identify any regional needs related to these assets. Needs characterization was completed for the Barrie TS and Everett TS station capacity needs. While the supply capacity need arising on the M6E/M7E circuits is in the longer-term, needs characterization was completed for this need to inform future options.

7.1 Options and Recommendations for Meeting Near/Medium-Term Needs

The Barrie/Innisfil IRRP will make recommendations to address near/mid-term timeframe needs. An options analysis, including NWA where feasible, has been conducted for these needs.

Barrie TS Station Capacity Need

Barrie TS currently serves two LDCs, Alectra Utilities and Hydro One Distribution with InnPower Corporation as an embedded customer. There are six 44 kV feeders serving Alectra Utilities and two 44 kV feeders serving InnPower Corporation. InnPower Corporation originally had one feeder but the first Barrie/Innisfil IRRP recommended an additional feeder due to the continued development of data centres in the city of Barrie and forecast growth in the Town of Innisfil. Demand growth continues to increase in the Innisfil area with InnPower's demand forecasted to reach 113 MW by 2029 which is more than the supply capability of the two feeders. Also, the overall demand forecast for Barrie TS will reach its 10-day LTR in 2027.

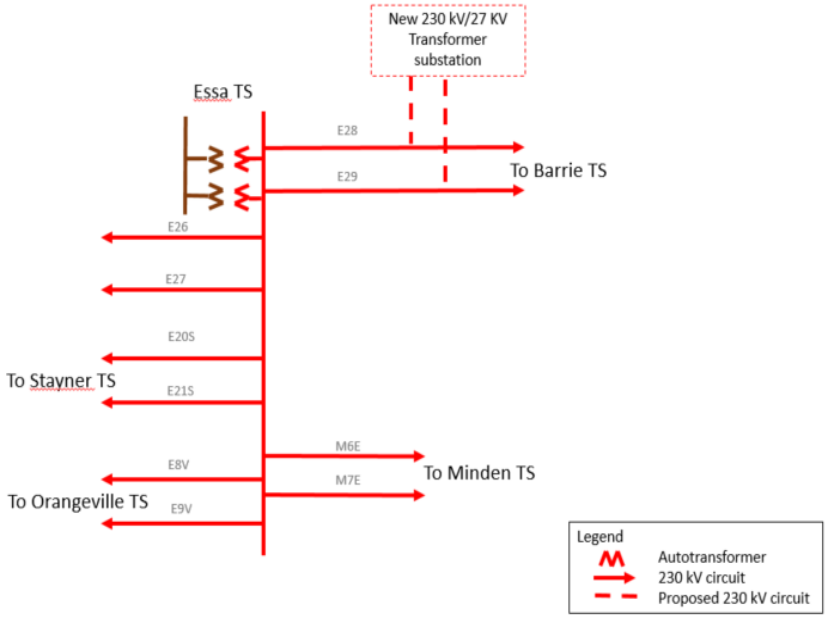
A variety of wires options are considered to address the increased demand growth served by Barrie TS and the supply capacity constraint at the 44 kV feeder level. These wires options are formulated from the detailed options analysis conducted after the Needs Assessment between the transmitter and the LDCs[6]. The following three options were explored and screened out on the basis that they do not fully meet the needs:

- InnPower to connect to existing Alectra feeder as an embedded customer. This requires InnPower to build a distribution tap to the closest Alectra owned feeder. However, there is no available feeder capacity.
- Additional 44 kV feeder position from Barrie TS at a cost of $20M. This solution would provide up to 25 MW of supply capacity which would help the need until 2027. Another solution would still need to be implemented to meet the needs beyond 2027 which would be at an additional cost.
- Load the existing 44 kV supply feeders beyond normal capacity. This alternative would increase each feeder supply capacity by 10 MW per feeder for a total of 20 MW at a cost of $8M. Again, this alternative would help delay the capacity need until 2027 and another solution would have to be implemented beyond 2027.

The wires alternative that is capable of meeting the need includes providing a 230 kV tap connection to the new 230 kV circuits E28/E29 (that will be available post BATU) for a new 230/27.6 kV transformer substation to service the InnPower demand growth. An existing Hydro One Transmission right-of-way (ROW) can be used for this and the length of the tap connection is between 7 to 10 km depending on the location of the transformer substation. This alternative would provide the supply capacity needed beyond the study period and would provide enough capacity for future demand growth in the area. For these reasons, the new transformer substation is chosen as the wires option to be compared against the non-wires alternatives.

[6] Refer to the South Georgian Bay-Muskoka Innisfil Area Supply Alternatives report

Figure 14| Transmission Option for Barrie Station Capacity Need



In terms of non-wires options, the Technical Working Group first reviewed the findings of the Local Achievable Potential Study for the Barrie TS service area that was recommended in the last Barrie/Innisfil IRRP, and subsequently completed between cycles. This study was conducted by Navigant and assessed potential demand-side resources available within the Alectra/InnPower service territories that could defer the need for transmission system investment. The study considered solar PV, CDM and demand response. The forecast technical potential for each non-wires alternative required to meet the need in each year of the forecast was determined and informed the total procurement cost of the non-wires portfolio. The net present value of the costs of the non-wires portfolio was compared to the net present value of the avoided costs associated with the wires solution and it was found that the non-wires portfolio was not cost effective when considering the value streams considered.

As part of the development of this IRRP, the Technical Working Group updated the analysis of non-wires alternatives to ensure it captures the latest information related to option screening, informed by the needs characterization, and option costs. Based on the characteristics of the need, incremental CDM was screened out due to the magnitude of the need as a percentage of the total demand at Barrie TS, and energy storage was considered as it is the least cost of the distributed resource options and serves as a benchmark that can be compared to the wires option.

Table 5 below summarizes the options considered and the net present value of their levelized cost for the Barrie station capacity need arising in 2027 and the supply capacity constraint at the 44 kV feeder level starting in 2025. The new transformer substation is the most cost effective option and the IRRP recommends that the RIP led by Hydro One should further develop and scope this solution.

Table 5 | Options for Barrie TS Station Capacity Needs and Costs

	Option	Cost NPV
Wires	Construct a new 230/27.6 kV transformer substation and connect it to the new 230 kV circuits E28B/E29B available post BATU	$48 M
Non-wires	Construct 81 MW battery storage	$130 M

Everett Station Capacity Need

Everett's near and medium-term needs can be addressed by adjusting the CT ratio of the transformers breakers; the NPV of this option is $ 0.5 M. The estimated costs of non-wires options are orders of magnitude larger and thus screened out from further consideration.

E8V/E9V End-of-Life Needs

When equipment reaches the end of its life and requires replacement, a number of options can be considered.

- Replacement of the equipment with "like-for-like" or closest available standard
- Reconfiguration of existing equipment to "right-size" the replacement option based on:
    - Demand forecast
    - Changes to the use of the equipment since it was originally installed
    - Reliability or other system benefits that an alternate configuration may provide
- Retirement of equipment, considering the impact on load supply and reliability

Since no violations were identified for sections of circuits E8V/E9V in system studies, a like-for-like replacement with the closest available standard is appropriate and can best address the end-of-life needs.

7.2 Options and Recommendations for Meeting Longer-Term Needs

A number of alternatives are possible to meet the region's longer-term needs. While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

Additionally, the Technical Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the demand forecast, it may be necessary to initiate the next iteration of the regional planning process earlier.

7.2.1 Midhurst and Alliston Station Capacity Needs

Midhurst TS and Alliston TS are expected to have station capacity needs by 2035 and 2037 respectively. Given the timing of the need, no firm recommendation is required at this time. It is advised to monitor the demand growth in the areas and provide enough lead time to capture changes into the next cycle of regional planning where these needs can be revisited.

7.2.2 M6E/M7E circuits Essa x Midhurst System Capacity Need

The IRRP considered a number of options include incremental cost-effective CDM and storage, even though this is a longer-term need. This analysis showed that incremental cost-effective CDM is a potentially well-suited for deferring this need. As such, the Technical Working Group should continue to consider incremental, cost-effective CDM in between cycles and in the next cycle of regional planning in the region.

7.3 Summary of Recommended Actions and Next Steps

Table 6, below, summarizes the specific recommendations that should be implemented to address the electricity supply needs in the Barrie/Innisfil sub-region.

Table 6 | Summary of Barrie/Innisfil IRRP Recommendations

Need Description	Recommendation	Lead Responsibility	Estimated Cost	Timeline
Everett TS to reach its summer 10-day LTR	Adjust the CT ratio of transformer breakers	Hydro One	~0.5M	2025
Barrie TS to reach its summer 10-day LTR and supply capacity constraint at 44 kV feeder level	Construct a new 230/27.6 kV transformer substation and connecting to the new 230 kV E28B/E29B post BATU	Hydro One and InnPower	~48M	2025
Sections of E8V/E9V circuits to reach end-of-life	Like-for-like replacement	Hydro One		2027

Need Description	Recommendation	Lead Responsibility	Estimated Cost	Timeline
M6E/M7E (Essa TS x Midhurst TS) supply capacity	Monitor demand growth in the area; consider CDM option in next cycle of regional planning as a means of deferring transmission upgrade	Technical Working Group		2034
Midhurst TS to reach its summer 10-day LTR	Monitor demand growth to ensure load supplying capability is maintained; consider in the next cycle of regional planning	Technical Working Group		2035
Alliston TS to reach its summer 10-day LTR	Monitor demand growth to ensure load supplying capability is maintained; consider in the next cycle of regional planning	Technical Working Group		2037
Essa TS Bulk System Supply	Will further be studied as part of Essa Bulk Study	IESO		Today

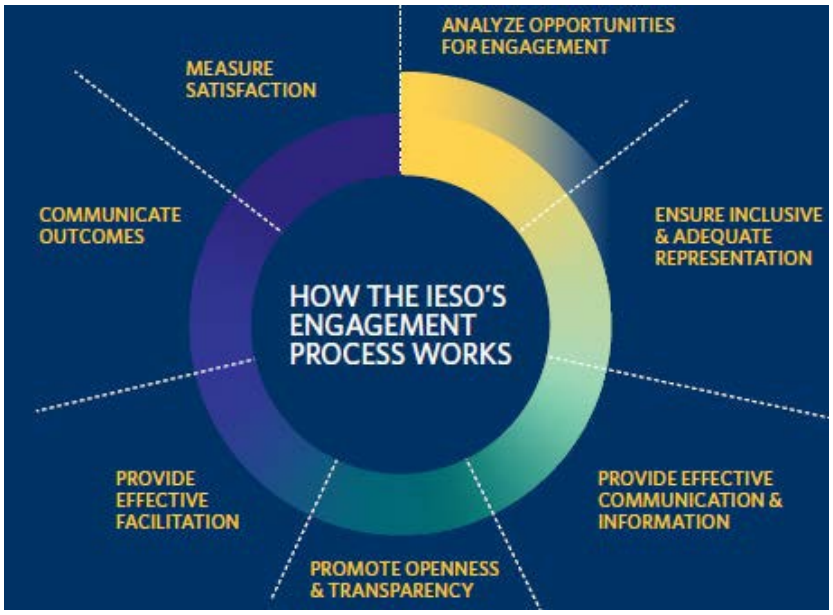
8. Engagement and Consultation

Engagement and consultation are critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Barrie/Innisfil IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 15 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Barrie/Innisfil

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;

- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

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

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted individual and small group meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region.

An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft South Georgian Bay/Muskoka Scoping Assessment Outcome Greater before it was finalized. Feedback received encouraged the IESO to consider renewable technologies to help reduce local demand.

Following a written comment window, the final Scoping Assessment Outcome Report was published in November 2020 that identified the need for a coordinated planning approach done through two sub-regional Integrated Regional Resource Plans (IRRP): Barrie/Innisfil and Parry Sound/Muskoka.

Following these initial discussions and finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the South Georgian Bay/Muskoka region, Indigenous communities and municipalities within boundaries of the sub-region to ensure that all interested parties were made aware of this opportunity for input.

Three public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. The webinars received cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

All interested parties were kept informed throughout this engagement initiative via email to South Georgian Bay/Muskoka region subscribers, municipalities and Indigenous communities as well as the members of the GTA/Central Regional Electricity Network.

Based on the discussions both through the Barrie/Innisfil IRRP outreach activities and broader network dialogue, there appears to be significant community growth planned and broad interest in electrification, net-zero development, and decarbonisation of electricity supply. To that end, ongoing discussions will continue through the IESO's GTA Central Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the dedicated regional planning engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on local planning and development activities as well as strategic initiative related to electricity to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, other opportunities for broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made throughout the development of the plan to Indigenous communities in or near the Southern Huron-Perth electricity planning sub-region or those that may have interests in the sub-region. This includes the First Nation communities of Beausoleil, Chippewas of Georgina Island, Chippewas of Rama, Henvey Inlet, Huron Wendat, Magnetawan, Moose Deer Point, Shawanaga, Wahta Mohawks and Wasauksing, as well as the Métis Nation of Ontario communities of Barrie South-Simcoe Métis Council, Georgian Bay Métis Council and Moon River Métis Council.

9. Conclusion

This report documents an IRRP that has been developed for the Barrie/Innisfil sub-region and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. The IRRP makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs. To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring demand growth and efficiency achievements. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the near term, the IRRP recommends the construction of a new transformer substation in or near Innisfil adjusting the CT ratio of transformer breakers at Everett TS, and replacing the E8V/E9V end-of-life with like-for-like. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth for Alliston and Midhurst stations to determine when further reinforcements will be needed. The IRRP also recommends to monitor the demand growth in the area served by the M6E/M7E circuits including Midhurst and to consider incremental cost-effective CDM to defer this need in the next cycle of regional planning given the suitability of this option observed as part of this IRRP. The IESO and the Technical Working Group will also continue to monitor community energy planning and monitor electrification trends.

The Technical Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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Integrated Regional Resource Plan

Parry Sound/Muskoka
May 2022

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List of Acronyms

BKF	Breaker Failure
CEP	Community Energy Plan
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
DG	Distributed Generation
GS	Generating Station
ERP	Enabling Resources Program
HONI	Hydro One Networks Inc.
ICECAP	Integrated Community Energy and Climate Action Plans
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LAP	Local Achievable Potential
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NWA	Non-Wires Alternatives
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
SGBM	South Georgian Bay Muskoka

SSS	Sustainable Severn Sound
TS	Transformer Station
TTC	Total Transfer Capability

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

This IRRP was prepared on behalf of the Technical Working Group of the Parry Sound/Muskoka sub-region which included the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Alectra Utilities
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.

The Technical Working Group assessed the reliability of electricity supply to customers in the Parry Sound/Muskoka sub-region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Parry Sound/Muskoka Technical Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community engagement and consultations. The Parry Sounds/Muskoka Technical Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This IRRP addresses the electricity needs of the Parry Sound/Muskoka sub-region over the next 20 years from 2021 to 2040. The Parry Sound/Muskoka sub-region is located in the South Georgian Bay Muskoka region and it encompasses the Districts of Muskoka and Parry Sounds and the northern part of Simcoe County.

The Parry Sound/Muskoka sub-region is winter peaking. Electrical supply to the sub-region is provided through the autotransformers at Essa TS (near Barrie) and Minden TS and the 230 kV transmission lines and step-down transformers as shown in Figure 1. Generation in the area includes the Des Joachims Hydroelectric Generating Station (GS) and the Henvey Inlet Wind Inlet GS.

The electricity within the sub-region is supplied by six local distribution companies (LDCs): Hydro One Networks, Alectra Utilities, Elexicon Energy, Lakeland Power, EPCOR Electricity Distribution Ontario Inc. and Newmarket-Tay Power Distribution Ltd. The transmission asset owner is Hydro One Networks. This IRRP report was prepared by the IESO on behalf of the Technical Working Group composed of the six LDCs and transmitter.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is conducted through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for each of the province's 21 electricity planning regions, including the South Georgian Bay Muskoka region, at least once every five years.

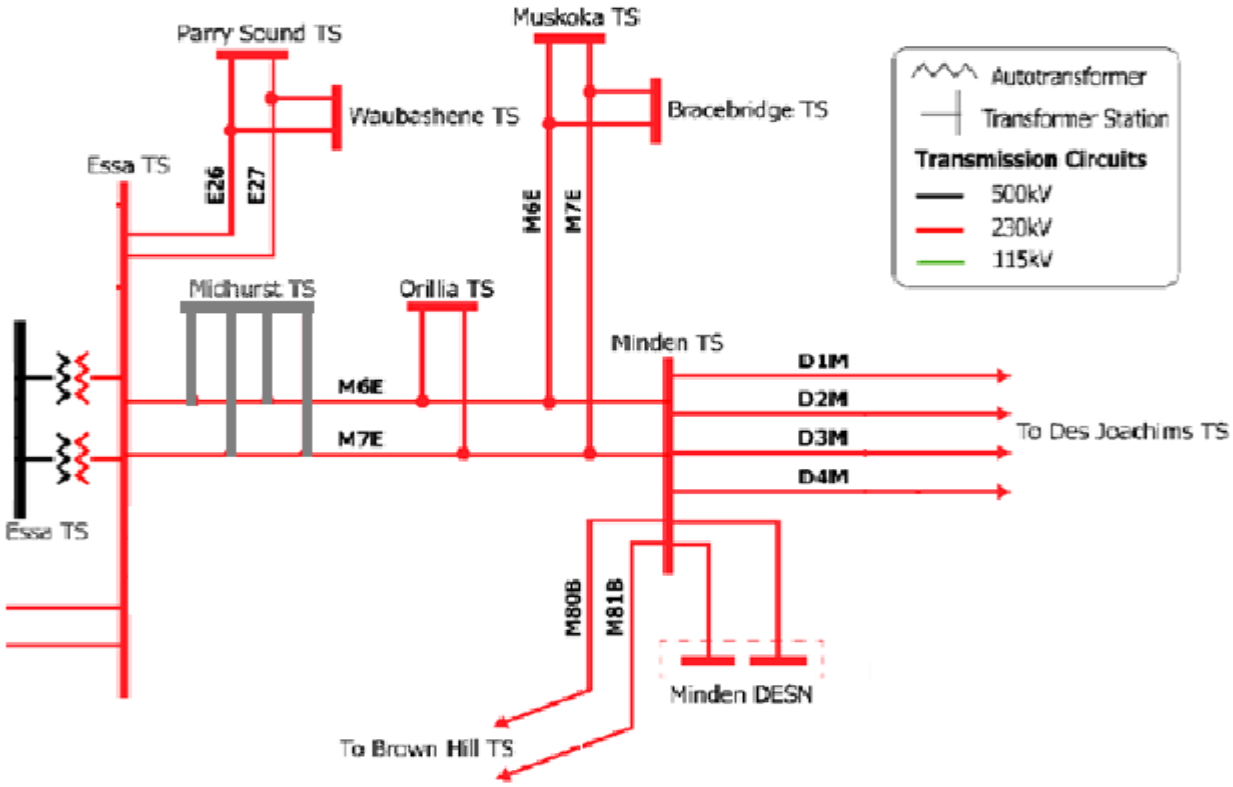
This is the second cycle of regional planning for the Parry Sound/Muskoka sub-region. This cycle began in 2020 with the publication of the South Georgian Bay Muskoka Needs Assessment Report. This was followed by a Scoping Assessment which identified needs that should be addressed through the IRRP process and recommended two IRRPs; one for Parry Sound/Muskoka sub-region and another for Barrie/Innisfil sub-region. A Technical Working Group was then formed to gather data, identify electricity needs in the region and developed recommendations included in this Parry Sound/Muskoka IRRP.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Parry Sound/Muskoka sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Parry Sound/Muskoka sub-region and the study scope are discussed in Section 4;
- The demand forecast and conservation and demand management (CDM) and distributed generation (DG) assumptions are described in section 5;
- Electricity needs in the Parry Sound/Muskoka sub-region are presented in Section 6;
- Alternatives and recommendations to address electricity needs are addressed in Section 7;

- A summary of engagement activities is provided in section 8; and
- The plan conclusion is provided in Section 9.

Figure 1| Parry Sound/ Muskoka Electricity System



2. The Integrated Regional Resource Plan

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

The following sections provide details of the needs identified and the recommendations to address these needs. The needs were identified over two main planning horizons, i) 7 to 10 years as near to medium-term and ii) beyond 10 years as longer-term. These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons.

2.1 Needs in the Near to Medium-Term Horizon and Recommendations

The summary of recommendations for the needs in the near to medium-term horizon is listed in the table below.

Table 1 | Summary of Near/Medium-term Plan for Parry Sound/Muskoka IRRP

Need Description	Recommendation	Lead Responsibility	Required by
Waubaushene TS over its summer 10-day Limited Time Rating (LTR)	Consider incremental, cost-effective CDM to defer the need arising in 2027 until the transformers are replaced for end-of-life. If by 2024 there are no commitments for incremental, cost-effective CDM, implement alternative solution such as advancing the end-of-life replacement of the transformers. The Regional Infrastructure Plan (RIP) will further explore this backstop solution	Technical Working Group Hydro One	2024 2027
Sections of M6E/M7E circuits to reach end-of-life	Like for like replacement	Hydro One	2024

Need Description	Recommendation	Lead Responsibility	Required by
Sections of D1M/D2M circuits to reach end-of-life	Like for like replacement	Hydro One	2028

2.1.1 Consider Incremental Cost Effective CDM at Waubaushene TS

Waubaushene TS peak demand forecast will exceed its 10-day LTR rating by 2027 and the existing transformers are reaching end-of-life in 2030. Assessments as part of this IRRP indicate that incremental, cost-effective CDM is a good candidate for deferring this need until the transformers can be replaced as part of their planned sustainment and is the recommended action. However, no provincial framework for CDM programs in 2027 currently exists, and, therefore, the TWG will continue to monitor these developments following plan completion and explore various pathways for incremental cost-effective CDM. If this CDM cannot be committed by 2024[1], the TWG recommends that a backstop solution be implemented, such as advancement of the end-of-life transformers. The backstop solution will be further explored in the Hydro One led RIP.

2.1.2 Like for Like Replacement for sections of 230 kV circuits M6E/M7E and D1M/D2M

Sections of 230 kV circuits M6E/M7E and D1M/D2M will reach end-of-life by 2024 and 2028 respectively. A like-for-like approach is recommended for the replacement of these assets.

2.2 Needs in Longer-Term Horizon and Recommendations

In the longer-term horizon, minor station capacity needs have been identified at Minden TS starting in 2038. A longer-term supply capacity need has also been identified on 230 kV circuit M6E for a Minden HL7 Breaker Failure (BKF).

While this need is expected to arise in the longer-term, potential options were contemplated to inform future plans. The analysis showed that incremental, cost-effective CDM is potentially a good candidate to defer this need, when considering the need characteristics. Given the time of the need, no firm recommendation is required at this time; however, it is recommended to continue to consider incremental, cost-effective CDM as an option in between planning cycles and bring these insights into the next cycle of regional planning for the region.

2.2.1 Supporting Community Energy Plans and Monitoring Energy Efficiency and Electrification Trends

Three main plans in the sub-region have been identified when pertaining to energy and climate change in communities. These include:

[1] This year has been selected on the basis of the lead-time for the backstop solution, i.e., to advance the end-of-life transformers.

- The Integrated Community Energy Climate Action Plans (ICECAP) for the townships for the Archipelago, Carling, Georgian Bay, McKellar, Seguin, Georgian Bay; the Town Parry Sound; Municipality of McDougall; Chimnissing/Beausoleil, Dokis, Henvey Inlet, Magnetawan, Moose Deer Point, Sawanaga, Wahta Mohawk and Wasauksing First Nations; and Wiikwemkoong Unceded Territory
- Sustainable Seven Sound (SSS) supported by seven municipalities in the County of Simcoe and the district Municipality of Muskoka including the Towns of Midland and Penetanguishene and the Township of Georgian Bay, Severn, Oro-Medonte, Tiny and Tay
- Energy Management Plan for Village of Sundridge and Township of Joly and Strong

The scope varies by municipality and plan but the general aim is to improve energy efficiency, building greater resiliency, lower greenhouse gas emissions, and invest in the local economy.

While the IRRP seeks to align with these plans where possible, not all of the objectives fall within the scope of the regional planning nor the IESO's mandate. For example, absent of provincial government policy, the IESO is technology agnostic and will generally choose the most economic option that adequately resolves the need and meets applicable reliability standards. Greenhouse gas emissions are considered in the IRRP's options analysis by accounting for the carbon price associated with emitting resources, but the IESO does not have emission reduction targets unless directed by government policy. Furthermore, while regional planning is responsible for ensuring electricity ratepayer value and minimizing electricity costs, the IESO relies on government policy for broader socioeconomic considerations.

There are three climate energy plan (CEP) objectives that the IESO and regional planning can play a role in supporting. First, the IESO recognizes that distributed energy resources (DER) are becoming increasingly prevalent and features prominently in many CEPs. DERs can provide benefits to both customers as well as the distribution and transmission systems. By enabling DERs to provide wholesale services, system costs can be reduced and opportunities for customers and investors can be increased. The IESO's Enabling Resources Program (ERP) will produce a 5-10 year plan to enable resources to provide services they cannot or cannot fully currently provide. The ERP has identified storage, hybrids, and DERs as high-priority opportunities. The IESO developed a DER roadmap in the fall of 2021 to provide clarity on IESO objectives, initiatives, and timing for DER integration and is completing a DER Potential Study by June 2022. More information can be found on the Distributed Energy Resource Roadmap engagement page.

Second, the Technical Working Group will continue to support and monitor energy efficiency uptake. Conservation expected to be achieved through codes, standards, and program delivery has already been included in the planning forecast as described in Section 5.4. On September 30, 2020, the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensures energy efficiency can continue to play a role in meeting the region's needs. The Technical Working Group will monitor uptake of the CDM framework as well as energy efficiency initiatives in CEPs and assess the impact of these additional savings on the timing of local reliability needs.

Finally, the Technical Working Group will monitor electrification trends and their impact on the demand forecast. The Technical Working Group recognizes that many CEPs are calling for ambitious electrification targets as a means to achieve carbon emission reductions. It is not yet clear how impactful electrification will be to the load forecast in the near-term but it could drive significantly higher demand in the long term that will necessitate new electricity supply into the area. While it is still difficult to establish when firm investments or infrastructure reinforcements will be needed, it is prudent to prepare for a future where electricity demand could potentially be significantly higher than forecast.

3. Development of the IRRP

3.1 The Regional Planning Process

In 2013, the OEB created a formal process for regional planning which is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The regional planning formal process sets out 21 different electricity planning regions for the province. Regional planning assesses the interrelated needs of a region over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the largest transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;

3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Further details on the components of the regional planning process in Ontario and the IESO's approach to regional planning can be found in Appendix A.

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues whereas distribution network planning considers the supply of electricity within an LDC's system. Regional planning is the intersection of those two.

A review of the regional planning process was finalized in 2021 following the completion of the first cycle of regional planning for all 21 regions. The Regional Planning Process Review Final Report is published on the IESO's website.

3.2 Parry Sound/Muskoka and IRRP Development

The process to develop the Parry Sound/Muskoka IRRP was initiated following the publication of Hydro One's South Georgian Bay Muskoka Needs Assessment report in April 2020 and the IESO's Scoping Assessment report in November 2020. The Scoping Assessment report recommended that the needs identified for the Parry Sound/Muskoka sub-region be considered through an IRRP in a coordinated regional approach. The Technical Working Group was then formed to develop the terms

of reference for this IRRP, gather data, identify needs, develop options and recommend solutions in the sub-region.

4. Background and Study Scope

This is the second cycle of regional planning for the Parry Sound/Muskoka sub-region. During the first cycle of regional planning, a Needs Assessment was conducted for the South Georgian Bay Muskoka Region in March 2015 that was led by Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination should be considered and a Scoping Assessment was published in June 2015 which recommended coordinated planning through an IRRP. Subsequently, the IRRP for Parry Sound/Muskoka was published in December 2016 and the RIP was published in August 2017.

This cycle of regional planning started with a Needs Assessment published by Hydro One in April 2020 which identified a number of needs requiring further regional coordination. This was followed by a Scoping Assessment which was published in November 2020. This report recommended an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2021.

4.1 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the Parry Sound/Muskoka sub region for the study period with a focus on providing an adequate, reliable supply to support community growth. The plan includes consideration of forecast electricity demand growth, conservation and demand management (CDM), distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

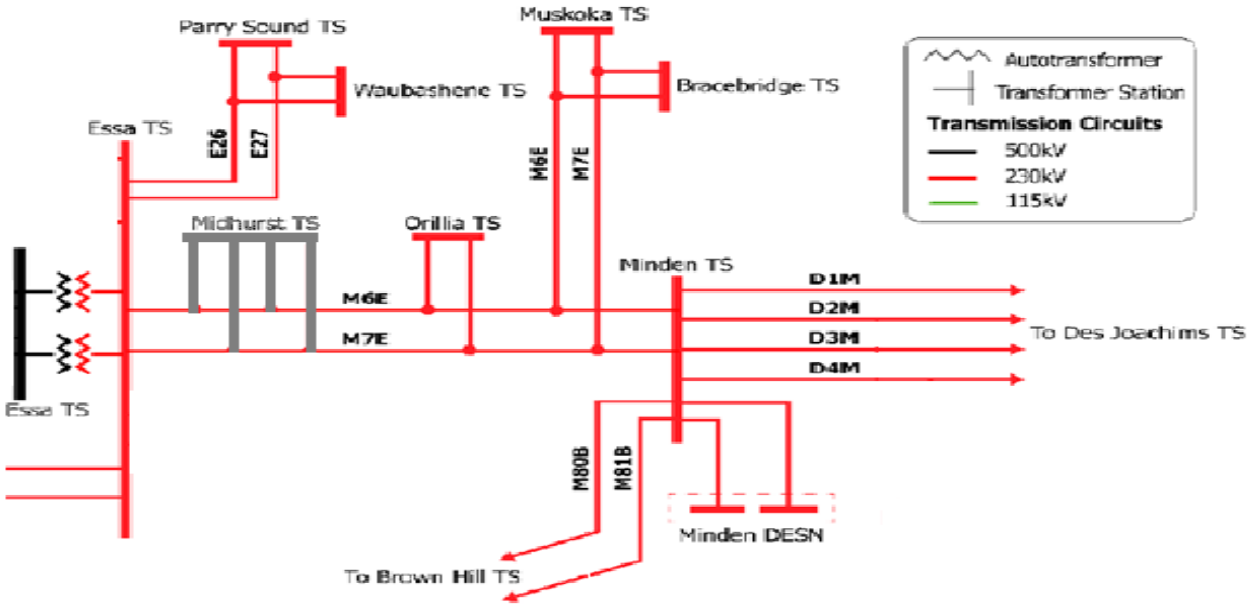
The following transmission facilities were included in the scope of this study:

Step-down transformer stations: Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS and Minden TS.

Transmission lines: D1M, D2M, D3M, D4M, E26, E27, M6E, M7E, M80B, M81B

The single line diagram of the Parry Sound Muskoka sub-region is shown in Figure 2 below. Note that Midhurst and Essa are not within the scope of the this IRRP.

Figure 2 | Single Line Diagram of Parry Sound/ Muskoka Sub-Region



The Parry Sound/ Muskoka IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the Load Meeting Capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC planning criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO controlled grid as described in section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

5. Electricity Demand Forecast

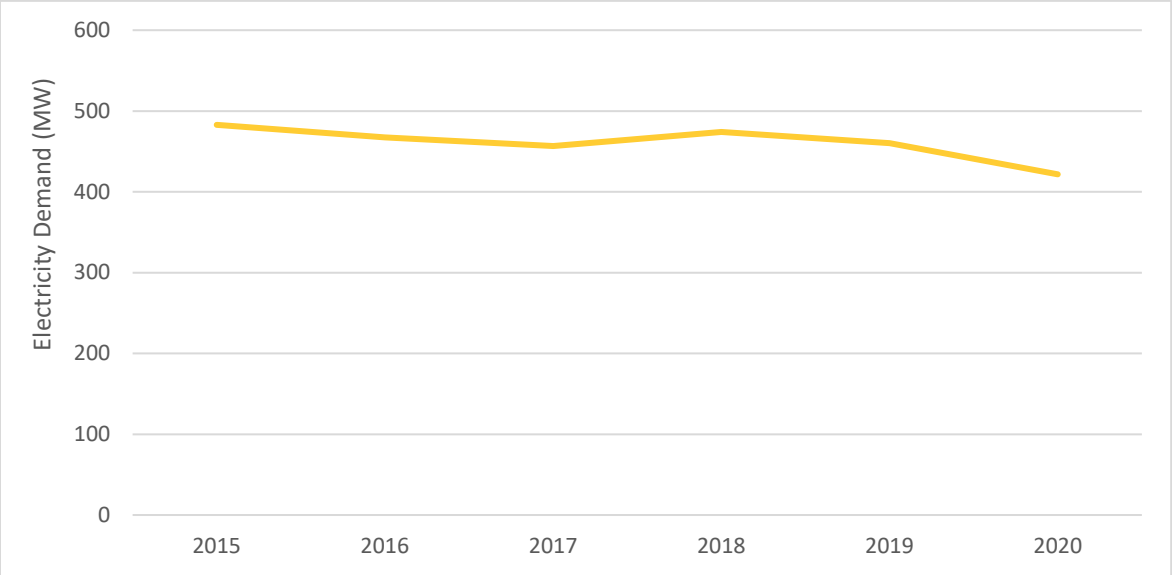
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the Parry Sound/Muskoka sub-region. It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Parry Sound/Muskoka sub-region, the peak loading hour for each year occurs in the winter.

5.1 Historical Electricity Demand

Electricity demand in the Parry Sound/Muskoka sub-region is primarily driven by residential and commercial customers and demand typically peaks during the winter months. However, station capacity needs arise in the summer as the ratings are lower then. The historical demand is shown below in Figure 3. The technical Working Group determined 2020 to be the base year to be used for developing the planning load forecast. The historical peak demand has decreased from 480 MW in 2015 to 420 in 2020.

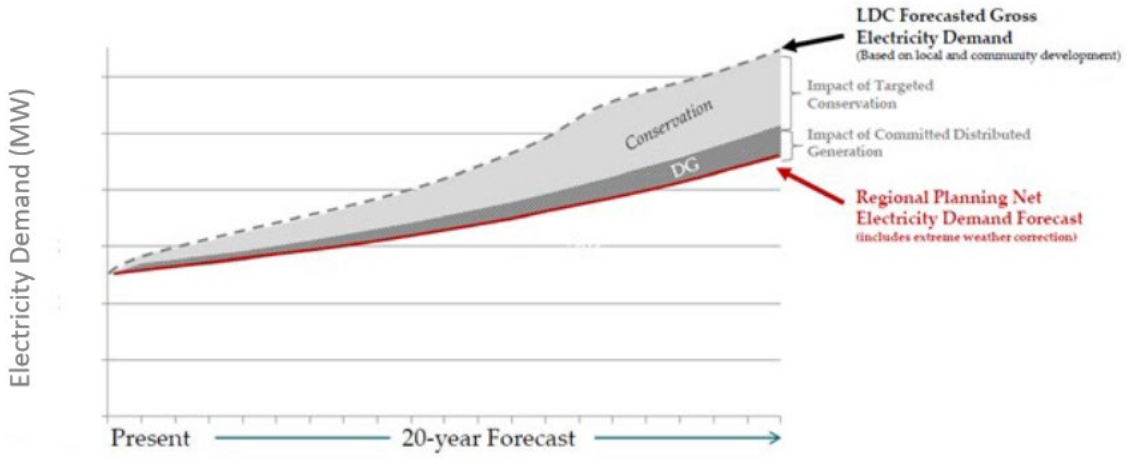
Figure 3 | Historical Winter Peak Demand – Parry Sound/ Muskoka Sub-Region



5.2 Demand Forecast Methodology

A 20-year regional peak demand forecast was developed to assess reliability needs for the Parry Sound/Muskoka sub-region; Figure 4 shows the steps taken to develop this. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions i.e., normal weather, were provided by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation savings and DG contracted through previous provincial programs such as FIT and microFIT. The forecasts were then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix B.

Figure 4 | Illustrative Development of the Demand Forecast



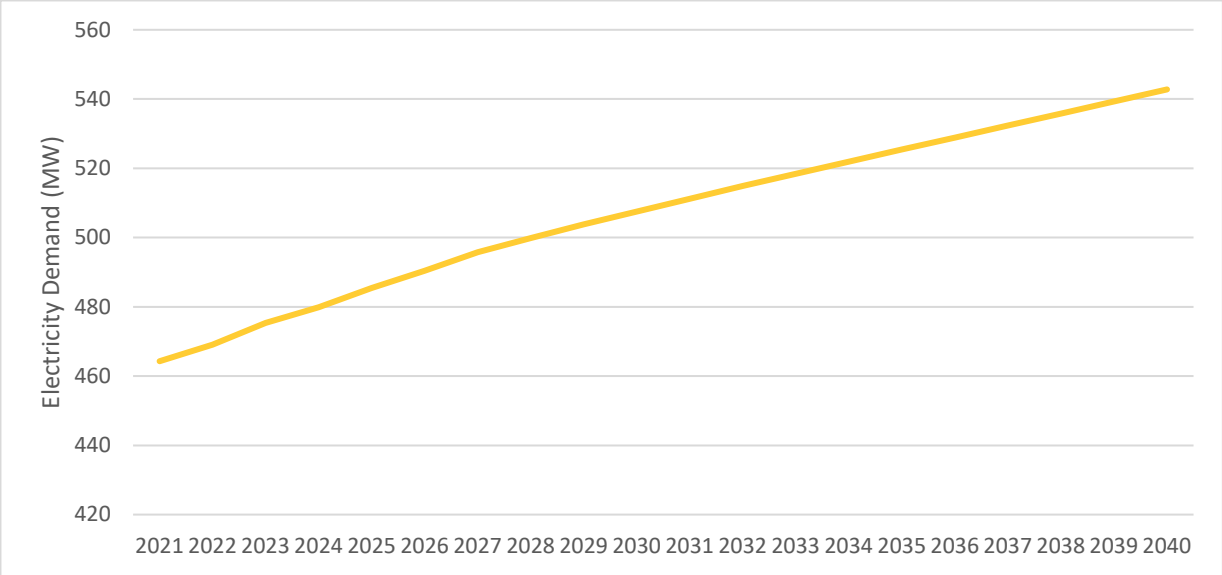
5.3 Gross Demand Forecast

Gross demand forecasts were submitted by each participating LDC in the Parry Sound/Muskoka sub-region. This is because LDCs have better insights of future local demand growth and drivers due to their direct involvement with their customers. This insight includes future connection applications and knowledge regarding typical electrical demand for different types of customer groups. Through engagement for the Parry Sound/Muskoka sub-region, it was communicated that Seguin Township submitted a Minister Zoning Order (MZO) in January 2022 to rezone land along the southern border of the town of Parry Sound for future housing development. The municipality of Parry Sound opposed the MZO application and listed four studies Seguin need to provide before the municipality of Parry Sound can partner with Seguin Township on the project. Also mentioned as part of engagement, was growth of a Parry Sound industrial park. Since these developments had not been committed yet, they were not considered in the gross demand forecasts submitted by the LDCs. These developments will be monitored in between regional planning cycles.

The LDC gross demand forecasts account for increases in demand due to new or intensified development, economic growth, population growth, changes in consumer behaviour, etc. Most LDCs cited alignment with municipal and regional official plans and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for by the IESO as discussed in Section 5.4 below. The gross LDC forecast assumes median on-peak weather conditions.

More details on the LDCs' load forecast methodology can be found in Appendix B. Figure 5 below shows the total gross coincident LDC forecast for both summer and winter weather.

Figure 5 | LDC Coincident Gross Winter Demand Forecast – Median Weather



5.4 Contribution of Conservation to the Demand Forecast

CDM helps in meeting Ontario's electricity needs by reducing demand. This is achieved through a mix of codes and equipment standards amendments as well as CDM program-related activities.

Demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers. Program-related activities include Save on Energy programs, as well as those that are being implemented as part of the 2021-2024 CDM framework.

CDM savings have been applied for the Parry Sound/Muskoka sub-region gross peak demand forecast for median weather, along with DG (as described in section 5.5) to determine the net peak demand for the sub-region. This takes into account both policy-driven conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

The final estimated conservation peak demand reductions applied to the gross demand forecast is shown in Table 2 for a selection of the forecast years. Additional details are provided on Appendix B.

Table 2 | MW Savings from Conservation and Demand Management

Year	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040
Winter Savings (MW)	7	14	17	19	22	24	24	24	24	24

5.5 Contribution of Distributed Generation to Demand Forecast

Distributed Generation is also factored in to offset the Parry Sound/Muskoka sub-region gross peak demand forecast for median weather. No assumptions were made regarding DG growth as in the long-term, the contribution of DG is expected to diminish as contracts expire. The resources that were included in the DG forecast were comprised of a mix of solar and hydroelectric projects. Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output.

The DGs included in this IRRP are distributed connected from the following sites:

- Minden TS
- Muskoka TS
- Orillia TS
- Parry Sound TS
- Waubaushene TS

Effective winter capacity totaled 29 MW in 2022. The expected annual peak demand contribution of contracted DG in the Parry Sound/Muskoka sub-region and capacity contribution factors can be found in Appendix B.

5.6 Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the sub-region and is used to carry out system studies for identifying potential needs in the Parry Sound/Muskoka sub-region. This forecast is created in three steps:

1. The gross median weather forecast, provided by the LDCs, is adjusted to extreme weather conditions, according to the methodology described in Appendix B. The result is the gross extreme weather forecast.
2. The impacts of forecast CDM savings and DGs output are added to the gross extreme weather forecast which results in a net extreme weather forecast, or planning forecast.

3. A coincidence factor is applied to convert the forecast to non-coincident. The coincidence factor is based on the contribution of each station to the group's coincident peak over the past five years. Non-coincident station forecasts are utilized for assessing the capacity adequacy of each transformer station in the sub-region.

The net extreme weather forecasts for the Parry Sound/Muskoka sub-region are shown in Figure 6 and Figure 7 below for summer and winter. For comparison, the figures also show the median gross weather forecast and the extreme gross forecast.

Figure 6 | Summer Net Extreme Weather Demand Forecast

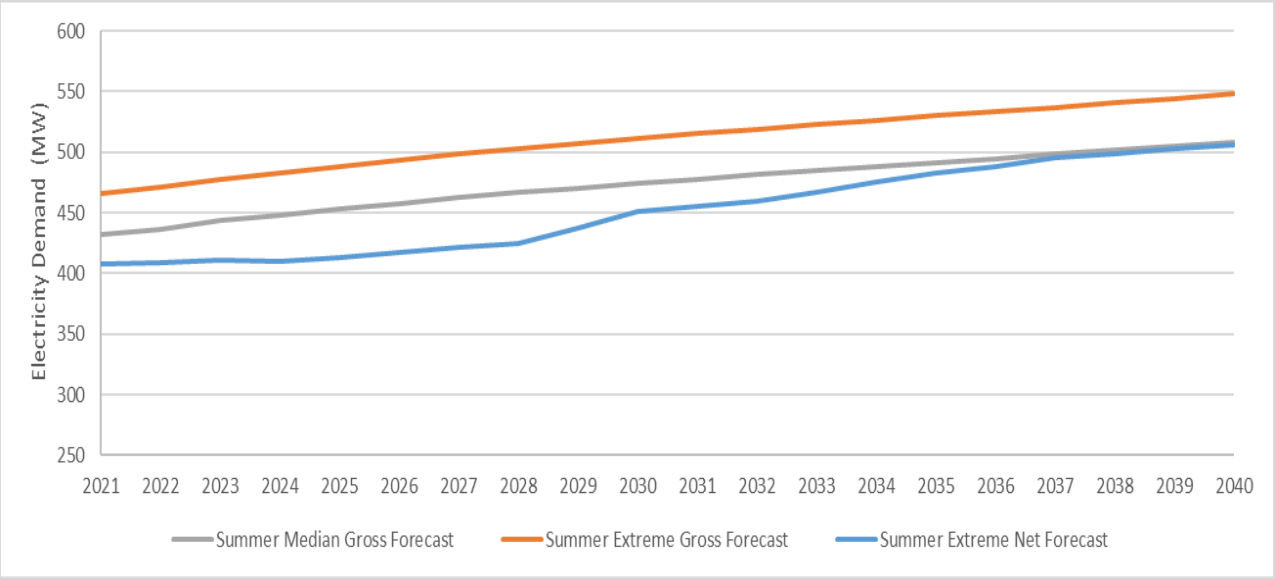
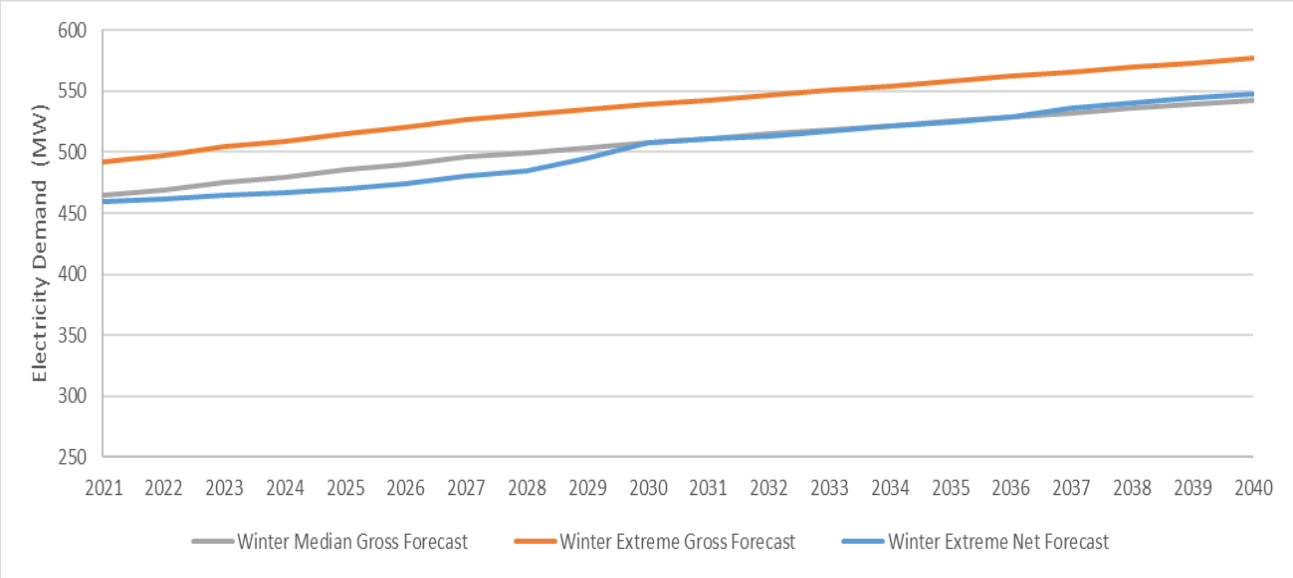


Figure 7 | Winter Net Extreme Weather Demand Forecast



5.7 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over 20 year forecast horizon) for a number of stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of Non-Wires Alternatives (NWA) options.

Additional load profile details including summary tables and hourly heat maps for each need can be found in Appendix B.

5.8 Sensitivity Scenario

A sensitivity scenario was performed for higher demand. This higher demand scenario is to take into account a variety of factors that could drive demand higher; these include but are not limited electric vehicles charging infrastructure and electrified space heating installations in the sub-region. For this, a growth factor of 5% was applied equally to each LDC's station in the sub-region to determine the impact this would have on the need dates identified in system studies.

The higher demand scenario will not be used to drive any firm recommendations for this IRRP; however, it will help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can be useful for communities conducting Community Energy Plans, for the TWG in determining areas to monitor in future cycles of regional planning, and for communities and stakeholders as they think about various projects in the sub-region.

6. Electricity System Needs

6.1 Needs Assessment Methodology

Based on the net extreme weather planning demand forecast, the transmitter's identified end-of-life asset replacement plans and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Technical Working Group identified electricity needs for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results can be found in Appendix D. The needs identified are discussed in the section below.

6.2 Needs Identified

Table 3 below summarizes the needs identified by the Parry Sound/Muskoka IRRP.

Table 3 | Summary of Needs for Parry Sound/Muskoka IRRP

No.	Need	Need Description	Need Date
1	Waubaushene Station Capacity	Waubaushene TS demand forecast is over its summer 10-day LTR	2027
2	End-of-Life refurbishment	M6E/M7E section[2]	2024
3	End-of-Life refurbishment	D1M/D2M section	2028
4	M6E/M7E Supply Capacity	After a loss of either M6E or M7E, the remaining circuit will exceed its Long Term Emergency (LTE) rating	2034
5	Minden Station Capacity	Minden TS demand forecast will exceed its summer 10-day LTR	2038

The summary of the location of the needs identified in the Parry Sound/Muskoka sub-region are shown in Figure 8.

Figure 8 | Summary of Location of Needs



[2] Note that the sections of M6E and M7E that are at end-of-life are different than the thermally limited sections

6.2.1 Station Capacity Needs

Table 4 below shows that there are station capacity needs for the Parry Sound/Muskoka sub-region according to the planning forecast. In the near to medium-term, there are station capacity needs at Waubaushene TS. The summer demand forecast for Waubaushene TS exceeds its 10-day LTR by 2027 as seen in Figure 9. In the longer-term, there are capacity needs for Minden TS arising in 2038 as its summer demand forecast exceeds Minden TS 10-day LTR as seen in Figure 10.

Table 4 | Step-down Station Summer Capacity Needs

Station	10-day LTR Rating (MW)	2022 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Minden TS	52	44.3	44.2	45.8	52.8
Waubaushene TS	94	89.9	91.5	98.6	116.4

Figure 9 | Waubaushene TS Capacity Needs

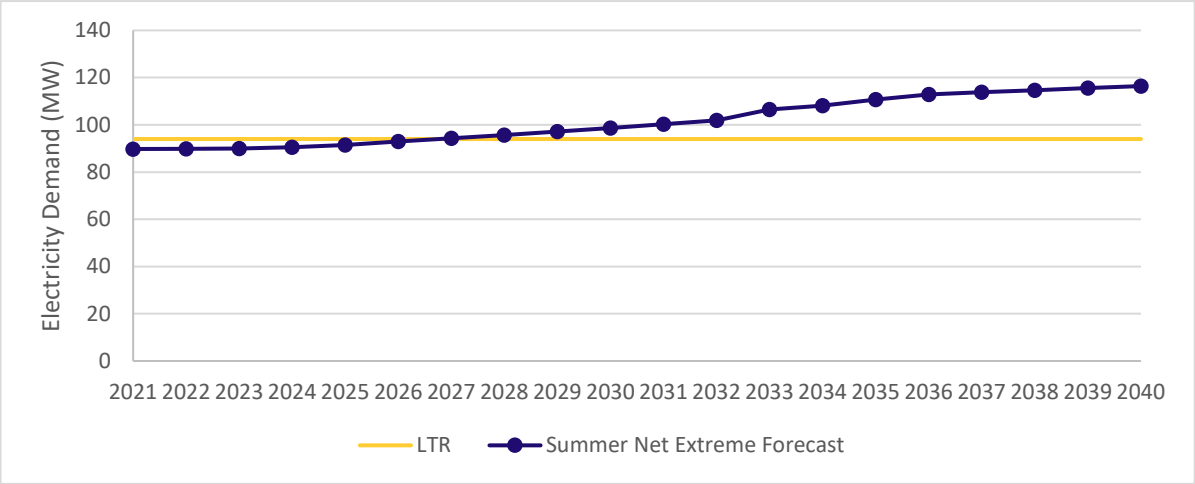
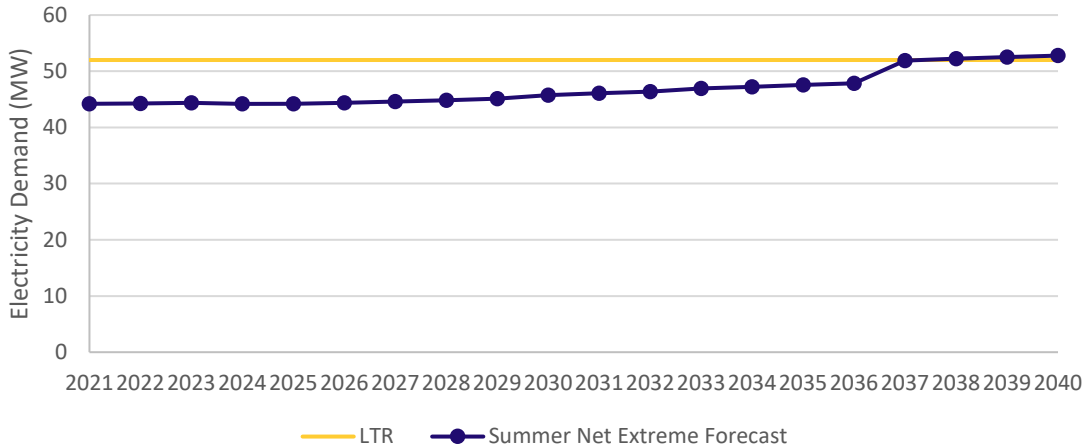


Figure 10 | Minden TS Capacity Needs



In the higher demand sensitivity scenario, the station capacity need is advanced to 2022 for Waubaushene TS and to 2037 for Minden TS.

Besides the station capacity needs identified above, Hydro One's Needs Assessment also identified station capacity need at Parry Sound TS which was identified in the previous cycle of regional planning. The transformers were also assessed at being end-of-life. In order to address the station capacity and end-of-life needs, Hydro One is installing new 230/44 kV 83 MVA transformers which are scheduled to be in service by 2024. The LTRs of the new transformers were applied in the IRRP's assessment of station capacity needs and no further station capacity needs were identified.

6.2.2 Supply Capacity Needs

The circuits M6E and M7E form a 230 kV double circuit from Essa TS to Minden TS. These circuits provide supply to Midhurst, Orillia, Bracebridge and Muskoka. This need occurs for section Minden TS to Cooper Falls JCT (51 km in length) which belongs to the Parry Sound/Muskoka sub-region. M6E section Minden TS to Cooper Falls JCT TS will exceed its LTE rating for a failure of breaker HL7 at Minden HL7 starting in 2038. Also, with M7E already out of service, for loss of Essa T3, M6E is at 133% of its LTE in 2040. Note that in the higher demand sensitivity scenario, this supply capacity need is advanced by two years.

6.2.3 End-of-Life Refurbishment Needs

As per information provided by Hydro One, sections of 230 kV circuits M6E/M7E and D1M/D3M are reaching end-of-life. The in service dates will be 2024 for M6E/M7E and 2028 for D1M/D3M. The end-of-life section includes 25 km from Orillia TS to Cooper Falls JCT for M6E/M7E and 62 km from Minden TS to Otter Creek TS for D1M/D3M.

6.2.4 Load Security and Restoration Needs

There are no load security or restoration needs identified for Parry Sound/Muskoka sub-region for the time frame.

7. Plan Options and Recommendations

In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

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

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or to mitigate certain reliability concerns.

2. Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as NWA and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need.

The screening process resulted in NWA being considered for all of the near/medium-term needs to be addressed by the IRRP, except the end-of-life needs. Needs characterization was completed for the Waubaushene TS station capacity need. While the supply capacity need arising on the M6E/M7E circuits is in the longer-term, needs characterization was completed for this need to inform future options.

7.1 Options and Recommendations for Meeting Near/Medium-Term Needs

7.1.1 Waubaushene TS Station Capacity Need

Waubaushene TS will reach end-of-life (EOL) in 2030 and was planned for replacement at this time; however, current needs show an earlier replacement is required. Waubaushene will be over its 10-day summer LTR in 2027.

In terms of non-wires options, the Technical Working Group first reviewed the findings of the Local Achievable Potential (LAP) Study for the Parry Sound and Waubaushene TS service area that was recommended in the last Parry Sound/Muskoka IRRP, and subsequently completed between cycles.

The LAP study was to determine the cost and feasibility of using distributed energy resources (DER) and CDM options to defer needs requiring major capital investments. The LAP explored needs at Parry Sound and Waubaushene and determined that:

1. Dispatchable DERs are required to meet the characteristics of the needs; and
2. There are limited opportunities for dispatchable DER in the area

As part of the development of this IRRP, the Technical Working Group updated the analysis of NWA to ensure it captures the latest information related to option screening, informed by the needs characterization, and options costs. Based on the characteristics of the need, the non-wires alternatives assessment for Waubaushene indicated incremental CDM to be a good candidate for a non-wires solution.

In terms of wires options, the transformers replacement can be advanced and upgraded to larger units to meet the need. However, this requires a lead time of 2-3 years. Another non-wires option considered was energy storage as it is the least cost of the distributed resource options and serves as a benchmark that can be compared with the transformers replacement option.

The table below summarizes the options considered and the net present value of their levelized cost for the Waubaushene station capacity needs.

Table 5 | Options for Waubaushene TS Station Capacity Needs and Costs

	Option	Cost NPV
Wires	Station replacement/upgrade. Transformers are scheduled for replacement in 2030 but this can be advanced and upgraded to larger units. There is an opportunity to align the station capacity needs with EOL replacement; however, a 2-3 year lead time is required	$5 M
Non-wires - Storage	29 MW of storage	$30 M
Non-wires- CDM	Incremental cost effective CDM in the area served by the station	-

It is recommended to consider incremental, cost-effective CDM to defer the need arising in 2027 until the transformers are replaced for end-of-life. If by 2024 there are no commitments for incremental, cost-effective CDM, implement alternative solution such as advancing the end-of-life replacement of the transformers. The RIP will further explore this backstop solution.

7.1.2 D1M/D2M & M6E/M7E (Orillia x Copper) End-of-Life Needs

When equipment reaches the end of its life and requires replacement, a number of options can be considered.

- Replacement of the equipment with "like-for-like" or closest available standard;
- Reconfiguration of existing equipment to "right-size" the replacement option based on:
    - Demand forecast,
    - Changes to the use of the equipment since it was originally installed,
    - Reliability or other system benefits that an alternate configuration may provide; and
- Retirement of equipment, considering the impact on load supply and reliability.

Since no violations were identified for the identified circuits in system studies, a like-for-like replacement with the closest available standard is appropriate and can best address the end-of-life needs at sections of D1M/D2M and M6E/M7E.

7.2 Options and Recommendations for Meeting Longer-Term Needs

For needs appearing in the long term, there is an opportunity to develop and explore options, as specific projects do not need to be committed immediately. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential conservation measures in the study area; test emerging technologies; engage with communities and stakeholders; and lay the foundation for informed decisions in the future.

Additionally; the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast, it may be necessary to initiate the next iteration of the regional planning process earlier.

7.2.1 Minden Station Capacity Needs

Minden TS is expected to have station capacity needs by 2038. Given the timing of the need, no firm recommendation is required at this time. It is advised to monitor the load growth in the areas and provide enough lead time to capture changes into the next cycle of regional planning where these needs can be revisited.

7.2.2 M6E/M7E (Minden x Copper) System Capacity Need

The IRRP considered a number of options including incremental cost-effective CDM and storage, even though this is a longer-term need. This analysis showed that incremental cost-effective CDM is a potentially well-suited for deferring this need. As such, the Technical Working Group should continue to consider incremental, cost-effective CDM in between cycles and in the next cycle of regional planning in the region.

7.3 Summary of Recommended Actions and Next Steps

Table 6, below, summarizes the specific recommendations that should be implemented to address the electricity supply needs in the Parry Sound/Muskoka sub-region.

Table 6 | Summary of Parry Sound/Muskoka IRRP Recommendations

Need Description	Recommendation	Lead Responsibility	Timeline
Minden TS to reach its summer 10-day LTR	Monitor load growth to ensure load supplying capability is maintained; consider in the next cycle of regional planning	Technical Working Group	2038
Waubaushene TS to reach its summer 10-day LTR	Consider incremental, cost-effective CDM to defer the need arising in 2027 until the transformers are replaced for end-of-life. If by 2024 there are no commitments for incremental, cost-effective CDM, implement alternative solution such as advancing the end-of-life replacement of the transformers. The RIP will further explore this backstop solution	Hydro One	2024/2027
M6E/M7E (Minden TS x Cooper Fls JCT) supply capacity	Monitor demand growth in the area; consider CDM option on next cycle of regional planning as a means of deferring transmission upgrade	Hydro One	2034
Sections of D1M/D2M circuits to reach end-of-life	Like-for-like replacement approach	Hydro One	2028
Sections of M6E/M7E Orillia to Cooper to reach end-of-life	Like-for-like replacement approach	Hydro One	2024

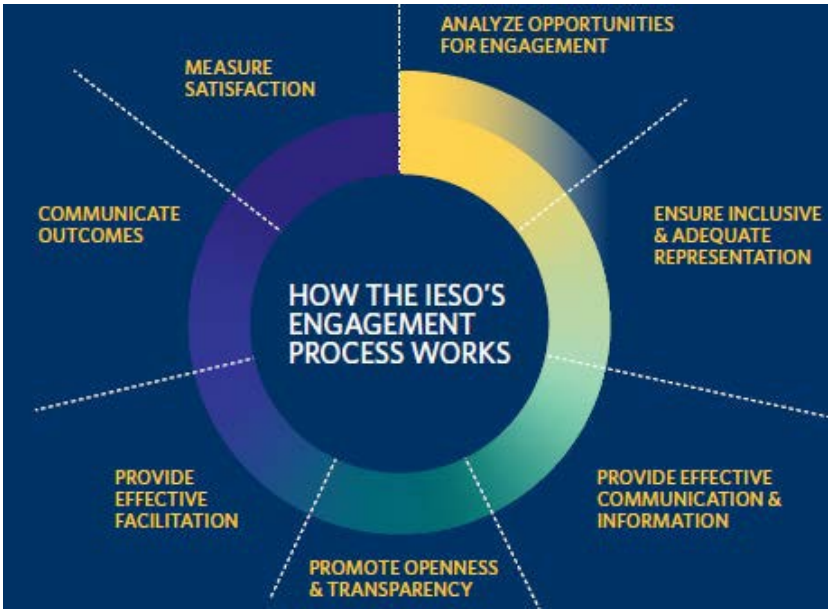
8. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for the IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 11 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Parry Sound/Muskoka

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;

- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

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

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Targeted individual and small group meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region.

An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft South Georgian Bay/Muskoka Scoping Assessment Outcome Greater before it was finalized. Feedback received encouraged the IESO to consider renewable technologies to help reduce local demand.

Following a written comment window, the final Scoping Assessment Outcome Report was published in November 2020 that identified the need for a coordinated planning approach done through two sub-regional IRRP: Barrie/Innisfil and Parry Sound/Muskoka.

Following these initial discussions and finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the South Georgian Bay/Muskoka region to ensure that all interested parties were made aware of this opportunity for input.

Three public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. The webinars received cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.
2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

All interested parties were kept informed throughout this engagement initiative via email to South Georgian Bay/Muskoka region subscribers, municipalities and communities as well as the members of the GTA/Central Regional Electricity Network.

Based on the discussions both through the Parry Sound/Muskoka IRRP outreach activities and broader network dialogue, there appears to be significant community growth planned in more rural area requiring new infrastructure, and broad interest in electrification, renewable energy solutions, net-zero development, and decarbonisation of electricity supply. To that end, ongoing discussions will continue through the IESO's GTA Central Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

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

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Southern Huron-Perth electricity planning sub-region or that may have interests in the sub-region throughout the development of the plan. This includes the First Nation communities of Alderville, Beausoleil, Chippewas of Georgina Island, Chippewas of Rama, Curve Lake, Henvey Inlet, Hiawatha, Huron-Wendat Nation, Magnetawan, Mississaugas of Scugog Island, Moose Deer Point, Shawanaga, Wahta Mohawks and Wasauksing as well as the Métis Nation Ontario communities of Barrie South-Simcoe Métis Council, Georgian Bay Métis Council and Moon River Métis Council

9. Conclusion

The Parry Sound/Muskoka IRRP identifies electricity needs in the sub-region and opportunities to preserve or enhance system reliability for the next 20 years. This report makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth and efficiency achievements. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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NEEDS ASSESSMENT REPORT

GTA North Region

Date: July 14, 2023

Prepared by: GTA North Region Technical Working Group

Disclaimer

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

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

Executive Summary

Region	GTA North Region (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	March 17, 2023	**End Date**	July 14, 2023

1. INTRODUCTION

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

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

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in March 2023 for the GTA North Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA North Region NA includes:

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

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

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon.

The provincial push towards decarbonization as outlined in the IESO's "Pathways to Decarbonization" report published on December 15, 2022, is expected to impact the electricity demand over the longer term. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than previously anticipated or as discussed in this report. The impact of decarbonization will be considered during the next phases of this regional planning cycle.

5. ASSESSMENT METHODOLOGY

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

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast and variability of demand drivers such as electrification.

6. NEEDS

Needs that were identified in the last RP cycle with current need dates are as follows:

- New Markham MTS #5 – need date is 2028
- Uprate 230kV circuits P45/46 from Parkway TS to Markham MTS #4 Jct. – need date is 2028
- New Northern York TS - need date is 2027
- Woodbridge TS: Replace transformer T5 with similar and size equipment as per current standard – need date is 2027
- New Vaughan MTS #5 – need date is 2030
- Claireville TS x Brown Hill TS Transmission circuit capacity need – need date is 2030
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P – Existing need[1]

New needs identified in this NA are:

- Kleinburg TS 44kV: Load transfer to Northern York TS – need date is 2027
- New Vaughan MTS #6 – need date is 2027
- New Toubner TS (CTS) – need date is 2027
- New Richmond Hill MTS #3 – need date is 2032
- Load Restoration needs for 230kV circuits P45/P46 – need date is 2027

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need and work will be proceeding as planned:
   - Woodbridge TS: Replace transformer T5
   - Toubner TS: Build new station
   - Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
   - Kleinburg TS 44kV: Load transfer to Northern York TS
   - Markham MTS #5: Build new station
   - 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
   - Northern York TS: Build new station
   - Vaughan MTS #5: Build new station
   - Richmond Hill MTS #3: Build new station
   - Claireville TS x Brown Hill TS Transmission circuit capacity need and load restoration needs
   - Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P

1. No action considered was considered necessary in the last regional planning cycle

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1 INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report.

This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this Needs Assessment ("NA") is to identify new needs in the region, reaffirm and update previously identified needs in the last GTA North RP cycle, and recommend which needs require further assessment and regional coordination.

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

Table 1-1: GTA North Region TWG Participants

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

2 REGIONAL ISSUE/TRIGGER

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

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

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

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

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA North Region is comprised of the Northern York Area, Southern York Area, and the Western Area. Electrical supply to the region is provided from sixteen 230kV step-down transformer stations. The 2022 Summer Peak area load of the region was approximately 2249MW. Please refer to Figure 4-1.

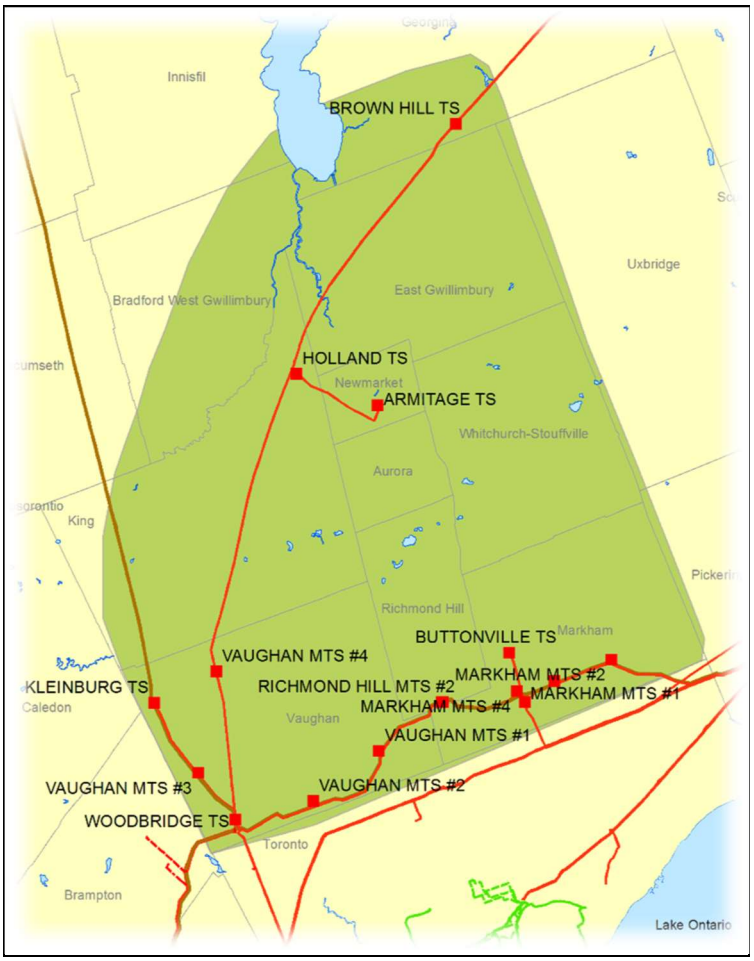


Figure 4-1: GTA North Region Map

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B88H/B89H in King Township. Please refer to Figure 4-2.

The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and

three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and Alectra.

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

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

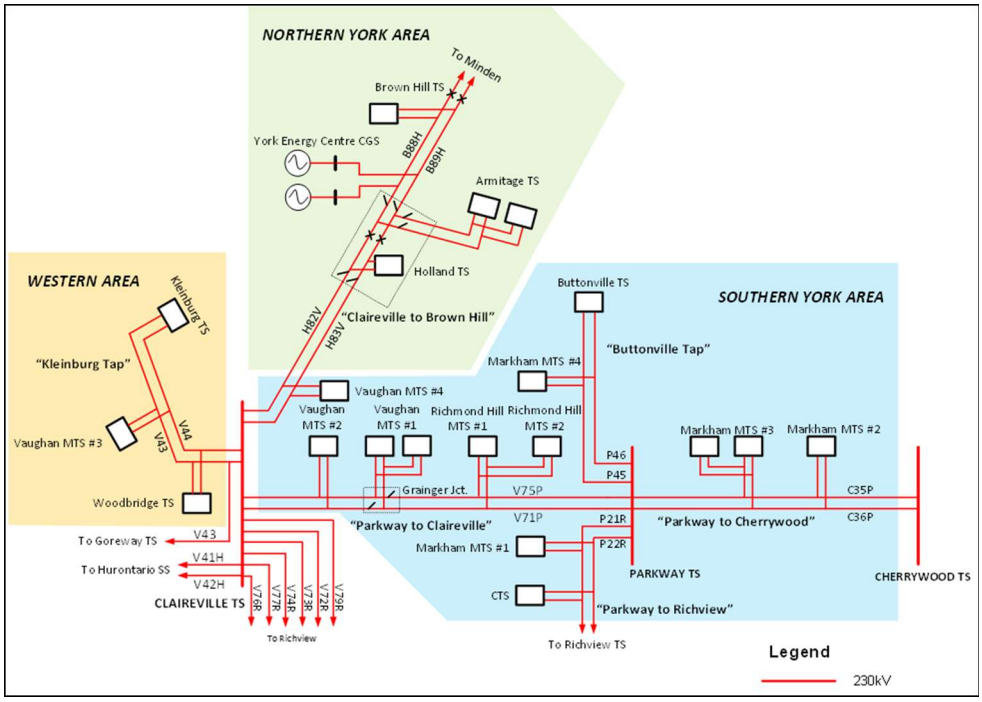


Figure 4-2: GTA North Region– Single Line Diagram

The transformer stations and circuits in the area are listed in Appendix A and Appendix B.

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA North Region NA. The information provided includes the following:

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

In December 2022, the IESO published a report [1] on developing an achievable pathway to the decarbonization of the electricity system. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than anticipated or discussed in this report. The impact of the decarbonization and resulting electrification will be considered during the next phase of this regional planning cycle.

6 ASSESSMENT METHODOLOGY

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

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the GTA North Region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") forecast and Distributed Generation ("DG") contract information for the Toronto Region. The region's extreme summer non-coincident peak gross load forecast for each station was prepared by applying the growth rates from the LDC load forecast to the actual 2022 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. The extreme summer weather corrected net non-coincident peak for the individual stations in the GTA North Region are given in Appendix C.
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment.
- System reliability and operational considerations.

[1] IESO Report, "Pathways-to-Decarbonization", Dec15, 2022

- Asset renewal for major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
- Sensitivity analysis to capture uncertainty in the load forecast

The following other assumptions are made in this report.

- The study period for this NA is 2023-2032.
- Coincident loads have been assumed equal to non-coincident loads for the purpose of transmission line adequacy assessment.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 ADEQUACY OF EXISTING FACILITIES

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

7.1 Adequacy of Northern and Southern York Area Facilities

7.1.1 500 and 230 kV Transmission Facilities

All 500 and most 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 4-2.

Northern York Area:

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

Southern York Area:

- Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
- Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
- Parkway TS to Buttonville TS **(**"Buttonville Tap") 230 kV circuits: P45 and P46[2].
- Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Western Area:

- Claireville TS to Kleinburg TS 230 kV circuits: V43 and V44[3]

The NA review shows that all flows on all transmission lines are within rating during the 2023-2032 study period except for the Claireville x Brown Hill corridor and the Parkway TS to Buttonville TS line. These are discussed below:

1) Loading on the Claireville TS to Brown Hill TS 230kV Corridor comprising the double circuit line H82/H3V and B88H/B89H will exceed the thermal limits by summer 2030.

[2] Radial from Parkway TS
[3] Radial from Claireville TS

Table 7-1 Loading on Claireville TS x Brown Hill TS Corridor

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Armitage TS (44kV)		285	290	296	301	305	303	305	308	311	313	
Brown Hill TS (44kV)		94	100	118	121	125	124	125	125	126	126	
Holland TS (44kV)		166	173	176	179	169	169	169	169	169	169	
Northern York Station						66	80	89	99	109	118	
Vaughan MTS #4 (28kV)		101	100	128	149	148	147	146	145	143	142	
Vaughan MTS #5 (28kV)									64	132	138	
Total	850	646	663	718	750	813	823	834	911	989	1007	2030

2) Loading on the Parkway TS x Markham MTS #4 Jct. section of the 230kV Parkway TS x Buttonville TS double circuit Line P45/P46 will exceed the rating of line by summer 2028

Table 7-2 Loading on the Parkway TS x Markham MTS #4 Jct. Section of 230kV Line P45/P46

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Buttonville TS (28kV)		144	152	154	152	160	149	148	147	146	145	
Markham MTS #4(28kV)		116	117	141	162	191	177	175	174	173	171	
Markham MTS #5(28kV)							68	136	140	139	138	
Toubner TS (28kV)						32	31	50	52	55	72	
Total	420	260	269	294	314	384	425	509	513	513	526	2028

7.1.2 Step down Transformer Station Facilities

There are a total of fifteen Hydro One and LDC owned step-down transformers stations and one direct transmission connected industrial customer owned station in the GTA North Region as given in Table 7-3 Step-Down Transformer Stations in the GTA North Region below:

Table 7-3 Step-Down Transformer Stations in the GTA North Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS #1[1]	Markham MTS #2[1]
Markham MTS #3[1]	Markham MTS #4[1]	Richmond Hill MTS[1]
Vaughan MTS #1[1]	Vaughan MTS #2[1]	Vaughan MTS #4[1]
Industrial Customer		
Western Area		
Kleinburg TS	Vaughan MTS #3[1]	Woodbridge TS

1. Stations owned by Alectra

The loadings on these stations were reviewed. Based on the forecast in Appendix C, additional capacity is required in the Northern York, Markham, and Vaughan areas starting in 2027. The station loading in each area and the associated station capacity and need dates are summarized in Table 7-**.**

Table 7-4 Adequacy of the Step-Down Transformation Facilities in the GTA North Region

Area/Supply	LTR-Capacity (MW)	2023 Summer Forecast (MW)	Need Date
Northern York Area (Armitage TS, Holland TS)	485	452	2027
Northern York Area (Brown Hill)	184	94	-
Markham / Richmond Hill transformation Capacity (Buttonville TS, Markham MTS #1, 2, 3, 4, and Richmond Hill MTS #1, 2)[1]	957	847	2028
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	551	2030
Vaughan Transformation Capacity (Vaughan MTS #3)[2]	153	145	2027
Kleinburg Area (Kleinburg TS 44kV)	97	102	Note [3]
Woodbridge TS (44kV)	80	85	Note [4]

1. Two stations required Markham MTS #5 in 2028 and Richmond Hill MTS #3 in 2032
2. Vaughan MTS #6 is a station dedicated for a large customer.
3. Excess load to be transferred to Northern York TS when new station complete in 2027
4. Loads to be managed by Hydro One Distribution

7.2 Asset Renewal Needs

No asset renewal needs have been identified in the GTA North Region over the current study period other than replacement of transformer T5 at Woodbridge TS listed in the 2020 RIP.

7.3 Load Restoration and Load Security Needs

Load Restoration and /or security needs were identified for theV43/V44, H82V/H83V, and V71P/V75P circuits in the 2020 RIP. One new load restoration need has been identified for the P45/P46 circuits. The needs and the recommended plan to address them are summarized below:

1. Load restoration following loss of the Claireville TS x Kleinburg TS 230kV circuits (V43/V44).

Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively, as per the ORTAC restoration criteria. The RIP recommended that this need would be addressed as part of the longer-term plan to reinforce the Claireville TS to Kleinburg TS corridor. No further action was proposed at the time. This will be re-visited in the next phase of this RP cycle.

2. Load Restoration following loss of the Claireville TS to Holland TS circuits (H82V/H83V).

All loads exceeding 250 MW cannot be restored within 30 minutes per the ORTAC criteria. Following the loss of H82V/H83V, the normal station service supply to YEC generation is also lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. The RIP had recommended that the IESO pursue alternative station service configurations at YEC to facilitate faster restoration of load on H82V/H83V, consistent with the load restoration criteria. This will be re-visited in the next phase of this regional planning cycle.

3. Load Security Need for the Parkway TS to Claireville TS 230kV double circuit Line V71P/V75P

The loss of this line can result in an interruption to over the 600MW which is more than what is permitted under the ORTAC criteria. The RIP had recommended that no further action is required. While the load security criteria was not met, Hydro One has installed inline switches at Grainger Jct. – located just outside of Vaughan MTS #1 - which permits quick restoration of the loads. This will be re-visited in the next phase of this regional planning cycle.

4. Load Restoration Need for the Parkway TS to Buttonville TS 230kV double circuit Line P45/P46

The line loading is expected to reach 384MW by summer 2027. Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively for a double circuit outage, as per the ORTAC restoration criteria. This is a new need and will be reviewed in the next phase of this regional planning cycle.

8 NEEDS

This section identifies any new needs in the GTA North Region and reaffirms and provides an update on the needs already identified in the previous RIP.

Table 8-1 Near and Medium Terms Needs in the GTA North Region

No.	Need	Recommended Action Plan	Need Date[1]
Needs as per last RIP[2]			
1	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027
2	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027
3	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS and connect to 230kV circuits P45/P46	2028
4	Increase Capability of 230kV Circuits P45+P46 (supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Uprate circuits P45/46 from Parkway to Markham MTS #4 Jct.	2028
5	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #5	2030
6	Claireville X Brownhill Circuit Upgrade	Uprate circuits- H82/H3V and B88H/B89H	2030
7	Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P[3]	To be reviewed in next phase of this regional planning cycle	Existing
New Needs identified			
8	Kleinburg TS Area	Transfer load to Northern York TS	2027
9	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #6 and connect to 230kV circuit V43/V44	2027
10	Markham Area: New Customer Connection	Build New Toubner TS and line tap to 230kV circuits P45/46	2027
11	Richmond Hill Area: Step-down Transformation Capacity	Build new Richmond Hill #3 MTS	2032
12	Load Restoration for 230kV circuits P45/46	To be reviewed in next phase of this regional planning cycle	2027

1. Need date based on current forecast
2. Please see Reference 1 in Section 11
3. No action was considered necessary for these needs in the last regional Planning cycle. Needs will be reviewed again in the IRRP and RIP phases of this regional planning cycle.

8.1 Station and Transmission Capacity Needs in the Near and Medium Term

As shown in the Table above, the 2020 RIP had identified three new station capacity needs, one in the Markham area designated as Markham MTS #5, the second in the Vaughan Area, designated as Vaughan MTS #5 and the third in the Northern York Area, designated as Northern York TS. Since then, based on

the current load forecast and customers' request, the need for three additional stations has been identified over the study period - Richmond Hill MTS #3, Vaughan MTS #6 and Toubner TS.

8.1.1 Markham Area - Build Markham MTS #5 and Uprate circuits P45/P46 -2028

Markham MTS #5 was previously identified to provide additional step-down transformation capacity in Markham-Richmond Hill area and planned to be built adjacent to the Buttonville TS and supplied from the same 230kV Parkway TS x Buttonville TS circuits P45/P46 (See Figure 8-1 below). The new station will have 2 x75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building.

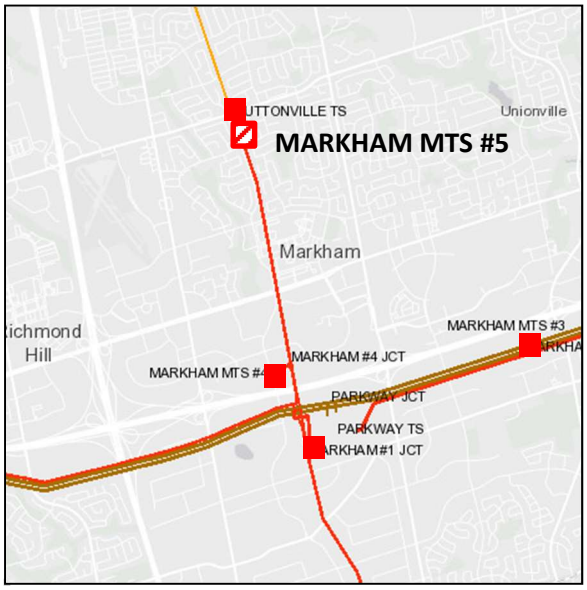


Figure 8-1: Markham MTS #5 Location

The TWG reaffirmed the need to build the new Markham MTS #5 and to uprate the limiting section of the P45/P46 line between Parkway TS and Markham MTS #4 Jct. to provide the needed capacity. The station project need date based on current forecast is summer 2028 (See Table 7-4) and the lines project need date is summer 2028 (see Table 7-2). This will be re-visited in the next phase of this regional planning cycle.

8.1.2 Northern York Region - Build Northern York Area TS and supply from 230kV Line B88H/B89H - 2027

The Northern York Area TS was recommended to be built in the Northern York Region to provide additional step-down transformation capacity in the Bradford, East Gwillimbury, and Newmarket area. This area is currently supplied from Armitage TS and Holland TS and total area load is forecast to exceed the capacity of these existing two stations by summer 2027 as shown in Table 8-2 below.

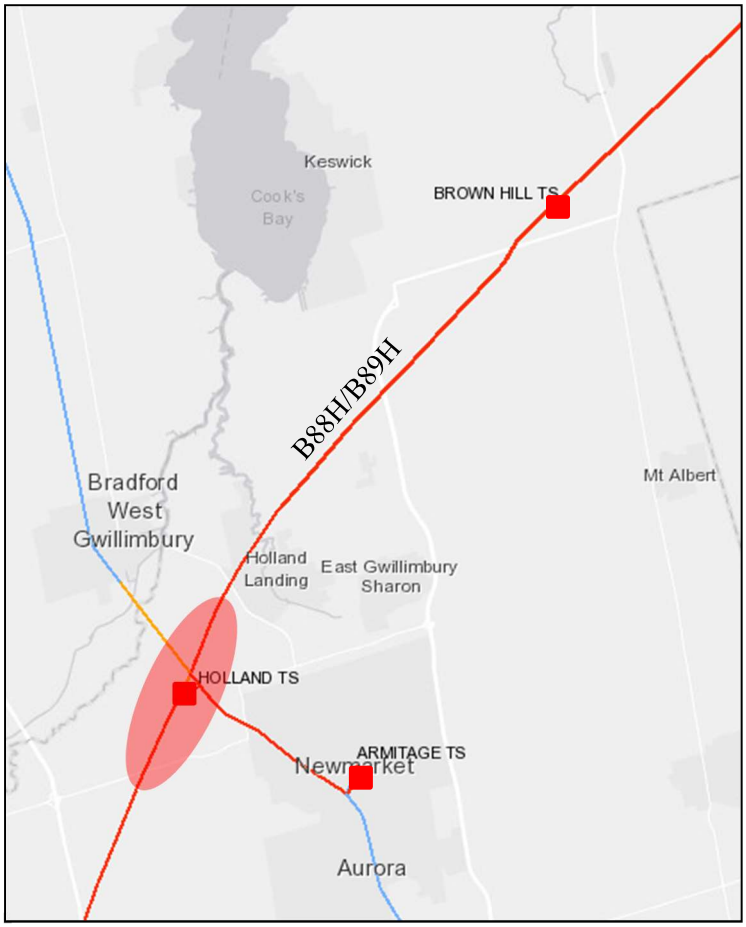


Figure-8-2 Northern York Area TS – Potential Location

Table 8-2: Northern York Area Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Holland TS (44kV)[1]	169	166	173	176	179	169	169	169	169	169	169
Northern York Station	170					66	80	89	99	109	118
Total	485	451	463	472	480	540	552	564	577	589	600

1. Holland load above LTR to be transferred to new Northern York station.

The TWG has reaffirmed the need for building a new station close to these two stations, in the area shown in Figure 8-2. The new station is planned to be supplied from 230kV double circuit line H82V/H83V or B88H/B89H and planned to have 2x75/125MVA, 230/44-27.6kV transformers and 27.6kVand 44kV switchyards. The new station should increase the transformation capacity in Northern York Region by about 170 MW. The station location and timing will be further discussed with the area LDCs in the next phase of the regional planning process.

8.1.3 Vaughan Area – Build Vaughan MTS #5 and supply from 230kV Line H82V/H83V -2030

The Vaughan MTS #5 was previously identified to provide additional step-down transformation capacity in Vaughan area and planned to be built adjacent to the existing Vaughan MTS #4 – see Figure 8-3. The new station is planned to have 2 x75/125MVA, 230/27.6kV transformers, a 27.6kV switchgear building and is planned to be supplied from the 230kV double circuit line H82V/H83V.

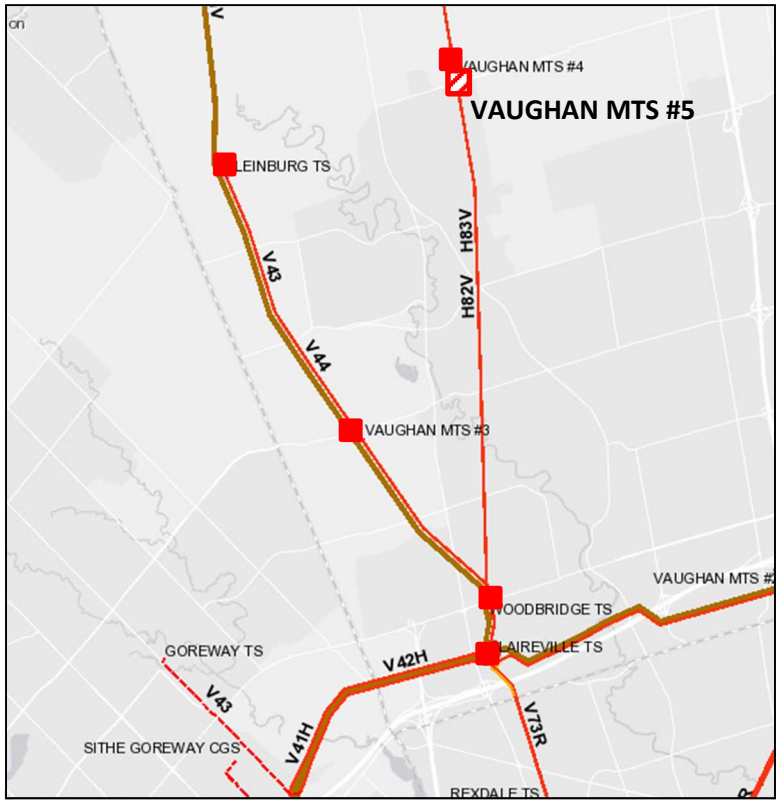


Figure-8-3 Vaughan MTS #5 Location

Table 8-3: Vaughan Area Station Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)									64	132	138
Total	612	551	545	569	585	580	575	570	631	694	696

As mentioned in Table 7-1, there isn't sufficient transmission capacity available on the Claireville to Brown Hill corridor to fully supply Vaughan MTS #5, given that a new station in Northern York is anticipated by 2027. Therefore, a plan to increase transmission supply capability to the area will be required before a plan for the new transformation station in Vaughan can be committed. This will be addressed in the next phase of this regional planning cycle.

8.1.4 Kleinburg TS Area – Transfer Load to Northern York TS

Kleinburg TS 44kV loading is a newly identified need. Kleinburg TS has 2 x 75/125MVA, 230/44-27.6kV transformers with separate 44kV and 27.6kV switchyards. Significant new load is forecast to connect at 44kV in the 2023-2024 period as shown in Table 8-4 below.

Table 8-4 Kleinburg Area Station Capacity Load

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)	97	102	111	124	134	98	98	97	96	95	95
Load Transfer to be Managed		5	14	27	37						

To manage loading at Kleinburg TS, Hydro One DX intends to transfer loads in the northern area served by Kleinburg TS to the new Northern York TS planned to be in-service by 2027.The new Northern York TS is planned to be a 230/44-27.6kV station. The TWG will review this in the next phase of the regional planning cycle.

8.1.5 Vaughan Area – Build Vaughan MTS #6 and supply from 230kV Line V43/V44 - 2027

Vaughan MTS #6 is a new identified need. Alectra plans to build a new station to provide dedicated supply to a large customer. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building. Alectra has requested that Hydro One build a short underground line tap to supply the new station from the 230kV Claireville TS x Kleinburg TS double circuit line V43/V44. The planned in-service date for the station is the end of 2027.

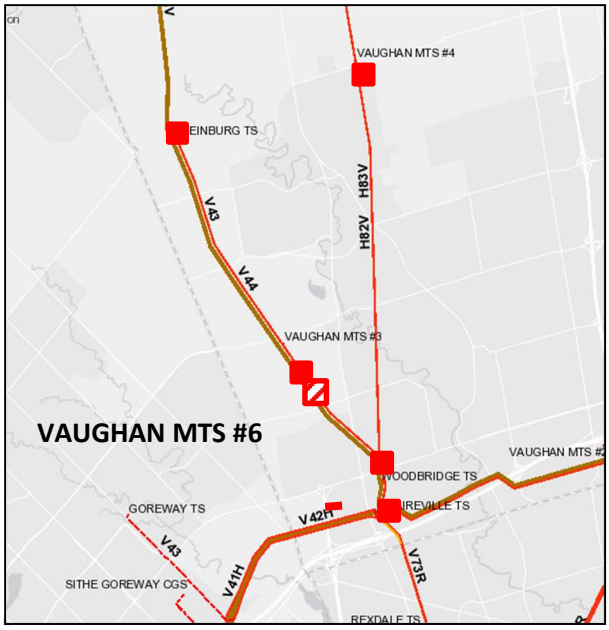


Figure-8-4 Vaughan MTS #6 Location

Table 8-5: Loading on the 230kV Claireville TS x Kleinburg TS line V43/V44

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)		62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)		102	111	124	134	98	98	97	96	95	95
Vaughan MTS #3 (28kV)		117	118	118	145	145	145	145	145	145	145
Vaughan MTS #6 (28kV)						32	31	50	52	68	72
Woodbridge TS (28kV)		87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)		85	85	86	86	86	87	87	88	90	91
Total	620	453	465	487	536	534	533	552	553	569	575

Table 8-5 shows the forecast loads connected to the line. As shown, there is adequate capacity to supply the loads over the study period.

Hydro One is currently in initial consultations with Alectra on the connection. Further details will be discussed in the next phase of the regional planning cycle.

8.1.6 Richmond Hill Area – Build Richmond Hill MTS #3 and supply from 230kV Line V71P / V75P - 2032

Richmond Hill MTS #3 is a new identified need. Alectra plans to build a new station to meet forecast loads in the 2030s. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchyard. Alectra has requested Hydro One to connect the new station to the 230kV Claireville TS x Parkway TS double circuit line V71P/V75P. The planned in-service date is summer 2032.

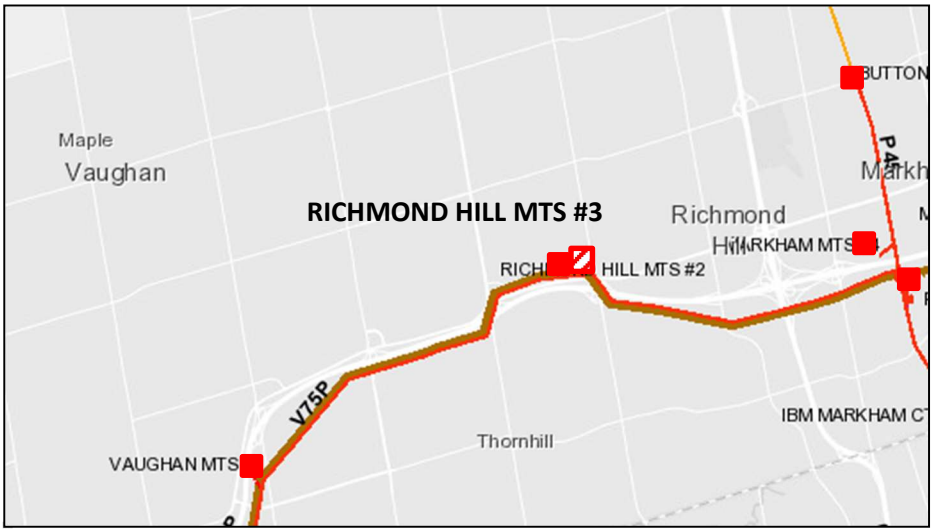


Figure-8-5 Richmond Hill MTS #3 Location

The 2020 RIP report had previously identified load security concerns with the V71P/V75P line as the connected loads exceed the 600 MW limit as per the ORTAC security criteria. However, as discussed in

Section 7.3, no action was recommended as Hydro One had installed sectionalizing switching on the line to restore load quickly in the event of a double circuit outage. The connection of the new station will further increase loading on the line. Alternatives to connect the station and address the load security need on the circuits will be developed and considered in the next phase of this RP cycle.

8.1.7 Toubner TS - 2027

Toubner TS is a new identified need. Hydro One has been requested to build a dedicated step-down transformer station for a direct industrial customer. The station will have 2 x 75/125 MVA, 230/27.6 kV transformers and a 27.6kV switchyard. The new station is in the Hwy. 7 and Hwy. 404 area and will be supplied from a tap for the 230kV line P45/P46 line tapped just north of Parkway TS. There is adequate capacity to supply the new station over the study period. The planned in-service date for the project is 2027.

Hydro One is currently in consultations with the customer to prepare connection estimates for the customer. Further details may be discussed in the current regional planning cycle.

8.1.8 Claireville x Brown Hill Transmission capacity Need- 2030

As described in Section 6.1 loading on the Claireville TS x Brown Hill TS corridor will exceed supply capacity by 2030. Alternatives to address this need will be developed and considered in the next phase of this regional planning cycle.

8.2 Long-Term Capacity Needs

With the provincial focus on decarbonization and the move away from fossil fuels, there will be a greater reliance on electricity. The GTA North region along with the rest of the province is about to embark on period of growth over the longer term driven by electrification, and large-scale development and customer connection projects are expected in several areas within the GTA North Region. The TWG will work with other stakeholders to ensure that all regional needs are met in a timely manner.

8.3 Asset Renewal Needs for Major HV Transmission Equipment – Woodbridge TS

As mentioned in Section 7.2 no asset renewal needs have been identified in the GTA North Region over the current study period other than Woodbridge TS identified in the last RIP.

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2022 44KV and 27.6kV actual peak loads were 55MW and 78 MW, respectively. Transformer T5 is currently about 51 years old and has been identified to be at its EOL.

The TWG is confirming the previous RIP identified need for the replacement of Woodbridge TS T5 transformer with similar type and size equipment as per current standard. Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area. The planned in-service date for the work is 2027.

8.4 Load Restoration and Security Needs

Load restoration need have been discussed earlier in Section 7.3, The TWG will consider these needs in the development of new plans to meet load growth and improve reliability of supply in the GTA North Region in the next phase of this regional planning cycle.

9 SENSITIVITY ANALYSIS

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

The uncertainty can stem from varying factors ranging from changes considered in potential evolution of public policy, electrification (e.g., electrification of transportation or other sectors), Municipal Energy Plans, Community Energy Plans, and Climate Action Plans (for actions that are not firm/committed), non-committed customer connections (both distribution and transmission), DER scenarios (e.g., battery storage), continued operation of off-contract generation.

A high demand growth forecast was developed by assuming that the forecast growth was 50% higher than the extreme summer corrected normal growth net load forecast given in Appendix C. Similarly, a low demand forecast was developed assuming that the growth was half the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Table 8-1 is summarized in Table 9-1.

Table 9-1: Impact of Sensitivity Analysis on the Identified Capacity Needs

No.	Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Toubner TS[1]	2027		
2	Vaughan MTS #6[1]	2027		
3	Northern York TS	2027	2026	2027
4	Markham MTS #5	2028	2027	2032
5	Vaughan MTS #5	2030	2030	2031
6	Richmond Hill MTS #3	2032	2029	Beyond 2032
7	Uprate circuits P45/P46[2]	2028	2028	Beyond 2032
8	Claireville X Brown Hill Corridor	2030	2027	Beyond 2032

[1]Customer requested work with defined in-service date.
[2]To be done along with the Markham MTS #5 project

Based on current equipment deliverability and construction schedules the earliest in-service dates for projects is summer 2027. The Toubner TS, Vaughan MTS #6 are customer driven projects and need to proceed. The remaining needs listed in Table 9-1will be addressed in the next phases of this planning cycle

in coordination with the additional identified network capacity and load security/restoration needs and considering a longer-term forecast for the area.

10 RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following needs and work will be proceeding as planned with all the three projects expected to be in-service by 2027.

- Woodbridge TS: Replace transformer T5
- Toubner TS: Build new station.
- Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the regional planning cycle to review and/or develop a preferred plan for the follow needs:

- Markham MTS #5: Build new station
- 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
- Northern York TS: Build new station
- Kleinburg TS 44kV: 44kV loads transfer to Northern York TS
- Vaughan MTS #5: Build new station
- Richmond Hill MTS #3: Build new station
- Claireville TS x Brown Hill TS Transmission circuit capacity need
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P.

11 REFERENCES

[1]. Hydro One, "GTA North Regional Infrastructure Plan", October 22, 2020.
GTA North REGIONAL INFRASTRUCTURE PLAN (hydroone.com)

[2]. Hydro One, "Need Assessment Report, GTA North Region", March 18, 2018.
Needs Assessment Report GTA North Region (hydroone.com)

[3]. IESO, "York Region: Integrated Regional Resource Plan", February 28, 2020.
York IRRP-20200228.pdf

[4]. IESO, "York Region Scoping Assessment Outcome Report", August 28, 2018.
York-Region-Scoping Assessment-Outcome-Report-20180828.pdf

12 APPENDIX A. STATIONS IN THE GTA NORTH REGION

No.	Station (DESN)	Voltage (kV)	Supply Circuits
1	Armitage TS T1/T2	230/44	B88H/B89H
	Armitage TS T3/T4	230/44	B88H/B89H
2	Brown Hill TS T1/T2	230/44	B88H/B89H
3	Buttonville TS T3/T4	230/27.6	P45/P46
4	CTS	230/13.8	P21R/P22R
5	Holland TS T1/T2, T3/T4	230/44	H82V/H83V
6	Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
	Kleinburg TS T1/T2 44	230/44	V44/V43
7	Markham MTS #1 T1/T2	230/27.6	P21R/P22R
8	Markham MTS #2 T1/T2	230/27.6	C35P/C36P
9	Markham MTS #3 T1/T2	230/27.6	C35P/C36P
	Markham MTS #3 T3/T4	230/27.6	C35P/C36P
10	Markham MTS #4 T1/T2	230/27.6	P45/P46
11	Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
	Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
12	Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
	Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
13	Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
14	Vaughan MTS #3 T1/T2	230/27.6	V44/V43
15	Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V
16	Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
	Woodbridge TS T3/T5 44	230/44	V44/V43

13 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

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

14 APPENDIX C: NON-COINCIDENT SUMMER PEAK NET LOAD FORECAST (2023 TO 2032)

	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Brown Hill TS (44kV)	184	94	100	118	121	125	124	125	125	126	126
Buttonville TS (28kV)	166	144	152	154	152	160	149	148	147	146	145
Holland TS (44kV)	169	166	173	176	179	169	169	169	169	169	169
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)[1]	97	102	111	124	134	98	98	97	96	95	95
Markham MTS #1 (28kV)	81	80	79	78	77	76	76	75	74	74	73
Markham MTS #2 (28kV)	101	88	98	97	96	106	94	93	93	92	91
Markham MTS #3 (28kV)	202	171	184	191	189	197	186	184	183	181	180
Markham MTS #4(28kV)	153	116	117	141	162	176	177	175	174	173	171
Markham MTS #5(28kV)	153						68	136	140	139	138
Northern York Station	170					66	80	89	99	109	118
Richmond Hill-1 MTS (28kV)	153	153	152	150	149	154	146	144	144	142	141
Richmond Hill-2 MTS (28kV)	101	95	105	104	104	111	104	104	104	105	105
Richmond Hill-3 MTS (28kV)	153										60
Toubner TS (28kV)	153					32	31	50	52	55	72
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #3 (28kV)	153	117	118	118	145	145	145	145	145	145	145
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)	153								64	132	138
Vaughan MTS #6 (28kV)	153					32	31	50	52	68	72
Woodbridge TS (28kV)	80	87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)	80	85	85	86	86	86	87	87	88	90	91
Grand Total		**2396**	**2459**	**2559**	**2652**	**2792**	**2814**	**2921**	**2997**	**3084**	**3173**

1. Kleinburg 44kV load exceeds LTR between 2023 and 2026. Excess load planned to be transferred to Northern York Region when station is built in 2027.

15 APPENDIX D: ACRONYMS

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



GTA North (York Region) Scoping Assessment Outcome Report

October 12, 2023

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Connecting Today.
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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of regional planning for the GTA North region (also known as "York Region"), and it was initiated in March 2023. Information and links to earlier products are available on the IESO webpage[1]. The Needs Assessment is the first step in the regional planning process and was carried out by the Technical Working Group (TWG) led by Hydro One. The Needs Assessment Report[2] was finalized on July 14, 2023 and identified needs that require further regional coordination. The Technical Working Group reviewed the nature and timing of all the needs identified in the region through the Needs Assessment process, to determine the most appropriate planning approach. It also considered provincial initiatives, including the IESO's recent Pathways to Decarbonization report and the provincial government's Powering Ontario's Growth report.

The Scoping Assessment process considers which of three potential planning approaches is most appropriate for addressing the region's needs, including: an IRRP – where both wires and non-wires options have the potential to address the needs and are considered as alternatives; a Regional Infrastructure Plan (RIP), which considers only wires (transmission and distribution) options; or a local plan undertaken by the transmitter and affected local distribution company or customer, where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and determines whether sub-regions should be defined;
- Considers impacts on planning assumptions and potential outcomes on needs resulting from local and provincial policy goals;
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the IRRP Technical Working Group.

[1] GTA North (York Region) Regional Planning Webpage, IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/GTA-North

[2] Needs Assessment Report GTA North Region, Hydro One. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/GTA%20North%20Region%20NA%20Report%20Final%20July%2014%202023.pdf

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation (Alectra)
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd (NT Power)
- Toronto Hydro-Electric System Limited (THESL)
- Hydro One Networks Inc. (Transmission), as the lead transmitter

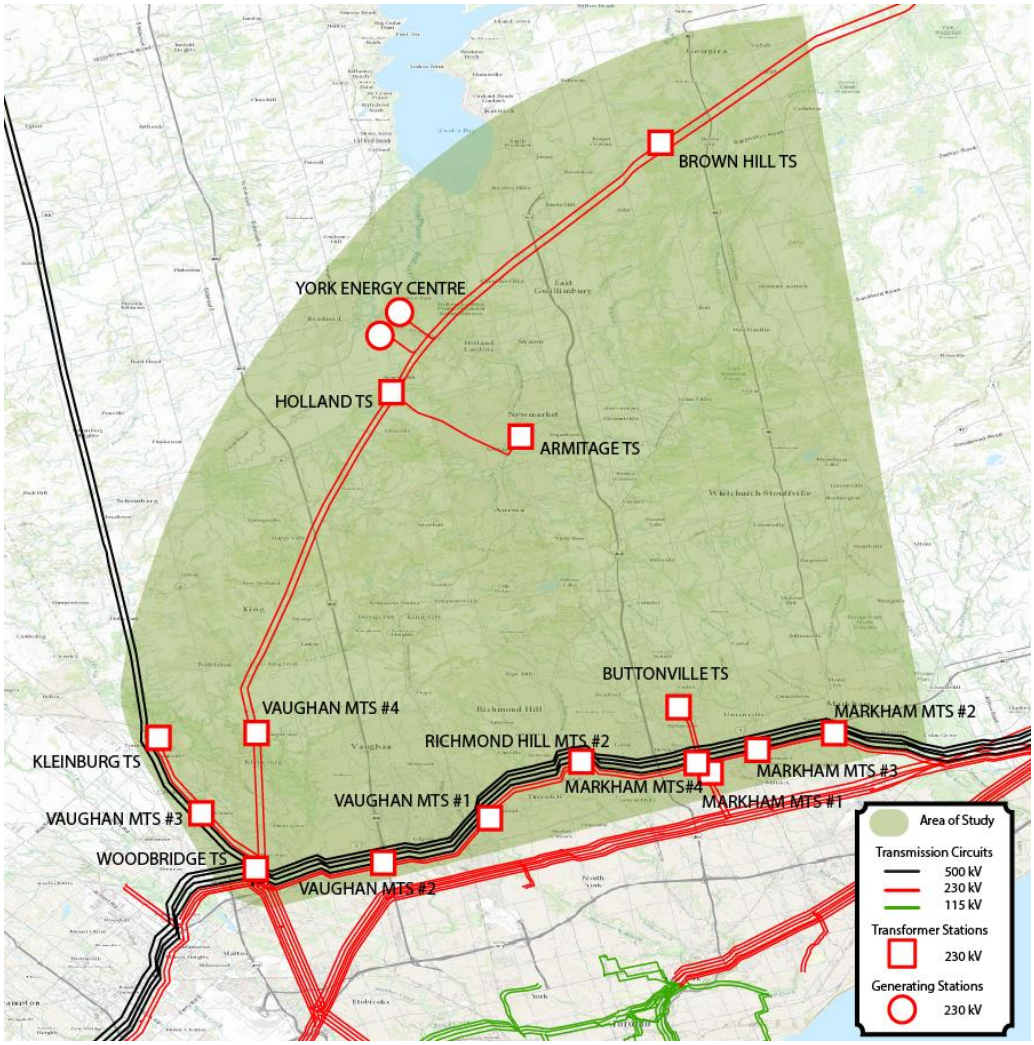
3. Categories of Needs, Analysis and Results

3.1 Overview of York Region

The GTA North Region, shown in Figure 1, roughly comprises the municipalities in the Regional municipality of York, including the Cities of Markham, Richmond Hill and Vaughan, the Towns of Aurora, East Gwillimbury, Georgina, Newmarket, Whitchurch-Stouffville, and the Township of King. Since the GTA North planning region roughly aligns with the boundaries of the Regional Municipality of York, it is commonly referred to as "York Region."

Indigenous communities including Alderville First Nation, Beausoleil First Nation, Curve Lake First Nation, Chippewas of Georgina Island First Nation, Haudenosaunee Development Institute/Hereditary Chiefs Council, Hiawatha First Nation, Kawartha Nishnawbe, Mississaugas of Scugog Island First Nation, Rama First Nation, Six Nations of the Grand River and the Mississaugas of the Credit First Nation are located in or have historical interest in the area.

Figure 1 | York Region Electricity Infrastructure



York Region is one of the fastest growing regions in Ontario. Provincial policies, including the Places to Grow Act have played a key role in facilitating and driving development in this region. Extensive urbanization in these areas over the past decade has resulted in continued increase in electricity demand. In 2022, York Region had an electricity peak demand of over 2,000 MW. Under the most recent update to the Places to Grow Act[3], significant population growth and intensification are expected to continue in York Region in the coming decades.

At the same time, many municipalities and communities in York Region are actively engaged in local energy planning activities and are exploring opportunities to better manage their energy uses using community-based energy solutions, such as energy storage, combined heat and power and renewable energy resources.

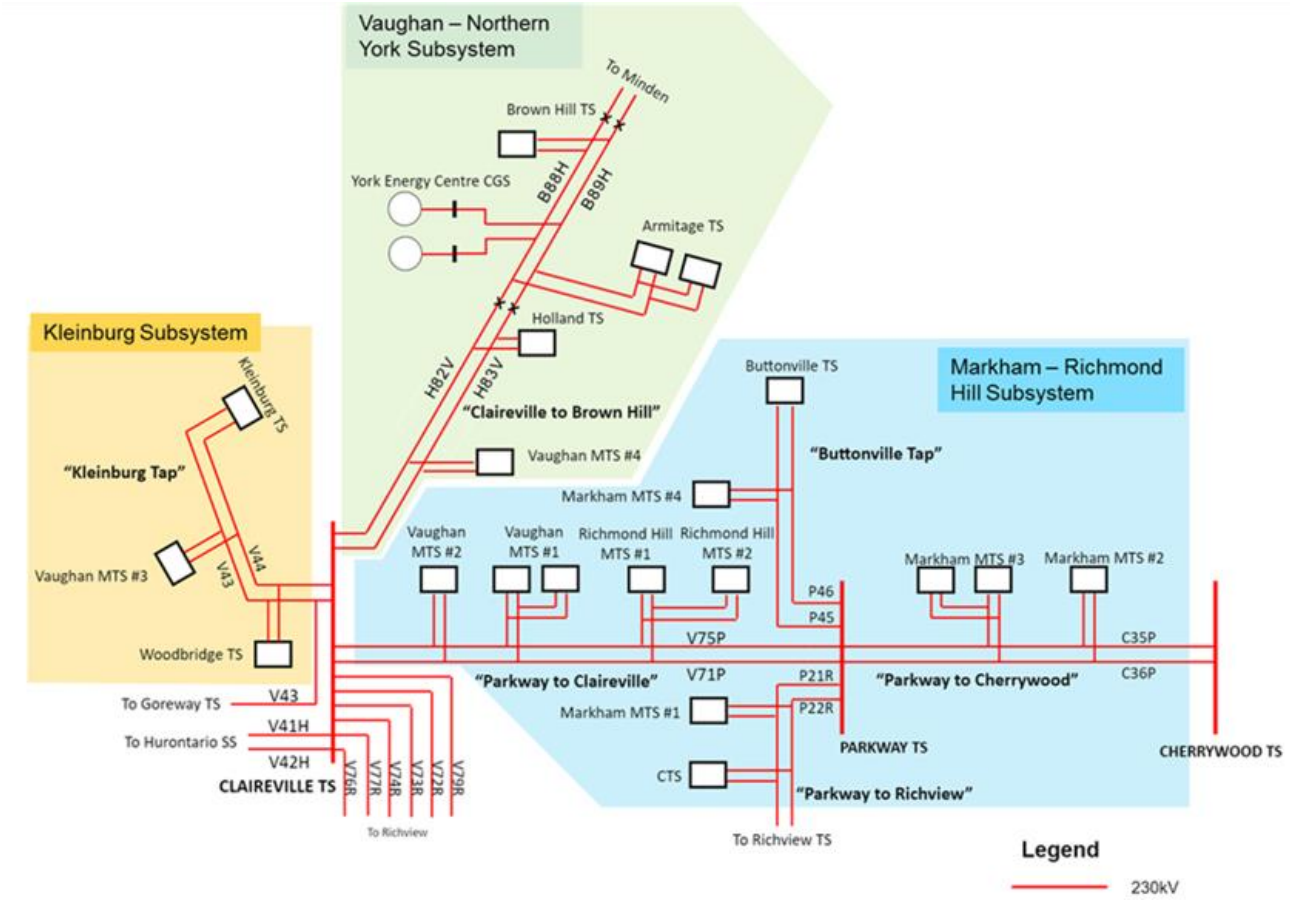
[3] A Place to Grow. Growth Plan for the Greater Golden Horseshoe. Office Consolidation 2020 https://files.ontario.ca/mmah-place-to-grow-office-consolidation-en-2020-08-28.pdf

3.1.1 Electricity System Supplying York Region

The electricity system supplying York Region consists of a high voltage (230 kV) network of transmission lines, shown in Figure 2. In addition to delivering power to this area, this network also serves as a pathway for power to flow between northern and southern Ontario as well as across the GTA.

York Energy Centre (YEC), a 393 MW natural gas-fired generating station, also provides a local source of supply within the region.

Figure 2 | Single Line Diagram of York Region



Power from the 230 kV network is delivered to communities and customers through 16 transformer stations located throughout the region that supply low-voltage (<50 kV) distribution networks and, in some cases, large individual customers. In York Region, the low-voltage distribution systems that deliver power to homes and businesses are managed and operated by four local distribution companies (LDCs): Alectra, NT Power, THESL, and Hydro One Distribution.

For the purpose of regional planning, this 230kV network is broken down into three subsystems, as shown in Figure 2:

- **Kleinburg Subsystem (V44/V43) -** This subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, as well as some areas of Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.
- **Vaughan-Northern York Subsystem (B88H/B89H, H82V/H83V)** - This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York Region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and the Chippewas of Georgina Island). YEC is connected to these 230 kV circuits. This subsystem also serves as a pathway for power to flow between northern and southern Ontario.
- **Markham-Richmond Hill Subsystem (V75P/V71P, P45/P46, P21R/P22R, C35P/C36P)** - This subsystem consists of 12 step-down transformer stations that are located in urban communities in the Markham, Richmond Hill and Vaughan areas. This subsystem also serves as a pathway for power to flow across the GTA along the Parkway Belt/Highway 407 transmission corridor.

3.2 Previous Regional Plans

The first cycle of the regional planning process for York Region was completed in 2016 with the publication of the Region's first Integrated Regional Resource Plan (IRRP)[4]. This plan focused on ensuring there was adequate supply to support near-term growth in the Vaughan area and on minimizing the impact of supply interruptions under major outage conditions. It recommended a number of projects to support near-term growth and to maximize the use of the existing system, including the installation of a new transformer station in Vaughan and new switching equipment at Holland transformer station and on the Parkway Belt/Highway 407 corridor.

The second cycle of regional planning was completed in 2020[5]. This IRRP mainly focused on medium and long-term system and station capacity needs. It explored multiple alternatives to increase supply capacity to York Region in the long term. As most of the needs occurred in the long-term timeframe, this plan recommended actions to preserve options and that they be revisited in the third cycle of regional planning.

[4] Available upon request to engagement@ieso.ca.

[5] 2020 York Region IRRP, IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/York/York-IRRP-20200228.ashx

3.3 Needs Identified

3.3.1 Needs Identified in the Needs Assessment Phase of the Current Planning Cycle

For this third cycle of regional planning, Hydro One's Needs Assessment Report provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in York Region based on a new 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated transmission asset condition information, and updated conservation and demand management (CDM) and distributed generation (DG) forecasts provided by the IESO.

Some of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (see Table 1). However, most of the identified needs were determined to require a significant amount of planning, have a shared impact with other system assets or needs, or have the potential to be met with a combination of wires and non-wires alternatives. Therefore, the Needs Assessment concluded that these needs require further coordination (see Table 2).

Table 1 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Woodbridge TS	End of life replacement of transformer T5
2	Toubner TS	Build new station in Markham[6]
3	Vaughan MTS #6	Build new station in Vaughan[4]

[6] This new station is for a single, large, industrial customer. Upstream effects of the new station on the 230 kV network will be studied in this cycle of regional planning.

Table 2 | Needs Identified in the Needs Assessment as Requiring Coordination

Need #	Location of Need	Need Type	Need Description
1	Kleinburg	Station Capacity	Significant new load is forecast to connect at the 44kV bus in the 2023-2024 period, exceeding its capacity.
2	Markham	Station Capacity	Markham area stations are expected to exceed their capacities by 2028
3	Buttonville Tap transmission corridor	System Capacity	Circuits supplying Markham MTS #4 and Buttonville TS are expected to exceed their capacities by 2028
4	Northern York Region	Station Capacity	Northern York region is expected to reach the area's stations' capacity by 2027
5	Vaughan	Station Capacity	Vaughan area stations are expected to exceed their capacities by 2030
6	Richmond Hill	Station Capacity	Richmond Hill area stations are expected to exceed their capacities by 2032
7	Claireville to Brown Hill transmission corridor	System Capacity	Loading on the Claireville TS x Brown Hill TS corridor is expected to exceed its capacity by the early 2030s.
8	Kleinburg Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance
9	Claireville to Brown Hill transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.
10	Buttonville Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.

Need #	Location of Need	Need Type	Need Description
11	Parkway to Claireville transmission corridor	Load Security	The loss of this line can result in an interruption to over 600 MW of customer load, which is more than permitted by planning criteria

3.3.2 Determination of Study Scope

The Technical Working Group (TWG) has discussed the identified needs in York Region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for implications on the upstream bulk power system
- The opportunity to explore effects of a high electrification scenario.

In general, the more complex a set of needs are and the greater the need for coordination and engagement, the more likely an IRRP will be selected as the preferred regional planning approach. If the needs are relatively straightforward, there are few feasible alternatives to address them, and solutions can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The TWG agreed that for each of the identified needs requiring coordination, a range of alternatives including wires and non-wires solutions should be assessed.

The TWG agreed that an IRRP should be undertaken to further assess the needs. The scope of an IRRP includes an assessment of CDM, DERs, and other community-based solutions. A Draft Terms of Reference for the York Region IRRP is attached in Appendix B.

The TWG has also determined that, as the identified needs span all areas of York Region, and there may be alternatives that address multiple needs across the region, there is no benefit to defining sub-regions for separate study within this IRRP process. Therefore, the recommended IRRP scope covers York Region in its entirety. Additionally, several needs were identified which do not require further coordinated planning (see Table 1), but should still be considered in scope of further study as the implementation and timing of solutions have the potential to affect other needs in the area.

3.3.3 Pathways to Decarbonization and Powering Ontario's Growth

In December 2022, the IESO published its Pathways to Decarbonization Report[7]. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all Greenhouse Gas (GHG) emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial processes

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

In the provincial government's "Powering Ontario's Growth" report[8], it is recognized that *"growth to date has been met by existing transmission lines, energy efficiency programs and strategically located generation assets"* and recognizes the challenge of *"future demand growth and a shift away from natural gas electricity generation"*.

Accordingly, the York Region IRRP will evaluate a scenario in which YEC, a local gas-fired generation plant, is phased out. The Pathways to Decarbonization report had previously identified that this could not be achieved within the timelines considered by the 2035 Moratorium scenario, so the IRRP will include identification of required system investments needed to accommodate this phase-out, and an estimated timeline for how quickly this could be accomplished.

Consideration will also be given to a separate "high electrification" demand forecast that would examine and evaluate the needs that arise on the electricity system in York Region under a more aggressive decarbonisation scenario and provide recommendations on near-term actions to facilitate this transition.

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[7] Pathways to Decarbonization, IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.ashx

[8] Powering Ontario's Growth, Province of Ontario. https://www.ontario.ca/page/powering-ontarios-growth

A summary of planning scenarios for inclusion in the IRRP is provided in Table 3, below:

Table 3 | Summary of Planning Scenarios

Scenario	Demand Forecast	Generation Assumptions	Notes
1a	Basecase	Continued operation of York Energy Centre	Basecase Scenario. Needs and recommendations will form the main deliverables of the IRRP
1b	Basecase	Phase out of York Energy Centre	Identify incremental needs and recommended options resulting from York Energy Centre phase out
2	High Electrification	Phase out of York Energy Centre	Identify incremental needs and recommend options resulting from transition to net zero energy system

3.3.4 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook[9] (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in York Region, its findings (i.e. needs and recommended solutions) will be coordinated with the York Region IRRP, and vice-versa.

[9] 2022 Annual Planning Outlook. IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/2022-Annual-Planning-Outlook.ashx

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- An IRRP is to be undertaken for York Region;
- The IRRP Working Group will include the IESO, Alectra, NT Power, Hydro One Distribution, and Hydro One Transmission. Other LDCs in the region will be informed of any needs or solutions that may affect their facilities or customers;
- The IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa;
- Given the significant scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required.

An IRRP was recommended on the basis of the scale of load growth anticipated, potential for diverse types of solutions (including wires and non wires), and long term uncertainty associated with regional development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

All IRRPs include opportunities for engagement with local communities and stakeholders, including discussion of any local initiatives focused on energy and/or reducing GHG emissions and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or other similar products. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the York Region IRRP is attached in Appendix B.

Appendix A – List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station
TWG	Technical Working Group

Appendix B – York Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

The GTA North Region (York Region) is one of the 21 electricity planning regions in Ontario as identified through the Ontario Energy Board's (OEB) Regional Planning Process. Since the geographical boundaries of GTA North Region roughly encompass the Regional Municipality of York, this planning region is often referred to as York Region.

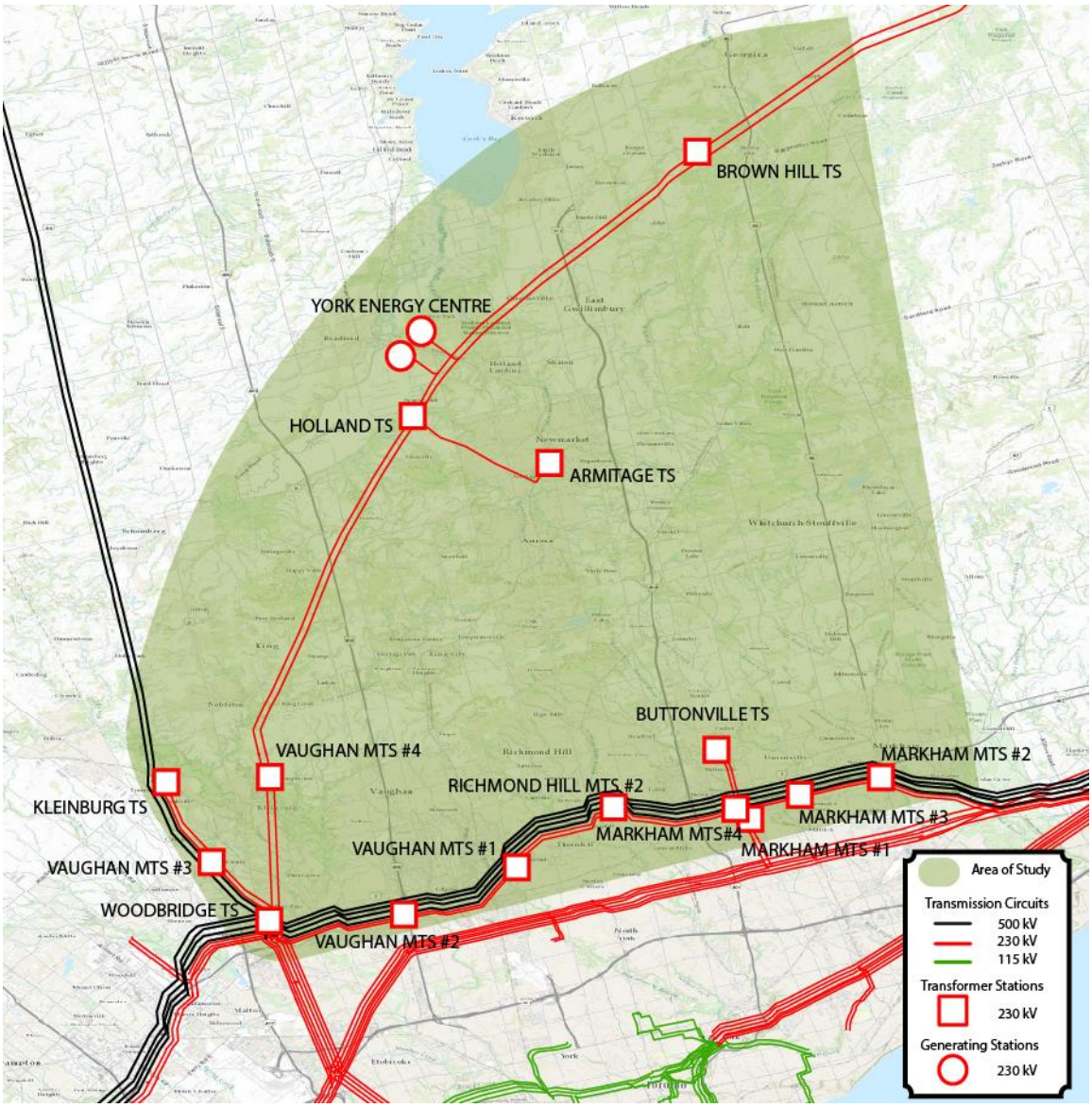
These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for York Region.

1.1 GTA North Region (York Region)

York Region, shown in Figure 3, roughly comprises the municipalities in the Regional municipality of York, including the Cities of Markham, Richmond Hill and Vaughan, the Towns of Aurora, East Gwillimbury, Georgina, Newmarket, Whitchurch-Stouffville, and the Township of King.

Indigenous communities including Alderville First Nation, Beausoleil First Nation, Curve Lake First Nation, Chippewas of Georgina Island First Nation, Haudenosaunee Development Institute/Hereditary Chiefs Council, Hiawatha First Nation, Kawartha Nishnawbe, Mississaugas of Scugog Island First Nation, Rama First Nation, Six Nations of the Grand River and the Mississaugas of the Credit First Nation are located in or have historical interest in the area.

Figure 3 | York Region Electricity Infrastructure



1.2 Background

In July 2023, Hydro One completed the Needs Assessment Report[10] for York Region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP was recommended on the basis of the scale of load growth anticipated, potential for diverse types of solutions (including wires and non wires), and long term uncertainty associated with regional development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid that provides electricity supply to York Region over the next 20 years.
2. Account for capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the identified needs.
5. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparatory work for medium-term needs, and planning direction for the long term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of York Region. The plan is a joint initiative involving the IESO, Alectra, NT Power, Hydro One Distribution, and Hydro One Transmission[11] and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, CDM, DER uptake, transmission and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The York Region IRRP includes the following needs, that were identified in the Needs Assessment as requiring coordination:

[10] Hydro One: GTA North Needs Assessment Report, July 2023. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/GTA%20North%20Region%20NA%20Report%20Final%20July%2014%202023.pdf

[11] A small portion of Toronto Hydro's service area is also supplied by feeders from some stations in York Region. Toronto Hydro will not form part of the core Technical Working Group. However, they will be informed of any developments that may impact their facilities and/or customers.

Table 4 | Needs Identified in the Needs Assessment as Requiring Coordination

Need #	Location of Need	Need Type	Need Description
1	Kleinburg	Station Capacity	Significant new load is forecast to connect at the 44kV bus in the 2023-2024 period, exceeding its capacity.
2	Markham	Station Capacity	Markham area stations are expected to exceed their capacities by 2028
3	Buttonville Tap transmission corridor	System Capacity	Circuits supplying Markham MTS #4 and Buttonville TS are expected to exceed their capacities by 2028
4	Northern York Region	Station Capacity	Northern York region is expected to reach the area's stations' capacity by 2027
5	Vaughan	Station Capacity	Vaughan area stations are expected to exceed their capacities by 2030
6	Richmond Hill	Station Capacity	Richmond Hill area stations are expected to exceed their capacities by 2032
7	Claireville to Brown Hill transmission corridor	System Capacity	Loading on the Claireville TS x Brown Hill TS corridor is expected to exceed its capacity by the early 2030s.
8	Kleinburg Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance
9	Claireville to Brown Hill transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.
10	Buttonville Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.

Need #	Location of Need	Need Type	Need Description
11	Parkway to Claireville transmission corridor	Load Security	The loss of this line can result in an interruption to over 600 MW of customer load, which is more than permitted by planning criteria

Other identified needs in the Needs Assessment not listed in Table 4 above will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the Working Group informed on project development.

3.2 Pathways to Decarbonization and Powering Ontario's Growth

In December 2022, the IESO published its Pathways to Decarbonization Report[12]. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all Greenhouse Gas (GHG) emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial processes

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

In the provincial government's "Powering Ontario's Growth" report[13], it is recognized that *"growth to date has been met by existing transmission lines, energy efficiency programs and strategically located generation assets"* and recognizes the challenge of *"future demand growth and a shift away from natural gas electricity generation"*.

[12] Pathways to Decarbonization, IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.ashx

[13] Powering Ontario's Growth, Province of Ontario. https://www.ontario.ca/page/powering-ontarios-growth

Accordingly, the York Region IRRP will evaluate a scenario in which YEC, a local gas-fired generation plant, is phased out. The Pathways to Decarbonization report had previously identified that this could not be achieved within the timelines considered by the 2035 Moratorium scenario, so the IRRP will include identification of required system investments needed to accommodate this phase-out, and an estimated timeline for how quickly this could be accomplished.

Consideration will also be given to a separate "high electrification" demand forecast that would examine and evaluate the needs that arise on the electricity system in York Region under a more aggressive decarbonisation scenario and provide recommendations on near-term actions to facilitate this transition.

A summary of planning scenarios for inclusion in the IRRP is provided in Table 5, below:

Table 5 | Summary of Planning Scenarios

Scenario	Demand Forecast	Generation Assumptions	Notes
1a	Basecase	Continued operation of York Energy Centre	Basecase Scenario. Needs and recommendations will form the main deliverables of the IRRP
1b	Basecase	Phase out of York Energy Centre	Identify incremental needs and recommend options resulting from York Energy Centre phase out
2	High Electrification	Phase out of York Energy Centre	Identify incremental needs and recommend options resulting from transition to net zero energy system

3.3 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook[14] (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in York Region, its findings (i.e. needs and recommended solutions) will be coordinated with the York Region IRRP, and vice-versa.

[14] 2022 Annual Planning Outlook. IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/2022-Annual-Planning-Outlook.ashx

4. Activities

The IRRP process will consist of the activities listed below. The activities and anticipated timelines are summarized in Table 6 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast scenarios to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand forecast to be used.

1) Develop two electricity demand forecasts for York Region:
    a. The first, a "business as usual" forecast, should account for all municipalities' and LDCs' committed long-term policy goals and plans, taking into account local and provincial policy goals, commitments, and climate change action plans. This is the primary forecast which will be used to identify needs, preferred options, and recommendations.
    b. The second, a high electrification forecast, will represent the impacts of a net zero energy system by 2050, consistent with the Pathways to Decarbonization report. This forecast will be used to evaluate the incremental needs and develop recommendations to accommodate a net zero target.
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook and the YEC phase out scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors.

Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.

6) Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.
7) Develop a long-term plan for the electricity system in York Region to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in York Region could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
        i. This will include studying a scenario where transmission-connected gas generation is phased out per the timelines in the Pathways to Decarbonization report.
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in Section 5 below.

5. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information and trends for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by TS, etc.
    - Coincident peak demand data
    - Identified potential future load customers, including transit expansions, electrification of personal vehicles, space heating/cooling, water heating, and other end-uses due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on region's share of the provincial target found in the 2021-2024 CDM Framework
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities, if applicable
    - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
    - Local building codes, energy performance requirements, etc.

- Local resources
    - Existing local generation resources, including distributed energy resources (DER), district energy resources, customer-based generation, as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local and provincial plans and studies, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal policies with an impact on electricity usage
    - Municipal Growth Plans
    - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion (e.g. Yonge subway extension), and transit electrification (e.g. GO train electrification)
    - Pathways to Decarbonization and Powering Ontario's Growth reports

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
        - Supply capability

        - Load security
        - Load restoration requirements
    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- Asset renewal considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Alectra Utilities Corporation (Alectra)
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd
- Hydro One Networks Inc. (Transmission)

6.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the York Region IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 5 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 6 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	October 2023
2. Develop the planning forecast scenarios for the region		Long-term planning forecast scenarios	Q4 2023 – Q1 2024
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	LDCs		
d. Establish existing, committed, and potential DG	IESO, LDCs		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs / Hydro One Transmission	Load transfer capabilities under normal and emergency conditions	Q1 2024
4. Provide and review relevant community plans, if applicable	LDCs, communities, stakeholders, and IESO	Relevant community plans	Q1 2024
5. Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2 – Q3 2024
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q3 – Q4 2024
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the load meeting capability (LMC) of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and LDCs		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
g. Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement to be launched in Q4 2023
a. Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and LDCs		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1 2025
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	April 2025

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NEEDS ASSESSMENT REPORT

Greater Toronto Area West

August 30, 2024

Needs Assessment Report

Greater Toronto Area (GTA) West Region

August 30, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: GTA West Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Toronto Area West and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the Needs Assessment phase and b) require further assessment and regional coordination. The results reported in this Need Assessment are based on the input and information provided by the Technical Working Group (the "TWG") for this region at the time. Updates may be made based on best available information throughout the planning process.

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

Executive Summary

REGION	Greater Toronto Area West (GTA West) Region (the "Region")
LEAD	Hydro One Networks Inc. ("Hydro One")

START DATE: May 3, 2024 **END DATE:** August 30, 2024

1. INTRODUCTION

The second Regional Planning cycle for the GTA West Region was completed in February 2022 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report). This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered for the GTA West Region on May 3rd, 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTW West Region NA includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA West Region includes the area roughly bordered by Highway 27 to the northeast, Highway 427 to the southeast, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south. The Region area comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville and portions of Burlington.

5. INPUTS/DATA

The TWG comprises of representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the Region regarding capacity needs, reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy
b) System reliability needs and operational concerns
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs discussed in the GTW West second cycle RIP have been addressed or updated:

- R19TH/R21TH overload under specific N-1-1 contingencies at peak load condition: A Key Operation Point ("KOP") procedure has been implemented in Hydro One control room to manage the N-1-1 post contingency thermal overload.
- Erindale T1/T2 DESN load will exceed station LTR by 2028: New forecast suggests the need will trigger in 2030. The TWG recommends this need is addressed with further regional planning coordination in conjunction with other capacity needs in Mississauga.
- Cardiff TS load will exceed station LTR by 2029: New forecast suggests the need will trigger in 2030. The TWG recommends this need is addressed with further regional planning coordination in conjunction with other capacity needs in Mississauga.
- Pleasant T1/T2 DESN capacity will be exceeded in 2027: Transformer replacement with standard LTR will provide sufficient capacity for forecasted loads.
- Erindale T5/T6 DESN load will exceed station LTR by 2031: New load forecast in this NA suggests the need will trigger beyond 2033.
- Lorne Park T2 replacement: Planned in service beyond 2033
- Bramalea T3/T4 replacement: Planned in service beyond 2033
- Tomken T1/T2 replacement: Planned in service beyond 2033
- T38B/T39B loads will exceed 600MW load security criteria in 2030: New load forecast suggests the threshold will be reached in 2029.

The following needs and projects discussed in the GTA West second cycle RIP are currently underway:

- Circuits H29/H30 reconductoring: planned in service in Q2, 2028.
- Palermo TS transformer replacement with larger capacity units: planned in service in Q4, 2027.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Halton T3/T4 (27.6kV)
- Pleasant T5/T6 (27.6kV)

b) Station Capacity

- Halton TS (27.6kV)
- Bramalea T1/T2 DESN (27.6kV)
- Cooksville T1/T2 DESN and T3/T4 DESN (all 27.6kV)
- Pleasant T5/T6 DESN (27.6kV)

- Jim Yarrow T1/T2 (27.6kV)
- Goreway T5/T6 DESN (27.6kV).
- Bramalea T3/T4 DESN (44kV)
- Lorne Park T1/T2 DESN (27.6kV)

c) Transmission Line Capacity

- No new transmission Line Capacity need identified

d) System Reliability, Operation and Load Restoration

- Trafalgar 230kV bus over-voltage issue under light load condition as reported by IESO.

e) Transmission System Reinforcement

- Major transmission expansion in Milton area will be needed to accommodate increasing new load connection requests including large transmission-connected data centers. Existing 230kV facilities, especially the radial section of T38B/T39B from Trafalgar TS, do not have sufficient capacity to supply the new demand and may not be simply addressed by reconductoring. In addition, T38B/T39B corridor will exceed the load security limit of 600MW in this NA timeframe

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and new station capacity needs. These needs will be assessed again during the next phases of this Regional Planning cycle

No.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Halton TS LTR	2026	2026	2029
2	Cardiff TS LTR	2030	2028	2032
3	Erindale T1/T2 LTR	2030	2027	2032
4	Bramalea T1/T2 LTR	2031	2030	Beyond 2033
5	Bramalea T3/T4 LTR*	2024	2024	2024
6	Lorne Park LTR*	2031	2030	Beyond 2033
7	Cooksville T1/T2 LTR	2030	2030	Beyond 2033

8	Cooksville T3/T4 LTR	2030	2029	Beyond 2033
9	Pleasant T1/T2 LTR*	2027	2026	Beyond 2033
10	Pleasant T5/T6 LTR	2026	2025	2027
11	Jim Yarrow T1/T2 LTR	2030	2028	Beyond 2033
12	Goreway T5/T6 LTR	2026	2025	2026
Additional capacity needs under high growth scenario				
13	Meadowvale TS LTR	Beyond 2033	2029	
14	Palermo TS LTR	Beyond 2033	2029	
15	Tremaine TS LTR	Beyond 2033	2029	
16	Tomken T1/T2 LTR	Beyond 2033	2031	
* The need can be addressed by transformer renewal with higher LTR specification				

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

a) Integrated transmission reinforcement plan in Milton area to accommodate new transmission and distribution connected loads including large data centers. A reinforcement plan should also help to manage T38B/T39B load security. The TWG recommends further regional coordination to address the capacity constraints. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing such plan.

b) Accommodation of loads growth beyond LTR at Halton TS with a new 230/27.6kV Halton #2 station

c) Accommodation of load growth beyond LTRs at Bramalea T1/T2, Erindale T1/T2 and Cardiff TS in Mississauga area

d) Accommodation of load growth beyond LTRs at Cooksville T1/T2 and Cooksville T3/T4 in Mississauga area

e) Accommodation of load growth beyond LTRs at Pleasant T5/T6 and Jim Yarrow T1/T2 in Brampton area

f) Accommodation of load growth beyond LTRs at Goreway T5/T6 and Bramalea T1/T2 in Brampton area.

II. Needs that do not require further regional coordination

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

a) Accommodation of load growth at Pleasant T1/T2 through transformer renewals with standard LTR specification
b) Accommodation of load growth at Bramalea T3/T4 through transformer renewals with upsized rating
c) Accommodation of load growth at Lorne Park T1/T2 through T2 renewal with standard LTR specification (T1 has sufficient LTR).

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities Co.
- Milton Hydro Distribution Inc.
- Halton Hills Hydro Inc.
- Oakville Hydro Electricity Distribution Inc.
- Burlington Hydro Inc.
- Hydro One Networks Inc. (Distribution)

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1. Introduction

The second cycle of the Regional Planning process for the GTA West Region was completed in February 2022 with the publication of the Regional Infrastructure Plan ("RIP") Report [1] - (RIP link). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the GTA West Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is shown in Figure 1 below.

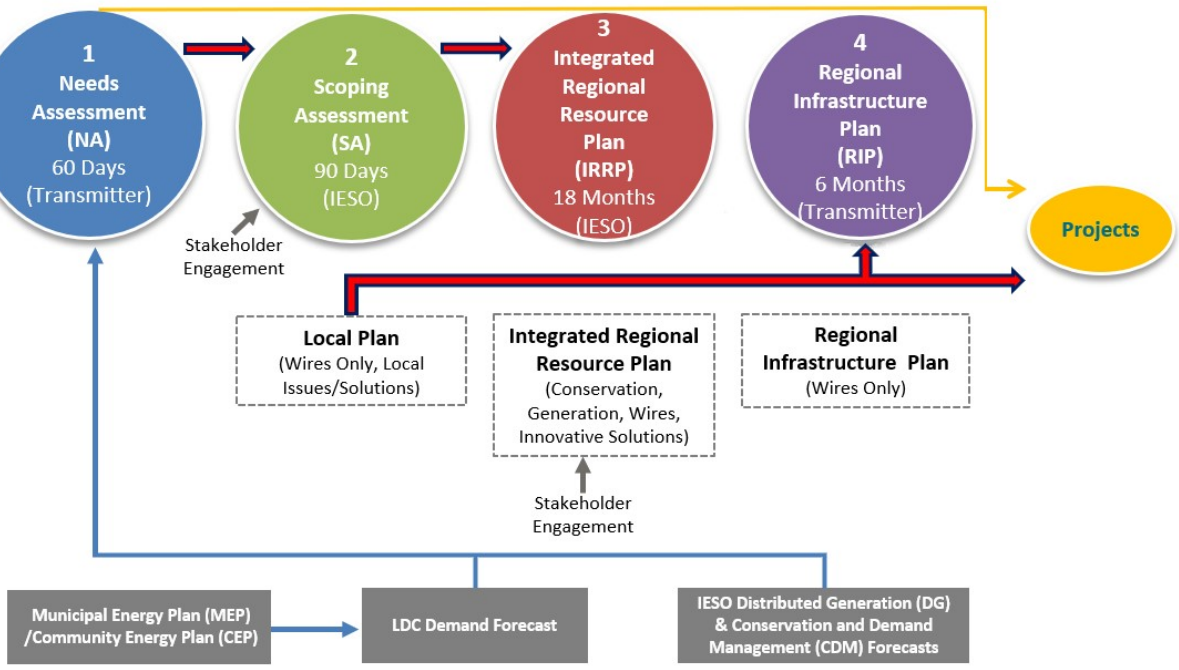


Figure 1: Regional Planning Process

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

Table 1: GTA West Region TWG Participants

No.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission) - (Lead Transmitter)
2	Hydro One Networks Inc. (Distribution)
3	Independent Electricity System Operator
4	Alectra Utilities Co.
5	Burlington Hydro Inc.
6	Milton Hydro Distribution Inc.
7	Halton Hills Hydro Inc.
8	Oakville Hydro Electricity Distribution Inc.

2. Regional Issue/Trigger

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the third Regional Planning cycle was triggered for the GTA West Region.

3. Scope of Needs Assessment

The scope of this NA covers the GTA West region and includes:

- Review and update needs and plans identified in the previous cycle RIP,
- Identify any new needs resulting from this assessment,
- Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan, and
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is 10 years.

4. Regional Description and Connection Configuration

The GTA West Region includes the area roughly bordered geographically by Highway 27 to the northeast, Highway 427 to the southeast, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south. The GTA West Region area comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville and portions of Burlington.

The geographical boundaries of the Region are shown in Figure 2.



Figure 2: Map of GTA West Regional Planning Area

Electrically the GTA West Region is bounded by Richview TS to Manby TS 230 kV circuits on the east, Richview TS to Trafalgar TS to Burlington TS 230 kV circuits on the north and Manby TS to Cooksville TS to Oakville TS 230 kV circuits on the south. The distribution system in this Region is at two voltage levels, 44 kV and 27.6 kV. Local generation in the area include the two gas fired plants, the 1196MVA Goreway CGS in Brampton and the 755MVA TCE CGS in Halton Hills.

The Local Distribution Customers (LDC) in the Region include Burlington Hydro Inc., Alectra Utilities Co., Halton Hills Hydro Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc. and Oakville Hydro Electricity Distribution Inc. The high-voltage system in this Region also provides supply to one customer owned transformer station. An electrical single line diagram for the GTA West Region facilities is shown in Figure 3.

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

Table 2: Transmission Station and Circuits in the GTA West Region

230kV circuits	Transformer Stations	Generation Stations
H29/H30 R14T/R17T R19TH/R21TH T36B/T37B T38B/ T39B V41H/V42H V43 B15C/B16C K21C/K23C, R24C	Bramalea TS Cardiff TS Churchill Meadows TS Claireville TS[1] Cooksville TS Erindale TS CTS-1 Glenorchy MTS Goreway TS Halton TS Halton Hills MTS Jim Yarrow MTS Lorne Park TS Meadowvale TS Oakville TS Palermo TS Pleasant TS Richview TS Tomken TS Trafalgar TS[1] Tremaine TS (Hurontario SS)	Sithe Goreway CGS, 787MW[2]/1196MVA TCE Halton Hills CGS, 526MW[3]/755MVA

1: 500kV Stations with Autotransformers installed

2: At 35°C ambient temperature. Generation capacity will increase by 40MW under IESO's Expedited Long-term RFP

3: At 35°C ambient temperature. Generation capacity will increase by 29MW under IESO's Expedited Long-term RFP

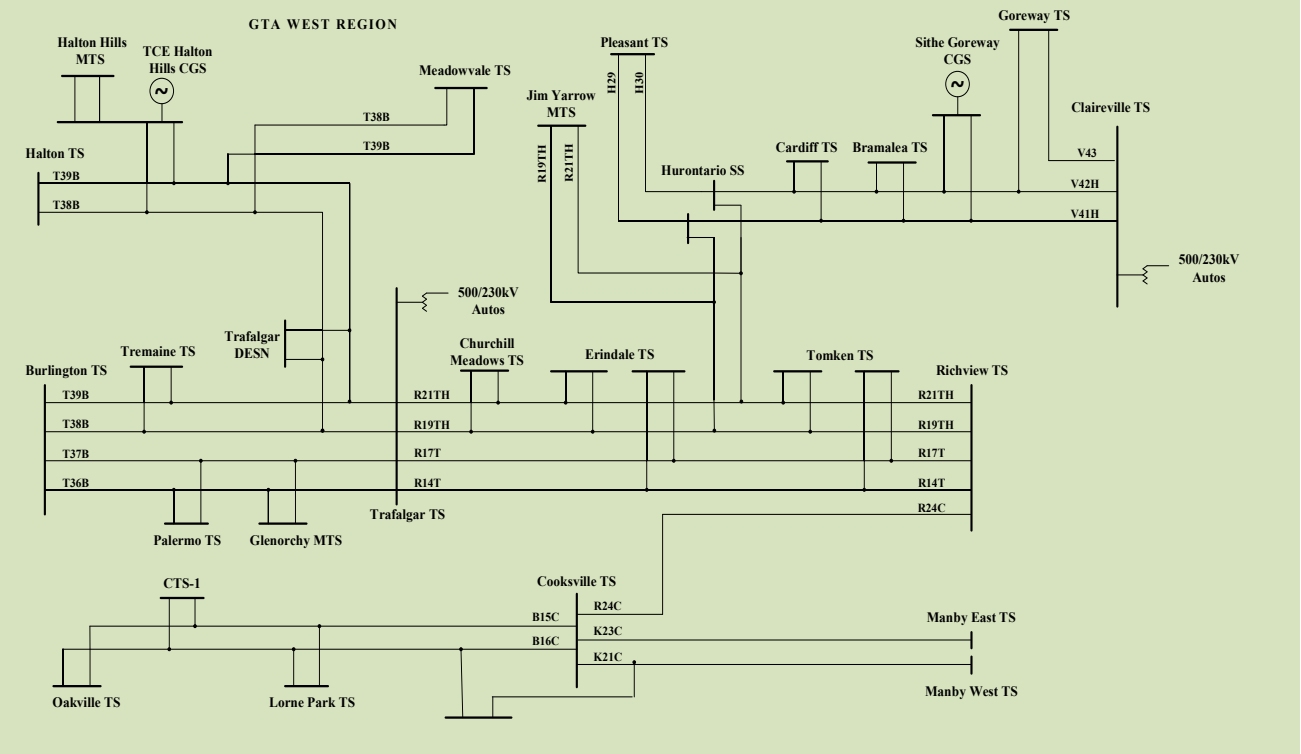


Figure 3: GTA West Transmission Single Line Diagram

5. Inputs and Data

TWG participants, including representatives from LDCs, IESO, and Hydro One provided input for the GTA West NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022 [2]. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the followings:

- GTA West 10-year summer and winter load forecast for all supply stations inclusive of the inputs provided by the municipalities listed in Appendix E
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement or refurbishment
- Planned transmission and distribution investments that are relevant to Regional Planning for the GTA West
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. Assessment Methodology

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy
- System reliability and operational considerations
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"
- Load forecast data requested from industrial customers in the region
- Summer peak load condition. Three load forecasts were developed, i.e. normal growth scenario, high and low growth scenario. The high and low growth load forecasts are developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, government policies, higher than expected EV charging trend during peak load conditions, etc.

The following assumptions are made in this report:

- The study period for this Needs Assessment is 2024-2033.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC) [3].

6.2 Information Gathering Process

6.2.1 Load forecast

The LDCs provided their summer and winter load forecast for all the stations supplying their loads in the GTA West region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Region. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point

the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Region is given in Appendix A.

6.2.2 Sensitivity analysis

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3 Asset renewal needs for major HV equipment

A list is generated for major HV transmission equipment planned or identified to be replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4 System reliability and operational issues

Relevant information regarding system reliability and operational issues in the region as feedback is provided by the IESO during the NA phase.

7. Needs

This section describes new needs identified in the Region and updates on previously identified needs since the completion of previous regional planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates:

- Palermo T3/T4 replacement with larger capacity units: project is in progress with planned in service in Q4, 2027.
- Tomken T1/T2 replacement: expected in service date is updated as Q4, 2035.
- Lorne Park T2 replacement: expected in service date is updated as Q4, 2034.
- Bramalea T3/T4 replacement with larger capacity units: expected in service date is updated as Q2, 2040.
- Pleasant T1/T2 capacity need: will plan to replace T1/T2 with standard LTR rating, in service date is to be determined.
- Erindale T5/T6 capacity need: updated load forecast suggests the need is beyond 2033.
- Circuit H29/H30 capacity need: reconductoring to higher capacity is in progress, expected in service date is Q2, 2028.
- R19TH/R21TH post-contingency overload under specific N-1-1 scenarios: operational KOP has been implemented in Hydro One control room.
- T38B/T39B Lantz Junction to Trafalgar DESN (~200m) post-contingency overload: being re-evaluated since more new load connection requests are received, this could be included an integrated transmission reinforcement plan in the area.

All new near and midterm needs that are discussed as a part of this report are summarized in Table 3. Note the planned in-service year for the projects is tentative and is subject to change.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Halton T3/T4 end-of-life replacement	Planned in service Q4, 2035	N/A	Sec. 7.1
Pleasant T5/T6 End-of-life replacement	Planned in service Q3, 2037	N/A	Se. 7.1

Station Capacity Needs			
Halton TS Forecasted demand will exceeds LTR in 2026.	Plan Halton TS #2 to accommodate new load.	Sec. 6.2	Sec. 7.2.1
Bramalea T1/T2 Forecasted demand will exceed LTR in 2031	Plan Mississauga and Brampton areas to accommodate new load	N/A	Sec.7.2.2
Erindale T1/T2 Forecasted demand will exceed LTR in 2030.	Plan area to accommodate new load	Sec. 6.2, 7.4	Sec. 7.2.4
Cardiff T1/T2 Forecasted demand will exceed LTR in 2030.	Plan area to accommodate new load	Sec. 6.2, 7.4	Sec. 7.2.5
Lorne Park T1/T2 Forecasted demand will exceed LTR in 2031	Replace Lorne Park T2 with standard LTR	N/A	Sec. 7.2.6
Cooksville T1/T2, T3/T4 Forecasted demand will exceed LTR in 2030	Plan area to accommodate new load	N/A	Sec. 7.2.7
Pleasant T5/T6 Forecasted demand will exceed LTR in 2026	Plan area to accommodate new load	N/A	Sec. 7.2.9
Jim Yarrow T1/T2 Forecasted demand will exceed LTR in 2030.	Plan area to accommodate new load	Sec. 7.8.1	Sec. 7.2.10
Goreway T5/T6 Forecasted demand will exceed LTR in 2026.	Plan area to accommodate new load	Sec. 6.2	Sec. 7.2.11
System Reliability, Operation and Load restoration Needs			
T38B/T39B load security and restoration	Consolidate with Milton area transmission reinforcement need and assess further in next phase of regional planning	Sec. 7.6	Sec. 7.4
Trafalgar 230kV high voltage control under light load condition	IESO and Hydro One operations coordinate to assess solutions	N/A	Sec. 7.4
Transmission System Reinforcement Needs			
Milton area reinforcement for load supply and security	Develop an integrated transmission system reinforcement plan in further regional planning phases to address substantial new load connection requests in Milton area	N/A	Sec. 7.5

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Region. The complete list of planned major HV transmission equipment requiring replacement is provided in Table 4. Only Palermo T3/T4 will be put in service in next 10 years according to Hydro One's recent investment planning. Note the in service year is subject to change as the asset renewal planning is a dynamic process.

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

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

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

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

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

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

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

In the list of Table 4, Halton T3/T4 and Pleasant T5/T6 transformers are newly identified asset for replacement but the in-service dates will be outside of this NA window based on recent Hydro One investment planning outcome. It is expected that Lorne Park TS capacity will increase once T2 is replaced

with standard LTR specification (sec. 7.2.6). Bramalea T3/T4 may also be replaced with larger capacity to address the capacity issue (sec. 7.2.3).

Table 4: Major HV Transmission Asset Assessed for Replacement in the Region in Next 10 Years

Station/Circuit	Need Description	Planned ISD
Palermo T3/T4	Built in 1969, applied in 1970, replacement with upsized units	2027
Assets planned for replacement post 2033		
Halton T3/T4	Built in 1989, applied in 1990	Beyond 2033
Pleasant T5/T6	Built in 1988, applied in 1991	Beyond 2033
Lorne Park T2	Built in 1974, applied in 1975	Beyond 2033
Tomken T1/T2	Built and applied in 1970	Beyond 2033
Bramalea T3/T4	Built in 1970, applied in 1983	Beyond 2033

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV Transforming stations in the Region using the summer peak load forecasts. Based on the results, the identified station capacity needs are flagged in Table 5. Comparing with the recommendations in RIP 2022 [1], Bramalea T1/T2, Cooksville T1/T2, T3/T4 and Pleasant T5/T6 are newly identified needs in this NA period. Previously identified capacity need of Erindale T5/T6 in [1] has been updated to post 2033.

Table 5: Stations with Capacity Need

TS	LTR (MW)	Load Forecast (MW)									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Halton T3/T4	195	154.0	179.1	**215.9**	234.4	231.3	250.2	264.2	266.5	268.8	273.5
Bramalea T1/T2	193	134.7	139.5	144.6	149.9	156.4	170.2	182.7	**205.3**	228.8	252.8
Bramalea T3/T4	111	**113.6**	115.1	114.6	119.1	122.7	126.0	126.4	127.3	128.8	130.4
Bramalea T5/T6	169	103.4	103.4	105.0	107.7	111.4	114.9	118.5	118.9	119.8	122.7
Erindale T1/T2	180	166.6	169.2	174.4	180.0	179.8	179.2	**184.5**	193.5	199.2	215.4
Erindale T3/T4	190	156.8	163.0	164.6	166.3	167.3	166.9	166.7	167.3	169.3	181.0
Erindale T5/T6	194	132.9	134.8	135.7	136.2	137.8	139.2	140.6	142.7	145.3	147.9
Cardiff T1/T2	113	109.3	110.8	111.6	111.9	113.3	113.2	**115.6**	118.5	121.8	125.1
Lorne Park T1/T2	144	104.4	105.8	111.2	116.1	122.0	128.2	136.9	**146.1**	152.3	151.8
Cooksville T1/T2	117	50.7	51.4	51.8	51.9	64.1	78.3	**123.9**	152.5	171.4	204.9
Cooksville T3/T4	117	40.2	40.8	41.1	51.2	67.9	87.4	**130.4**	150.3	168.6	202.9
Pleasant T1/T2	155	122.7	131.9	147.1	**156.3**	158.2	158.8	158.9	159.7	161.1	162.8
Pleasant T5/T6	187	181.8	186.2	**191.6**	197.1	203.6	209.2	216.0	223.3	231.9	241.3
Pleasant T7/T8	183	108.0	111.3	115.2	119.3	124.0	128.2	133.1	138.4	144.5	151.1
Jim Yarrow T1/T2	157	134.3	137.6	141.5	145.6	150.4	154.6	**159.6**	165.0	171.3	178.3
Goreway T5/T6	181	177.6	181.9	**187.1**	192.5	198.9	204.4	211.0	218.2	226.6	235.8
Goreway T1/T2	180	74.4	77.3	80.7	84.3	88.4	92.1	96.3	100.8	105.9	111.4

7.2.1 Halton TS

Halton TS (27.6kV) supplies loads from Milton Hydro and Halton Hills Hydro. Milton Hydro forecasts rapid load growth at Halton TS in next three years, while Halton Hills Hydro load forecast remain flat in next 10 years. By end of this assessment cycle, Milton Hydro forecasts nearly 80MW loads beyond Halton TS LTR need to be served from other supplies. As the LTR at Halton TS cannot be increased through standard transformer replacement, a new station Halton TS #2 as previously suggested in [1,6] could be appropriate to address the need. In near term, Milton Hydro plans to use Oakville Hydro's Glenorchy MTS and upsized Palermo TS to meet the increasing demand before Halton TS #2 is available. The TWG recommends that the capacity need at Halton TS be investigated further through the regional planning process in conjunction with Milton area load supply planning (sec. 7.5).

7.2.2 Bramalea T1/T2

Bramalea TS has three DESNs as shown in Table 5, supplying Alectra's loads in Mississauga and Brampton. T1/T2 is the only 27.6kV DESN in Bramalea. The forecasted load at T1/T2 is expected to exceed its LTR in 2031. As Erindale T1/T2 (27.6kV) and Cardiff TS (27.6kV) in Mississauga will have similar capacity need (7.2.4 and 7.2.5 below) in medium term, the TWG acknowledges that a new station might be one option and recommends further regional coordination to address this need.

7.2.3 Bramalea TS T3/T4

Bramalea T3/T4 (44kV) are 83.3MVA CGE units built in 1970. Operating data shows the actual peak load at T3/T4 has slightly exceeded summer LTR and the load will grow at moderate rate near 2%. The issue can be addressed by replacing the transformers with higher rating such as standard 125MVA units. At interim, Alectra may balance the 44kV load with Bramalea T5/T6 DESN that can accommodate extra load. The TWG acknowledges load rebalance and transformer replacement could address the issue.

7.2.4 Erindale TS T1/T2

Erindale TS has three DESNs as shown in Table 5, all supplying Alectra's loads. T1/T2 is the only 27.6kV DESN in Erindale. The forecasted load will exceed T1/T2 LTR in 2030. The TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.5 Cardiff TS

Cardiff T1/T2 (27.6kV) serves Alectra's loads with two 83.3MVA transformers built in 2004. The LTRs of the transformers are further limited by its MVGIS breakers. Load forecast suggests the station will be overloaded by 2030. Since it is impractical to upsize the transformers and MVGIS still in good condition, the TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.6 Lorne Park TS

Lorne Park T1/T2 (27.6kV) serves Alectra loads only. The LTR of the station is determined by T2 (built in 1974) that has lower overloading capability than T1 (built in 2008). The forecast shows that Lorne Park TS load will exceed T2 LTR in 2031 and further growth is moderate. The TWG acknowledges that T2 replacement with standard LTR should be one option to address the issue.

7.2.7 Cooksville TS

Cooksville TS (27.6kV) has two DESNs, T1/T2 and T3/T4, supplying Alectra's loads only. All the transformers are 83.3MVA units built in 2013. Alectra forecasts significant load growth at Cooksville after 2028 as shown in Table 5. Lakeview Village, Rangeview, Dixie Mall conversion, Trillium Hospital new building, Water and Wastewater Treatment Plants expansion are examples of the new need to be served. The load growth rates will peak at 60% for T1/T2 DESN and 50% for T3/T4 DESN in 2030. As a result, the LTRs at both DESNs will be exceeded in 2030. Considering the existing transformers are still young and the T1/T2 27.6kV yard was just rebuilt in 2014, the TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.8 Pleasant TS T1/T2

Pleasant TS has three DESNs. T1/T2 DESN (44kV) supplies loads from Alectra, Hydro One Distribution and Halton Hills Hydro. Combined load forecasts from the three LDCs suggest moderate LTR violation after 2027 as shown in Table 5. T1/T2 are Westinghouse 125MVA units built in 1975 and their LTRs are lower than today's standard (above 180MVA). The TWG recommends this issue is addressed by regular transformer end-of-life renewal with standard LTR specifications.

7.2.9 Pleasant T5/T6

Pleasant T5/T6 (27.6kV) supplies Alectra load only. The DESN is heavily loaded at present. Alectra's load forecast suggests steady annual growth rate near 5% throughout the assessment period and the DESN LTR will be exceeded as early as 2026. As another 27.6kV station adjacent to Pleasant, Jim Yarrow MTS (sec. 7.2.10) also forecasts its LTR will be exceeded during this NA timeframe, the TWG acknowledges that a new station might be one option and recommends that further regional coordination take place to address this need.

7.2.10 Jim Yarrow T1/T2

Jim Yarrow MTS is an Alectra-owned station built in 2004. The load at the MTS is forecasted to grow at approximately 4.4% annually and its LTR will be exceeded in 2030. Since adjacent Pleasant TS is also expected to reach full capacity in this assessment period, the TWG acknowledges that a new station might be one option and recommends that further regional coordination takes place to address this need.

7.2.11 Goreway T5/T6

Goreway TS has two 27.6kV DESNs T1/T2, T5/T6 and one 44kV supply from T4, all supplying Alectra load. The forecasted demand at T5/T6 DESN will exceed LTR in 2026 and keep growing at approximately 4% per year. As Alectra forecasts additional new Brampton loads beyond Bramalea T1/T2 capacity, the TWG acknowledges that a new station in the area may be appropriate and recommends that further regional coordination takes place to address this need. In near term, available capacity from Goreway T1/T2 could be utilized to meet the load growth need in the area.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such

as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV Transmission line circuits in the Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, there is no new transmission line capacity need other than identified in the second cycle RIP [1].

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The system should also meet load security and load restoration criteria as defined in ORTAC [3]. Based on input from the IESO and LDCs, the following operational issues are identified:

- The new load forecast suggests T38B/T39B corridor will exceed load security limit of 600MW [3] in 2029. Table 6 shows load growth of all double-circuit corridors in the Region (assuming the new Halton TS #2 will still tap to T38B/T39B in 2030). The TWG recommends further regional coordination to address the T38B/T39B load security issue. All other double circuits corridors will not have more than 600MW net loads in the assessment window.

- All double-circuit corridor loads will exceed 250MW in this assessment timeframe. The ORTAC [3] requires the amount of load interruption in excess of 250MW must be restored within 30 minutes (and within 4 hours for load loss more than 150MW). The TWG surveyed transmission load interruption performance data from 2014 to 2024 for the Region. The results show that delivery points supplied by the circuits in Table 6 did not log load loss of more than 250MW for longer than 30 minutes, or loss of more than 150MW for longer than 4 hours in the 10 years. Based on past performance data, the TWG would not recommends capital investment for load restoration at this point. Hydro One shall proactively monitor load restoration data and identify opportunities to reduce risk of prolonged load restoration.

Table 6 Double-circuit Corridor Load

Circuits	Loads served by the double circuits (MW)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
T38B/T39B	444.8	492.1	558.6	570.3	588.3	**606.9**	676.2	688.6	703.7	721.2
T36B/T37B	231.6	236.1	241.2	247.5	299.1	283.0	294.5	304.8	314.7	327.6
R14T/R17T	449.9	459.0	466.2	474.7	483.9	483.7	484.2	486.4	491.8	502.7
R19TH/R21TH	456.5	463.2	470.1	476.3	487.4	505.6	510.1	515.4	520.1	526.0
H29/H30	395.0	411.0	431.6	444.1	450.2	454.6	459.2	464.8	471.7	479.3
B15C/B16C	220.1	224.0	230.1	235.8	242.7	249.6	257.9	268.6	277.7	282.1
V41H/V42H	371.7	378.2	383.7	393.8	405.7	421.8	436.9	459.0	482.8	496.6

- IESO reports high voltage at Trafalgar 230kV bus under light load conditions. Hydro One and IESO operation departments are coordinating to assess alternatives including Trafalgar TS Autotransformer tap changer position adjustment.

7.5 Transmission System Reinforcement Needs

Milton area transmission reinforcement:

In addition to the rapid organic load growth forecasted in T38B/T39B corridor, multiple proponents have requested to connect large-scale loads in Milton area, especially in proximity to Milton SS. Majority of the requests are large data centers with combined capacity exceeding 1000MW. It is not feasible for the existing 230kV transmission infrastructure in Milton area to accommodate such sizeable loads. Due to the scale and complexity of such connections, the TWG recommends further regional coordination to address the capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.

8. Sensitivity Analysis

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the GTA West region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The impact of sensitivity analysis for the high and low growth scenario is shown in Table 7. The additional capacity needs identified towards the end of the study period will be assessed again during the next phases of the Regional Planning cycle.

Table 7: Impact of Sensitivity Analysis on Capacity Needs in the Region

No.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Halton TS LTR	2026	2026	2029
2	Cardiff TS LTR	2030	2028	2032
3	Erinddale T1/T2 LTR	2030	2027	2032
4	Bramalea T1/T2 LTR	2031	2030	Beyond 2033
5	Bramalea T3/T4 LTR*	2024	2024	2024
6	Lorne Park LTR*	2031	2030	Beyond 2033
7	Cooksville T1/T2 LTR	2030	2030	Beyond 2033
8	Cooksville T3/T4 LTR	2030	2029	Beyond 2033
9	Pleasant T1/T2 LTR*	2027	2026	Beyond 2033
10	Pleasant T5/T6 LTR	2026	2025	2027
11	Jim Yarrow T1/T2 LTR	2030	2028	Beyond 2033
12	Goreway T5/T6 LTR	2026	2025	2027
Additional capacity needs under high growth scenario				
13	Meadowvale TS LTR	Beyond 2033	2029	
14	Palermo TS LTR	Beyond 2033	2029	
15	Tremaine TS LTR	Beyond 2033	2029	
16	Tomken T1/T2 LTR	Beyond 2033	2031	
* The need can be addressed by transformer renewal with standard rating specification				

9. Conclusion and Recommendation

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs not Requiring Further Regional Coordination

No.	Need	Recommendation
1	Bramalea T3/T4 DESN LTR violation	Replace T3/T4 with higher rating during transformer renewal. Balance T3/T4 load with Bramalea T5/T6 as interim solution.
2	Pleasant T1/T2 DESN moderate LTR violation	Replace T1/T2 with standard LTR.
3	Lorne Park T1/T2 DESN moderate LTR violation	Replace T2 with standard LTR.

Table 9: Needs Requiring Further Regional Coordination

No.	Need
1	Transmission reinforcement at Milton area to accommodate large load connection requests including data centers and manage load security
2	Accommodate Halton TS load growth beyond LTRs
3	Accommodate Mississauga 27.6 kV load growth beyond LTRs at Cardiff T1/T2, Bramalea T1/T2 and Erindale T1/T2
4	Accommodate Mississauga 27.6kV load growth beyond LTRs at Cooksville T1/T2 and T3/T4
5	Accommodate Brampton 27.6 kV load growth beyond LTRs at Pleasant T5/T6 and Jim Yarrow T1/T2
6	Accommodate Brampton 27.6kV load growth beyond LTRs at Goreway T5/T6 and Bramalea T1/T2

List of LDC(s) to be involved in further regional planning activities:

- Alectra Utilities Co.
- Milton Hydro Distribution Inc.
- Halton Hills Hydro Inc.
- Oakville Hydro Electricity Distribution Inc.
- Burlington Hydro Inc.
- Hydro One Networks Inc. (Distribution)

10. References

[1] Hydro One, RIP Report GTA West 2022 (hydroone.com) (issue February 23, 2022)

[2] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[3] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[4] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[5] Ontario Energy Board, Distribution System Code (issue July 14, 2000 rev. March 27, 2024)

[6] Independent Electricity System Operator, IRRP Report GTA West 2021.

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: GTA West Region – Non-coincident Normal Growth Net Load Forecast

Station	LTR (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea T1/T2	193	134.7	139.5	144.6	149.9	156.4	170.2	182.7	**193.1**	**193.1**	**193.1**
Bramalea T3/T4	111[1]	**113.6**	115.1	114.6	119.1	122.7	126.0	126.4	127.3	128.8	130.4
Bramalea T5/T6	169	103.4	103.4	105.0	107.7	111.4	114.9	118.5	118.9	119.8	122.7
Bramalea Total	473	351.8	358.0	364.2	376.7	390.6	411.0	427.6	439.4	441.6	446.2
Cardiff	113	109.3	110.8	111.6	111.9	113.3	113.2	**113.2**	**113.2**	**113.2**	**113.2**
Erindale T1/T2	180	166.6	169.2	174.4	180.0	179.8	179.2	**180.3**	**180.3**	**180.3**	**180.3**
Erindale T3/T4	190	156.8	163.0	164.6	166.3	167.3	166.9	166.7	167.3	169.3	181.0
Erindale T5/T6	194	132.9	134.8	135.7	136.2	137.8	139.2	140.6	142.7	145.3	147.9
Erindale Total	564	456.3	467.0	474.8	482.5	484.8	485.2	487.6	490.3	495.0	509.2
Churchill Meadows	168	99.8	101.1	101.9	102.2	103.4	104.9	106.1	107.9	110.0	112.2
Cooksville T1/T2	117	50.7	51.4	51.8	51.9	64.1	78.3	**117.0**	**117.0**	**117.0**	**117.0**
Cooksville T3/T4	117	40.2	40.8	41.1	51.2	67.9	87.4	**116.6**	**116.6**	**116.6**	**116.6**
Cooksville Total	234	90.9	92.2	92.9	103.1	132.0	165.6	233.6	233.7	233.6	233.7
New gross loads to be served in Mississauga								21	71	165	277
CTS-1	75	20.0	21.5	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Glenorchy MTS	153	115.9	120.7	125.5	131.9	138.0	116.8	120.0	126.2	133.3	140.0
Goreway T1/T2	180	74.4	77.3	80.7	84.3	88.4	92.1	96.3	100.8	105.9	111.4
Goreway T5/T6	181	177.6	181.9	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**	**181.3**
Goreway T4	73	26.9	27.0	27.2	27.3	27.6	27.7	27.9	28.3	28.8	29.3
Goreway Total	434	278.9	286.3	289.8	293.1	297.3	301.2	305.7	310.5	315.9	322.0
Halton TS	195	154.0	179.1	**195.2**	**195.2**	**195.1**	**195.1**	**195.1**	**195.1**	**195.1**	**195.1**
New Halton #2 (Gross)	187[2]	0	0	0	0	0	0	70.5	73.3	76.0	81.1
Halton Hills MTS	102	4.0	6.4	6.4	12.7	16.4	22.4	26.0	29.6	33.2	36.9
Jim Yarrow MTS	157	134.3	137.6	141.5	145.6	150.4	154.6	**157.0**	**157.0**	**157.0**	**157.0**
Lorne Park TS	144[1]	104.4	105.8	111.2	116.1	122.0	128.2	136.9	**146.1**	152.3	151.8
Meadowvale	188	125.1	127.5	140.3	141.2	154.5	166.3	170.3	173.8	178.7	182.6
Oakville	172	126.8	128.6	130.2	132.3	134.9	137.3	138.7	142.3	146.9	152.3
Palermo	187[3]	118.0	118.5	119.7	121.0	168.2	173.5	183.1	188.2	**191.8**	198.9
Pleasant T1/T2	155[1]	122.7	131.9	147.1	**156.3**	158.2	158.8	158.9	159.7	161.1	162.8
Pleasant T5/T6	187	181.8	186.2	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**	**187.2**
Pleasant T7/T8	183	108.0	111.3	115.2	119.3	124.0	128.2	133.1	138.4	144.5	151.1
Pleasant Total	525[4]	412.5	429.4	449.5	462.8	469.6	474.3	479.2	485.3	492.9	501.0
New gross loads to be served in Brampton		0	0	0	0	0	0	32	46	124	159
Tomken T1/T2	165	150.8	151.8	152.7	154.3	156.7	157.6	159.0	161.1	164.8	165.3
Tomken T3/T4	192	118.3	118.9	120.5	122.2	126.4	129.2	131.3	133.1	133.4	134.8
Tomken Total	357	269.2	270.6	273.1	276.5	283.2	286.8	290.3	294.2	298.2	300.1
Trafalgar DESN	123	88.7	90.4	92.1	94.5	96.9	99.1	99.7	101.6	103.7	105.9
Tremaine	185	113.4	132.4	157.0	159.7	160.9	162.1	163.9	166.4	170.2	174.9
Total		3166	3277	3392	3474	3624	3710	3917	4032	4229	4379
Note	1. Capacity can be increased by transformer renewal with higher LTR 2. Assumption based on typical station, final LTR will be determined after the station is built 3. Assumption for upsized transformers, final LTR will be determined after transformers are delivered 4. Presently limited to 419 MW by upstream transmission lines H29/H30										

Table A.2 GTA West Region – Coincident Normal Growth Net Load Forecast

Station	LTR (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bramalea T1/T2	193	109.2	113.0	117.2	121.5	126.8	138.0	148.1	166.5	185.5	193.0
Bramalea T3/T4	111	94.2	95.4	95.0	98.8	101.7	104.4	104.8	105.6	106.8	108.1
Bramalea T5/T6	169	66.9	66.9	67.9	69.7	72.1	74.3	76.7	76.9	77.5	79.4
Bramalea Total	473	270.3	275.4	280.1	289.9	300.6	316.7	329.6	349.0	369.7	380.5
Cardiff	113	101.4	102.8	103.5	103.9	105.1	105.1	107.3	110.0	113.0	116.1
Erindale T1/T2	180	157.6	160.1	165.1	170.3	170.1	169.6	174.6	183.1	188.5	203.8
Erindale T3/T4	190	143.1	148.8	150.2	151.8	152.7	152.3	152.1	152.7	154.6	165.2
Erindale T5/T6	194	122.4	124.1	125.0	125.4	126.9	128.1	129.5	131.4	133.7	136.2
Erindale Total	564	423.2	433.0	440.3	447.5	449.6	450.0	456.2	467.2	476.8	505.2
Churchill Meadows	168	98.5	99.8	100.5	100.8	102.1	103.5	104.7	106.5	108.6	110.7
Cooksville T1/T2	117	47.5	48.2	48.5	48.7	60.1	73.4	116.2	143.0	160.7	192.1
Cooksville T3/T4	117	39.5	40.0	40.3	50.2	66.6	85.8	128.0	147.5	165.5	199.2
Cooksville Total	234	87.0	88.2	88.9	98.9	126.7	159.2	244.2	290.5	326.2	391.3
CTS-1	75	20.0	21.5	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Glenorchy MTS	153	114.6	118.5	122.6	127.6	132.3	111.0	112.9	118.2	124.4	130.3
Goreway T1/T2	180	70.1	72.9	76.1	79.5	83.4	86.8	90.8	95.0	99.8	105.1
Goreway T5/T6	181	176.2	180.5	185.7	191.0	197.3	202.8	209.3	216.4	224.8	233.9
Goreway T4	73	23.0	23.1	23.2	23.3	23.5	23.7	23.9	24.2	24.6	25.0
Goreway Total	434	269.3	276.5	285.0	293.8	304.2	313.3	324.0	335.6	349.2	363.9
Halton TS & #2	195	141.6	164.6	195.3	195.3	195.3	195.3	255.7	257.8	259.8	264.0
Halton Hills MTS	102	4.0	6.3	6.3	12.2	15.7	21.3	24.4	27.7	31.0	34.3
Jim Yarrow MTS	157	128.6	131.7	135.5	139.4	143.9	148.0	152.7	157.9	164.0	170.6
Lorne Park TS	144	85.9	87.1	91.5	95.6	100.4	105.5	112.7	120.2	125.3	124.9
Meadowvale	188	103.3	105.2	115.7	116.5	127.5	137.2	140.5	143.4	147.4	150.6
Oakville	172	114.4	116.0	117.4	119.4	121.7	123.8	125.1	128.4	132.5	137.4
Palermo	187	117.0	117.5	118.7	119.9	166.7	172.0	181.5	186.6	190.2	197.2
Pleasant T1/T2	155	115.6	124.2	138.5	147.2	149.0	149.5	149.6	150.4	151.7	153.3
Pleasant T5/T6	187	180.1	184.5	189.8	195.3	201.7	207.3	214.0	221.3	229.8	239.1
Pleasant T7/T8	183	99.3	102.3	105.9	109.6	114.0	117.9	122.4	127.2	132.8	138.8
Pleasant Total	525	395.0	411.0	434.2	452.1	464.7	474.7	486.0	498.9	514.3	531.3
Tomken T1/T2	165	149.1	150.1	150.9	152.6	155.0	155.8	157.2	159.3	162.9	163.5
Tomken T3/T4	192	107.2	107.7	109.1	110.7	114.5	117.0	118.9	120.5	120.8	122.1
Tomken Total	357	256.3	257.7	260.0	263.2	269.5	272.8	276.1	279.8	283.8	285.6
Trafalgar DESN	123	86.8	88.4	90.1	92.5	94.8	97.0	97.6	99.4	101.5	103.7
Tremaine	185	109.3	127.5	151.2	153.8	155.0	156.1	157.9	160.3	163.9	168.5
Total		2926	3029	3159	3244	3398	3484	3711	3859	4004	4188

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station		Voltage (kV)	Supply Circuits
1	Bramalea TS (Alectra)	T1/T2	230/27.6	V41H/V42H
		T3/T4	230/44	
		T5/T6	230/44	
2	Cardiff TS (Alectra)	T1/T2	230/27.6	V41H/V42H
3	Churchill Meadows TS (Alectra)	T1/T2	230/44	R19TH / R21TH
4	Cooksville TS (Alectra)	T1/T2	230/27.6	B16C/K21C
		T3/T4	230/27.6	
5	Erindale TS (Alectra)	T1/T2	230/27.6	R14T / R17T
		T3/T4	230/44	
		T5/T6	230/44	R19TH / R21TH
6	CTS-1	T1/T2	230/27.6	B15C / B16C
7	Glenorchy MTS (Oakville Hydro)	T1/T2	230/27.6	T36B / T37B
8	Goreway TS (Alectra)	T1/T2	230/27.6	V42H / V43
		T5/T6	230/27.6	
		T4	230/44	V43
9	Jim Yarrow MTS (Alectra)	T1/T2	230/27.6	R19TH / R21TH
10	Halton Hills MTS (Halton Hills Hydro)	T4/T5	230/27.6	T38B/T39B
11	Halton TS (Milton Hydro, Halton Hills Hydro)	T3/T4	230/27.6	T38B/T39B
12	Lorne Park TS (Alectra)	T1/T2	230/27.6	B15C / B16C
13	Meadowvale TS (Alectra)	T1/T2	230/44	T38B / T39B
14	Oakville TS (Alectra, Oakville Hydro)	T5/T6	230/27.6	B15C / B16C
15	Palermo TS (Oakville Hydro, Milton Hydro, Burlington Hydro)	T3/T4	230/27.6	T36B / T37B
16	Pleasant TS (Alectra, HONI, Halton Hills Hydro)	T1/T2	230/44	H29 / H30
		T5/T6	230/27.6	
		T7/T8	230/27.6	
17	Tomken TS (Alectra)	T1/T2	230/44	R14T/R17T
		T3/T4	230/44	R19TH/R21TH
18	Trafalgar DESN (Oakville Hydro)	T1/T2	230/27.6	T38B/T39B
19	Tremaine TS (Milton Hydro, Burlington Hydro)	T1/T2	230/27.6	T38B/T39B

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	**Hurontario SS***, Pleasant TS	H29/H30	230
2	**Richview TS*, Trafalgar TS*,** Tomken TS, Erindale TS	R14T/R17T	230
3	**Richview TS*, Trafalgar TS*, Hurontario SS*,** Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, Tomken TS	R19TH/R21TH	230
4	**Trafalgar TS*, Burlington TS*,** Palermo TS, Glenorchy MTS,	T36B/T37B	230
5	**Trafalgar TS*, Burlington TS*,** Tremaine TS, Trafalgar DESN, Meadowvale TD, Halton TS, **TCE Halton Hills CGS***, Halton Hills MTS	T38B/ T39B	230
6	**Claireville TS* Hurontario SS***, Cardiff TS, Bramalea TS, **Sithe Goreway CGS*,** Goreway TS	V41H/V42H	230
7	**Cooksville TS*,** Lorne Park TS, CTS-1, Oakville TS	B15C/B16C	230
8	**Manby TS*, Cooksville TS***	K21C/K23C	230
9	**Claireville TS*,** Goreway TS	V43	230
10	**Richview TS*, Cooksville TS***	R24C	230
*: terminal stations, others are stations tapped to the circuits			

Appendix D: List of LDC's

No.	Name of LDC
1	Alectra Utilities Co.
2	Burlington Hydro Inc.
3	Halton Hills Hydro Inc.
4	Milton Hydro Distribution Inc.
5	Oakville Hydro Electricity Distribution Inc.
6	Hydro One Networks Inc. (Distribution)

Appendix E: List of Municipalities in the region

No.	Name of Municipality
1	Brampton
2	Burlington
3	Caledon
4	Halton Hills
5	Milton
6	Mississauga
7	Oakville

Appendix F: Acronyms

Acronym	Description
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
KOP	Key Operating Point
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LP	Local Plan
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
MVGIS	Medium Voltage Gas Insulated Switchgear
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SS	Switching Station
TS	Transformer Station



GTA West Region

Scoping Assessment Outcome Report

November 28, 2024

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Connecting Today.
Powering Tomorrow.

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1. Introduction

This Scoping Assessment Outcome Report is produced as part of the Ontario Energy Board's regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license. This third cycle of regional planning for the GTA West region was initiated in Summer 2024, with a Needs Assessment, initiated and led by Hydro One Networks Inc. (Hydro One), and establishment of a Technical Working Group (TWG) comprised of Hydro One, the Independent Electricity System Operator (IESO) and the Local Distribution Companies with assets in the region. A Needs Assessment Report was published on August 30, 2024. The 2024 Needs Assessment identified several power system needs which are key input to this Scoping Assessment. The TWG reviewed the nature and timing of these needs to assess and determine the appropriate planning approach to address them. The Scoping Assessment also considered past or ongoing energy initiatives in the region, including drivers such as the Ontario government's recent Powering Ontario's Growth (POG) plan, and local policies concerning the future of natural gas fired generation.

The Scoping Assessment considers three potential planning approaches including: an Integrated Regional Resource Plan (IRRP) – where wires and non-wires both have potential to address the needs and regional coordination is needed; a Regional Infrastructure Plan (RIP) – which is limited to wires only but still requires regional coordination; or a local plan undertaken by the transmitter where no further regional coordination is needed.

This Scoping Assessment Outcome Report:

- Summarizes the power system needs, as identified in the Needs Assessment report, that require further planning.
- Reviews the areas to be studied and the potential for grouping of needs on a geographic basis if splitting the region into sub-regions would be beneficial). This Scoping Assessment does not recommend splitting the region into sub-regions.
- Considers impacts on planning assumptions and potential outcomes on needs resulting from local and provincial policy goals.
- Determines if an IRRP is the appropriate regional planning approach where there are needs requiring regional coordination or more comprehensive integrated planning; this Scoping Assessment recommends an IRRP.
- Establishes a Terms of Reference for the IRRP.
- Establishes the composition of the Technical Working Group for the IRRP.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

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

3. Categories of Needs, Analysis and Results

3.1 Overview of the GTA West Region

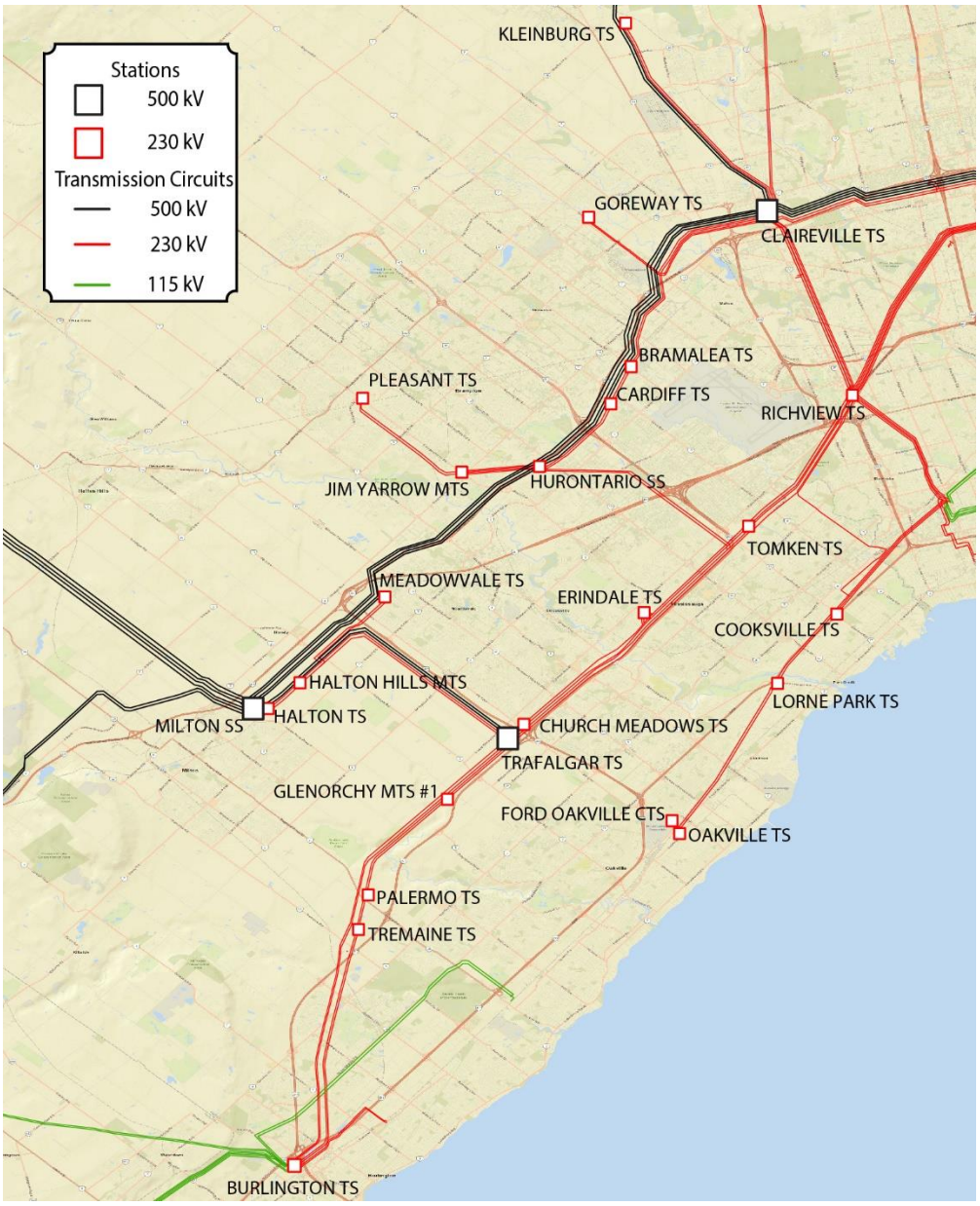
The GTA West region comprises the Regional Municipalities of Peel and Halton, which include the City of Brampton, City of Mississauga, Town of Caledon, Town of Halton Hills, Town of Milton, and Town of Oakville. Geographically, the area is roughly bounded by Highway 27/Highway 427 to the east, Regional Road 25 to the west, King Street to the north, and Lake Ontario to the south.

Electrically, the GTA West Region is defined by the high-voltage transmission within an area between the Claireville Transformer Station (TS) and Richview TS and Manby TS to the east, and Burlington TS to the west. Transmission infrastructure in the northern reach of the GTA West region is sparse. Many of the 230 kV transmission circuits in this area provide services for the bulk network and provide regional supply. That is, in addition to supplying the local area, the transmission also forms part of the integrated network facilitating large transfers of power through the region to other regions of the province. The 500 kV transmission facilities in are generally considered bulk network assets. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and contingencies evaluated.

The local distribution systems in this region operate at two voltage levels - 44 kV and 27.6 kV. Local generation in the area includes two gas fired plants: the 880 MW Goreway Generating Station (GS) in Brampton and the 673 MW Halton Hills GS in Halton Hills. Customers are served by Local Distribution Companies (LDCs) including Burlington Hydro Inc., Alectra Utilities Co., Halton Hills Hydro Inc., Hydro One Networks Inc., Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc.

The electricity demand in the region currently peaks in the summer season. In summer 2023, the peak demand in GTA West was approximately 2,700 MW. A map of the electricity infrastructure supplying GTA West is shown in Figure 1.

Figure 1 | Electricity Infrastructure of the GTA West Region



3.1.1 Indigenous Communities

The GTA West region is home to Indigenous peoples from across Canada. Located within and around the region are the Mississaugas of the Credit First Nation, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council (HCCC), Métis Nation of Ontario (MNO), Alderville First Nation, Chippewas of Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, and Mississaugas of Scugog Island First Nation. The IESO will notify these communities that regional planning for the GTA West region is underway and will invite them to participate in engagement activities.

3.2 Previous Regional Planning Cycles in GTA West

Two cycles of regional planning preceded the present cycle. The first cycle of the regional planning process for the GTA West region was completed in January 2016, and the second cycle was completed in February 2022. In both the first and second cycles, an IRRP was completed as well as a Regional Infrastructure Plan (RIP).

Previous planning recommendations for the region focused on accommodating the near and medium -term forecasted demand growth, maintaining system reliability, optimizing end-of-life asset replacements as an opportunity to upsize transmission infrastructure, and to closely monitor growth in the region in advance of planning for larger electricity infrastructure needs. As acknowledged in the previous planning cycle, rapid community growth is expanding northward in the region where there is presently no transmission infrastructure to support it. Therefore, the IESO and the Ministry of Energy and Electrification are engaged in a joint study to identify a suitable corridor of land that can be preserved for future transmission infrastructure should the need arise. This work is ongoing.

3.3 Needs Identified in the 2024 Needs Assessment

The Needs Assessment provided an update on recommendations from the previous planning cycles, identified new needs in the GTA West region based on updated transmission assumptions (including end-of-life sustainment activities planned by the transmitter), and a revised 10-year demand forecast. A summary of the current projects and plans underway to address previously identified needs, plus the new needs identified in the Needs Assessment, are outlined below.

3.3.1 Projects and Plans Underway or Complete to Address Previously Identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle and provides an update on the status of project implementation for the options recommended to address them (Table 1). These projects provide a starting point for subsequent assessments and will be accounted for in this planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Need	Plan Update and Timing
Palermo TS transformer replacement with larger capacity transformers (T3, T4)	Project in progress, Expected in-service Q4, 2027
Tomken TS transformer replacement (T1, T2)	Expected in-service Q4, 2035
Lorne Park TS transformer replacement (T2)	Expected in-service Q4, 2034
Bramalea TS transformer replacement with larger capacity transformers (T3, T4)	Expected in-service Q2, 2040
Pleasant TS transformer replacement (T1, T2)	Expected in-service TBD

Need	Plan Update and Timing
Erindale T5/T6 capacity need	Timing of need revised to beyond 2033
H29/H30 capacity need	Reconductoring in progress, Expected in-service Q2, 2028
T38B/T39B Lantz JCT to Trafalgar DESN overload	Expected in-service to be confirmed in this plan cycle

Additionally, since the previous regional planning cycle, Hydro One has implemented an operating procedure under which the Jim Yarrow MTS load can be transferred to different transmission circuits if the normal supply to the station is out of service. This operational measure is a low-cost way to address the risk of overloading of key 230 kV transmission circuits under certain pre-contingency outage conditions (i.e., maintenance outages).

3.3.2 Needs Requiring Further Coordination or Study in the Current Planning Cycle

The Needs Assessment identified new system needs in the GTA West region using the 10-year station-level demand forecast provided by the local distribution companies, updated end-of-life asset information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecasts developed by the IESO. Several needs were assessed and the TWG determined that they either fall outside the Needs Assessment ten-year window (Table 2), or will not require further coordinated study through the regional planning process (Table 3). In a subsequent planning study these needs may be considered in relation to the broader needs in the region.

Several needs identified in the Needs Assessment will require further planning or have a shared impact with other system assets or needs. For example, infrastructure needs impacting existing rights-of-way, such as asset renewal or replacement, may have an impact on shared, downstream, or alternate facilities, or they may present opportunities to do something different (i.e., non-like-for-like). A need for additional step-down capacity could interact with a broader need, if the station is located within an area with limited bulk transmission capacity to accommodate station growth. These types of needs may or may not require coordinated study through an IRRP.

The remaining needs determined through the Needs Assessment to require further coordinated study are listed in Table 4. Most needs deal with infrastructure capacity constraints. Additionally, transmission upgrades may be required to accommodate rapid load growth being experienced in the Milton area.

Table 2 | Needs Determined to be Outside Needs Assessment Forecast (i.e., >10 years)

Need #	Station/Circuit	Description of Need
1	Halton TS: T3/T4	• Asset renewal
2	Pleasant TS: T5/T6	• Asset renewal
3	Lorne Park TS: T2	• Asset renewal
4	Tomken TS: T1/T2	• Asset renewal
5	Bramalea TS: T3/T4	• Asset renewal

Table 3 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Bramalea TS: T3/T4	• Station capacity
2	Lorne Park TS	• Station capacity
3	Pleasant TS: T1/T2	• Station capacity

Table 4 | Needs identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need
1	Halton TS	• Station capacity
2	Bramalea TS: T1/T2	• Station capacity
3	Erindale TS: T1/T2	• Station capacity
4	Cardiff TS	• Station capacity

Need #	Station/Circuit	Description of Need
5	Cooksville TS	• Station capacity
6	Pleasant TS: T5/T6	• Station capacity
7	Jim Yarrow TS: T1/T2	• Station capacity
8	Goreway TS: T5/T6	• Station capacity
9	T38B/T39B	• Load security
10	T38B/T39B	• System capacity

3.3.3 Analysis of Needs and Planning Approach

The TWG reviewed the needs in the GTA West region and the different possible planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including the available lead time to develop solutions.
- The potential linkages between needs and the level of coordination required to assess possible solutions, particularly if they overlap across LDC territories or planning regions.
- The opportunity for community and stakeholder engagement to inform the assessment.
- The potential for different types of options to address the needs, including non-wires alternatives.
- The potential for interaction between regional needs and the upstream bulk power system.

In general, the greater the complexity and need for regional coordination and engagement, the more likely an IRRP will be the preferred planning approach. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The TWG agreed that for each of the identified needs requiring further study, a range of alternatives including wires and non-wires solutions should be assessed. Additionally, several needs were identified which do not require further coordinated planning but should still be considered in scope of further study as the implementation and timing of solutions have the potential to affect other needs in the area. These include needs whose previously recommended solutions are already underway, and asset renewal needs with the potential to affect overall capacity needs in the area.

Based on discussions, the TWG agreed that an IRRP is the preferred planning approach. The scope of an IRRP will include an assessment of Demand-side Management, Distributed Energy Resources

(DERs), and other community-based solutions, in addition to transmission infrastructure. A Terms of Reference for the IRRP is attached in Appendix B.

3.3.5 Additional Planning Considerations

It is widely recognized that the energy transition will shape the ways that electricity is produced and consumed. In July 2023, the Ministry of Energy and Electrification published its Powering Ontario's Growth Report (POG). The POG report was created in response to the expected demand increase resulting from the province's rapid economic development, decarbonization, and electrification efforts. It speaks to reducing the province's reliance on natural gas generation, and strategically planning transmission to unlock future opportunities.

Accordingly, the GTA West IRRP will evaluate a scenario in which the two local gas-fired generation plants are phased out and identify the magnitude of system investments needed to accommodate this scenario. Consideration will also be given to a "high electrification" demand forecast scenario. This scenario will evaluate the potential impact to the regional electricity system to accommodate electrification.

3.3.6 Northwest GTA Transmission Corridor

The IESO and the Ministry of Energy and Electrification are conducting a joint study to identify land to be protected for a future transmission corridor to support anticipated long-term growth in demand for electricity in the GTA West region. This initiative will ensure that transmission in the study area can be accommodated if and when they arise in an effort to plan today to keep future options alive.

3.3.7 South and Central Ontario Bulk Planning Study

This study will review the capability of the bulk system to support future generation connections and demand growth in key areas throughout the province, to enable a decarbonized power system in the future. This work will also consider opportunities to preserve additional new or expanded linear corridors for future transmission development.

As the South and Central Bulk Study will be conducted in parallel with regional planning in GTA West, its findings (i.e., needs and recommended solutions) will be coordinated with the GTA West IRRP, and vice-versa.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Based on the available information, an IRRP is to be undertaken for the GTA West region;
- The implementation of recommendations from the previous planning cycle should continue;
- The composition of the IRRP Working Group will include the IESO, Hydro One Transmission, Hydro One Distribution, Alectra Utilities, Burlington Hydro, Milton Hydro, Oakville Hydro, and Halton Hills Hydro.
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required;
- The GTA West IRRP will co-ordinate its findings with the South and Central Bulk Study, and vice-versa;

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The Terms of Reference for the GTA West IRRP is attached in Appendix B.

Appendix A – List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
EA	Environmental Assessment
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
POG	Powering Ontario's Growth
RIP	Regional Infrastructure Plan
TS	Transformer Station
TWG	Technical Working Group

Appendix B – GTA West Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, deliverables and engagement timelines for an Integrated Regional Resource Plan (IRRP) for the GTA West region.

Based on the power system needs identified throughout the region, an IRRP is the appropriate planning approach for this region.

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid[1] that provides electricity supply to the GTA West region over the next 25 years.
2. Account for major asset renewal/end-of-life needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long-term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the GTA West region. The plan is a joint initiative involving Hydro One Transmission, Hydro One Distribution, Alectra Utilities, Burlington Hydro, Milton Hydro, Oakville Hydro, Halton Hills Hydro, and the IESO, and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, Conservation and Demand Management, Distributed Energy

Resource uptake, transmission and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The scope of the GTA West IRRP includes the following needs, as identified in the Needs Assessment:

Table 5 | Needs Identified in the Needs Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
Halton TS	Station capacity	2026
Bramalea TS: T1/T2	Station capacity	2031
Erindale TS: T1/T2	Station capacity	2030
Cardiff TS	Station capacity	2030
Cooksville TS	Station capacity	2030
Pleasant TS: T5/T6	Station capacity	2026
Jim Yarrow TS: T1/T2	Station capacity	2030
Goreway TS: T5/T6	Station capacity	2026
T38B/T39B	Load security	2029
T38B/T39B	System capacity	TBD

Other identified needs in the Needs Assessment not listed in Table 5 will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the Working Group informed on project development.

4. IRRP Activities

The development of the IRRP will consist of the activities as listed below. The activities and anticipated timelines are summarized in Table 6 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of the 20-year electricity demand forecast to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the TWG agreeing on the demand forecast and associated forecast scenarios to be considered in the plan.

1) Develop an electricity demand forecast for the GTA West region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can impact the future electricity requirements in the region (Local Distribution Companies/LDCs provide forecast data).
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:

    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6) Develop recommendations for actions and document them in the plan, to address needs in the near-term and medium-term (generally up to ten years out).
7) Develop a long-term plan for the electricity system in GTA West region to address the identified long-term needs, considering uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in GTA West could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

To carry out this scope of work, the TWG will consider the data and assumptions outlined in Section 5.

5. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information and trends for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by TS, etc.
    - Coincident peak demand data
    - Identified potential future load customers, including transit expansions, electrification of personal vehicles, space heating/cooling, water heating, and other end-uses due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on region's share of the provincial target found in the 2021-2024 CDM Framework
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities, if applicable
    - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
    - Local building codes, energy performance requirements, etc.

- Local resources
    - Existing local generation resources, including distributed energy resources, district energy resources, customer-based generation, as applicable
    - Existing or committed renewable generation procurements
    - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local and provincial plans and studies, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal and community policies with an impact on electricity usage
    - Municipal Growth Plans
    - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion and electrification (e.g. GO train electrification)
    - Pathways to Decarbonization Report

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
        - Supply capability
        - Load security
- Load restoration requirements

    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- End-of-life asset considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Hydro One Networks Inc. (Transmission)
- Hydro One Networks Inc. (Distribution)
- Alectra Utilities Corporation
- Burlington Hydro Inc.
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.
- Halton Hills Hydro

6.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders is key to the planning process. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the GTA West IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions, as outlined in Section 5, will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 6 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	December 2024
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q1-Q3 2025
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	LDCs		
d. Establish existing, committed, and potential DG	IESO, LDCs		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs/ Hydro One	Load transfer capabilities under normal and emergency conditions	Q4 2025
4. Provide and review relevant community plans, if applicable	LDCs, communities, stakeholders, and IESO	Relevant community plans	Q4 2025
5. Complete system studies to identify needs over a 20-year time horizon Obtain base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2025 – Q1 2026
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q1 2026
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the LMC of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and LDCs		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
g. Technical and economic comparison and evaluation of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
7. Plan and undertake community and stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement to be launched in Q1-Q2 2025
a. Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and LDCs		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q4 2025 – Q1 2026
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	March 2026

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NEEDS ASSESSMENT REPORT

Toronto Region

Date: December 19, 2022

Prepared by: Toronto Region Technical Working Group

Disclaimer

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

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

Executive Summary

REGION	Toronto Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	August 23, 2022	**END DATE**	December 19, 2022

1. INTRODUCTION

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

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

2. REGIONAL ISSUE/TRIGGER

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

3. SCOPE OF NEEDS ASSESSMENT

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

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

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

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

5. ASSESSMENT METHODOLOGY

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

A technical assessment of needs was undertaken based on:

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

6. NEEDS

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

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

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

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

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

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

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

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

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

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

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

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

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

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

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

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1 INTRODUCTION

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

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

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

Table 1: Toronto Region TWG Participants

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

2 REGIONAL ISSUE/TRIGGER

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

3 SCOPE OF NEEDS ASSESSMENT

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

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

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

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

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region covers the area roughly bordered geographically by Lake Ontario on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east. It includes the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Please see Figure 1 for the Toronto Region map. Electrical supply to this Region is provided by thirty-five 230kV and 115kV transmission and step-down stations as shown in Figure 2. The eastern, northern, and western parts of the Region are supplied by seventeen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and sixteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The region is also supplied locally by Portlands Energy Centre, a 550 MW combined-cycle power generating station. The sum of 2021 non-coincident summer station peak load of the Region was about 4,850 MW.

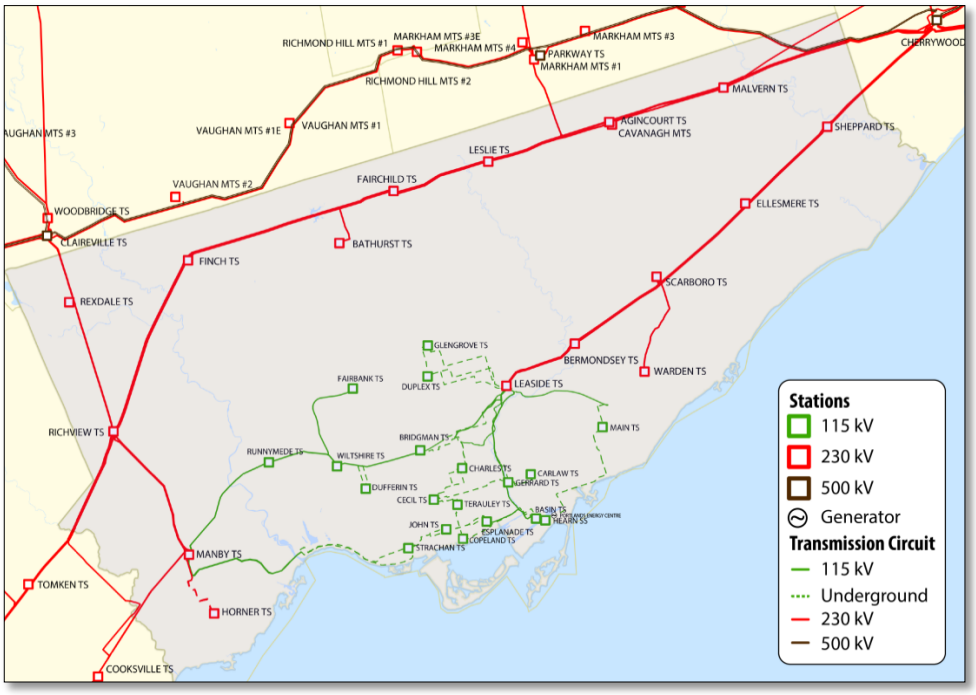


Figure 1: Toronto Region Map

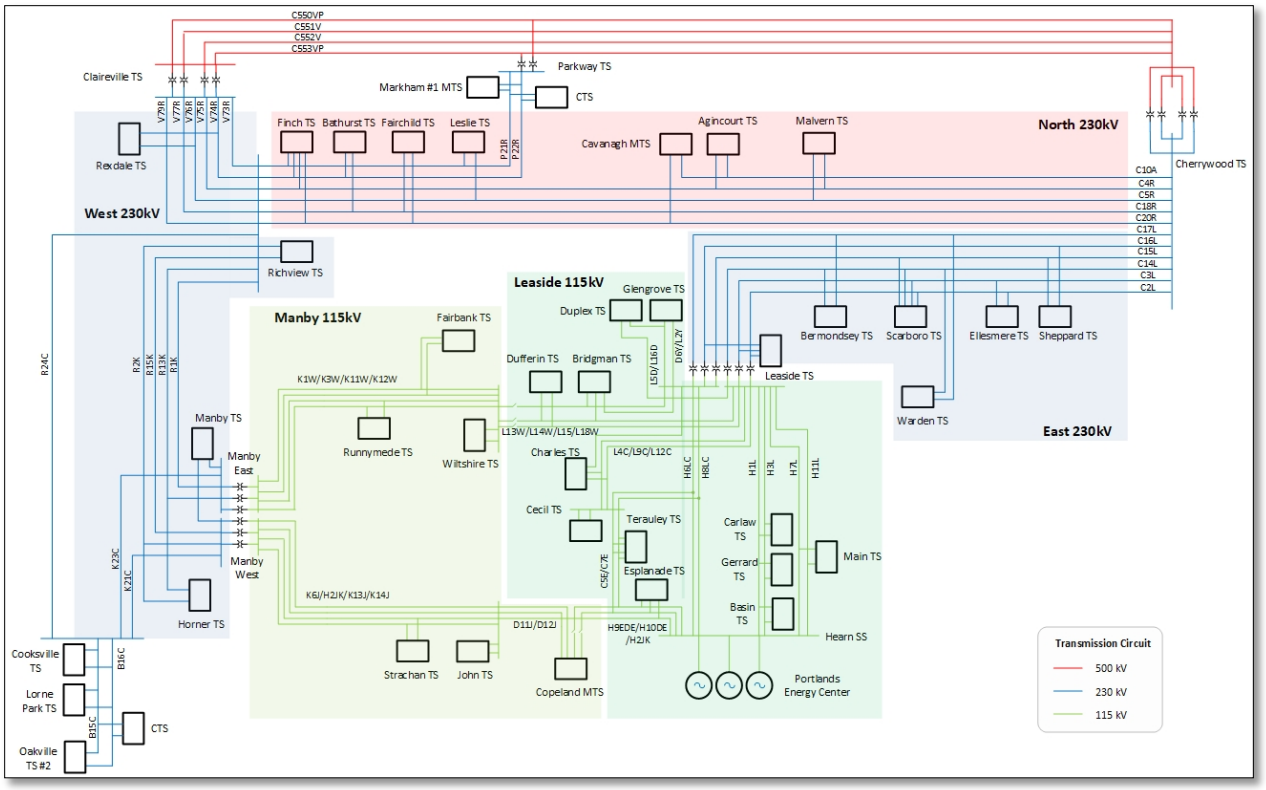


Figure 2: Toronto Region – Single Line Diagram

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Toronto Region NA. The information provided includes the following:

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

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

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

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

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

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

A technical assessment of needs was undertaken based on:

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

The following other assumptions are made in this report.

- The study period for this NA is 2022-2031.
- Transmission system adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 NEEDS

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

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

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

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

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

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

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

(1) Includes needs identified in the previous RIP that do not have projects in execution yet.

(2) The replacement/refurbishment scope, timing, and prioritization are based on the best available information at the time, and are subject to change.

(3) Earliest in-service of reconductoring the overhead line K13J/K14J is expected to be around 2028 if the development and estimate work is to be initiated in 2023.

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

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

7.1 Asset Renewal Needs for Major HV Transmission Equipment

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

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

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

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

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

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

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

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

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

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

7.1.1 Strachan TS

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

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

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

7.1.2 Charles TS

Charles TS comprises two DESN units, T1/T2 (60/100 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 211 MW. The station's 2021 actual non-coincident summer peak load was about 127 MW and is forecasted to be approximately 165 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 55 years old and require replacement based on asset condition assessment.

The load at Charles TS is forecasted to be almost 80% of its LTR in the medium term. The load at three of the closest stations, Bridgman TS, Cecil TS and Terauley TS, is also forecasted to be about 80%, 65%, and 80% in the medium term.

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

7.1.3 Duplex TS

Duplex TS comprises two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 128 MW. The station's 2021 actual non-coincident summer peak load was about 88 MW and is forecasted to be approximately 112 MW (net adjusted for extreme weather) in 2031.

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

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

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

7.1.4 Basin TS

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

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

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

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

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

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

7.1.5 Scarboro TS

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

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

Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to

downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing T23 is not a viable option. Upgrading the transformer is also not an option since it is already at the maximum standard size.

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

7.1.6 Fairchild TS

Fairchild TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 346 MW. The station's 2021 actual non-coincident summer peak load was about 216 MW and is forecasted to be approximately 243 MW (net adjusted for extreme weather) in 2031. Transformers T1 is 52 years old but was rebuilt 36 years ago. The companion DESN transformer T2 failed and was replaced under emergency in 2017 with a similar 75/125 MVA unit. Transformers T3 and T4 in the other DESN are 39 years old. Transformers T1, T3 and T4 require replacement in the medium term based on asset condition assessment.

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

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

7.1.7 Bermondsey TS

Bermondsey TS comprises two DESN units, T1/T2 (75/125MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 348 MW. The station's 2021 actual non-coincident summer peak load was about 153 MW and is forecasted to increase significantly in the near term due to new load customers in the area. The load is forecasted to be approximately 275 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 57 years old and require replacement in the near term based on asset condition assessment.

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

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

7.1.8 Malvern TS

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

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

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

7.1.9 Manby TS

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

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

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

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

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

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

7.1.10 Leslie TS

Leslie TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 323 MW. The station's 2021 actual non-coincident summer peak load was about 221 MW and is forecasted to be approximately 249 MW (net adjusted for extreme weather) in 2031. Transformer T1 is currently about 59 years old and require replacement based on asset condition assessment. The companion DESN transformer T2 is currently 25 years old and does not require replacement in the near or medium term.

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

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

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

7.1.11 Overhead Transmission Line H1L/H3L/H6LC/H8LC

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

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

7.1.12 Overhead Transmission Line L9C/L12C

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

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

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

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

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

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

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

As previously documented, the recommendation is to proceed with:

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

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

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

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

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

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

and Leaside / Hearn subsystems, obtaining the said outages to complete this work could be very challenging, and worsen further as the load increases in these areas.

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

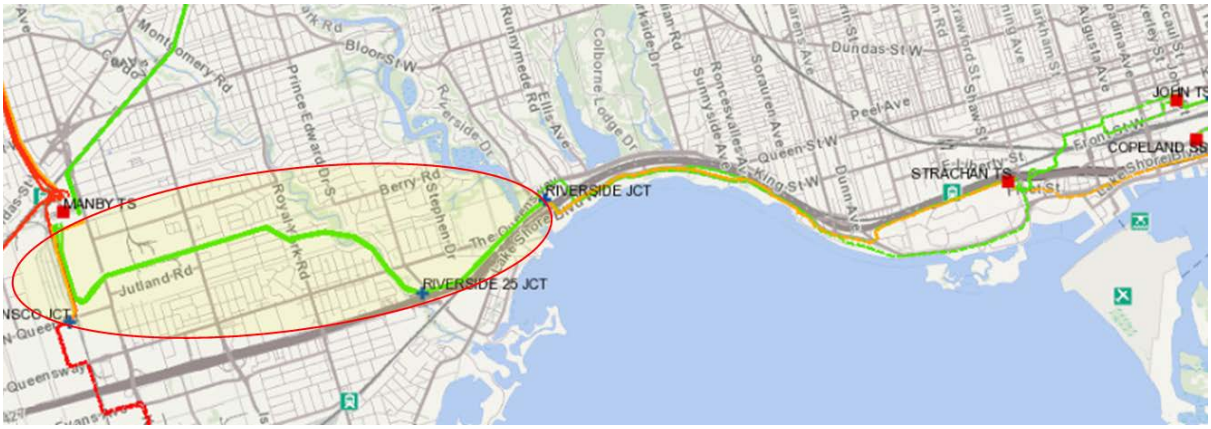


Figure 3: 115 kV Corridor between Manby TS and John TS (overhead section is circled)

7.3 Long-Term Capacity Needs

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

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

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

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

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

7.3.1 Fairbank TS – Station Capacity

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

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

7.3.2 Sheppard TS – Station Capacity

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

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

7.3.3 Strachan TS – Station Capacity

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

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

7.3.4 Basin TS – Station Capacity

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

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

7.3.5 Glengrove TS – Station Capacity

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

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

7.3.6 Finch TS / Bathurst TS – Station Capacity

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

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

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

7.3.7 Warden TS – Station Capacity

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

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

7.3.8 Manby W TS Autotransformers – Transformation Capacity

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

7.3.9 Leaside TS Autotransformers – Transformation Capacity

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

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

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

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

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

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

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

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

7.4 Load Restoration Analysis

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

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

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

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

8 SENSITIVITY ANALYSIS

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

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

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

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

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

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

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

(1) The objective of a low growth scenario analysis is to identify any deferment in the timing of needs identified in this NA. Therefore, the long-term needs will not be looked at in the low growth scenario analysis.

(2) Forecasted load demand at Warden TS exceeds its capacity from 2024 but THESL plans to manage it by transferring the excess load to Scarboro TS. A higher load growth scenario will certainly advance the need to relieve Warden TS and further assessment will be carried out during the next phases of this Regional Planning cycle.

(3) Like the normal growth scenario, the high growth scenario does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may be advanced to the medium term. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

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

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

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

9 RECOMMENDATIONS

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

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

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

Table 7 summarizes the above recommendations.

Table 7: Summary of Recommendations

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

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

10 REFERENCES

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[5]. IESO, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0, August 22, 2007 https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.ashx

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

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

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

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

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

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L14W/L15/L18W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Copeland MTS T1/T3	115/13.8	D11J/D12J
Dufferin TS T1/T3	115/13.8	L13W/L18W
Dufferin TS T2/T4	115/13.8	L13W/L18W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10DE(C5E)/H9DE(C7E)
Fairbank TS T1/T3 (to be T5/T6)	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T1/T2	230/27.6	C18R/C20R
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T2	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
Horner TS T1/T2	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	Leaside Buses HL2, HL3, HL16
Leaside TS T19/T20/T21 27.6	230/27.6	Leaside Buses HL2, HL3, HL16
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4 27.6	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1

Station (DESN)	Voltage (kV)	Supply Circuits
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T1/T2	115/27.6	K12W/K11W
Runnymede TS T5/T6 (was T3/T4)	115/27.6	K12W/K11W
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T5/T6 (was T3/T4)	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T7X/T2X	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)

Appendix C: Lists of Transmission Circuits

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	D11J, D12J, H9DE, H10DE	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix D: Acronyms

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



Toronto Region Scoping Assessment Outcome Report

March 21, 2023

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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of regional planning for the Toronto region, and it was initiated in fall 2022. Information and links to earlier products are available on the IESO webpage, here. The Needs Assessment is the first step in the regional planning process and was carried out by the Technical Working Group (TWG) led by Hydro One. The Needs Assessment Report was finalized on December 19, 2022 and identified some needs that may require further regional coordination. This need information was an input into the Scoping Assessment. The Technical Working Group reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region, including the recent Pathways to Decarbonization report.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an IRRP – where both wires and non-wires options have potential to address needs; a Regional Infrastructure Plan (RIP) – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Considers impacts on planning assumptions and potential outcomes on needs resulting from local and provincial policy goals;
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the IRRP Technical Working Group.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

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

3. Categories of Needs, Analysis and Results

3.1 Overview of the Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 1. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

In addition to the transmission infrastructure described above, the Portlands Energy Centre (550 megawatt [MW] summer capacity) is a natural gas-fired combined cycle power plant that provides a major source of supply to Toronto. This station is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS) shown in Figure 1.

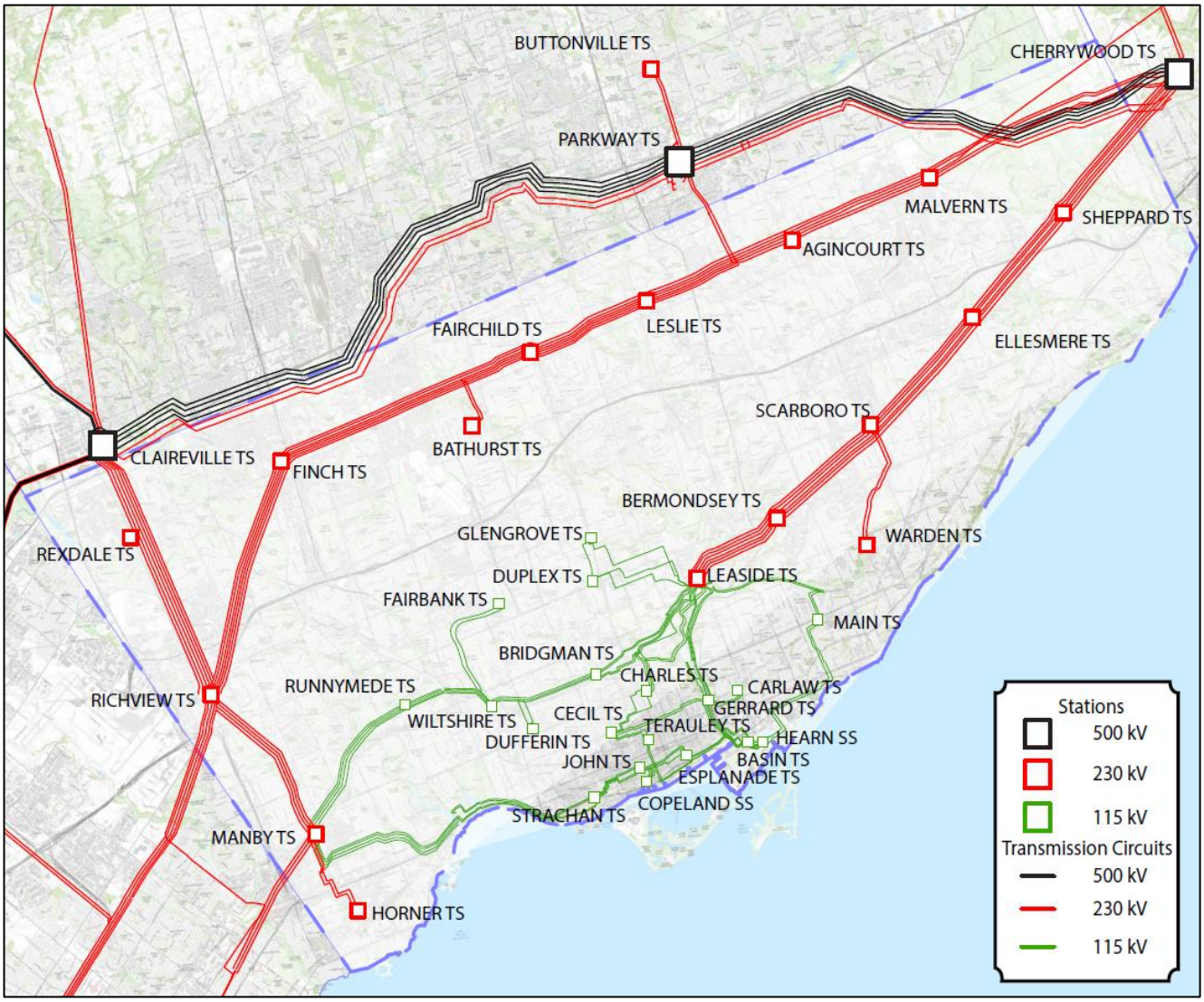
Numerous distributed energy resource (DER) facilities are located throughout the City. For example, through previous procurements such as the Feed-in Tariff program, Renewable Energy Standard Offer Program, and Combined Heat and Power (CHP) Standard Offer Program, approximately 1,900 individual renewable and CHP facilities have been placed in service in the City of Toronto. The total combined electrical supply capacity of these DERs is 106 MW.[1]

The region is summer peaking and the 2022 peak summertime electricity demand in the Toronto region was approximately 4,400 MW.[2]

[1] This translates to about 40 MW of "effective" capacity that system planners can count on during the peak demand period (assuming 34% capacity factor for solar PV, 13.6% for wind, and 100% for all other fuel types, including CHP).

[2] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2022, demand was 4,356 MW.

Figure 1 | Electricity Infrastructure of the Toronto Region



3.1.1 Indigenous Communities

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council (HCCC) and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

3.2 Background of the Previous Planning Process

The first cycle of the regional planning process for the Toronto region was formally completed in January 2016 with the publication of Hydro One's Regional Infrastructure Plan (RIP) for the Central Toronto area, following the publication of an IRRP for Central Toronto in April 2015. In February 2017, an update was published to reflect plans to convert commuter heavy rail (Metrolinx - GO) from diesel to electric power.

In mid-2017, Hydro One identified a number of transmission asset renewal needs in Toronto over the next ten years. The scale and timing of these needs necessitated the initiation of another regional planning cycle. Hydro One initiated a Needs Assessment, which officially started the next regional planning cycle for the region. The Needs Assessment was completed in October 2017, and subsequent Scoping Assessment was completed in 2018. An IRRP was initiated in 2018, and released in 2019. This plan focused on transmission asset renewal needs, and preparing to address local and regional capacity needs emerging in the longer term.

The second round of regional planning for the Toronto region was completed in March 2020, with the release of the Hydro One led RIP.

An updated analysis for the Richview to Manby Upgrade project (now known as the "Etobicoke Greenway Project") was conducted in 2021. This analysis reaffirmed the findings in the 2019 IRRP and 2020 RIP and recommended the project go ahead.

3.3 Needs Identified

For this third cycle of regional planning, Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the Toronto region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway or Complete to Address Previously Identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation for the options recommended to address them (see Table 1). These projects provide a starting point for future assessments and will be accounted for in this planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Need	Solution and Timing
Copeland TS Phase 2, address capacity need	In-service 2024
Bridgman TS transformer replacement (T11, T12, T13, T14)	Expected completion 2024

Need	Solution and Timing
Fairbank TS transformer replacement (T1, T2, T3, T4)	Expected completion 2024
Main TS transformer replacement (T3, T4)	Expected completion 2024
John TS transformer replacement (T5, T6)	Expected completion 2025
C5E/C7E underground cable replacement between Esplanade TS and Terauley TS	Expected completion 2026
Richview TS to Manby TS 230 kV Corridor Upgrade	Expected completion 2026

Since the previous regional planning cycle, the following additional projects have also been implemented by Hydro One:

- Second DESN at Horner TS, complete 2022
- Refurbishment projects at Runnymede TS (T3, T4), Sheppard TS (T3, T4), and Strachan TS (T12), complete 2021-2022
- Replacement of John TS transformers (T1, T2, T4), complete 2019-2021

3.3.2 Needs Requiring Further Coordination or Study in the Current Planning Cycle

The Needs Assessment then identified new or updated needs in the Toronto region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated asset condition information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Several of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (see Table 2). However, many may still require a significant amount of planning or have a shared impact with other system assets or needs. For example, any needs dealing with major right of ways, even routine maintenance or like-for-like replacement, may have an impact on shared, downstream, or alternate facilities. Stepdown station asset renewal needs can also be linked to broader needs, if the station is located within a rapidly growing or supply constrained area. These types of needs do not require coordinated study through an IRRP, but should still be considered in scope of further regional planning activities to ensure that outage schedules and other shared impacts are appropriately accounted for.

Table 2 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Richview TS to Manby TS 230 kV Corridor[3]	• Line Capacity Need
2	Manby TS, autotransformers (T7, T9, T12)[4] and step-down transformers (T13/T14)	• Asset renewal need
3	115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	• Asset renewal need
4	115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section	• Asset renewal need
5	Strachan TS: T14 & T13/T15	• Asset renewal need
6	Charles TS: T3/T4	• Asset renewal need
7	Duplex TS: T1/T2 & T3/T4	• Asset renewal need
8	Basin TS: T3/T5	• Asset renewal need
9	Scarboro TS: T23	• Asset renewal need
10	Fairchild TS: T1 & T3/T4	• Asset renewal need
11	Bermondsey TS: T3/T4	• Asset renewal need
12	Malvern TS: T3	• Asset renewal need
13	Fairbank TS	• Station Capacity Need
14	Strachan TS	• Station Capacity Need

[3] Further regional planning is not required as the project was recommended in the previous cycle of regional planning. Hydro One is developing the project, with an expected in-service date of mid-2026.

[4] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity in Toronto as a whole will be assessed in the upcoming IRRP.

The remaining needs, which were determined through the Needs Assessment to require further coordinated study are listed in Table 3. Most needs deal directly with capacity constraints, or load restoration, as a range of solutions may be considered and the impact on broader system operation would need to be evaluated. Note that some step down station capacity needs (Fairbank TS and Strachan TS) were not included in this list, as solutions to address needs have already been identified.

Table 3 | Needs identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need
1	115 kV Manby TS to Riverside Jct. Corridor	• Line capacity need
2	230 kV Parkway TS to Richview TS Corridor	• Line capacity need
3	115kV Leaside TS to Wiltshire TS Corridor	• Line capacity need
4	230/115kV Manby W Autotransformers[5]	• Autotransformer capacity need
5	230/115kV Leaside TS Autotransformers	• Autotransformer capacity need
6	Sheppard TS	• Station capacity need
7	Basin TS	• Station capacity need
8	Glengrove TS	• Station capacity need
9	Finch TS / Bathurst TS	• Station capacity need
10	Warden TS	• Station capacity need
11	Loss of C14L/C17L	• Load restoration need
12	Loss of C18R/P22R	• Load restoration need

[5] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity will be looked at in the upcoming IRRP.

3.3.3 Analysis of Needs and Identification of Region

The Technical Working Group (TWG) has discussed the needs in the Toronto region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs are and the greater the need for coordination and engagement, the more likely an IRRP will be selected. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The participants agreed that for each of the identified needs requiring further study, a range of alternatives including wires and non-wires solutions should be assessed. Additionally, several needs were identified which do not require further coordinated planning, but should still be considered in scope of further study as the implementation and timing of solutions have the potential to affect other needs in the area. These include needs whose previously recommended solutions are already underway, and asset renewal needs with the potential to affect overall capacity needs in the area.

Based on discussions, it was agreed that an IRRP should be undertaken to further assess these needs. The scope of an IRRP includes an assessment of CDM, DERs, and other community-based solutions. A Draft Terms of Reference for the IRRP is attached in Appendix B.

The participants also agreed, for the purpose of the next regional plan, that the City of Toronto should not be divided into sub-regions. While most of the needs identified impact electricity infrastructure in the downtown area, some needs have been identified in other parts of Toronto, outside of the central part of Toronto.

Lastly, because none of the needs identified directly impact facilities that supply customers of Alectra Utilities Corporation, Elexicon Energy Inc., or Hydro One Distribution, it was agreed that the core Working Group for the IRRP will include the IESO, Toronto Hydro, and Hydro One Transmission. The other utilities will be informed and invited to participate if any needs, or proposed solutions, may affect their facilities or customers.

3.3.4 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[6] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[7]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

3.3.5 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including

[6] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[7] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, the Terms of Reference for the Toronto IRRP may be amended at a future time to account for additional objectives, activities, and assumptions required to align deliverables with new provincial direction.

3.3.6 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Based on the available information, an IRRP is to be undertaken for the Toronto region;
- No sub-regions within Toronto will be created for the IRRP; the region should be treated as a whole for the purpose of developing a comprehensive plan;
- The implementation of recommendations from the previous planning cycle should continue;
- The composition of the IRRP Working Group will include the IESO, Toronto Hydro, and Hydro One Transmission. Other Local Distribution Companies in the region will be informed of any needs or solutions that may affect their facilities or customers;
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required;
- In addition to addressing the needs identified in the Needs Assessment, two focus areas will be examined in detail in the IRRP: Port Lands and Downsview;
- The Toronto IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa;
- The IESO may amend the Terms of Reference for the Toronto IRRP as required to align with provincial direction following consultation related to the Pathways to Decarbonization Report.

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the Toronto IRRP is attached in Appendix B.

Appendix A – List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station
TWG	Technical Working Group

Appendix B – Toronto Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the Toronto region.

Based on the power system needs identified throughout the region (including a number of transmission stations and lines requiring replacement based on asset condition assessment in the near term and medium term), strong urban growth and intensification projections in the City of Toronto, expansion of electrified transit, and potential demand and resource pressures from decarbonization policies, an IRRP is the appropriate planning approach for this region.

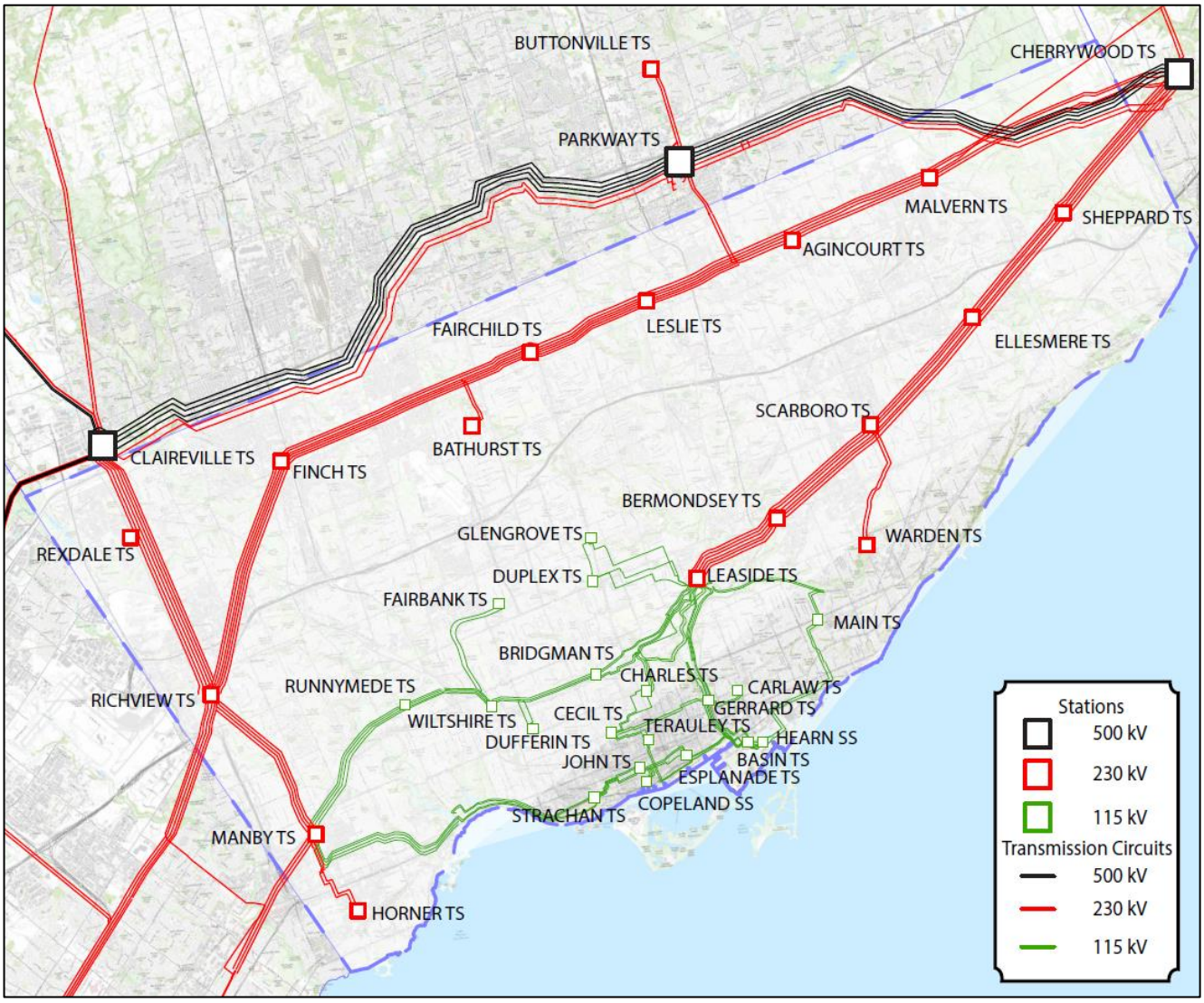
1.1 The Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 2. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

For the purpose of this IRRP, no divisions are proposed that would create any sub-regions to assess within the City of Toronto.

Figure 2 | Electricity Infrastructure of the Toronto Region



1.2 Background

In December 2022, Hydro One completed the Needs Assessment report for the Toronto region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP is ultimately recommended on the basis of the scale of load growth anticipated, potential for diverse types of solution (including wires and non wires), and long term uncertainty associated with city development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid[8] that provides electricity supply to the Toronto region over the next 25 years.[9]
2. Account for major asset renewal needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long-term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the Toronto region. The plan is a joint initiative involving Toronto Hydro, Hydro One Transmission, and the IESO,[10] and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, CDM, DER uptake, transmission and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The scope of the Toronto IRRP includes the following needs, as identified in the Needs Assessment:

Table 4 | Needs Identified in the Needs Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
115 kV Manby TS to Riverside Jct. Corridor	Line capacity need	2028
230 kV Parkway TS to Richview TS Corridor	Line capacity need	Beyond 2031
115kV Leaside TS to Wiltshire TS Corridor	Line capacity need	Beyond 2031
230/115kV Manby W Autotransformers	Autotransformer capacity need	Beyond 2031

[8] The scope of the assessment includes transmission stations.

[9] The typical planning horizon in a regional study is 20 years; however, Toronto Hydro produces a long-range forecast spanning 25 years and this forecast will be used as the basis for assessing long-term system needs in the IRRP.

[10] Alectra Utilities, Elexicon Energy Inc. and Hydro One Distribution are also supplied by feeders from Toronto. These utilities will not form part of the core Technical Working Group. However, they will be informed of any developments that may impact their facilities and/or customers.

Facilities	Type of Need	Expected Timing
230/115kV Leaside TS Autotransformers	Autotransformer capacity need	Beyond 2031
Sheppard TS	Station capacity need	Beyond 2031
Basin TS	Station capacity need	Beyond 2031
Glengrove TS	Station capacity need	Beyond 2031
Finch TS / Bathurst TS	Station capacity need	Beyond 2031
Warden TS	Station capacity need	Beyond 2031
Loss of C14L/C17L	Load restoration need	2031
Loss of C18R/P22R	Load restoration need	2031

Other identified needs in the Needs Assessment not listed in Table 4 above will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the Working Group informed on project development.

3.2 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[11] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[12]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

[11] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[12] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

3.3 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, this Terms of Reference may be amended at a future time to account for additional objectives, activities, and assumptions required to align the Toronto IRRP deliverables with new provincial direction.

3.4 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Activities

The IRRP process will consist of the activities as listed below. The activities and anticipated timelines are summarized in Table 5 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand forecast to be used.

1) Develop an electricity demand forecast for the Toronto region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region:
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6) Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.

7) Develop a long-term plan for the electricity system in Toronto to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in Toronto could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in section 4 below.

5. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information and trends for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by TS, etc.
    - Coincident peak demand data
    - Identified potential future load customers, including transit expansions, electrification of personal vehicles, space heating/cooling, water heating, and other end-uses due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on region's share of the provincial target found in the 2021-2024 CDM Framework
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities, if applicable
    - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
    - Local building codes, energy performance requirements, etc.

- Local resources
    - Existing local generation resources, including distributed energy resources (DER), district energy resources, customer-based generation, as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local and provincial plans and studies, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - City policies with an impact on electricity usage, including TransformTO
    - Municipal Growth Plans
    - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion (e.g. Ontario Line), and transit electrification (e.g. GO train electrification)
    - Pathways to Decarbonization Report

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
        - Supply capability

        - Load security
        - Load restoration requirements
    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- Asset renewal considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Toronto Hydro Electric System Limited (Toronto Hydro)
- Hydro One Networks Inc. (Transmission)

The following LDCs will not be part of the IRRP Technical Working Group but will be informed of any developments that may impact their facilities and/or customers:

- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

6.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Toronto IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 5.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 5 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	March 2023
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q2-Q4 2023
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	Toronto Hydro		
d. Establish existing, committed, and potential DG	IESO, Toronto Hydro		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	Toronto Hydro/ Hydro One	Load transfer capabilities under normal and emergency conditions	Q1 2024
4. Provide and review relevant community plans, if applicable	Toronto Hydro, communities, stakeholders, and IESO	Relevant community plans	Q1 2024
5. Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1-Q2 2024
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 2024
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the LMC of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and Toronto Hydro		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and Toronto Hydro		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and Toronto Hydro		
g. Technical comparison and evaluation	IESO, Hydro One Transmission, and Toronto Hydro		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement to be launched in Q2-Q3 2023
a. Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and Toronto Hydro		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and Toronto Hydro		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and Toronto Hydro		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1-Q2 2024
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	September 2024

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NEEDS ASSESSMENT REPORT

Region: Burlington to Nanticoke

Date: September 06, 2022

Prepared by: Burlington to Nanticoke Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Burlington to Nanticoke Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group (TWG) for this region.

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

Executive Summary

REGION Burlington to Nanticoke Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: MAY 11, 2022 **END DATE:** September 06, 2022

1. INTRODUCTION

The second Regional Planning cycle for the Burlington to Nanticoke Region was completed in October 2019 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to: a) identify any new needs and/or to reaffirm needs identified in the previous Regional Planning cycle; and, b) recommend which needs may be i) addressed by developing a preferred plan as part of the NA phase which do not require further regional coordination and ii) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in May 2022 for the Burlington to Nanticoke Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Burlington to Nanticoke Region and includes:

- Review and reaffirm needs/plans identified in the RIP;
- Identify any new needs resulting from this assessment;
- Develop options and recommend a preferred plan for need(s) that do not require further regional coordination; and
- Recommend which need(s) require further assessment/regional coordination in the next phases of the Regional Planning cycle.

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

The planning horizon for this NA assessment is 10 years.

4. INPUTS/DATA

The TWG representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity

needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The community energy plans will be further evaluated during the next phases of this Regional Planning cycle.

5. ASSESSMENT METHODOLOGY

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

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major HV equipment requiring replacement with consideration to "right-sizing".

6. NEEDS

I. Update of identified needs from previous cycle

The following near- term needs identified in the Burlington to Nanticoke 2nd Cycle RIP report have been addressed/ completed:

1. Cumberland TS: Power factor correction
2. 115 kV B3/B4: Line section from Horning Mountain Jct. to Glanford Jct. requiring refurbishment
3. Elgin TS: Transformers & switchgears requiring replacement (Replacing two DESNs with a single unit)
4. Newton TS: Transformers (T1/T2) requiring replacement
5. Kenilworth TS: Transformer & switchgear requiring replacement (Replacing two DESNs with a single unit)

The status of remaining near-term needs is as follows:

1. 115 kV B7/B8: Line section from Burlington TS to Nelson Jct. requiring refurbishment
   Planned for in-service in 2024
2. Dundas TS (Load transfers/Balancing)
   Planned for in-service in 2023
3. Gage TS: Transformers & switchgear (T3/T4 and T5/T6 DESNs) requiring replacement
   In Execution: Planned in-service in Q4 2023
4. Kenilworth TS: Power factor correction
   Planned for in-service in Q4 2023

5. Norfolk area supply capacity

Near Term:

- Load transfers from Norfolk area to Jarvis TS is planned to be completed by the end of 2022.
- Additional reactive support at Norfolk TS is planned for 2023-24 timeframe.

Mid-Term:

- Upgrade Jarvis TS and build feeders to pick up Norfolk area loads – is planned for 2027-32 timeframe

II. Newly identified needs in the region

a. Line / Station Capacity

The following station capacity needs were identified in the Region:

1. Norfolk TS and Bloomsburg DS (Norfolk Area)

The loads at Norfolk TS and Bloomsburg DS are forecasted to exceed their supply capacities in 2030 and 2025 respectively. The supply capacity needs for these stations will be addressed through load transfers to Jarvis TS by building new feeders to pick Norfolk area loads. The Jarvis TS upgrade and required feeders to pickup Norfolk area loads are currently planned for 2027-2032 timeframe as described above. This need will be further reviewed during the next phases of this Regional Planning cycle.

2. Brant Area Supply

The 115 kV Brant area is supplied by two stations, i.e. Brant TS and Powerline MTS supplied by three 115 kV. Two (2) of the three (3) 115 kV circuits are supplied from Burlington TS and the third from Karn TS. The supply capacity of 115 kV system to Brant area to 165MW.

The coincident load in the 115 kV Brant area system may exceed the LMC of 165 MW before the end of the study period (2022-32). TWG recommends that this potential need be reviewed during the next phases of this Regional Planning cycle.

3. Caledonia TS

The load at Caledonia TS is forecasted to exceed its supply in 2030. The TWG recommended monitoring on the loading at Caledonia TS and to be further reviewed during the next phases of this Regional Planning cycle.

4. Nebo TS

The load at T3/T4 230/ 13.8 kV DESN at Nebo TS had been historically around its supply capacity and is currently forecasted to grow above its supply capacity. The TWG recommended monitoring the loading at this station and take remedial measures, if required. This DESN is planned to be refurbished in the 2027-2032 timeframe replacing existing 75 MVA nonstandard

transformers with Hydro One standard 100 MVA units. This will also address the supply capacity need at this station. This need will be further reviewed during the next phases of this Regional Planning cycle.

5. Mohawk TS

The load at Mohawk TS had been historically around its current loading levels however is forecasted to grow and exceed station supply capacity by 2024. The TWG recommended Hydro One and Alectra to monitor loading levels at this station and take necessary actions, if required e.g. load transfers to the neighboring stations. This need will be further reviewed during the next phases of this Regional Planning cycle.

b. Aging Infrastructure Transformer Station and Transmission Circuit Replacements

Based on asset condition assessment, Newton TS 115 kV breakers have been identified for replacement.

7. RECOMMENDATIONS

The TWG recommends to continue with:

- Refurbishment of section of 115 kV B7/B8 line;
- Refurbishment of Gage TS (T3/T4 and T5/T6 DESNs);
- Load transfer from Dundas TS to Dundas TS #2 to address overloading;
- Supply capacity in Norfolk area;
- Power factor correction at Kenilworth TS; and
- Refurbishment need for 115 kV breakers at Newton TS.

The TWG also recommended that the concerned LDC and Hydro One to monitor the loading levels in Norfolk and Brant areas as well at Caledonia TS, Nebo TS and Mohawk TS and take necessary action to address overloading, if required. These needs will be further reviewed during the Scoping Assessment phase of this Regional Planning cycle.

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1 INTRODUCTION

The second cycle of the Regional Planning process for the Burlington to Nanticoke Region was completed in October 2019 with the publication of the Regional Infrastructure Plan ("RIP") Report.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm and update any needs identified in the previous Burlington to Nanticoke Regional Planning cycle.

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

Table 1: Burlington to Nanticoke Region TWG Participants

1	Burlington Hydro Inc.
2	GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power)
3	Alectra Utilities Corporation (former Horizon Utilities Inc.)
4	Hydro One Networks Inc. (Distribution)
5	Oakville Hydro Electricity Distribution Inc.
6	Independent Electricity System Operator
7	Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As such, the 3rd Regional Planning cycle was triggered for the Burlington to Nanticoke region

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Burlington to Nanticoke region and includes:

- Review and reaffirm needs/plans identified in the RIP;
- Identify any new needs resulting from this assessment;

- Develop options and recommend a preferred plan for need(s) that do not require further regional coordination; and
- Recommend which need(s) require further assessment/regional coordination in the next phases of the Regional Planning cycle.

The TWG may identify additional needs during the next phases of the Regional Planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

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 thirty 230 kV and 115 kV step-down transformer stations. The sum of 2021 non-coincident summer station peak load of the Region was about 2341 MW. The boundaries of the Region are shown in Figure 1 below.

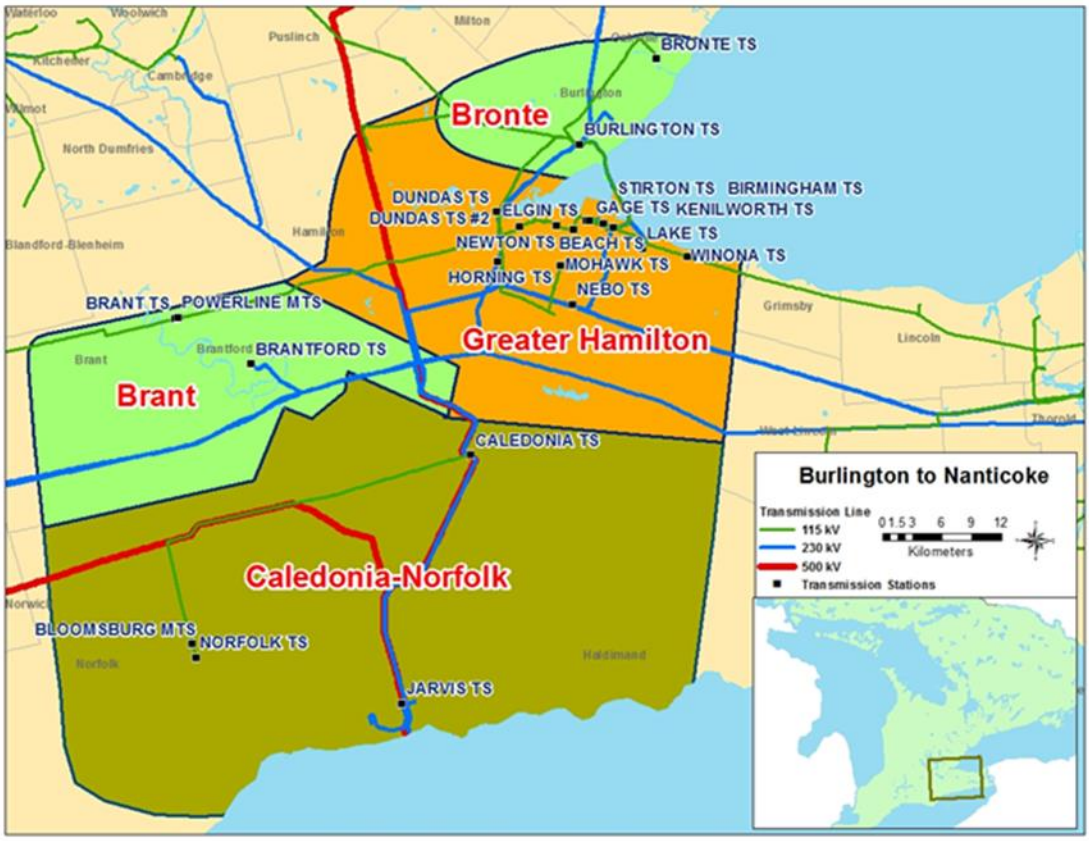


Figure 1: Map of Burlington to Nanticoke Regional Planning Area

Bulk electrical supply to the Burlington to Nanticoke Region is provided through the 500/230 kV autotransformers at Nanticoke TS and Middleport TS and 230 kV circuits from Middleport TS, Nanticoke TS and Beck TS. The 115 kV network is supplied by 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS. The area loads are supplied by a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into four sub-regions as shown in Figure 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 2.

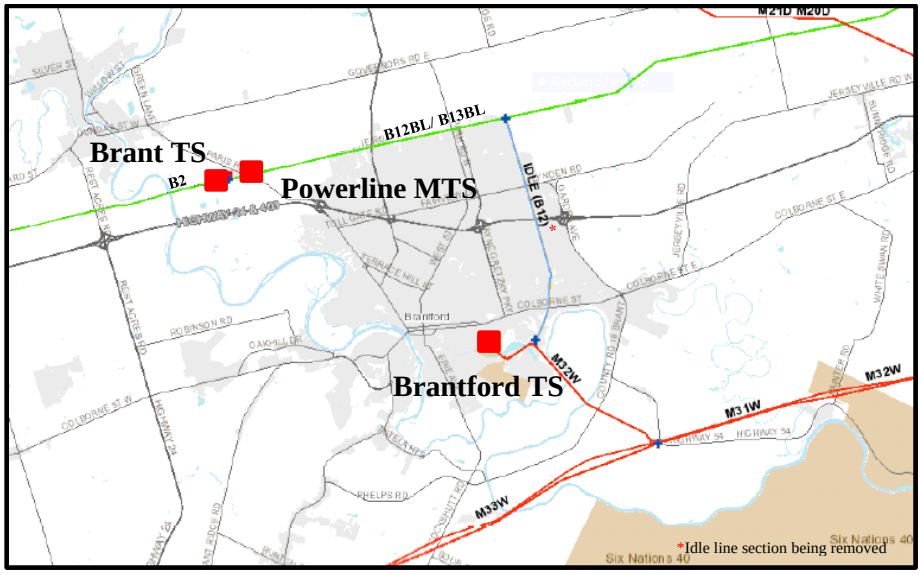


Figure 2: **Map of Brant sub-region**

The total 2021 non-coincident peak demand of the three stations was 280 MW. GrandBridge Energy (Merger of Brantford Power Inc. and Energy+ Inc.) is 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.

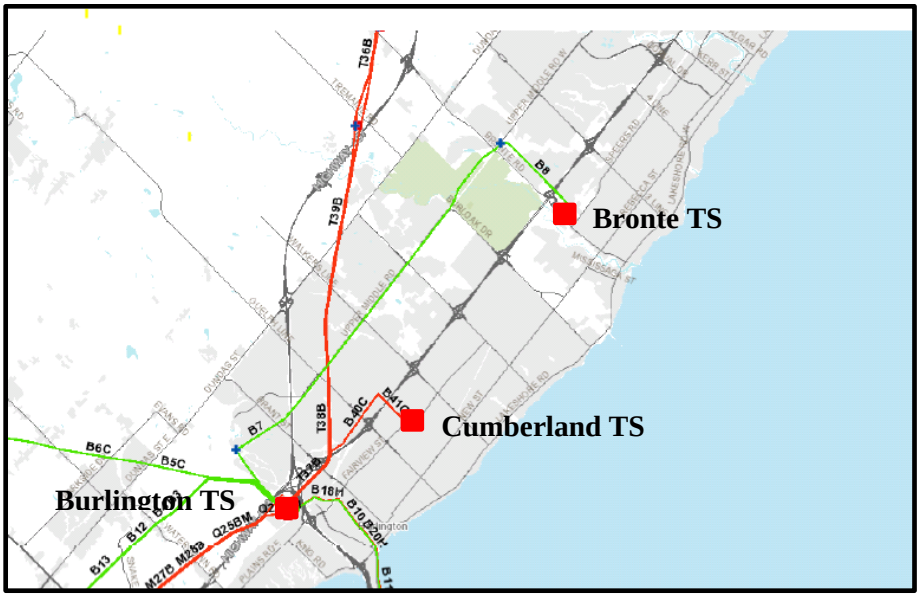


Figure 3: Map of Bronte sub-region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial, and industrial customers. The total 2021 non-coincident peak station demand of the three stations was 358 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.
  - A large industrial customer currently supplied through 230 kV system is planning to connect a large additional load within his facilities.

  The Greater Hamilton sub-region transmission facilities are shown in Figure 4.

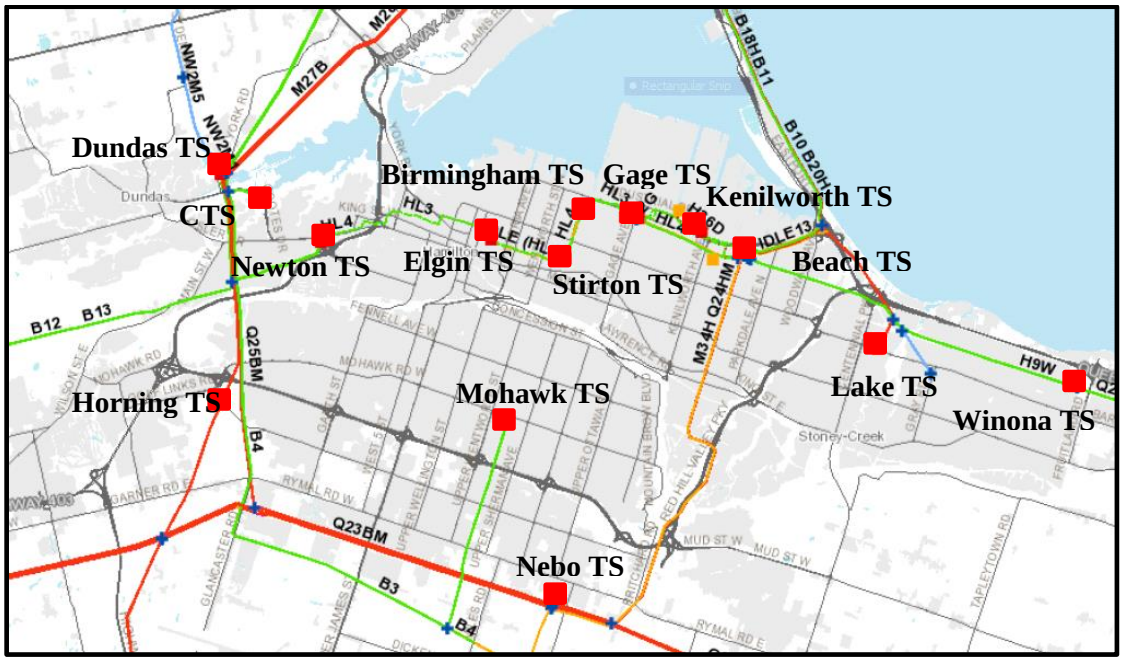


Figure 4: Map of Greater Hamilton sub-region

The total 2021 non-coincident peak demand of the Greater Hamilton sub-region was 1365 MW. The area is served by Alectra Utilities, Hydro One Distribution and Customer Transformer Stations (CTS) 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 two (2) CTSs supplied from the 230 kV double circuit line N21J/N22J.
  - One of the CTSs is supplied from the 230 kV single circuit N20K. This is a new station where a large industrial customer previously supplied through Jarvis TS will be supplied by a new CTS.
  - 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 5.

  The area is served by Hydro One Distribution. The electricity demand mix is comprised of residential, commercial, and industrial uses. The 2021 non-coincident peak demand of this sub-region was 381 MW.

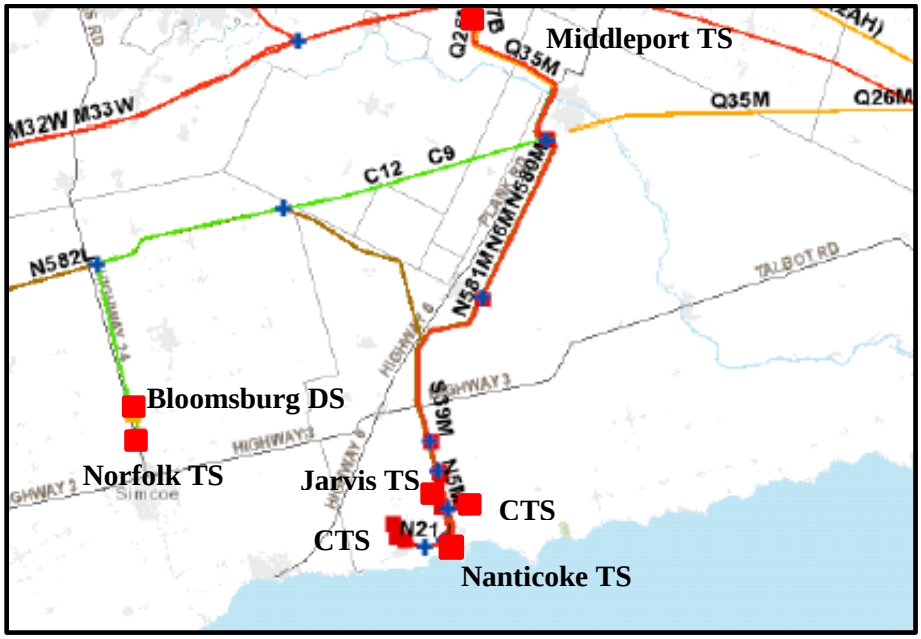


Figure 5: Map of Caledonia Norfolk sub-region

- 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 6 and Figure 7.

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

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

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

*Stations with Autotransformers installed

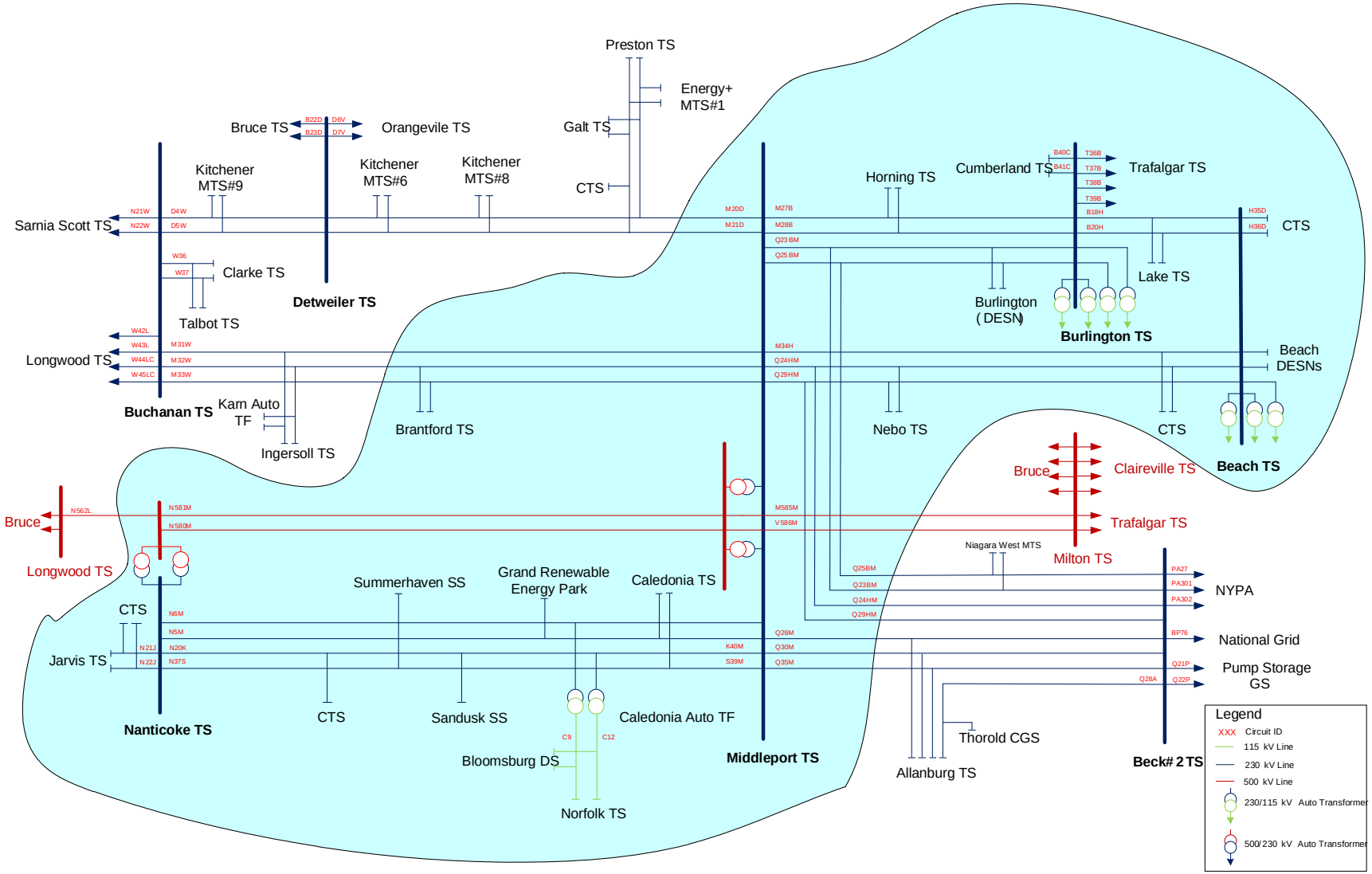


Figure 6: Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

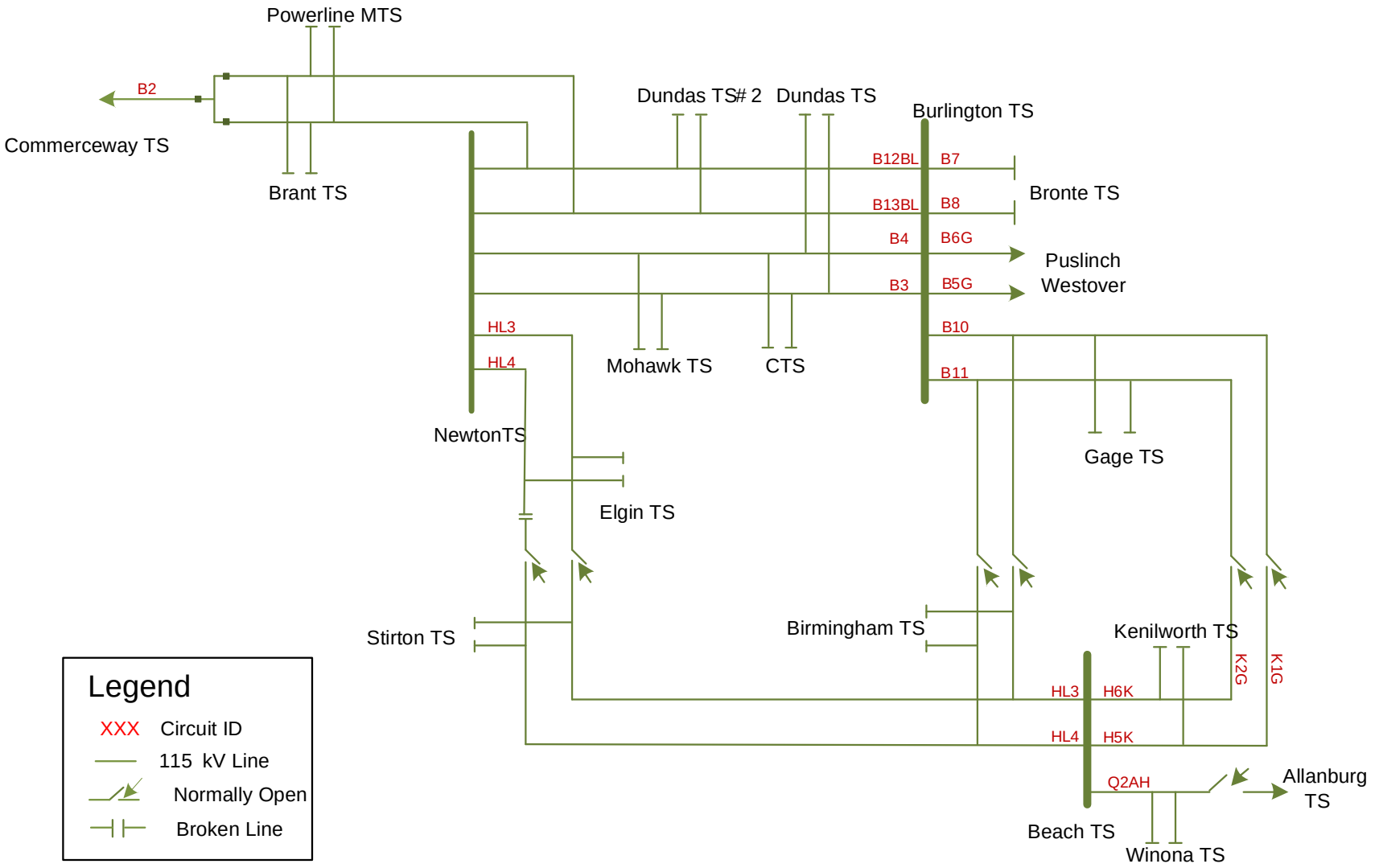


Figure 7: 115 kV Network Supplied by Burlington TS and Beach TS

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Burlington to Nanticoke Region NA. The information provided includes the following:

- Burlington to Nanticoke Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the Burlington to Nanticoke Region.

The community energy plans will be further evaluated during the next phases of this regional planning cycle.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the Burlington to Nanticoke region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Burlington to Nanticoke region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2021 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Burlington to Nanticoke region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns;

- Any major high voltage equipment requiring replacement;
- Load forecast data was requested from industrial customers in the region; and
- The Region is summer peaking so is this assessment based on summer peak loads. Two load forecasts were developed i.e. Normal Growth scenario and High Growth scenario. The High Growth scenario load forecast was developed to conduct a sensitivity analysis to cover unforeseen developments like higher than expected EV charging trend during peak load conditions.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2022-2032.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 NEEDS

This section describes emerging needs identified in the Burlington to Nanticoke Region, and reviews the near, mid, and long-term needs already identified in the previous Regional Planning cycle. A contingency analysis was performed for the region using the load forecast developed and no new system needs were identified.

The following near- term needs identified in the Burlington to Nanticoke 2nd Cycle RIP report have been addressed/completed:

1. Cumberland TS: Power factor correction
2. 115 kV B3/B4: Line section from Horning Mountain Jct. to Glanford Jct. requiring replacement
3. Elgin TS: Transformers & switchgears requiring replacement
4. Newton TS: Transformers requiring replacement
5. Kenilworth TS: Transformer & switchgear requiring replacement

The status of the remaining near-term needs identified in the Burlington to Nanticoke 2nd Cycle RIP report is summarized in Table 3 below.

Table 3: Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Status
1	115 kV B7/B8: Line section from Burlington TS to Nelson Jct. requiring refurbishment	Planned for in-service of 2024
2	Dundas TS: Load transfers	Hydro One Distribution is currently planning to build feeders required for load transfers from Dundas TS to Dundas TS #2. No new additional work inside Dundas TS #2 is required for these load transfers. The combined supply capacity of both Dundas stations is sufficient over and beyond the study period
3	Gage TS: Transformers & switchgear requiring replacement	Project in execution for the refurbishment of T3/ T4 and T5/ T6 DESNs to be replace with a new single DESN having larger transformers with a planned in-service in the Q4 2023
4	Kenilworth TS: Power factor correction	At Kenilworth TS the historical loading data indicated that under peak load the power factor is lagging below the ORTAC requirement of 0.9. To address this issue The TWG 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 at Kenilworth TS will be initiated after completion of refurbishment of this supply station in Q4 2023
5	Norfolk area supply capacity	Electrical supply to the Norfolk Area is provided through two (2) 115 kV C9/C12 transmission circuits supplied by 230/115 kV autotransformers at the Caledonia TS. These two 115 kV circuits have a load meeting capability (LMC) of approximately 88 MW and supply Norfolk area loads through two step down transformer stations, i.e. Bloomsburg DS and Norfolk TS. The load in Norfolk Area has held constant over the years below the LMC. The load however, has peaked at 94 MW during the summer of 2018. The 2nd cycle Burlington to Nanticoke RIP made recommendations to address immediate supply capacity needs in the Norfolk Area. This recommendation included distribution load transfers of approximately 6.5 MW from Norfolk area to Jarvis TS using existing feeders and additional reactive support at Norfolk TS to improve the voltage profile, resulting in an increase of the Norfolk Area LMC by approximately 10 MW. These two recommendations will increase the LMC of the pocket to approximately 105MW.

No.	Needs	Status
		The load transfers from Norfolk area to Jarvis TS are planned to be completed by end of 2022 and the additional reactive support at Norfolk TS is planned for 2023-24 timeframe. The RIP also recommended a further assessment to be carried out by the IESO and Hydro One to review the near to mid-term capacity needs. The IESO carried out this assessment and identified preferred options based on the load forecast at that time. No study report was published. These options should be reexamined with the updated forecast and an appropriate planning approach determined in the scoping assessment phase.

The current timing for the mid- and long-term electrical infrastructure needs identified in the Burlington to Nanticoke Region 2nd cycle RIP report are summarized below in Table 4.

Table 4: Status Update of Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Planned Timeframe**
1	Birmingham TS: Transformer and metalclad switchgears requiring replacement	2027-32
2	Mid-Term Transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4) requiring replacement	2027-32
3	Mid-Term replacement requirement of switchgears at Norfolk TS and Burlington TS	2027-32
4	Cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4 requiring replacement	2033*
5	Norfolk area supply capacity: Install new 230 kV double circuit lines and a new DESN	2027-32
6	Beach TS: 230 kV autotransformers and DESN transformers requiring replacement	2027-32
7	Lake TS: Transformers and switchgear requiring replacement	2026-27
8	Burlington TS: 230 kV autotransformer requiring replacement	2027-32
9	Gage TS (T8/T9 DESN): Transformer and switchgears requiring replacement	2027-32

*- To be finalized through Hamilton IRRP Addendum by the IESO

**- Subject to change depending on multiple factors

7.1 Asset Replacement Needs for Major HV Transmission Equipment

The major HV transmission equipment considered in this assessment is shown in Table 5.

Table 5: Major High-Voltage Transmission Equipment Assessed for Replacement

No.	HV Equipment Included
1.	230/115kV Autotransformers
2.	230kV and 115kV load serving step-down transformers
3.	115kV Breakers
4.	230kV and 115kV transmission lines*
5.	230kV and 115kV underground cables*

*Requirement for a Leave to Construct (Section 92) for any alternative to like-for-like would be an appropriate threshold for which segments to include

Hydro One has identified 115 kV breakers at Newton TS with a planned in-service of 2025 as new additional asset replacement need for its major HV equipment over the next 10 years in the Burlington to Nanticoke Region. These needs are determined by asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc.

The TWG recommended continuation of addressing the new identified asset replacement need of 115 kV breakers at Newton TS as well as needs identified in the 2nd cycle RIP report for the Burlington to Nanticoke Region.

7.2 Station and Transmission Capacity Needs in the Burlington to Nanticoke Region

The Station and Transmission supply capacities have been reviewed and the following needs have been identified in the Burlington to Nanticoke region during the study period of 2022 to 2032.

7.2.1 230/115 kV Autotransformers

The 230/115 kV autotransformers in the Burlington to Nanticoke TS supplying 115 kV stations in the Region are within their ratings for the loss of a single unit and are adequate to supply the forecasted load over the study period.

7.2.2 115kV Transmission Lines

The new area supply needs identified the following which may require regional coordination:

a) Bronte Area Supply

The Bronte Sub-region is within the Burlington-Nanticoke planning region. It roughly encompasses the cities of Burlington and Oakville. An IRRP was completed in 2016 to address the supply capacity issues for the loads supplied by Bronte TS. Bronte TS is radially supplied from the double-circuit 115 kV

transmission line B7/B8 originating from Burlington TS. This IRRP recommended that the peak demand at Bronte TS be limited to 135 MW through incremental load transfers (as required) from Bronte TS to other neighboring stations. For the loads in excess of 135 MW the thermal loading of B7/B8 exceeds capacity following the loss of the companion circuit and the post contingency voltage drop exceeds 10% at Bronte TS. The loads at Bronte TS are forecasted to remain around the current supply capacity of 135 MW over the study period and beyond.

TWG recommend that the loading at Bronte TS has reached its capacity and any future loads in excess of 135 MW in this area be supplied from neighboring stations.

b) Brant Area Supply

The 115 kV Brant area is supplied by two stations i.e. Brant TS and Powerline MTS. An IRRP was completed by the IESO in 2015 to addresses the electricity needs of the area over the next 20 years up to 2033. The report recommended installation of a capacitor bank at Power line MTS and building of a new switching station integrating B12 and B13 115 kV circuits from Burlington TS with a single 115 kV circuit B8W supplied from Karn TS. These two measures increased the Load Meeting Capability (LMC) of 115 kV supply system to Brant area to 165MW.

The coincident load in the 115 kV Brant area system may exceed the LMC of 165 MW before the end of the study period (2032). Additional analysis is required to better assess the need timeframe is required.

TWG recommends Hydro One to monitor the loading on the Brant 115 kV supply system and take remedial measures, if required. This need will be reviewed during the Scoping Assessment phase of this Regional Planning cycle.

c) Norfolk Area Supply

The Norfolk area loads are supplied through Norfolk TS and Bloomsburg DS supplied through two 115 kV circuits from Caledonia autotransformers. In 2020, the IESO carried out an assessment of the supply capability in the Norfolk area when additional load growth was identified by the LDCs. As a result of this assessment, load transfers out of the Norfolk area and additional reactive support at Norfolk TS was recommended. These measures will increase the LMC of supply to Norfolk area from 88MW to 105 MW. In the mid-term the preferred option based on the load forecast at that time was to upgrade Jarvis TS and build four (4) 27.6 kV feeders from this station to Norfolk area to pick up loads limiting the loads supplied from the existing Norfolk area system to within its supply capacity.

Based on the current Normal Growth load forecast the loads are growing at a higher rate than anticipated before. TWG recommends Hydro One monitor the loading levels of Norfolk area supply system and take remedial measures, if required. This need will be reviewed during the Scoping Assessment phase of this Regional Planning cycle.

The remaining115kV circuits supplying the Region are adequate over the study period for the loss of a single 115kV circuit in the Region under the study assumptions of the Needs Assessment.

7.2.3 230 kV and 115 kV Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV supply stations in the Region using the summer station peak load forecasts. The results are as follows:

a) Transformer stations

i. Norfolk TS and Bloomsburg DS (Norfolk Area)

Norfolk TS and Bloomsburg DS are currently supplying loads of 66 MW and 38 MW Norfolk area loads respectively. The supply capacities of these two stations are 97 MW and 49 MW respectively.

The loads at Norfolk TS and Bloomsburg DS are forecasted to exceed their supply capacities in 2030 and 2025 under the Normal Growth scenario.

The current supply capacity of Norfolk area is limited by the capacity two (2) 115kV circuits supplying this area which is about 88 MW much lower than the combined supply capacity of Norfolk TS and Bloomsburg DS.

As described above in Table 3 and in Section 7.2.2, the supply capacity of Norfolk area is currently planned to be addressed mainly through load transfers reducing the loads on Norfolk TS and Bloomsburg DS bringing loading well below their supply capacities. This need will be reviewed during the Scoping Assessment phase of this Regional Planning cycle.

ii. Caledonia TS

Caledonia TS is currently supplying loads of 44 MW having a supply capacity of 99 MW. The load at Caledonia TS is forecasted to exceed its supply in 2030 under Normal growth load forecast scenario.

The TWG recommended Hydro One to monitor the loading at Caledonia TS and this need will be reviewed again during the Scoping Assessment phase of this Regional Planning cycle.

iii. Nebo TS

Nebo TS has two DESNs inside the station supplying loads in the city of Hamilton and surrounding areas. T1/T2 is a 27.6 kV DESN with current load of 122 MW having a supply capacity of 178 MW sufficient over the study period. The loads at T3/T4 13.8 kV DESN at Nebo TS had been historically around its supply capacity and is currently marginally overloaded supplying loads of 55 MW against its supply capacity of 51 MW.

The loads at this DESN are currently forecasted to grow above and beyond its supply capacity.

The TWG recommended that Hydro One and Alectra monitor the loading at Nebo TS T3/T4 DESN and take remedial measures, if required until refurbishment of this DESN is completed. This refurbishment is currently planned to be completed in the 2027-2032 timeframe replacing existing 75 MVA nonstandard transformers with Hydro One standard 100 MVA units. This need will be reviewed during the Scoping Assessment phaseof this Regional Planning cycle.

iv. Mohawk TS

Mohawk TS is a single DESN station supplying loads in the city of Hamilton. This station is currently supplying 81 MW of load having a supply capacity of 90 MW.

The peak load at Mohawk TS had been historically around its current loading levels, however the load at this station is forecasted to exceed its supply in 2024 under Normal growth scenario.

The TWG recommended that Hydro One and Alectra to monitor the loading Mohawk TS and take necessary actions, if required e.g. load transfers to the neighboring stations. This need will be reviewed during the Scoping Assessment phaseof this Regional Planning cycle.

All other transformer stations in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next planning cycle.

Depending on the load growth and the future decisions on contracts for distributed energy resources connected to the station, the capacity of some stations could be reached in the long term (10+ years). The TWG will continue to monitor the load growth at the stations and will re-evaluate the capacity at the next planning cycle.

7.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues have been identified for this Region. Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

8 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Burlington to Nanticoke region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying + 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high growth scenario identified the following updates or new station capacity needs:

No.	Need	Normal Growth Scenario	High Growth Scenario
1	Brant Area Supply**	-*	-*
2	Norfolk Area Supply***	-*	-*
3	Norfolk TS***	2030	2028
4	Bloomsburg DS***	2025	2025
5	Caledonia TS	2030	2027
6	Nebo TS	2022	2022
7	Mohawk TS	2024	2023
8	Brant TS**	-	2031
9	Elgin TS	-	2027
10	Newton TS	-	2030

*- To be further assessed during the next phases of this Regional Planning cycle.

**- Supply capacity at Brant TS will be addressed along with Brant Area Supply capacity need

***- Supply capacity at Norfolk TS and Bloomsburg DS will be addressed along with Norfolk Area Supply capacity need

The sensitivity analysis identified the additional capacity needs at Brant TS, Elgin TS and Newton TS towards the end of the study period. These needs will be assessed again during the next phases of this Regional Planning cycle.

There are two (2) new CTSs one each in Caledonia-Norfolk and Hamilton sub-regions supplied through 230 kV systems. None of these CTS are expected to impact the supply capacity or reliability in the Burlington to Nanticoke Region.

9 CONCLUSION AND RECOMMENDATIONS

The TWG recommends to continue with the refurbishment of section of 115 kV B7/B8 line and Gage TS (T3/T4 and T5/T6 DESNs), load transfer from Dundas TS to Dundas TS #2 to address overloading at this station, supply capacity in Norfolk area, power factor correction at Kenilworth TS as well continue with new identified refurbishment need for 115 kV breakers at Newton TS.

The TWG also recommended that the concerned LDC and Hydro One to monitor the loading levels in Norfolk and Brant areas as well at Caledonia TS, Nebo TS and Mohawk TS and take necessary action to address overloading, if required. These needs will be further reviewed during the Scoping Assessment phase of this Regional Planning cycle.

10 REFERENCES

1. Regional Infrastructure Plan Report – Burlington to Nanticoke – October 2019
2. IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
3. Bronte IRRP (2016)
4. Brant IRRP (2015)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: Burlington to Nanticoke Region – Non-Coincident- Normal Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	74	81	86	87	88	88	89	89	90	94	95	96	97	98	100	101	102	103	105	106	108
	Powerline MTS (T1 / T2)	114	85	76	77	84	98	99	99	100	101	102	103	104	105	107	109	110	112	113	115	117	118
Brant 230 kV	Brantford TS (T3 / T4)	188	159	159	163	166	151	159	160	161	163	164	165	167	168	170	172	174	176	178	180	182	184
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	138	135	132	132	133	133	134	135	135	137	136	135	135	135	134	134	134	134	134	134	134
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	141	149	157	156	155	154	153	152	152	151	150	149	149	149	148	148	148	148	148	148	148
	Cumberland TS (T3 / T4)	174	113	125	137	137	138	138	138	139	140	142	142	141	141	140	140	140	140	140	140	140	140
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	14	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	21
	Birmingham TS (T3 / T4)	91	65	66	68	70	72	73	74	75	76	77	79	80	81	83	85	87	89	90	92	92	92
	Dundas TS (T1 / T2)	99	104	104	105	106	107	107	108	108	109	110	111	112	113	123	124	125	126	128	129	130	130
	Dundas TS #2 (T5 / T6)	89	52	52	52	52	53	53	53	53	54	55	56	56	57	59	60	61	62	64	65	65	65
	Elgin TS (T1 / T2)	134	90	97	101	110	116	120	122	124	126	128	130	132	137	140	142	146	149	152	155	155	155
	Gage TS (T3 / T4)	57	21	21	21	29	37	37	37	37	37	37	38	38	39	40	41	42	43	43	44	44	44
	Gage TS (T5 / T6)	57	12	12	12	14	16	16	16	16	16	16	16	17	17	17	18	18	18	19	19	19	19
	Gage TS (T8 / T9)	123	16	15	15	18	20	20	20	20	20	20	20	21	21	22	22	23	23	24	24	24	24
	Kenilworth TS (T2 / T3)	124	67	69	71	73	75	77	79	80	82	83	85	86	88	89	91	93	95	97	99	99	99
	Mohawk TS (T1 / T2)	90	86	89	92	95	97	100	102	105	107	109	111	112	114	117	119	122	124	127	129	129	129
	Newton TS (T1 / T2)	75	48	48	52	61	62	63	64	65	66	67	69	70	71	72	74	76	77	79	81	81	81
	Stirton TS (T3 / T4)	112	55	55	55	56	57	59	60	62	63	64	65	66	67	69	70	71	73	75	76	76	76
	Winona TS (T1 / T2)	89	61	64	66	68	70	71	72	73	74	75	76	77	79	80	82	84	85	87	89	89	89
	CTS		1	1	23	23	24	22	21	19	15	13	11	9	9	9	9	9	9	9	9	9	9
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	33	34	36	37	38	39	40	41	42	42	43	44	44	45	46	47	48	49	50	50	50
	Beach TS (T5 / T6)	96	62	64	68	70	72	74	75	77	79	80	81	83	84	86	88	90	91	93	95	95	95
	Horning TS (T3 / T4)	113	71	73	76	78	81	83	85	87	89	90	92	93	95	97	99	101	103	105	107	107	107
	Lake TS (T1 / T2)	75	50	50	50	50	50	50	50	50	50	50	50	50	50	50	51	51	51	51	52	52	52
	Lake TS (T3 / T4)	113	54	56	58	59	59	59	60	62	63	64	65	66	67	69	70	71	73	75	76	76	76
	Nebo TS (T1/T2)	178	129	131	132	133	135	136	141	143	144	146	147	149	150	152	154	156	158	160	162	165	167
	Nebo TS (T3 / T4)	51	56	57	59	61	63	64	66	68	69	70	72	73	74	76	77	79	80	82	84	84	84
	CTS		262	259	257	255	254	252	250	249	247	246	245	244	242	242	241	241	241	241	241	241	241
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	71	74	77	82	87	86	93	96	99	103	105	108	110	113	115	118	121	123	126	129	132
	Bloomsburg DS (T1/T2)	49	35	37	40	50	57	55	57	59	64	66	68	70	72	75	77	79	81	83	85	87	89
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	57	63	68	79	84	85	95	98	100	103	105	108	110	113	115	118	121	124	127	129	132
	Jarvis TS (T3/T4)	105	51	55	58	62	69	72	74	76	79	82	84	86	90	92	94	97	100	102	105	107	110
	CTS		195	195	194	193	192	190	189	188	187	187	186	185	184	184	184	184	184	184	184	184	184

Table A.2: Burlington to Nanticoke Region – Coincident – Normal Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	57	62	66	66	67	67	68	68	69	73	73	74	75	76	77	78	79	80	81	82	83
	Powerline MTS (T1 / T2)	114	72	65	65	72	83	84	85	85	86	87	88	89	90	92	93	94	95	97	98	100	101
Brant 230 kV	Brantford TS (T3 / T4)	188	139	139	142	145	132	140	140	141	143	144	145	147	148	149	151	153	154	156	158	160	161
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	114	111	109	109	109	110	110	111	111	112	112	111	111	111	111	111	111	111	111	111	111
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	123	131	138	137	136	135	134	133	133	132	131	131	130	130	130	130	130	130	130	130	130
	Cumberland TS (T3 / T4)	174	98	109	119	119	120	120	121	121	122	123	123	123	123	122	122	122	122	122	122	122	122
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	4	4	4	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6
	Birmingham TS (T3 / T4)	91	48	49	50	51	53	54	54	55	56	57	58	59	60	61	62	64	65	67	68	68	68
	Dundas TS (T1 / T2)	99	93	94	94	95	96	96	97	97	98	99	100	100	101	111	112	113	114	116	117	117	118
	Dundas TS #2 (T5 / T6)	89	46	46	46	46	47	47	47	47	47	48	49	50	51	52	53	54	55	56	58	58	58
	Elgin TS (T1 / T2)	134	72	77	80	87	92	95	97	99	100	102	103	105	109	111	114	116	119	121	124	124	124
	Gage TS (T3 / T4)	57	7	7	7	10	13	13	13	13	13	13	13	13	14	14	14	14	15	15	15	15	15
	Gage TS (T5 / T6)	57	8	8	8	10	11	11	11	11	11	11	11	12	12	12	12	13	13	13	13	13	13
	Gage TS (T8 / T9)	123	11	11	11	13	15	15	15	15	15	15	15	15	16	16	16	17	17	17	18	18	18
	Kenilworth TS (T2 / T3)	124	41	42	43	45	46	47	48	49	50	51	51	52	53	54	55	56	58	59	60	60	60
	Mohawk TS (T1 / T2)	90	69	71	73	76	78	80	82	84	86	87	88	90	91	93	95	97	99	101	103	103	103
	Newton TS (T1 / T2)	75	43	43	47	54	56	57	58	58	60	61	62	63	64	65	66	68	69	71	73	73	73
	Stirton TS (T3 / T4)	112	49	50	50	50	51	53	54	55	57	58	59	59	60	62	63	64	66	67	68	68	68
	Winona TS (T1 / T2)	89	48	50	52	53	55	56	57	57	58	59	60	61	62	63	64	66	67	69	70	70	70
	CTS		0	0	14	14	14	13	12	11	8	6	4	3	3	3	3	3	3	3	3	3	3
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	17	17	18	19	19	20	20	21	21	21	22	22	22	23	23	24	24	25	25	25	25
	Beach TS (T5 / T6)	96	49	51	54	56	58	59	60	62	63	64	65	66	67	69	70	72	73	75	76	76	76
	Horning TS (T3 / T4)	113	60	62	64	66	68	70	72	73	75	76	77	79	80	82	83	85	87	89	91	91	91
	Lake TS (T1 / T2)	75	44	44	44	44	44	44	44	44	44	45	45	45	45	45	45	45	45	46	46	46	46
	Lake TS (T3 / T4)	113	48	50	52	52	52	52	53	55	56	57	58	59	59	61	62	63	65	66	67	67	67
	Nebo TS (T1/T2)	178	115	116	117	118	119	121	125	127	128	129	131	132	133	135	137	139	140	142	144	146	148
	Nebo TS (T3 / T4)	51	48	50	51	53	54	56	57	58	60	61	62	63	64	65	67	68	70	71	73	73	73
	CTS		197	195	193	192	191	189	188	187	186	185	184	183	182	182	181	181	181	181	181	181	181
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	60	62	65	69	73	74	79	83	85	89	91	93	95	97	99	102	104	106	108	111	113
	Bloomsburg DS (T1/T2)	49	32	34	37	46	52	50	52	54	59	61	63	65	66	69	71	73	75	77	78	80	82
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	56	61	67	77	82	83	93	96	98	100	103	105	108	110	113	115	118	121	124	126	129
	Jarvis TS (T3/T4)	105	28	30	31	34	38	39	40	41	43	44	46	47	49	50	52	53	55	56	57	59	60
	CTS		123	124	123	123	122	121	121	120	120	119	119	118	118	118	118	118	118	118	118	118	118

Table A.3: Burlington to Nanticoke Region Non-Coincident – High Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	74	84	92	93	94	95	96	97	98	104	106	107	109	111	112	114	116	118	120	122	124
	Powerline MTS (T1 / T2)	114	85	72	72	84	104	105	107	108	109	111	112	114	116	119	121	123	125	128	130	133	135
Brant 230 kV	Brantford TS (T3 / T4)	188	159	159	165	170	155	167	168	169	173	174	176	178	180	183	185	188	191	194	197	201	204
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	138	133	129	130	131	131	132	133	134	136	135	134	133	133	133	133	133	133	133	133	133
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	141	153	166	164	163	161	159	158	157	156	155	154	153	153	152	152	152	152	152	152	152
	Cumberland TS (T3 / T4)	174	113	131	149	149	150	151	151	152	154	156	156	155	155	154	154	154	154	154	154	154	154
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	14	15	15	16	17	17	18	18	19	19	20	20	21	21	22	22	23	24	24	24	24
	Birmingham TS (T3 / T4)	91	65	67	69	73	75	77	79	80	82	84	86	88	90	92	95	98	101	103	106	106	106
	Dundas TS (T1 / T2)	99	104	105	105	107	108	109	110	111	112	113	114	116	117	132	134	136	138	140	142	143	144
	Dundas TS #2 (T5 / T6)	89	52	52	52	53	54	54	54	54	55	56	57	59	60	62	64	66	68	70	72	72	72
	Elgin TS (T1 / T2)	134	90	100	106	120	128	135	138	141	144	147	150	153	160	164	168	173	178	183	188	188	188
	Gage TS (T3 / T4)	57	21	21	21	33	46	45	45	44	44	45	46	47	48	49	50	52	53	55	56	56	56
	Gage TS (T5 / T6)	57	12	12	12	15	18	18	18	18	18	18	19	19	19	20	20	21	22	22	23	23	23
	Gage TS (T8 / T9)	123	16	15	15	19	23	22	22	22	22	22	23	23	24	25	25	26	27	28	28	28	28
	Kenilworth TS (T2 / T3)	124	67	70	73	77	79	82	85	87	90	91	93	95	98	100	103	106	109	112	115	115	115
	Mohawk TS (T1 / T2)	90	86	90	94	99	103	107	110	114	118	120	123	126	128	132	135	139	143	147	151	151	151
	Newton TS (T1 / T2)	75	48	49	54	67	69	71	72	74	76	77	79	81	83	85	87	90	92	95	97	97	97
	Stirton TS (T3 / T4)	112	55	55	55	56	58	61	63	65	67	69	70	72	73	75	77	80	82	84	87	87	87
	Winona TS (T1 / T2)	89	61	65	68	71	74	77	78	79	80	82	84	86	88	90	92	95	98	100	103	103	103
	CTS		1	1	34	34	35	33	31	28	22	19	16	13	13	12	12	12	12	12	12	12	12
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	33	35	37	38	40	41	43	44	46	47	48	49	50	51	53	54	56	57	59	59	59
	Beach TS (T5 / T6)	96	62	65	71	74	77	79	82	85	88	89	91	93	95	98	100	103	106	109	112	112	112
	Horning TS (T3 / T4)	113	71	75	78	82	85	88	91	94	98	100	102	104	106	110	112	116	119	122	125	125	125
	Lake TS (T1 / T2)	75	50	50	50	50	50	50	50	50	50	50	50	50	50	51	51	51	52	52	52	53	53
	Lake TS (T3 / T4)	113	54	57	61	61	61	61	63	65	68	69	70	72	74	76	78	80	82	85	87	87	87
	Nebo TS (T1/T2)	178	129	132	133	135	137	140	147	149	151	154	156	158	161	163	166	169	173	176	179	182	186
	Nebo TS (T3 / T4)	51	56	58	61	64	66	69	71	74	76	78	80	81	83	86	88	90	93	95	98	98	98
	CTS		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	71	75	80	87	94	94	103	109	113	119	123	126	130	134	137	142	146	150	154	158	162
	Bloomsburg DS (T1/T2)	49	35	38	43	57	68	65	68	70	79	82	85	88	91	95	98	101	104	107	110	113	116
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	57	66	74	89	98	100	115	118	122	126	129	133	137	141	144	149	153	157	161	166	170
	Jarvis TS (T3/T4)	105	51	57	62	68	79	82	86	89	93	97	100	104	109	113	116	120	124	128	132	136	140
	CTS		195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195

Table A.4: Burlington to Nanticoke Region Region – Coincident – High Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	57	64	70	71	72	73	73	74	75	81	82	83	85	86	87	89	90	92	93	95	96
	Powerline MTS (T1 / T2)	114	72	61	62	71	89	90	91	92	93	95	96	97	99	101	103	105	107	109	111	113	115
Brant 230 kV	Brantford TS (T3 / T4)	188	139	139	144	149	135	147	148	149	152	154	155	157	159	161	163	166	169	171	174	177	179
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	114	110	106	107	107	108	109	109	110	112	111	110	110	110	109	109	109	109	109	109	109
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	123	134	145	144	142	141	140	138	138	136	135	135	134	134	133	133	133	133	133	133	133
	Cumberland TS (T3 / T4)	174	98	114	130	130	131	131	132	132	134	136	136	135	135	135	134	134	134	134	134	134	134
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	4	4	5	5	5	5	5	5	6	6	6	6	6	6	6	7	7	7	7	7	7
	Birmingham TS (T3 / T4)	91	48	49	51	53	55	57	58	59	60	62	63	65	66	68	70	72	74	76	78	78	78
	Dundas TS (T1 / T2)	99	93	94	94	96	97	98	98	99	100	102	103	104	105	120	122	123	125	127	129	130	130
	Dundas TS #2 (T5 / T6)	89	46	46	46	47	48	47	48	48	48	50	51	52	53	55	57	58	60	62	64	64	64
	Elgin TS (T1 / T2)	134	72	80	84	95	102	107	110	112	114	117	119	122	128	131	134	138	142	146	150	150	150
	Gage TS (T3 / T4)	57	7	7	7	12	16	16	16	15	15	16	16	16	17	17	18	18	18	19	19	19	19
	Gage TS (T5 / T6)	57	8	8	8	11	13	13	13	13	12	13	13	13	14	14	14	15	15	16	16	16	16
	Gage TS (T8 / T9)	123	11	11	11	14	17	17	16	16	16	16	17	17	18	18	19	19	20	20	21	21	21
	Kenilworth TS (T2 / T3)	124	41	42	44	46	48	50	51	53	54	55	57	58	59	61	62	64	66	68	70	70	70
	Mohawk TS (T1 / T2)	90	69	72	75	79	82	85	88	91	94	96	98	100	103	105	108	111	114	118	121	121	121
	Newton TS (T1 / T2)	75	43	44	49	60	62	64	65	66	68	69	71	73	74	76	78	81	83	85	87	87	87
	Stirton TS (T3 / T4)	112	49	50	50	50	52	54	56	58	60	62	63	65	66	68	70	72	74	76	78	78	78
	Winona TS (T1 / T2)	89	48	51	54	56	58	60	61	62	63	65	66	68	69	71	73	75	77	79	81	81	81
	CTS		0	0	21	21	22	20	19	16	11	9	7	4	4	4	4	4	4	4	4	4	4
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	17	18	19	19	20	21	22	22	23	24	24	25	25	26	27	27	28	29	30	30	30
	Beach TS (T5 / T6)	96	49	52	57	59	62	64	66	68	70	72	73	75	76	79	81	83	85	87	90	90	90
	Horning TS (T3 / T4)	113	60	63	66	69	72	75	77	80	83	84	86	88	90	93	95	98	100	103	106	106	106
	Lake TS (T1 / T2)	75	44	44	44	44	44	44	44	44	44	45	45	45	45	45	45	46	46	46	47	47	47
	Lake TS (T3 / T4)	113	48	51	54	54	54	54	56	58	60	61	62	64	65	67	69	71	73	75	77	77	77
	Nebo TS (T1/T2)	178	115	117	118	120	122	124	131	133	135	137	139	141	143	145	148	151	153	156	159	162	165
	Nebo TS (T3 / T4)	51	48	50	53	55	58	60	62	64	66	68	69	70	72	74	76	78	80	83	85	85	85
	CTS		201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	60	63	68	74	80	80	89	94	98	103	106	109	112	116	119	122	126	129	133	136	139
	Bloomsburg DS (T1/T2)	49	32	35	39	53	62	59	62	64	73	75	78	81	84	88	91	93	96	99	102	104	107
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	56	64	72	87	95	97	112	115	119	123	126	130	134	137	141	145	149	154	158	162	166
	Jarvis TS (T3/T4)	105	28	31	33	37	43	44	46	48	50	53	55	57	60	62	64	66	68	70	72	74	77
	CTS		123	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer 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: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Beach TS – CTS	H35D, H36D	230
2	Beach TS – Burlington TS	B18H, B20H	230
3	Beach TS – Middleport TS	M34H	230
4	Beach TS – Middleport TS – Beck #2 TS	Q24HM, Q29HM	230
5	Burlington TS – Cumberland TS	B40C, B41C	230
6	Burlington TS – Middleport TS	M27B, M28B	230
7	Burlington TS – Middleport TS – Beck #2 TS	Q23BM, Q25BM	230
8	Middleport TS – Beck #2 TS	Q30M	230
9	Middleport TS – Buchanan TS	M31W, M32W, M33W	230
10	Middleport TS – Detweiler TS	M20D, M21D	230
11	Middleport TS – Nanticoke TS	N5M, N6M	230
12	Middleport TS – Summerheaven SS	S39M	230
13	Middleport TS – Sandusk SS	K40M	230
14	Nanticoke TS – Jarvis TS	N21J, N22J	230
15	Summerhaven SS – Nanticoke TS	N37S	230
16	Sandusk SS – Nanticoke TS	N20K	230
17	Beach TS – Gage TS	B10, B11	115
18	Beach TS – Kenilworth TS	H5K, H6K	115
19	Beach TS – Newton TS	HL3, HL4	115
20	Beach TS – Winona TS	Q2AH	115
21	Beach TS – CSS	H9W	115
22	Burlington TS – Brant TS	B12BL, B13BL	115
23	Burlington TS – Bronte TS	B7, B8	115
24	Burlington TS – Cedar TS	B5G, B6G	115
25	Burlington TS – Newton TS	B3, B4	115
26	Caledonia TS – Norfolk TS	C9, C12	115
27	Kenilworth TS – Gage TS (Idle)	K1G, K2G	115

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



Burlington Nanticoke Region Scoping Assessment Outcome Report

December 5, 2022

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Connecting Today.
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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the regional planning process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

This is the third cycle of regional planning for the Burlington Nanticoke region, and was initiated in spring 2022. Information and links to earlier products are available on the IESO webpage, here. The Needs Assessment is the first step in the regional planning process and was carried out by the Study Team led by Hydro One. This report was finalized on September 6, 2022 and identified some needs that may require further regional coordination. This need information was an input into the Scoping Assessment. The Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an IRRP – where both wires and non-wires options have potential to address needs; a RIP – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the Technical Working Group.

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Transmission)
- Hydro One Networks Inc. (Distribution)
- Alectra Utilities Corporation
- Burlington Hydro Inc.
- GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power)
- Oakville Hydro Inc.

3. Categories of Needs, Analysis, and Results

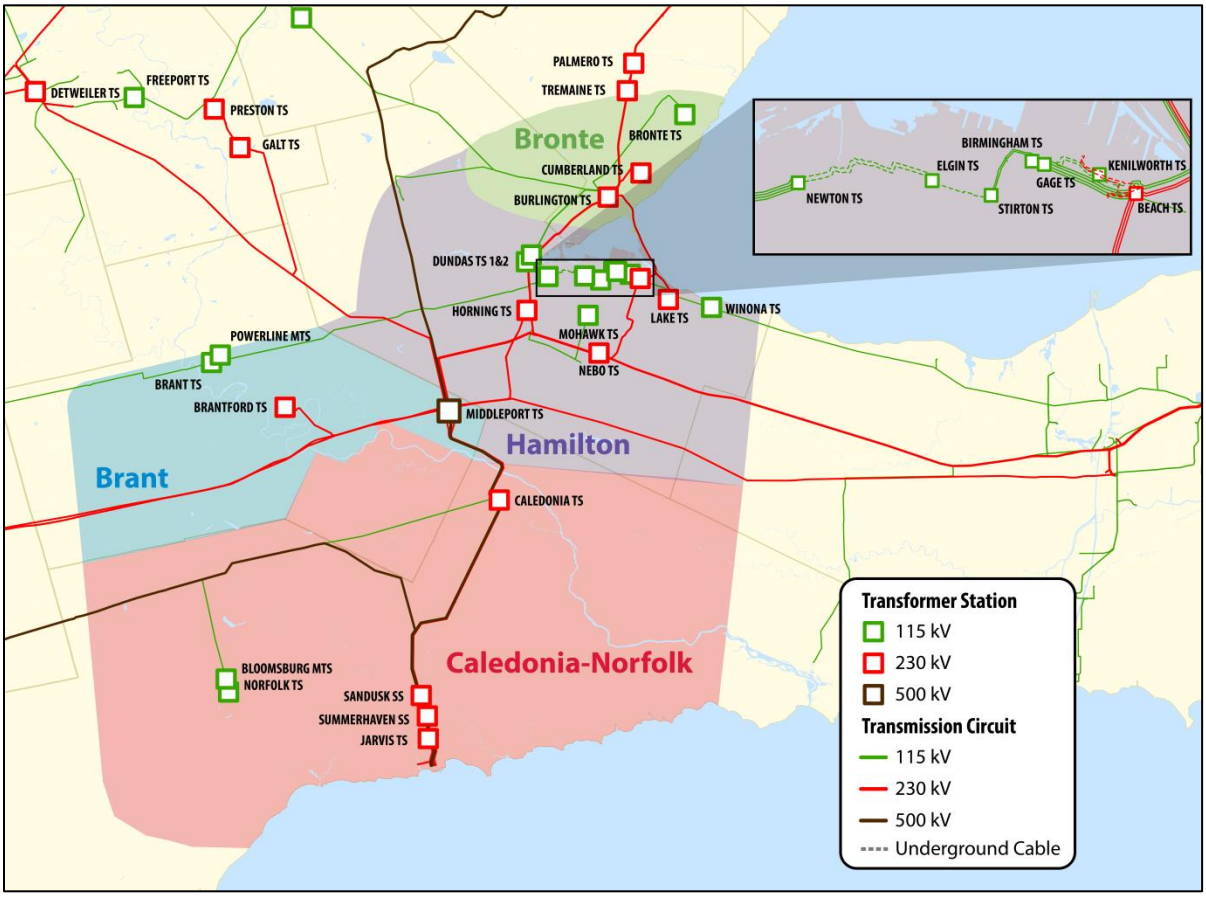
3.1 Overview of the Region

The Burlington to Nanticoke region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, Brant County, the City of Brantford, Haldimand County, Norfolk County, and the Regional Municipality of Halton. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Several Indigenous communities are located in or near the region including: Chippewas of the Thames, Mississaugas of the New Credit, Munsee-Delaware Nation, Oneida Nation of the Thames, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. The Huron Wendat Nation, now located in Wendake, Quebec, also has a historical interest in southern Ontario. A number of Métis Nation of Ontario (MNO) councils are also located within or near the region including MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

The electricity infrastructure supplying the Burlington to Nanticoke region is shown in Figure 1. For the purposes of regional planning, the Burlington to Nanticoke region has historically been sub-divided into four sub-regions: Bronte, Hamilton, Brant, and Caledonia-Norfolk.

Figure 3-1 | Overview of the Burlington Nanticoke Region



NOTE: Region is defined by electricity infrastructure; geographical boundaries are approximate.

The Bronte sub-region includes Burlington TS and the 230 kV and 115 kV supply northeast of the station which services Cumberland TS and Bronte TS, respectively. The 115 kV supply southwest from Burlington TS and the 230 kV supply from Beach TS service the 115 kV network in the Hamilton sub-region, while 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS, and Middleport TS and Burlington TS supply the Hamilton sub-region's 230 kV connected load supply stations. The Brant sub-region is supplied from the 230 kV supply west from Middleport TS and a 115 kV supply from Burlington TS. The 230 kV supply south from Middleport TS supplies the 230 kV connected stations in the Caledonia-Norfolk sub-region, including Caledonia TS. The 115 kV supply from Caledonia TS then supplies Bloomsburg MTS and Norfolk TS.

3.2 Background of the Previous Planning Process

The regional planning process was formalized by the OEB in August 2013. To prioritize and manage the process, Ontario was organized into 21 regions based on electricity infrastructure boundaries; each of which were assigned to one of three groups based on urgency of need, where Group 1 Regions were being reviewed first. When the Board formalized the regional planning process in 2013 planning work was already ongoing in the Brant area, a sub-region of the Burlington to Nanticoke

region. As such, Burlington to Nanticoke became one of the Group 1 planning regions, the first group to undergo the formalized regional planning process.

On May 23, 2014, Hydro One Transmission published the first needs assessment report for the region. Subsequently on September 25, 2014, the former OPA (now the IESO) published a scoping assessment report for the Burlington to Nanticoke region which specified the terms of reference for the Bronte IRRP, in addition to the already published terms of reference for the Brant IRRP which was already underway. No IRRP was required at the time for the Hamilton or Caledonia-Norfolk sub-regions. Regional plans were completed for the Brant and Bronte sub-regions in April 2015 and June 2016, respectively, and Hydro One completed a Local Planning Report for the broader region in October 2015, and a Burlington to Nanticoke RIP on February 7, 2017.

The second round of regional planning for Burlington-Nanticoke began with a Hydro One led Needs Assessment, completed in May of 2017. Based on these needs, the subsequent Scoping Assessment recommended the initiation of a Hamilton IRRP, which was completed in February 2019. This IRRP focused heavily on the large number of assets in the Hamilton area which were approaching their expected end-of-life. The IRRP explored opportunities to "right-size" equipment; that is, refurbish with a higher or lower rating depending on how capacity needs in the area have changed since it was originally installed. Capacity needs at two area stations were also studied, with recommendations ranging form upsizing at end-of life, and implementation and monitoring of CDM and non wires alternatives to defer the need for further infrastructure investment.

Additional information and links to reports form previous cycles are available on the IESO regional planning website for Burlington Nanticoke, available here.

Hydro One completed the most recent needs assessment for the Burlington to Nanticoke region on September 6th, 2022. The needs identified form the basis of the analysis for the scoping assessment and are discussed in further detail in section 3.3.

3.3 Needs Identified

Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the Burlington Nanticoke region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans underway to address previously identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation. Table 3-1 below summarizes this. These projects provide a basis for future assessments and should be accounted for in this planning cycle.

Table 3-1 | Needs Identified in the Previous Cycle and Implementation Plan Update

Need	Solution and Timing
115kV B7/B8 section from Burlington TS to Nelson Jct	Planned refurbishment for 2024 in-service
Dundas TS	Load transfers and balancing Planned 2023 in-service
Gage TS	Replacement of T3/T4 and T5/T6 transformers and switchgear, planned Q4 2023 in-service
Kenilworth TS	Power factor correction planned for 2023-2024 timeframe
Norfolk area Supply Capacity[1]	Load transfers from Norfolk TS to Jarvis TS planned by the end of 2022 Additional reactive support planned for Norfolk TS in 2023-2024 timeframe Jarvis TS upgrade with additional feeders to enable additional Norfolk area transfers, planned for 2027-2032 timeframe

Since the previous regional planning cycle, solutions to address the following needs have also been implemented:

- Cumberland TS: Power factor correction
- 115kV B3/B4 section from Horning Mountain Jct to Glanford Jct refurbishment
- Elgin TS: Transformer & switchgear replacement
- Newton TS: Transformer replacement
- Kenilworth TS: Transformer & switchgear replacement

3.3.2 Needs identified in the Current Planning Cycle

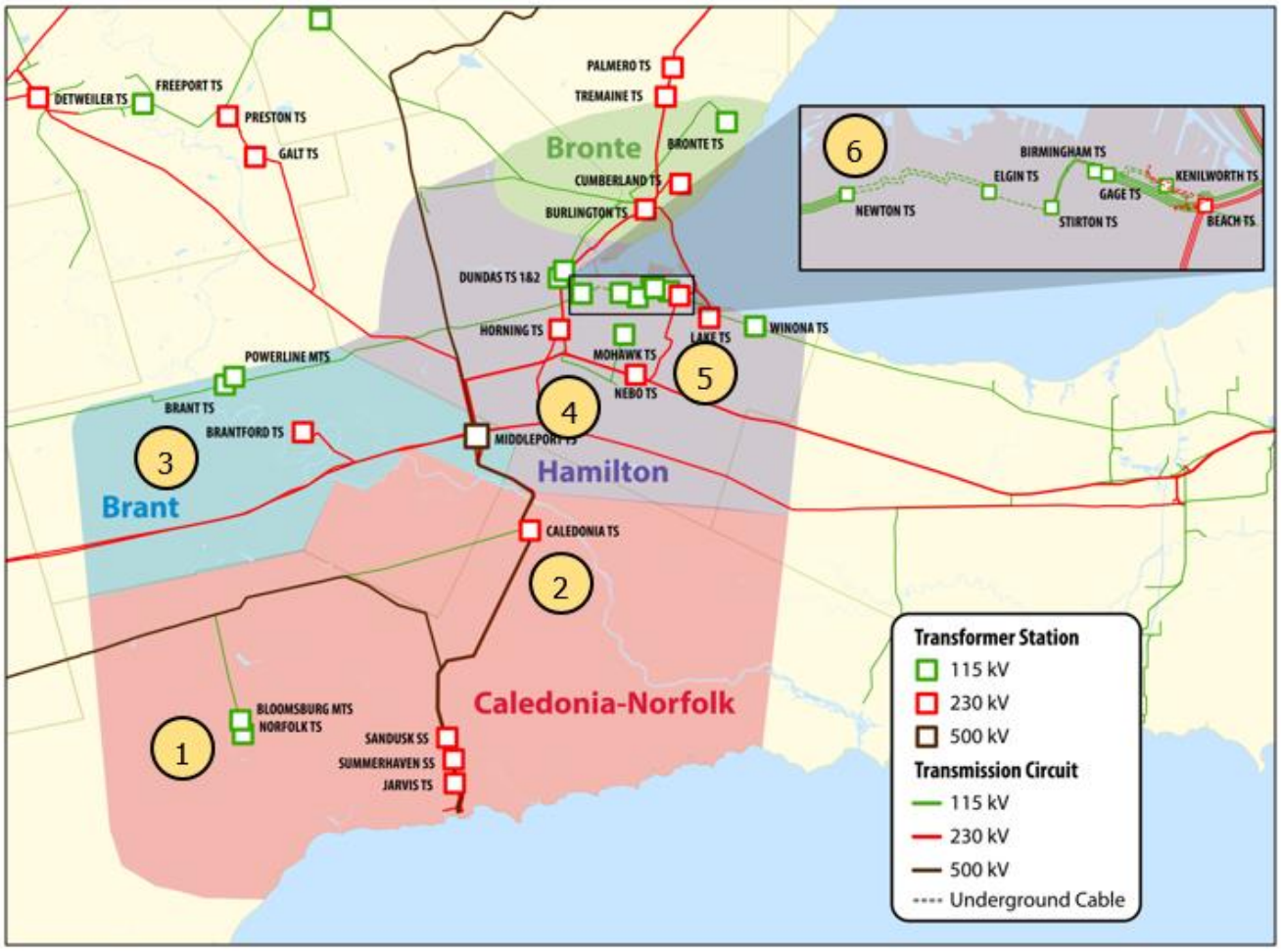
The Needs Assessment then identified new or updated needs in the Burlington to Nanticoke region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated end-of-life asset condition information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Table 3-2 below lists these regional needs and their timing. Their locations are shown in Figure 3-3.

Table 3-2 | Updated Regional Needs Identified in the Needs Assessment

[1] These needs were identified between planning cycles due to changes in the forecast growth for the sub-region.

Need #	Station/Circuit	Description of Need
1	Norfolk TS and Bloomsburg DS	• Station capacity expected to be exceeded in 2030 and 2025, respectively. Currently planned to be addressed through load transfers to upgraded Jarvis TS and new feeder connections in the 2027-2032 timeframe
2	Caledonia TS	• Station capacity expected to be exceeded in 2030
3	Brant Area Supply	• The coincident load of the Brant area is expected to exceed the LMC of the three 115 kV supply circuits supplying the area within the study period (2022-2032)
4	Nebo TS	• Station capacity expected to be exceeded over planning horizon. However, this station is expected to be refurbished in the 2027-2032 timeframe, and 75 MVA transformers could potentially be replaced with 100 MVA units at that time to increase capacity
5	Mohawk TS	• Station capacity expected to be exceeded in 2024
6	Newton TS 115 kV breakers	• Have been identified for replacement based on asset condition assessment • Refurbishment recommended as part of Needs Assessment

Figure 3-3 | Geographic Location of Needs Identified in the Needs Assessment



3.3.3 Analysis of Needs and Identification of Region

The Study Team has discussed the needs in the Burlington Nanticoke region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning Regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs and the greater the need for coordination and engagement, the more likely an IRRP will be selected. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk

power system, then a more streamlined planning approach with a narrower scope may be appropriate.

Of the six updated regional needs identified in the Needs Assessment, most have a fairly limited geographic impact, which makes them suitable to be considered in more discrete blocks:

1. Needs 1 and 2 (Norfolk TS, Bloomsburg DS, and Caledonia TS) are both primarily driven by increases in local peak electrical demand. Given the rate of growth is expected to be somewhat modest, these needs may be good candidates to consider non wires alternatives as a way to defer the need for infrastructure investments. The potential to shift load between stations in this pocket also makes it a good candidate for a shared scope of study.
2. Need 3 (Brant area supply), is another area whose needs are primarily driven by increases in peak demand. Because the need is expected to be triggered by the combined load of supply circuits, the combined step down stations in the sub region must be considered as a collective unit, and transfers between stations would not be an effective option to address supply needs. Instead, non wires alternatives may be considered as a potential deferment strategy compared to traditional wires infrastructure.
3. Needs 4, 5, and 6 (Hamilton area), are primarily driven by growth in peak capacity or aging infrastructure needs with consideration of a number of refurbishment opportunities within the planning timeline. The close proximity of loads, high anticipated growth rates from new development and intensification, and potential opportunity for right sizing of infrastructure during refurbishment all present opportunities to consider needs in a coordinated manner. Options to address needs would include conventional infrastructure and non wires alternatives. The area is also in close proximity, and shares key infrastructure, with parts of the bulk power system. This may require more detailed analysis during a study to understand potential impacts of needs or solutions on the regional vs bulk system.

The associated timelines for these needs vary, but are all within the near- (0-5 years) to mid-term (5-10 years), which suggests planning should be undertaken within the current regional planning cycle to ensure options can be evaluated and a preferred outcome selected and implemented in time.

Recommendation: Given the shared geographic impact of certain needs, and opportunities which may arise from considering solutions to those needs in a coordinated manner, separate studies should be undertaken for each of three sub-regions: Hamilton, Brant, and Caledonia-Norfolk. Due to the greater number of potential solutions to consider, the potential bulk system impact, and additional end of life opportunities, the full 18 months' timeline is expected to be required for the more complex Hamilton IRRP. The more limited number of needs and potential solutions, in addition to a smaller area of interest with limited bulk system impact, suggests the Brant and Caledonia-Norfolk IRRPs could be completed with an expedited 12-month timeline.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Further coordinated regional planning is required to identify, evaluate, and recommend solutions to address needs in three sub-regions of the Burlington-Nanticoke Region:
    1. A full scope IRRP is recommended for Hamilton, with a focus on accommodating overall demand growth, potential interactions with the local bulk system, and addressing options for equipment end of life. This will include needs identified in the Needs Assessment, as well as potential needs identified in the 2019 Hamilton IRRP as requiring monitoring.
    2. A reduced scope IRRP is recommended for Brant, with a focus on supply to the pocket and station capacity needs.
    3. A reduced scope IRRP for Caledonia-Norfolk, with a focus on station capacity and refurbishment needs.
- No further coordinated regional planning is required at this time for the Bronte sub-region

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the Hamilton IRRP, Brant IRRP, and Caledonia-Norfolk IRRP are attached in Appendix 2.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAPS	Local Achievable Potential Study
LDC	Local Distribution Company
MNO	Métis Nation of Ontario
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

Appendix 2 – Brant Sub-Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an IRRP of the Brant sub-region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Brant Sub-region

The Brant sub-region is one of the four sub-regions within the larger Burlington to Nanticoke planning region. The Burlington to Nanticoke region includes the 500 kV, 230 kV, and 115 kV electricity infrastructure located in Southwestern Ontario. The region is split into four smaller sub-regions for planning purposes: Bronte, Brant, Hamilton, and Caledonia-Norfolk. The Brant sub-region is a summer-peaking region that is serviced by 230 kV, and 115 kV circuits and transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-3.

Figure A-3 | Overview of the Sub-region



The Brant sub-region includes the County of Brant, City of Brantford, and the surrounding areas. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Indigenous communities located in or near the Brant sub-region are: Mississaugas of the New Credit, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. Three Métis Nation of Ontario (MNO) councils are also located within or near the region: MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Brant Sub-Region Electricity System

The electricity system supplying the Brant sub-region is shown in Figure A-4.

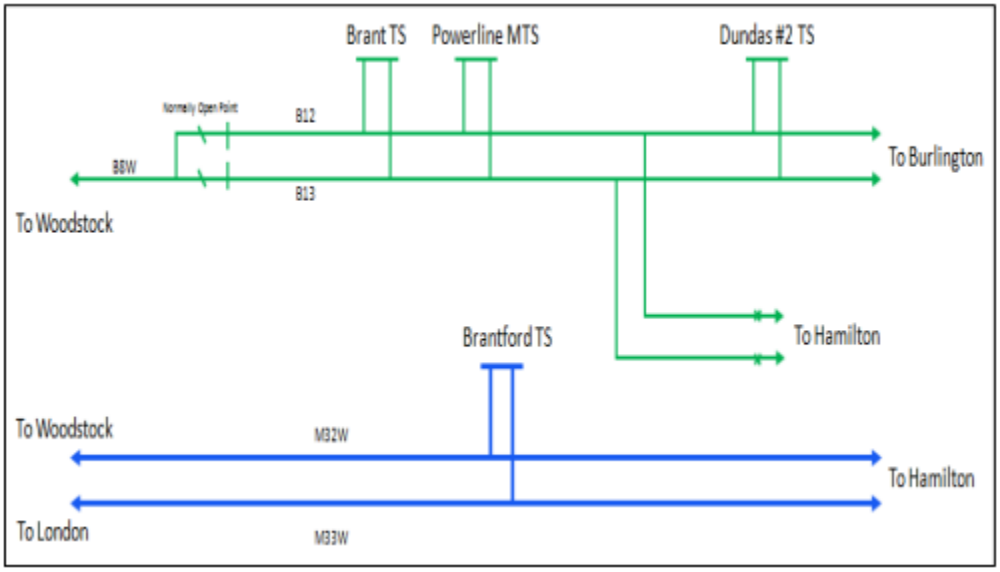


Figure A-4 | Brant Sub-Region Electricity System

The Brant sub-region is comprised of three transformer stations and a number of 115 kV and 230 kV circuits. The Brant sub-region is supplied from the 230 kV supply west from Middleport TS (located in Hamilton) and a 115 kV supply from Burlington TS (located in Bronte).

Background

In the last regional planning cycle for the Burlington to Nanticoke region, a needs assessment was conducted for the entire region and was published in 2017. This needs assessment concluded that further regional planning was required for the Hamilton sub-region only. The Hamilton sub-region IRRP was published in 2019, while local planning was implemented in the other three sub-regions.

In September 2022, Hydro One completed the 3rd Cycle Needs Assessment report for the Burlington to Nanticoke region. A system capacity need, for the 115 kV system that supplies the Brant area, was

identified in the sub-region. This need is dependant on the load levels in Hamilton, specifically the load levels at the Dundas DESNs. It was determined that this need required regional coordination and the consideration of non-wires alternatives, and as such, an IRRP would be required for the sub-region. The load forecasting for the Brant IRRP will coincide with the Hamilton IRRP load forecast which will be incorporated in the load flow simulations to capture the impact on the supply capacity to the Brant area.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Brant sub-region over the next 20 years.
2. To address the sub-region's system capacity needs, and develop a flexible, comprehensive, integrated electricity plan for the sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Brant sub-region. The plan is a joint initiative involving GrandBridge Energy Inc., Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will focus on the identified system capacity need in the sub-region. It will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

This IRRP will address regional needs in the Brant sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 115 kV connected transformer stations: Brant TS, Powerline MTS
- 230 kV connected transformer stations: Brantford TS
- 115 kV transmission circuits: double circuit B12BL(B12)/B13BL(B13), B2(B8W)
- 230 kV transmission circuits: double circuit M32W/M33W

The Brant IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices;

- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the sub-region; and
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, and environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
  - Historical coincident peak demand information for the region
  - Historical weather correction, median and extreme conditions
  - Gross peak demand forecast scenarios by region and TS, etc.
  - Coincident peak demand data, including transmission-connected customers
  - Identified potential future load customers
  - Customer/load segmentation information (e.g. residential, commercial, industrial) by TS
- Conservation and Demand Management
  - Conservation forecast for LDC customers, based on region's share of current energy efficiency programs and/or those reflected in the forecast for the most recent Annual Planning Outlook
  - Potential for CDM at transmission-connected customers' facilities
- Local resources
  - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators, and hydroelectric facilities as applicable
  - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
  - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans and Municipal Energy Plans
  - Municipal Growth Plans
  - Indigenous Community Energy Plans
- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria (ORTAC)

    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- End-of-life asset considerations/sustainment plans
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- GrandBridge Energy Inc.
- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Brant Sub-region IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2022
2. Develop the summer planning forecast for the sub-region[2]		Long-term planning forecast scenarios	Q1 2023
Establish historical coincident (for the sub-region and the 115 kV system) peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed, and potential DG	IESO, LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

[2] Will be coordinated with the forecasting activities for the Hamilton IRRP.

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop a high planning forecast scenario for sensitivity analyses, as appropriate (including but not limited to: consideration of electric vehicle/transportation trends and potential impact on Brant sub-region demand)	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q3 2023
4. Provide and review relevant community plans, if applicable	LDCs, public stakeholders, and IESO	Relevant community plans	Q3 2023
Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case Apply reliability criteria as defined in ORTAC to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q3-Q4 2023
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q4 2023
Conduct a screening to identify which non-wires options warrant further analysis	IESO		
Verify the LMC of the 115 kV system to better determine timing of needs and support options development	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop screened-in energy efficiency options	IESO and LDCs		
Develop screened-in local generation/demand management options	IESO and LDCs		
Develop the transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement would be launched in Q3 2023
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop communications materials	IESO, Hydro One Transmission, and LDCs		
Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1 2024
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	Q2 2024

Appendix 3 – Caledonia - Norfolk Sub-Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an IRRP of the Caledonia-Norfolk sub-region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Caledonia-Norfolk Sub-region

The Caledonia-Norfolk sub-region is one of the four sub-regions within the larger Burlington to Nanticoke planning region. The Burlington to Nanticoke region includes the 500 kV, 230 kV, and 115 kV electricity infrastructure located in Southwestern Ontario. The region is split into four smaller sub-regions for planning purposes: Bronte, Brant, Hamilton, and Caledonia-Norfolk. The Caledonia-Norfolk sub-region is the southern-most portion of the Burlington to Nanticoke region, and includes 115 kV and 230 kV circuits and transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-3.

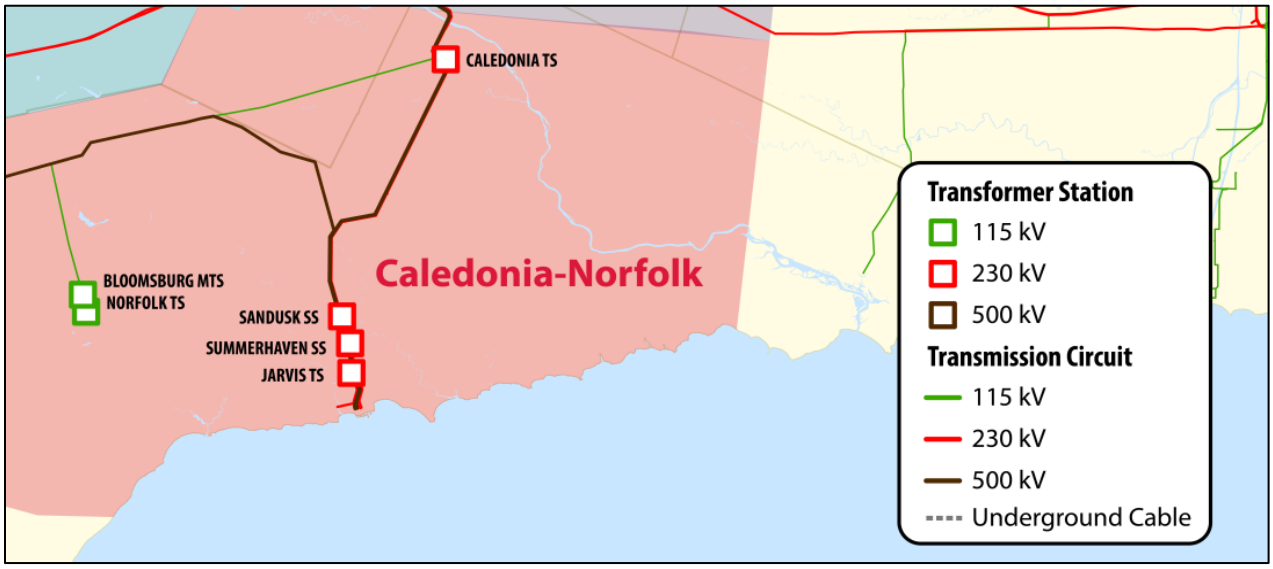


Figure A-3 | Overview of the Sub-region

The Caledonia-Norfolk sub-region covers the eastern part of Norfolk County and the western part of Haldimand County. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Indigenous communities located in or near the Caledonia-Norfolk sub-region are: Mississaugas of the New Credit, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. Three Métis Nation of Ontario (MNO) councils are also located within or near the region: MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Caledonia-Norfolk Sub-Region Electricity System

The electricity system supplying the Caledonia-Norfolk sub-region is shown in Figure A-4.

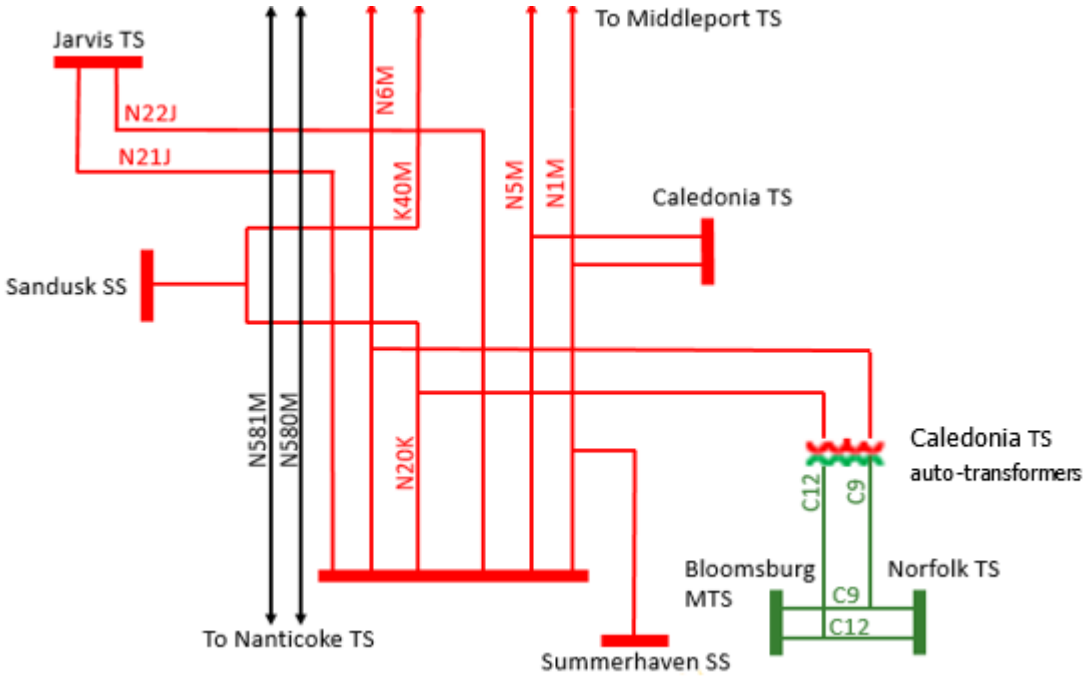


Figure A-4 | Burlington to Nanticoke Electricity System

The Caledonia-Norfolk sub-region is supplied by the 230 kV corridor that runs between Middleport TS, a 500/230 kV station located in the centre of the Burlington to Nanticoke region, and Nanticoke TS. The sub-region is comprised of six transformer stations. Specifically, the sub-region contains four 230 kV stations: Caledonia TS, Jarvis TS, and two customer owned transformer stations; in additon to two 115 kV transformer stations: Bloomsburg MTS and Norfolk TS. The 115 kV transformer stations are supplied by two 115 kV circuits: C9 and C12 which are supplied from Caledonia TS 230/115 kV autotransformers.

Background

In the last regional planning cycle for the Burlington to Nanticoke region, a Needs Assessment was conducted for the entire region and was published in 2017. This needs assessment concluded that further regional planning was required for the Hamilton sub-region only. The Hamilton sub-region

IRRP was published in 2019, while local planning was implemented in the other three sub-regions. Three needs were identified and recommended to be addressed through local planning in the Caledonia-Norfolk sub-region: the end-of-life of the LV switchgear at Norfolk TS, the end-of-life of the T1 transformers at Caledonia TS, and the end-of-life of the T3 and T4 transformers at Jarvis TS.

During the final step of regional planning in the last cycle – the Regional Infrastructure Plan ("RIP"), emerging capacity needs were identified in the Caledonia-Norfolk sub-region due to the new load growth in the Norfolk area. The RIP recommended near term solutions to address the overloads observed in the Norfolk area which include a new capacitor bank at Norfolk TS and load transfers from Norfolk TS to Jarvis TS. The RIP recommended a further assessment be carried out by the IESO and Hydro One to further examine the load growth, examine options and identify a recommended plan.

However, a large portion of the emerging capacity needs was driven by forecast load growth in the cannabis sector and load forecast uncertainty emerged before any planning reports were finalized, putting planning work on hold for the sub-region.

In September 2022, Hydro One completed the newest needs assessment for the Burlington to Nanticoke region. Two station capacity needs were identified in the Caledonia-Norfolk sub-region, at Norfolk TS (and Bloomsburg DS) and Caledonia TS. It was determined that these needs required regional coordination and as such, an IRRP would be required for the sub-region.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Caledonia-Norfolk sub-region over the next 20 years.
2. To address the sub-region's long-term capacity needs and demand forecast, and develop a flexible, comprehensive, integrated electricity plan for the sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Caledonia-Norfolk sub-region. The plan is a joint initiative involving Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will focus on the identified capacity needs in the sub-region. It will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

This IRRP will address regional needs in the Caledonia-Norfolk sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 230 kV connected transformer stations: Caledonia TS, Jarvis TS and two customer owned transformer stations
- 115 kV connected transformer stations: Bloomsburg MTS and Norfolk TS
- 115 kV transmission circuits: C9 and C12
- 230 kV transmission circuits: N5M, N6M, N20K, N21J, N22J, K40M, and S39M

The Caledonia-Norfolk IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices;
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the sub-region; and
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, and environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
  - Historical coincident peak demand information for the region
  - Historical weather correction, median and extreme conditions
  - Gross peak demand forecast scenarios by region and TS, etc.
  - Coincident peak demand data, including transmission-connected customers
  - Identified potential future load customers
  - Customer/load segmentation information (e.g. residential, commercial, industrial) by TS
- Conservation and Demand Management
  - Conservation forecast for LDC customers, based on region's share of current energy efficiency programs and/or those reflected in the forecast for the most recent Annual Planning Outlook
  - Potential for CDM at transmission-connected customers' facilities
- Local resources
  - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators, and hydroelectric facilities as applicable

    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- End-of-life asset considerations/sustainment plans
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*

- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Caledonia-Norfolk IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2022
2. Develop the summer planning forecast for the sub-region		Long-term planning forecast scenarios	Q4 –Q1 2023
Establish historical coincident (for the sub-region) and non-coincident (for Norfolk TS and Caledonia TS) peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Establish existing, committed, and potential DG	IESO, LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop a high planning forecast scenario for sensitivity analyses, as appropriate (including but not limited to: consideration of electric vehicle/transportation trends and potential impact on Caledonia-Norfolk sub-region demand)	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q1 2023
4. Provide and review relevant community plans, if applicable	LDCs, public stakeholders, and IESO	Relevant community plans	Q1 2023
5. Complete system studies to identify needs over a 20-year time horizon - Obtain PSS/E base case - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2023
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 2023

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Conduct a screening to identify which non-wires options warrant further analysis	IESO		
Produce hourly forecasts for Norfolk TS and Caledonia TS to enable detailed needs characterization and support options development	IESO		
Develop screened-in energy efficiency options	IESO and LDCs		
Develop screened-in local generation/demand management options	IESO and LDCs		
Develop the transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and LDCs		
Develop communications materials	IESO, Hydro One Transmission, and LDCs		
Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q2 – Q3 2023
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	Q2 – Q3 2023

Appendix 4 – Hamilton Sub-Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an IRRP of the Hamilton sub-region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Hamilton Sub-region

The Hamilton sub-region is one of the four sub-regions within the larger Burlington to Nanticoke planning region. The Burlington to Nanticoke region includes the 500 kV, 230 kV, and 115 kV electricity infrastructure located in Southwestern Ontario. The region is split into four smaller sub-regions for planning purposes: Bronte, Brant, Hamilton, and Caledonia-Norfolk. The Hamilton sub-region is a summer-peaking region that includes the City of Hamilton and is serviced by 230 kV, and 115 kV circuits and transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-3.

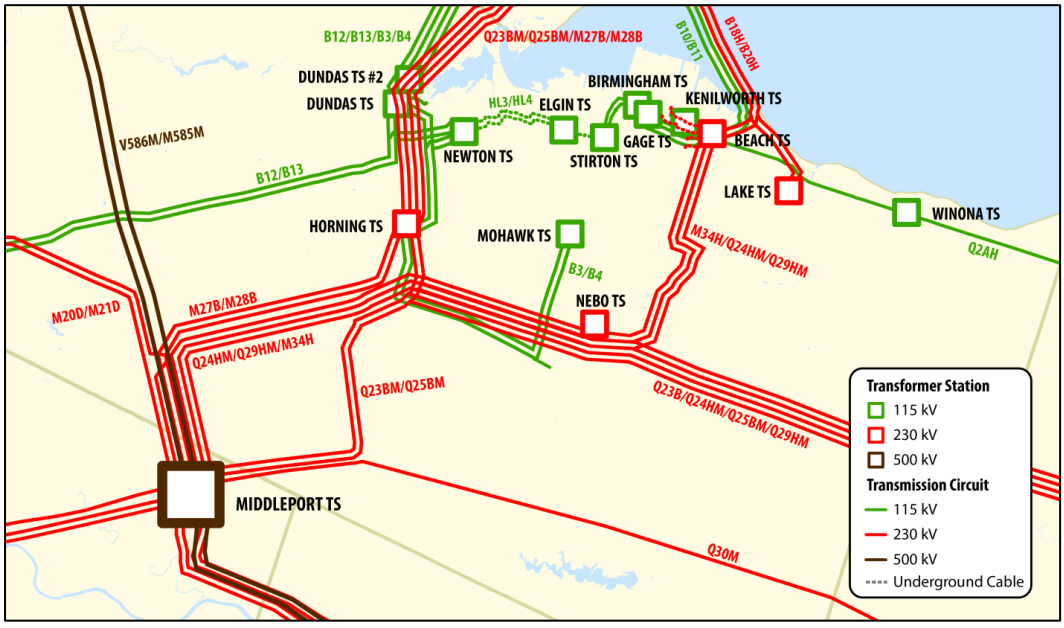


Figure A-3 | Overview of the Sub-region

The City of Hamilton includes the communities of Hamilton, Flamborough, Dundas, Ancaster, Glanbrook, Binbrook, Waterdown, and Stoney Creek. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Indigenous communities located in or near the Hamilton sub-region are: Mississaugas of the New Credit, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. Three Métis Nation of Ontario (MNO) councils are also located within or near the region: MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Hamilton Sub-Region Electricity System

The electricity system supplying the Hamilton sub-region is shown in Figure A-4.

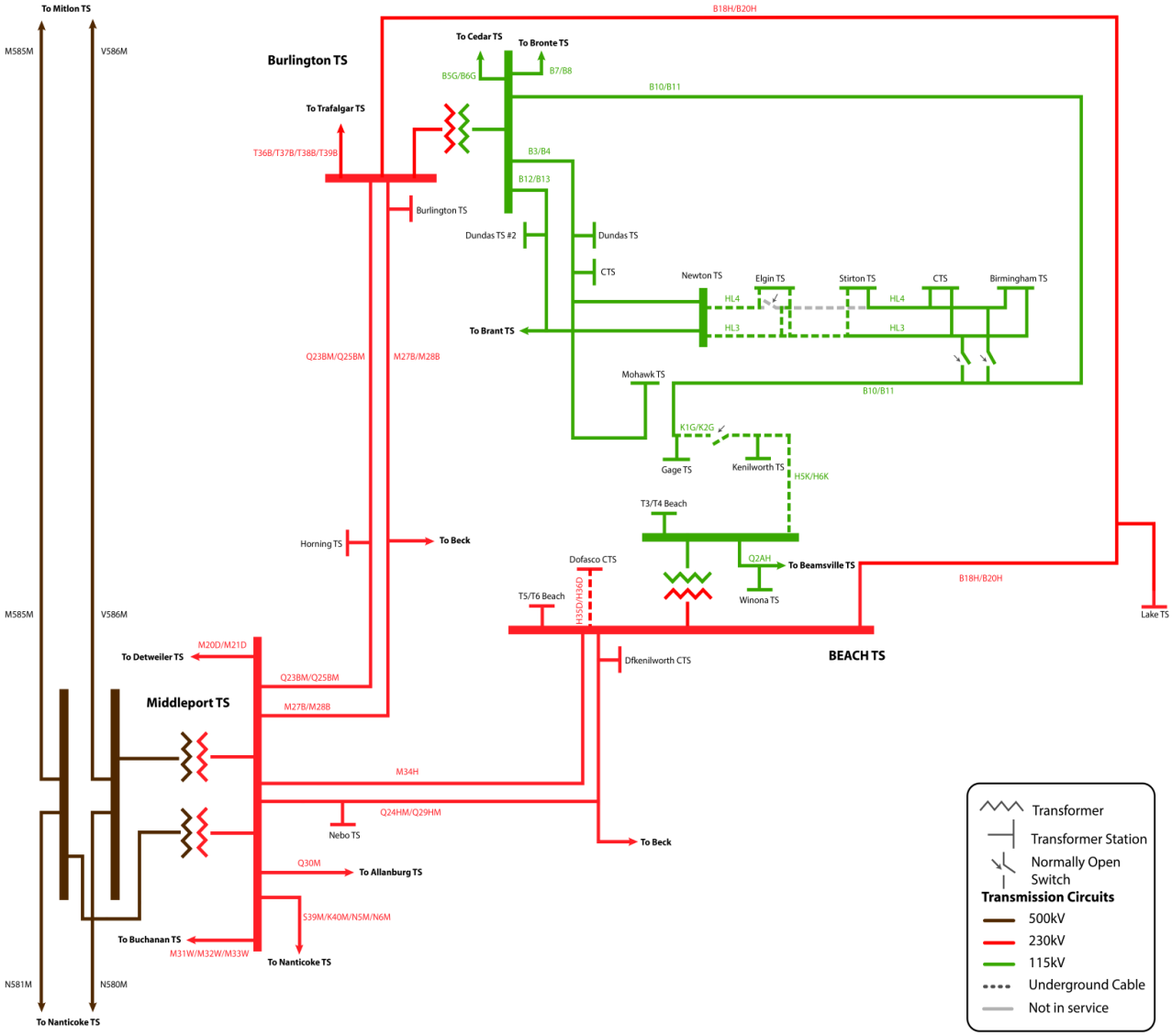


Figure A-4 | Hamilton Sub-Region Electricity System

The Hamilton sub-region is comprised of eighteen transformer stations and a number of 115 kV and 230 kV circuits. The 115 kV system in the sub-region is supplied by the 115 kV supply from Burlington TS (located north of Hamilton in Bronte) and the 230 kV supply from Beach TS. The primary 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS, and Middleport TS and Burlington TS supply the sub-region's 230 kV connected load supply stations.

Background

In the last regional planning cycle for the Burlington to Nanticoke region, a needs assessment was conducted for the entire region and was published in 2017. This needs assessment concluded that further regional planning was required for the Hamilton sub-region only. The Hamilton sub-region IRRP was published in 2019, while local planning was implemented in the other three sub-regions. The 2019 Hamilton Sub-region IRRP recommended replacements of multiple pieces of equipment reaching the end-of-life, including the switchgear at Lake TS T1/T2, the transformers and the low voltage switchgear at Newton TS, the T5/T6 low voltage switchgear at Beach TS, the Beach TS 230 kV/115 kV autotransformers, and various underground cables (H5K/H6K, K1G/K2G, HL3/HL4).

In September 2022, Hydro One completed the newest needs assessment for the Burlington to Nanticoke region. Two station capacity needs, at Nebo TS and Mohawk TS, and one asset end-of-life need at Newton TS were identified in the Hamilton sub-region. It was determined that these needs required regional coordination. In the last cycle of regional planning, a study of the 115 kV cable in Hamilton was recommended, however, study work was postponed due to updated equipment condition information from Hydro One. An IRRP was identified as required for the sub-region to review needs requiring regional coordination along with conducting the deferred assessment of the 115 kV cable for the sub-region.

2. Objectives

To assess the adequacy of electricity supply to customers in the Hamilton sub-region over the next 20 years.

To address the sub-region's asset renewal and capacity needs, and develop a flexible, comprehensive, integrated electricity plan for the sub-region. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Hamilton sub-region. The plan is a joint initiative involving Alectra Utilities Inc., Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will focus on the identified asset end-of-life and capacity needs in the sub-region. It will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

This IRRP will address regional needs in the Hamilton sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 230 kV Connected Stations: Beach TS (T3/T4), Horning TS, Lake TS
- 115 kV Connected Stations: Newton TS, Dundas TS, Dundas #2 TS, Mohawk TS, Elgin TS, Stirton TS, Birmingham TS, Gage TS, Kenilworth TS, Beach TS (T5/T6), Winona TS
- 4 customer owned transformer stations
- 230 kV Transmission Lines: B18H/B20H, H35D/H36D, Q24HM/Q29HM, M27B/M28B
- 115 kV Transmission Lines: B12/B13, Q2AH, B10/B11, B3/B4, HL3/HL4
- 115 kV Transmission Cables: H5K/H6K, K1G/K2G, HL3/HL4
- 230/115 kV auto-transformers at Beach TS and Burlington TS

The Hamilton IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices;
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the sub-region; and
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, and environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by region and TS, etc.
    - Coincident peak demand data, including transmission-connected customers
    - Identified potential future load customers
    - Customer/load segmentation information (e.g. residential, commercial, industrial) by TS
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on region's share of current energy efficiency programs and/or those reflected in the forecast for the most recent Annual Planning Outlook
    - Potential for CDM at transmission-connected customers' facilities

- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators, and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- End-of-life asset considerations/sustainment plans
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- Alectra Utilities Inc.
- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Hamilton Sub-region IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2022
2. Develop the summer planning forecast for the sub-region		Long-term planning forecast scenarios	Q1 2023
Establish historical coincident (for the sub-region) and non-coincident (for Nebo TS and Mohawk TS) peak demand information	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed, and potential DG	IESO, LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop a high planning forecast scenario for sensitivity analyses, as appropriate (including but not limited to: consideration of electric vehicle/transportation trends and potential impact on Hamilton sub-region demand)	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q1 2023
4. Provide and review relevant community plans, if applicable	LDCs, public stakeholders, and IESO	Relevant community plans	Q1 2023
5. Complete system studies to identify needs over a 20-year time horizon - Obtain PSS/E base case - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2 2023

Activity	Lead Responsibility	Deliverable(s)	Timeframe
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q3 2023
Conduct a screening to identify which non-wires options warrant further analysis	IESO		
Produce hourly forecasts for Nebo TS and Mohawk TS to enable detailed needs characterization and support options development	IESO		
Develop screened-in energy efficiency options	IESO and LDCs		
Develop screened-in local generation/demand management options	IESO and LDCs		
Develop the transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and LDCs		
Develop communications materials	IESO, Hydro One Transmission, and LDCs		
Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q4 2023

Activity	Lead Responsibility	Deliverable(s)	Timeframe
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	Q1 2024

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Burlington to Nanticoke Integrated Regional Resource Plan

December 18, 2024

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List of Acronyms

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

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Executive Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

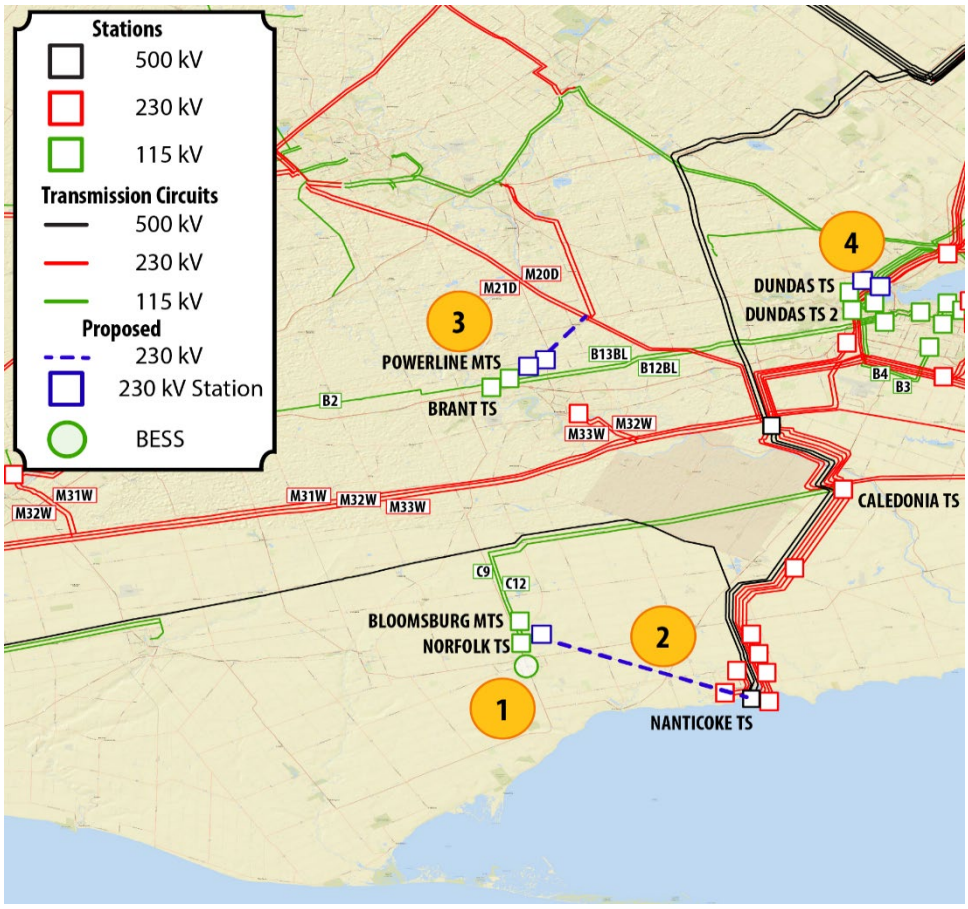
Summary of Recommendations

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

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

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

Medium/Long-Term Recommendations in the Burlington Nanticoke Region



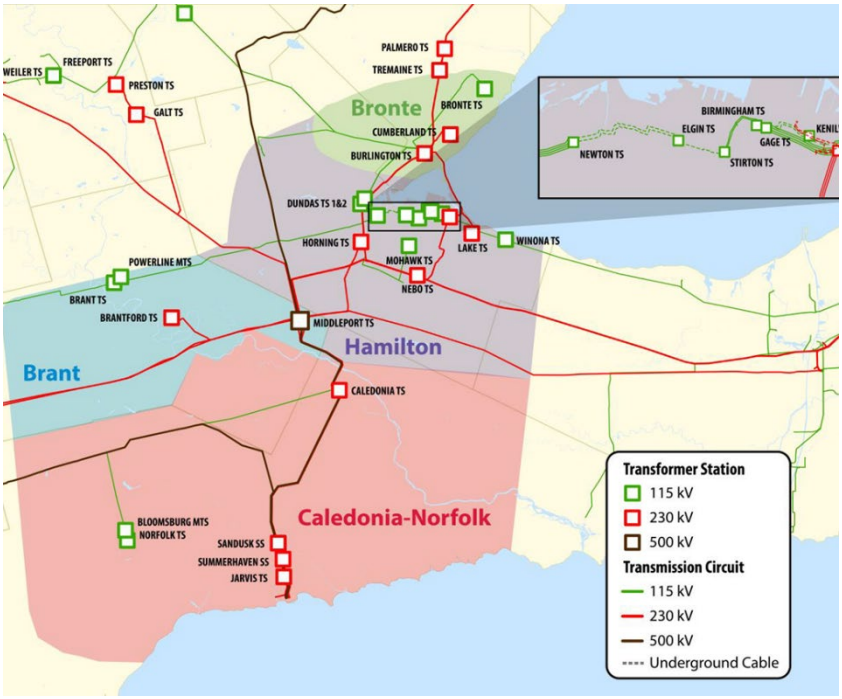
1 Introduction

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

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

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

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



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

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

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

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

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

This report is organized as follows:

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

2 The Integrated Regional Resource Plan

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

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

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

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

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

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

2.1 Status of Plans from Previous IRRP Cycles

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

Table 1 | Summary of Ongoing and Recently Completed Plans

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

2.2 Interim Plans

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

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

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

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

Table 2 | Interim Plans for Station and Supply Capacity Needs

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

2.3 Medium-Term Plans

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

2.3.1 Battery Energy Storage System in the Norfolk-Bloomsburg Area

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

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

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

2.3.2 Two New 230 kV DESNs at Dundas Station

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

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

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

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

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

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

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

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

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

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

2.4 Long-Term Plans

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

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

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

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

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

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

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

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

2.4.1 One New 230 kV DESN and Transmission Line into Simcoe

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

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

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

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

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

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

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

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

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

2.4.3 Separate Woodstock 115 kV Subsystem from Brant 115 kV Subsystem

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

2.5 Ongoing Initiatives

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

2.5.1 Undertake a Comprehensive Study of the Hamilton Subregion

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

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

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

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

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

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

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

2.5.3 Data Centre and Industrial Load Growth

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

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

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

3 Development of the Plan

3.1 The Regional Planning Process

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

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

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

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

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

3.2 Burlington to Nanticoke IRRP Development

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

4 Background and Study Scope

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

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

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

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

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

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

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

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

Transformer stations:

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

115 kV transmission circuits:

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

230 kV transmission circuits:

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

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

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

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

The Brant subregion consists of the following stations:

Brant TS	Brantford TS	Powerline MTS.

The Caledonia-Norfolk subregion consists of the following stations:

Bloomsburg DS	Jarvis TS	Caledonia TS
Norfolk TS	CTS1	CTS2

The Hamilton subregion consists of the following stations:

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

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

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

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

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

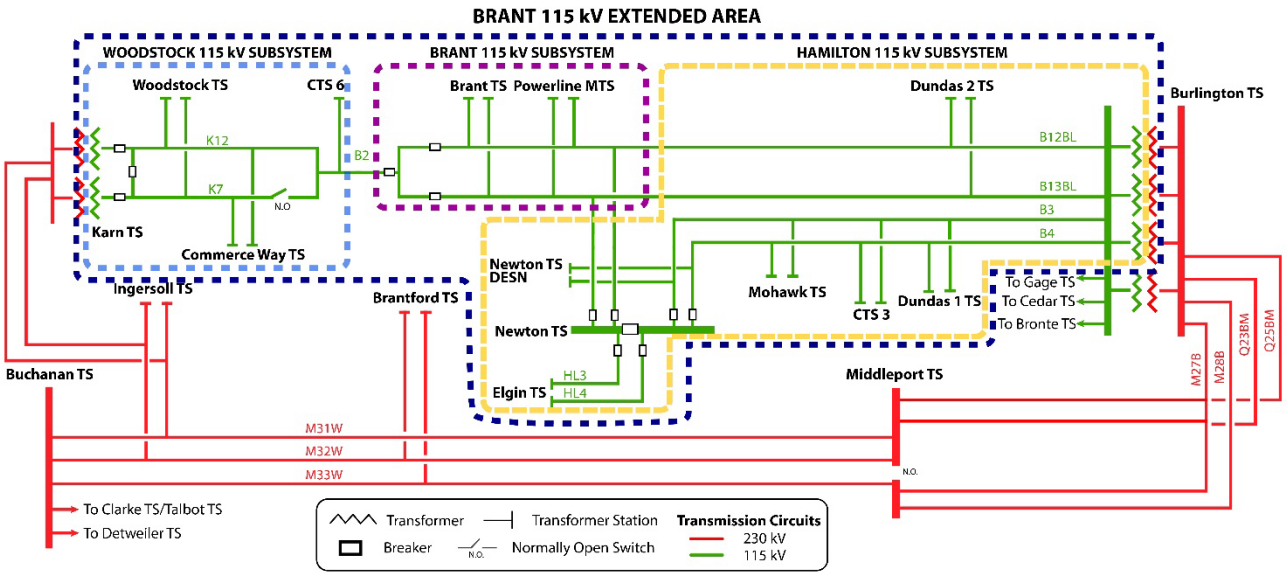


Figure 3 | Single Line Diagram of the Caledonia-Norfolk Subregion and Norfolk-Bloomsburg Area

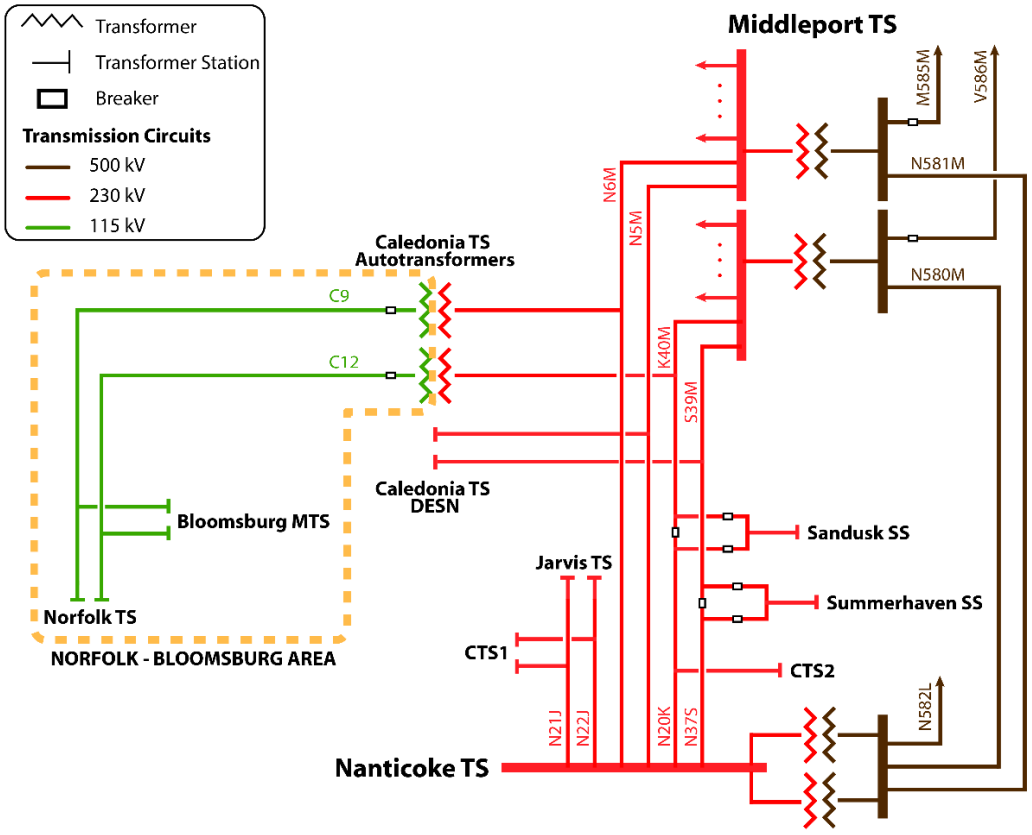
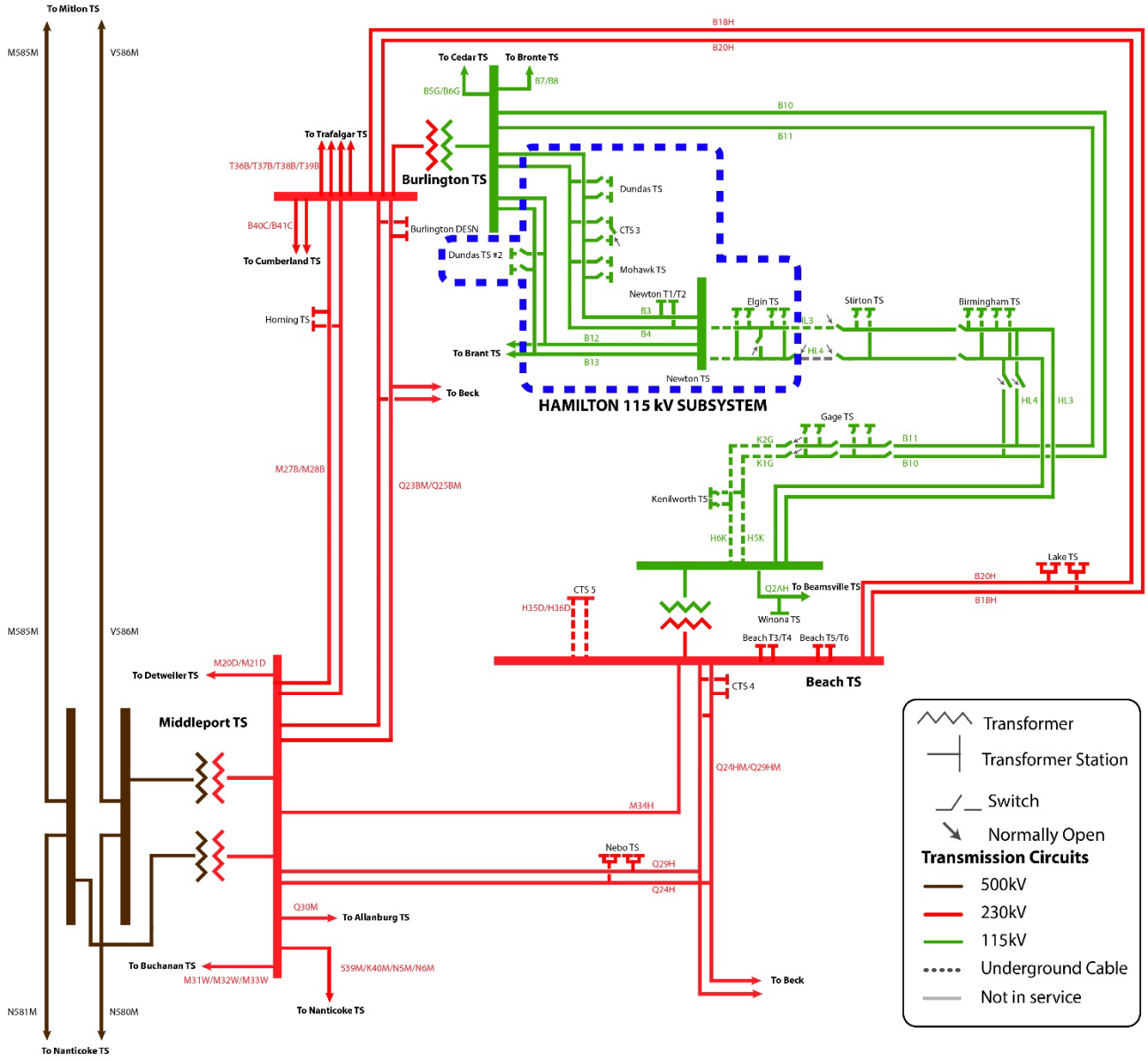


Figure 4 | Single Line Diagram of the Hamilton Subregion and Hamilton 115 kV Subsystem



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

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

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

5 Electricity Demand Forecast

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

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

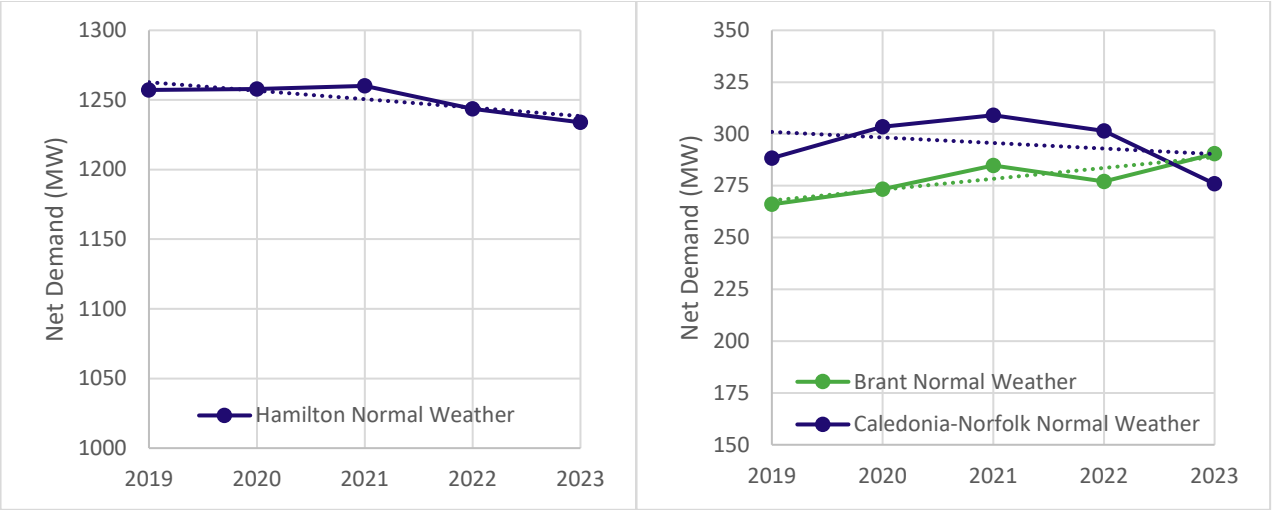
The coincident peak differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Each subregion of the Burlington to Nanticoke Region is summer peaking.

5.1 Historical Demand

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

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

Figure 5 | Historical Subregion Normal-Weather Demands

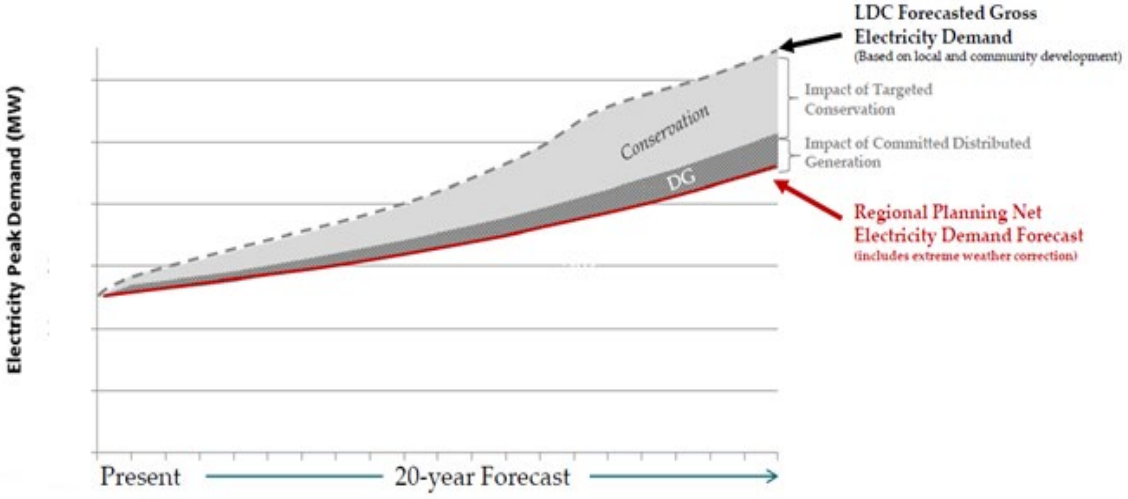


5.2 Demand Forecast Methodology

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

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

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

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

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

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

5.4 Contribution of Conservation to the Forecast

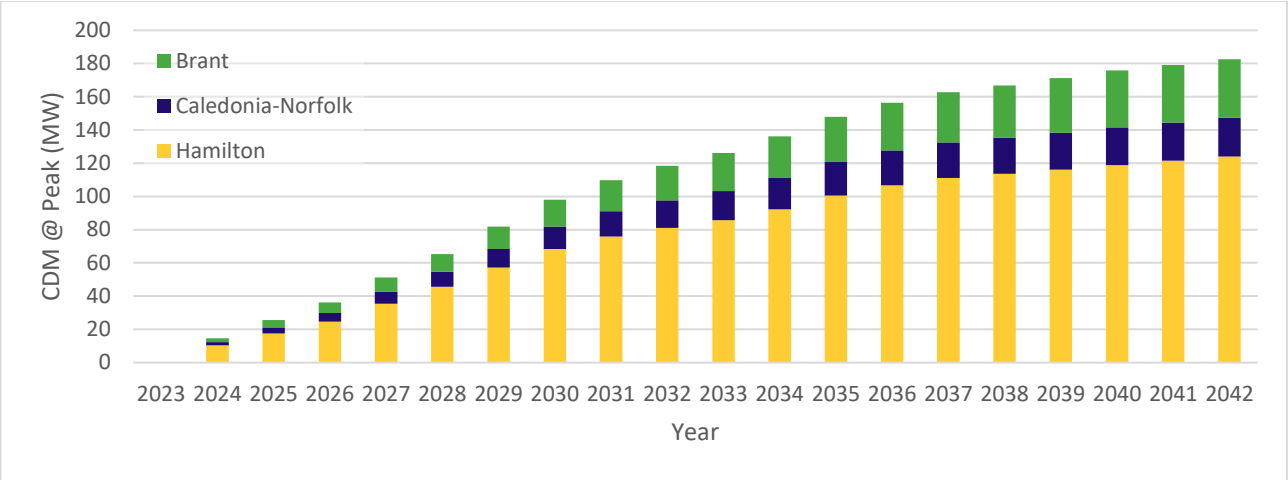
Conservation and demand management is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak-demand, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and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

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

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

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

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



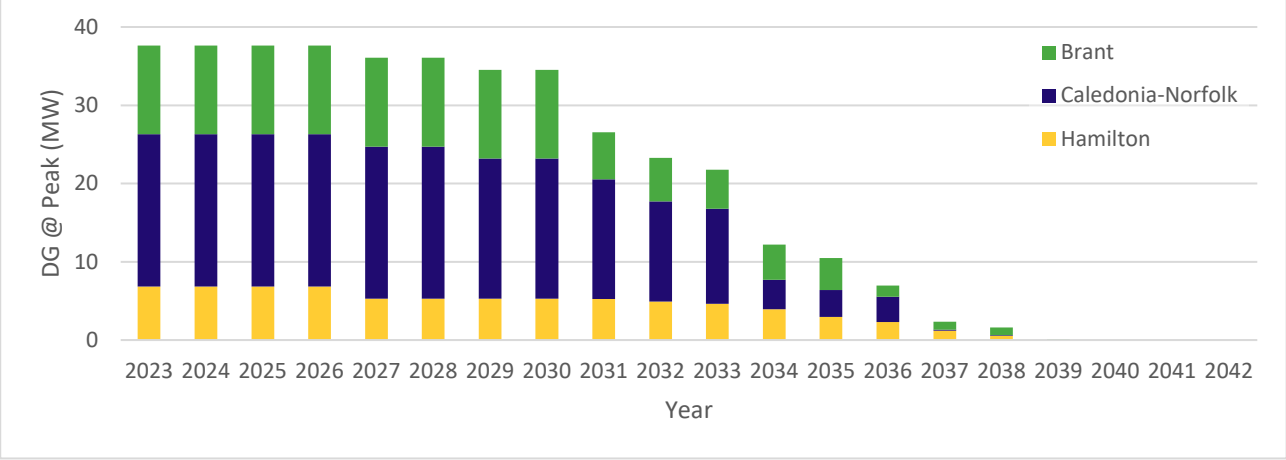
5.5 Contribution of Distributed Generation to the Forecast

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

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

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

Figure 8 | Peak Demand Reduction Due to Distributed Generation



5.6 Net Extreme Weather (Planning) Forecast

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

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

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

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

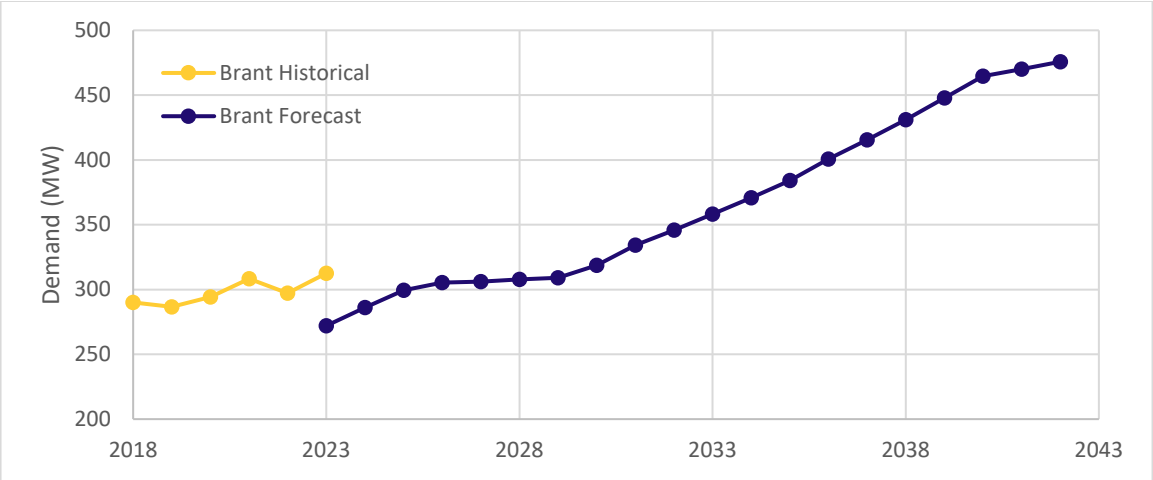
The second step is to adjust the resulting coincident gross normal weather forecast for extreme weather conditions. The weather correction methodology is described in Appendix B. This results in a coincident gross forecast which assumes extreme weather.

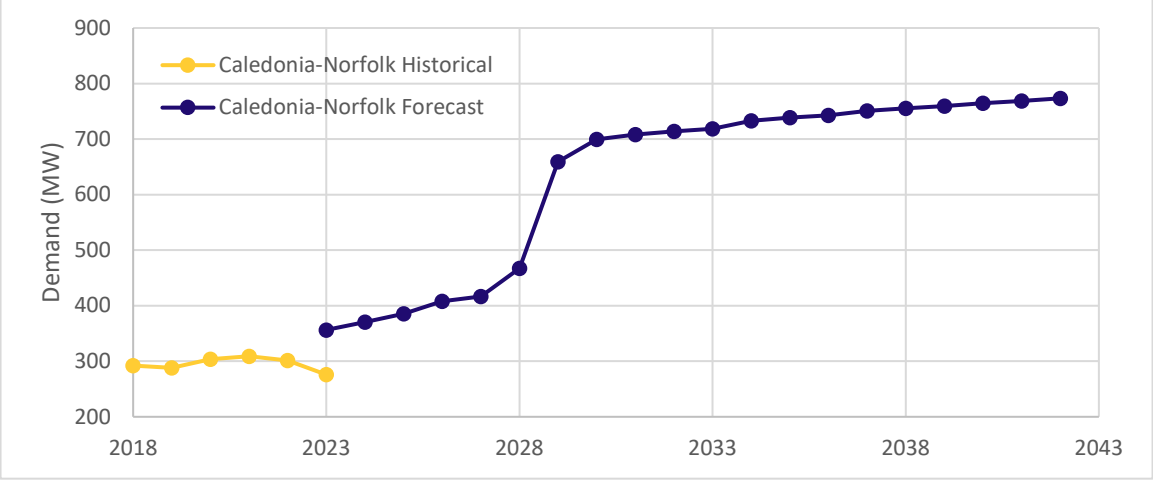
The last step is to adjust the resulting coincident gross extreme weather forecast for DG and conservation impacts. This is done by subtracting the forecasted DG and conservation impacts (as described in the above Sections) from the coincident gross extreme weather forecast. Finally, this results in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

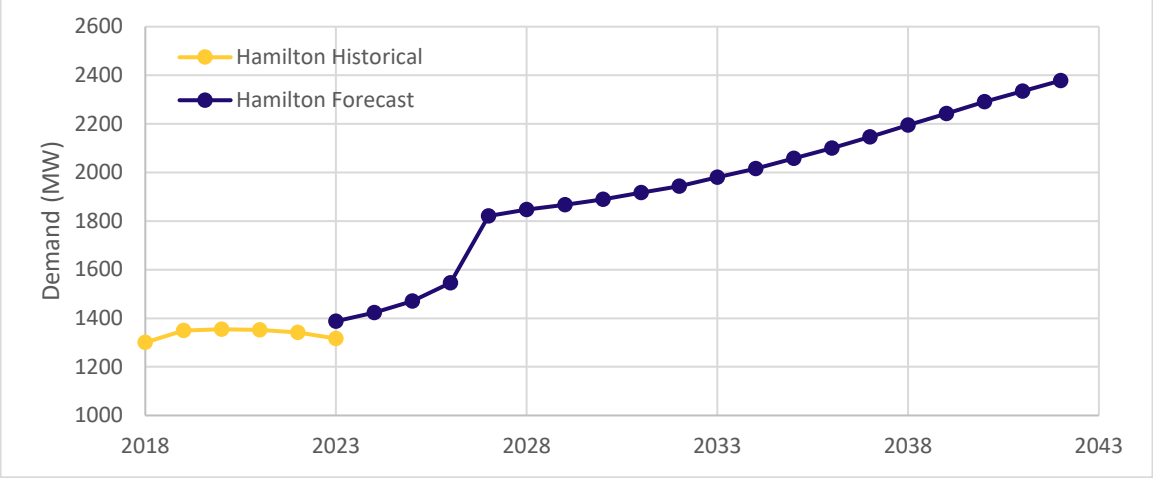
For station-specific needs, a non-coincident net extreme weather forecast used instead. The process for producing this forecast is similar as described above, except the first step is skipped.

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

Figure 9 | Historical Demand and Planning Forecast for the Subregions







5.7 Hourly Forecast Profiles

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

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

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

6 Needs

6.1 Needs Assessment Methodology

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

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

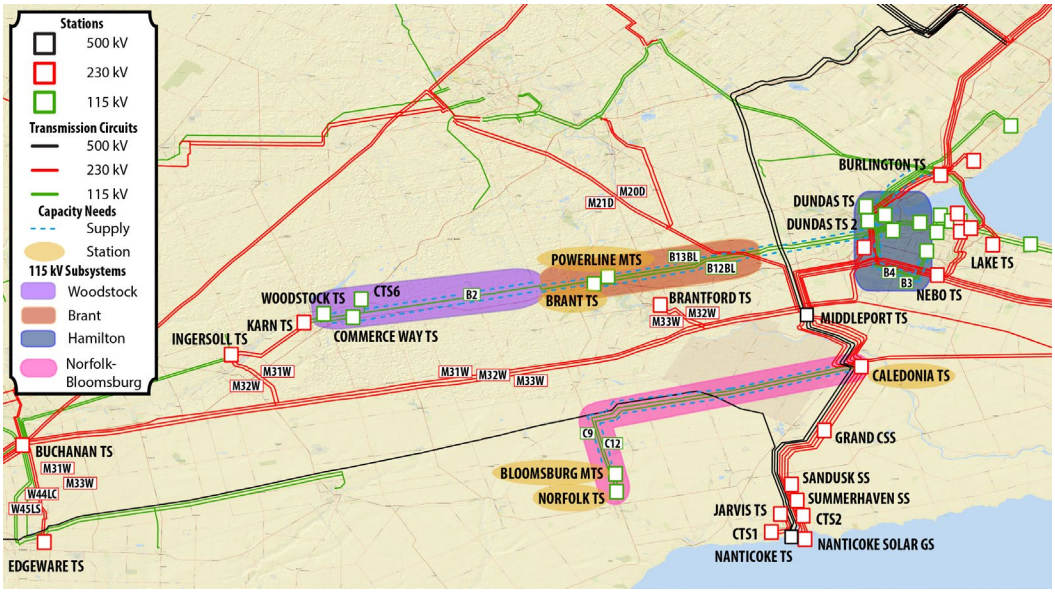
Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations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

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

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

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

Figure 10 | Needs Identified in the Burlington to Nanticoke Region



6.2 Station Capacity Needs

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

Table 5 | Station Capacity Needs

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

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

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

6.2.1 Brant Subregion Station Capacity Needs

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

6.2.2 Caledonia-Norfolk Subregion Station Capacity Needs

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

6.2.3 Hamilton Subregion Station Capacity Needs

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

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

6.2.4 Customer-Owned Transformer Stations

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

6.3 Supply Capacity Needs

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

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

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

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

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

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

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

Table 6 | Supply Capacity Needs

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

6.4 Asset Replacement Needs

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

Table 7 | Asset Replacement Needs

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

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

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

6.5 Load Security and Load Restoration Needs

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

The Technical Working Group did not identify any restoration needs.

7 Plan Options and Recommendations

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

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

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

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

7.1 Options Considered in IRRPs

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

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

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

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

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

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

7.2 Screening Options

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

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

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

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

Figure 11 | IRRP NWAs Screening Mechanism

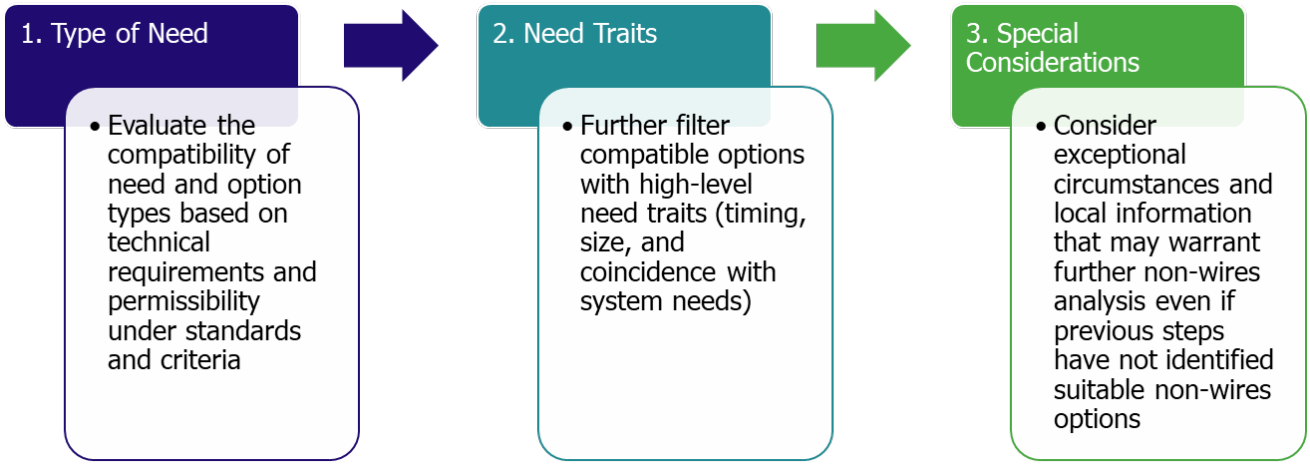


Table 8 | Options Screening Results for Station Capacity Needs

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

Table 9 | Options Screening Results for Supply Capacity Needs

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

7.2.1 Non-Wires Options for the Station Capacity Needs

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

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

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

7.2.2 Non-Wires Options for the Supply Capacity Needs

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

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

7.3 Options and Recommendations for the Brant Subregion

7.3.1 Station Capacity Needs

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

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

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

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

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

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

7.3.2 Supply Capacity Needs

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

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

7.3.2.1 Interim Solution – Operational Measures

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

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

7.3.2.2 Non-Wire Options

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

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

7.3.2.3 Wire Options

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

Option 1: Reinforcing 115 kV and Dynamic Voltage Support

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

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

Option 2: Upgrading 115 kV to 230 kV

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

7.4 Options and Recommendations for the Caledonia-Norfolk Subregion

7.4.1 Station Capacity Needs

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

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

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

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

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

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

7.4.2 Supply Capacity Needs

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

7.4.2.1 Interim Solution – Operational Measures

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

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

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

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

7.4.2.2 Non-Wire Options

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

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

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

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

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

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

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

7.4.2.3 Wire Options

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

Option 1: Dynamic Voltage Support and CDM

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

Option 2: Upgrading 115 kV System to 230 kV

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

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

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

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

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

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

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

Table 11 | Wire Options for Norfolk-Bloomsburg Area

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

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

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

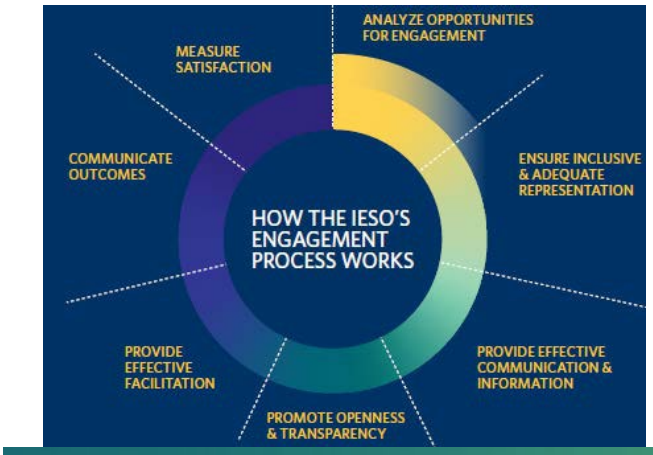
8 Community and Stakeholder Engagement

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

8.1 Engagement Principles

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

Figure 12 | The IESO's Engagement Principles



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

Purposeful
Initiate meaningful conversations that move the sector forward

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

Inclusive
Invite many voices and diverse perspectives to the table

Traceable
Allow everyone to follow the path that is being taken

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

Transparent
Show how engagement has shaped final outcomes

8.2 Engagement Approach

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

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

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

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

8.3 Engage Early and Often

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

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

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

The three stages of engagement at which input was invited:

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

Comments received during this engagement primarily focused on:

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

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

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

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

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

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

8.4 Involving Municipalities in the Plan

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

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

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

8.5 Engaging with Indigenous Communities

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

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

9 Conclusions

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

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

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

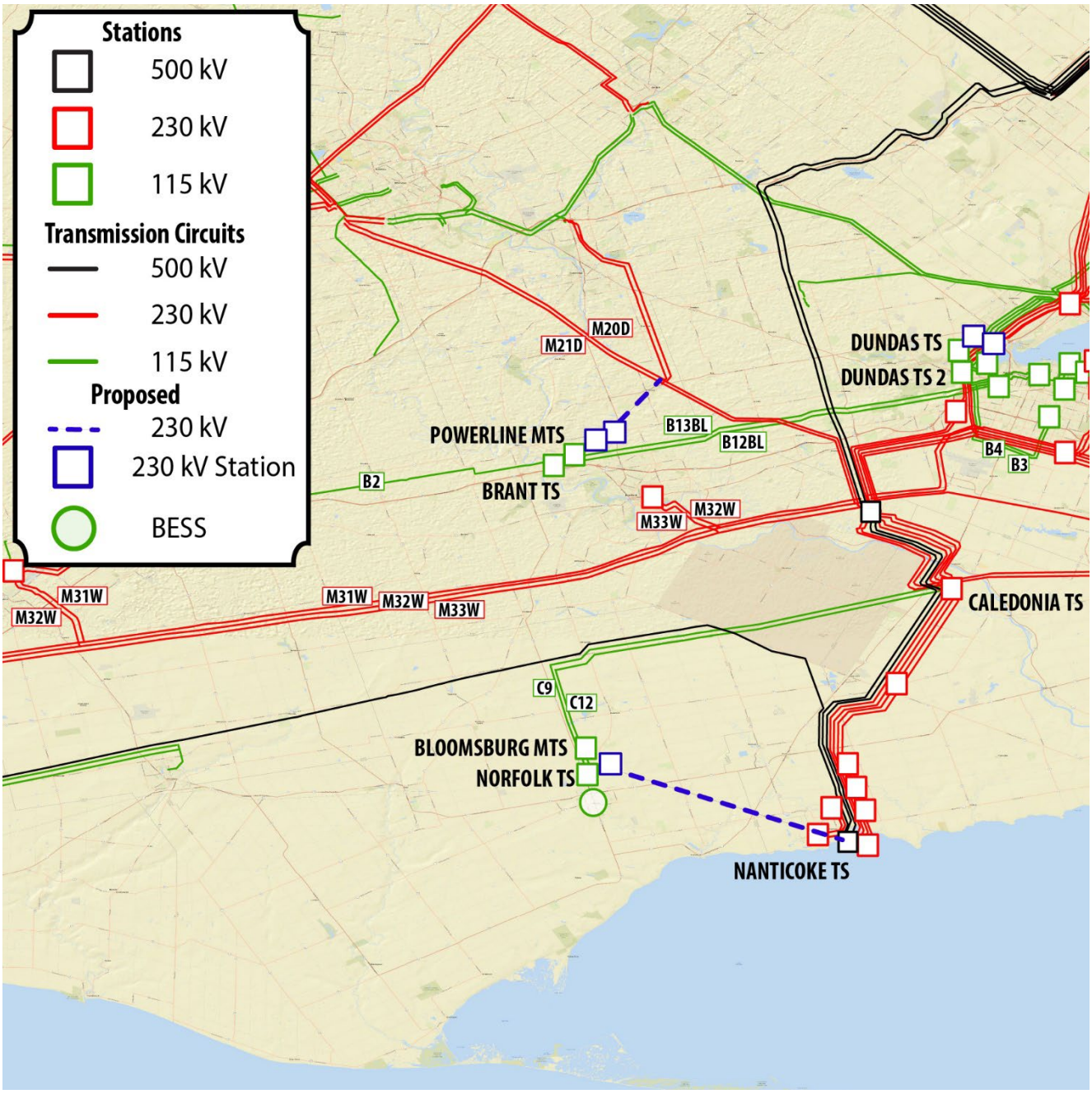
Finally, in the long term, the Technical Working Group recommends constructing two new double-circuit transmission lines and associated substations[5], separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem, and considering cost-effective CDM at Brantford TS and Caledonia TS closer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

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

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

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

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



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List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CNPI	Canadian Niagara Power Inc.
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOTL	Niagara-on-the-Lake
NPCC	Northeast Power Coordinating Council

Acronym	Definition
NPEI	Niagara Peninsula Energy Inc.
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

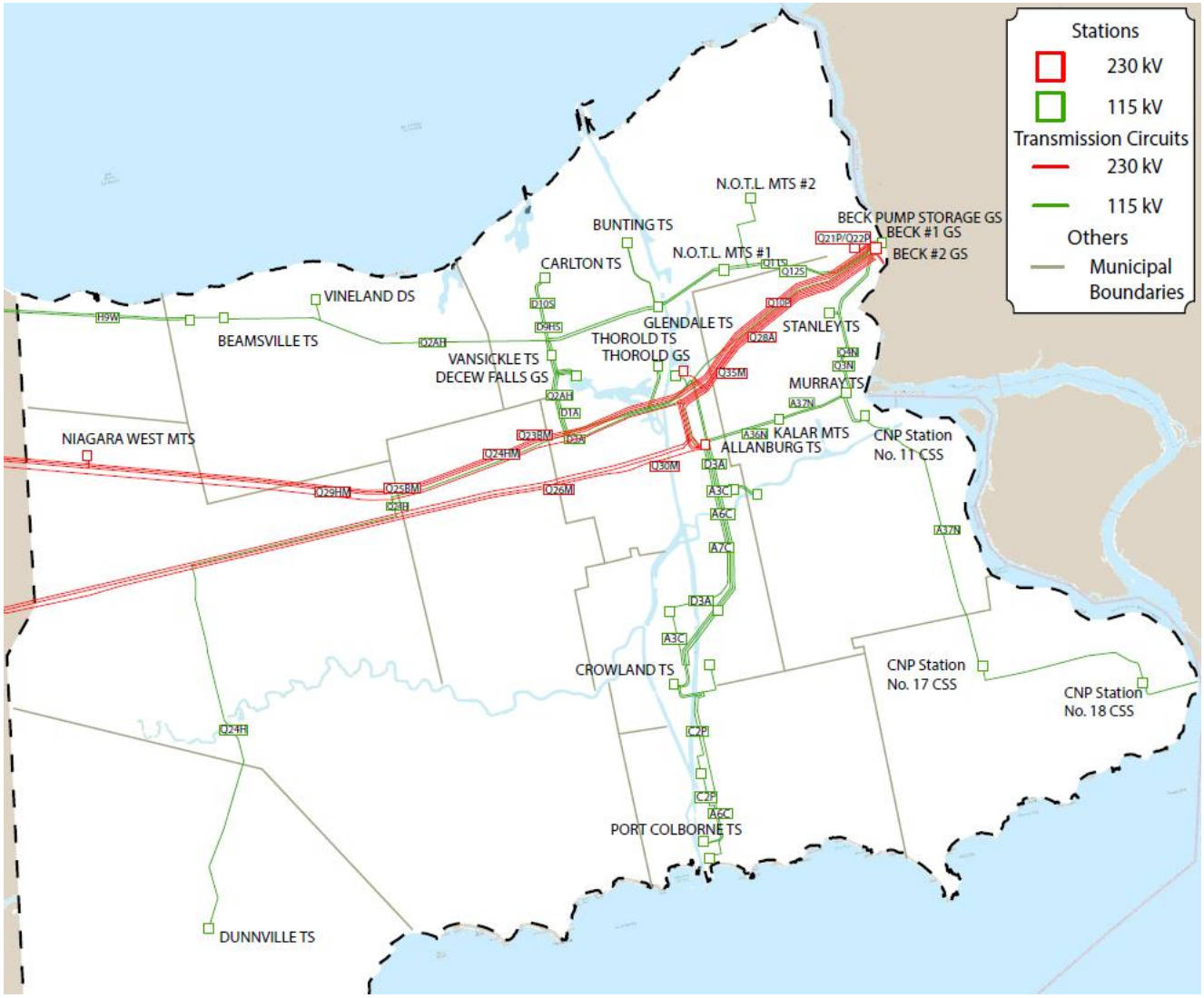
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Niagara Region over the next 20 years, from 2022 to 2041. The Niagara Region is located between Lake Ontario and Lake Erie, and includes one upper-tier municipality (Regional Municipality of Niagara) and 12 lower-tier municipalities: Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln.

This region also includes the following First Nations and Métis Nation of Ontario councils:

- Mississaugas of the New Credit
- Oneida Nation of the Thames
- Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council)
- Métis Nation of Ontario Niagara Region Métis Council

The Niagara Region is summer-peaking and, over the last five years, peak electrical demand has remained steady at an average of 810 MW. Electrical supply is provided primarily through 230/115 kilovolt ("kV") autotransformers at Allanburg Transformer Station ("TS"), and is generally served by 230 kV and 115 kV transmission lines and step-down transformation facilities as shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits that connect Sir Adam Beck Generating Station ("GS") #2 in the east to Burlington TS and Middleport in the west. Other large transmission-connected generating facilities include Sir Adam Beck GS #1 and Decew Falls GS connecting to the 115 kV system, and Thorold GS connecting to the 230 kV system.

Figure 1 | Overview of the Niagara Region



The region's electricity is delivered by six local distribution companies ("LDCs"): Alectra Utilities, Canadian Niagara Power Inc. ("CNPI"), Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara on the Lake Hydro Inc., Niagara Peninsula Energy Inc. ("NPEI"), and Welland Hydro Electric System Corp. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Niagara IRRP was initiated in August 2021, following the publications of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment identified needs for further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;

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

2. The Integrated Regional Resource Plan

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

The Niagara electricity demand forecast, provided by the LDCs, projects sustained growth driven by community area, employment area, and rural settlement expansions. This growth spans multiple municipalities, including (but is not limited to): Lincoln, West Lincoln, Welland, Thorold, and Niagara Falls.

The IRRP recommendations below are organized under a near-/medium-term plan and other ongoing or long-term initiatives. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term, as electrification, energy efficiency, and development plans evolve.

2.1 Near-/Mid-Term Plan

The near- and mid-term plan comprises several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. These recommendations are summarized in Table 1 and further discussed below.

Table 1 | Summary of the Near/Mid-Term Plan for the Niagara IRRP

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West Municipal Transformer Station ("MTS"), and Vineland Distribution System ("DS") station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development of a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental conservation and demand management ("CDM") to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Monitor load growth and transfer load in excess of the station limit to Murray TS transformer 13 and 14 (T13/T14)	• 2023

2.1.1 Load Transfers from Beamsville TS and a New or Expanded 230 kV Station

Stations limits are typically dictated by the lowest rated transformer. Beamsville TS is fully utilized today and there is no remaining capacity for growth. Nearby stations Niagara West MTS and Vineland DS are also forecast to reach their capacity limits by 2026 and 2030, respectively.

The IRRP considered the merits of a portfolio of "non-wires" (non-transmission) options as well as integrated "wires" (transmission) options. Based on planning-level cost estimates and its ability to address capacity shortfalls at the three stations, the Technical Working Group recommends that a new 230 kV station supplied by Q23BM and Q25BM is built. This could be accomplished by expanding the existing Niagara West MTS. Development and implementation for additional capacity should begin as soon as possible for a targeted in-service date of 2026-2027. The next stage of regional planning, the Regional Infrastructure Plan ("RIP") led by Hydro One, should confirm the party who will lead development work (i.e., Grimsby Power, NPEI, or Hydro One).

In the meantime, the IRRP recommends that the local distributors (Grimsby Power, NPEI, Hydro One Distribution), in conjunction with Hydro One Transmission where appropriate, develop a plan to transfer load from Beamsville TS to the other nearby stations (Niagara West MTS, Vineland DS) to manage the urgent Beamsville TS need until the new station is in-service.

2.1.2 Major High Voltage Equipment Replacement of Crowland TS, New 230 kV Transmission Lines, Q28A Upgrade, and Control Actions

The existing T5 and T6 transformers at Crowland TS will require major high voltage ("HV") equipment replacement in 2026, and are forecast to be fully utilized in 2022. Crowland TS, as well as other stations supplied by the A6C/A7C circuits, are also impacted by a load security need that exists today. Moreover, Crowland TS is included in the broader Niagara 115 kV sub-system whose supply capacity need exists today and continues to grow by the end of the planning horizon.

The IRRP developed and evaluated portfolios of non-wires options, standalone generation, and wires alternatives for the multiple needs in this area. Ultimately, the most feasible and cost-effective solution at this time requires wires reinforcements: the upgrade of Q28A, the replacement of 115 kV Crowland TS with a larger 230 kV station supplied by new 230 kV transmission lines from Q24HM and Q29HM, and a new load rejection scheme developed to manage the Niagara 115 kV sub-system load. The IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service dates of 2024, 2024, and 2028 for the load rejection scheme, Q28A upgrade, and new 230 kV station and lines, respectively. Measures to manage the HV equipment replacement infrastructure at Crowland TS should be implemented by Hydro One until the station replacement is in-service.

2.1.3 Load Transfers from Murray TS (T11/T12)

Murray TS (T11/T12) is forecast to be beyond capacity in 2022 during its station peak. Given the small magnitude of this need and the available capacity on the other set of transformers at Murray TS (T13/T14), the IRRP recommends that some load is re-allocated to T13/T14 and growth continues to be monitored.

2.2 Ongoing Initiatives

In addition to the near- and mid-term plan above, two ongoing actions were identified to manage needs expected in the long-term.

2.2.1 Monitor Load Growth

Carlton TS and Kalar MTS are expected to reach capacity in 2028 and 2030, respectively. In the case of Carlton TS, distribution-level load transfers to Bunting TS have been indicated as an option. Given the timing, no firm recommendation is required at this time for either need; the Technical Working Group will continue to monitor load growth and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also keep apprised of and participate in any future Community Energy Plans developed by municipalities of the Niagara Region.

2.2.2 Explore Opportunities for Targeted CDM

In addition to monitoring how the forecast demand materializes, the IRRP recommends continuing to consider opportunities for targeted CDM. During the options analyses, the benefits and potential of incremental, cost-effective CDM were identified – particularly if targeted to manage near-term needs until transmission reinforcements are in-service (as is the case for the Beamsville TS/Vineland DS/Niagara West MTS area, as well as the 115 kV sub-system), or to defer long-term needs (such as at Kalar MTS). The Technical Working Group should continue to support and monitor CDM uptake, and bring these insights into the next cycle of regional planning for the Niagara Region.

3. Development of the Plan

3.1 The Regional Planning Process

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

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

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

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

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

3.2 Niagara and IRRP Development

The process to develop the Niagara IRRP initiated in August 2021, following the publication of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment recommended that the needs identified for the Niagara Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

This is the second cycle of regional planning for the Niagara Region. This region roughly encompasses the municipalities Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln. This region also includes the following First Nations and Métis Nation of Ontario Councils: Mississaugas of the New Credit, Oneida Nation of the Thames, Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council), and the Métis Nation of Ontario Niagara Region Métis Council. Following a Needs Assessment and Scoping Assessment in 2016, a RIP was initiated by Hydro One and subsequently published in 2017, concluding the first planning cycle for the Niagara Region. An IRRP was not developed, as two electricity needs were identified in 2016, but no further regional coordination was required.

The current cycle of regional planning began in 2021 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2021 Niagara Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2022.

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

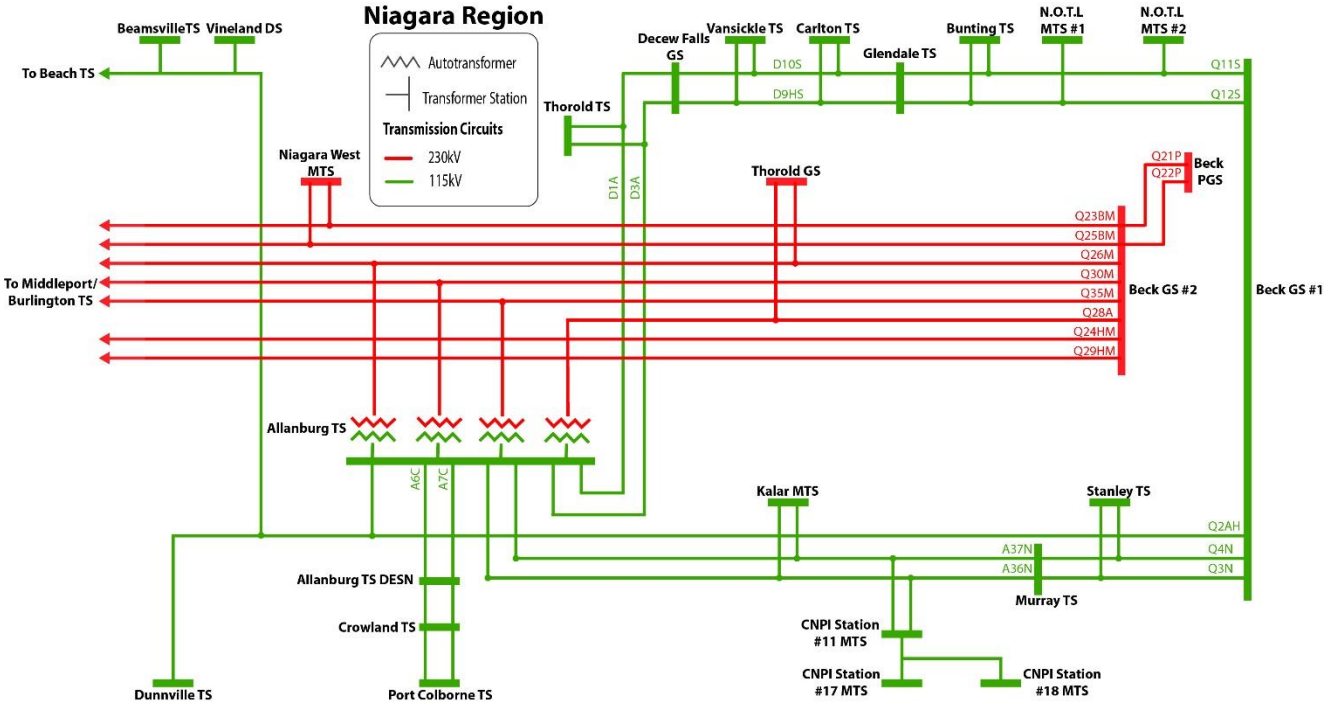
The following transmission facilities were included in the scope of this study:

- Transformer stations: Allanburg TS, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Murray TS, Niagara West MTS, Niagara-on-the-Lake ("NOTL") York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI #11 MTS, CNPI #17 MTS, CNPI #18 MTS. Except for Niagara West MTS, all stations are supplied from 115 kV transmission circuits.
- 115 kV transmission circuits: Q3N/Q4N, Q11S/Q12S, Q2AH, A36N/A37N, A6C/A7C, D1A/D3A, D9HS/D10S.
- 230 kV transmission circuits: Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M.

The single line diagram of the Niagara Region is shown in Figure 2 below. Note that the bulk system transfer capabilities on the Queenston Flow West interface[1] through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[1] Includes flow out at Beck (Q25BM + Q23BM + Q24HM + Q29HM) and flow in at Middleport (Q30M + Q26M + Q35M).

Figure 2 | Single Line Diagram of the Niagara Region



The Niagara IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
  - Examining the load meeting capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
  - Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
  - Confirming identified asset replacement needs and timing with the transmitter and LDCs;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including CDM;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

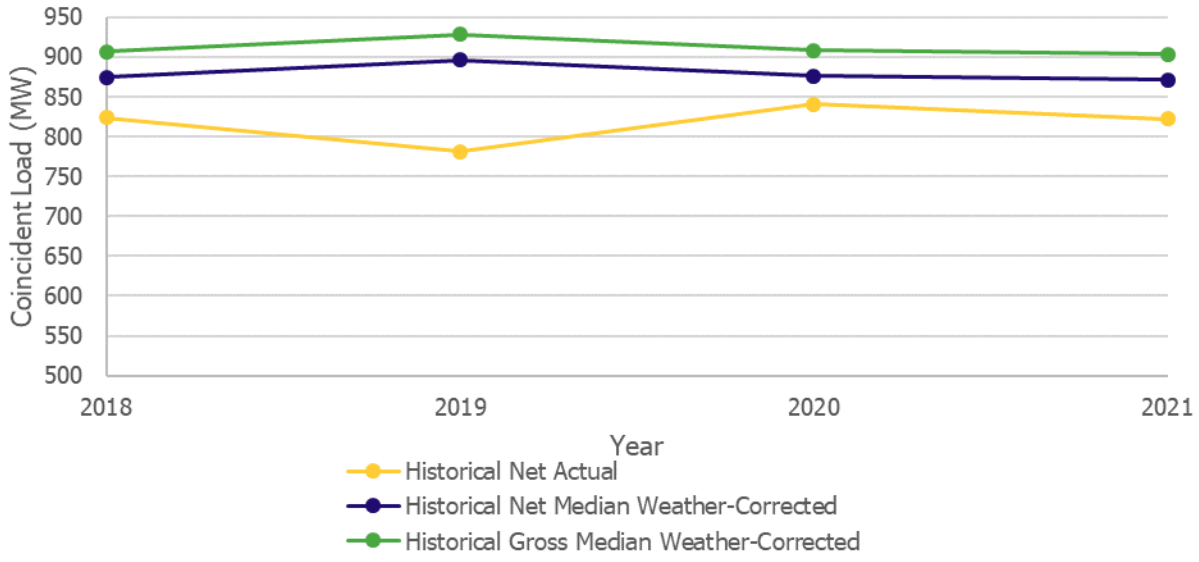
Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Niagara Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of CDM and DG, and the development of a high growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.7.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Niagara Region, the peak loading hour for each year has historically occurred in the summer.

5.1 Historical Demand

Peak electricity demand within the Niagara Region has been steady over the last four years. Figure 3 below shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and gross median weather-corrected (contribution of DG removed) historical demand. The gross median weather-corrected demand has averaged 910 megawatts ("MW") over the past four years, with the peak demand hour for each year occurring consistently in the summer between approximately 4 PM to 7 PM. The 2021 gross median weather-corrected peak at each station in the Niagara Region was used as the starting point for the forecast.

Figure 3 | Historical Demand in the Niagara Region

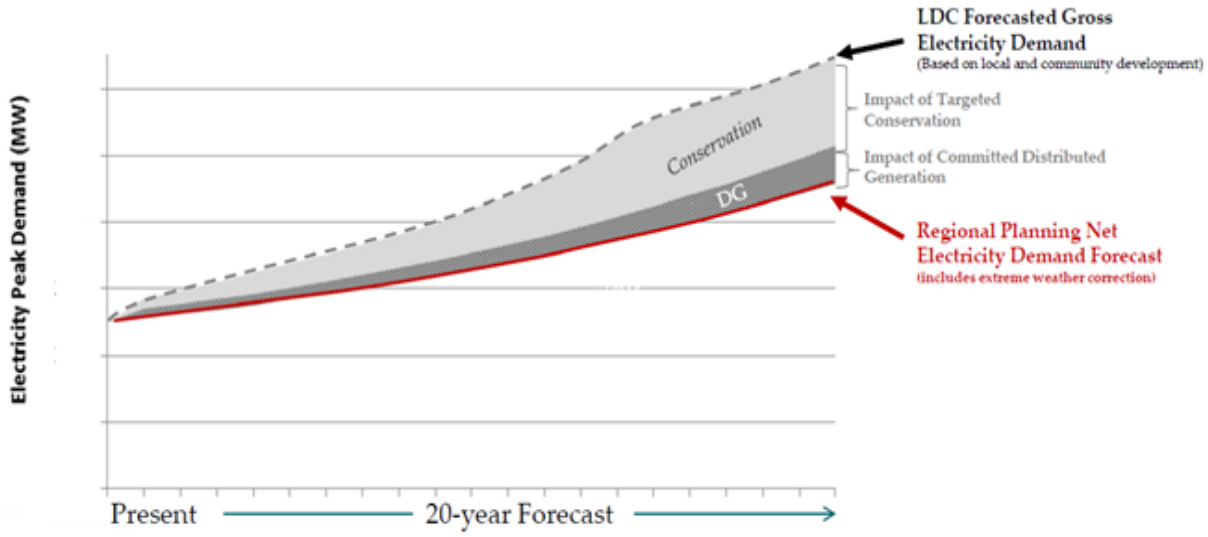


5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 4. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs such as Feed-In Tariff ("FIT") and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Niagara IRRP forecast was created prior to October 2022, the Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 4 | Illustrative Development of Demand Forecast



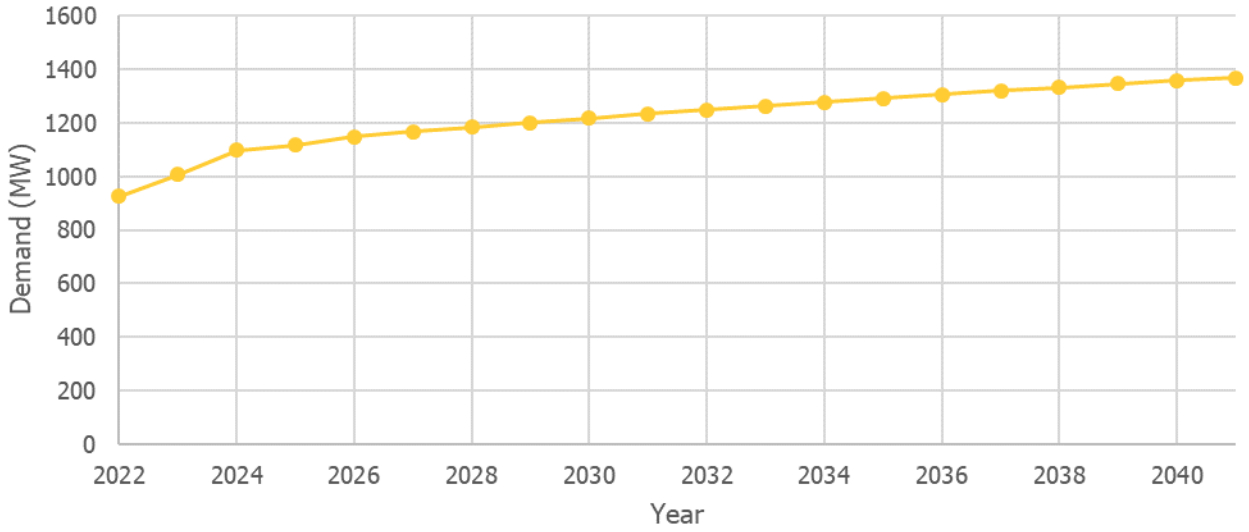
5.3 Gross LDC Forecast

Each participating LDC in the Niagara Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans, and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes median on-peak weather conditions, and station loading that is coincident to the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and municipalities and communities which they serve. The IESO typically carries out demand forecasting at the

provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.8. Figure 5 below shows the total gross demand forecast provided by the LDCs for the Niagara Region.

Figure 5 | Total Gross Demand Forecast Provided by LDCs (Median Weather)[2]



5.4 Contribution of Conservation to the Forecast

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

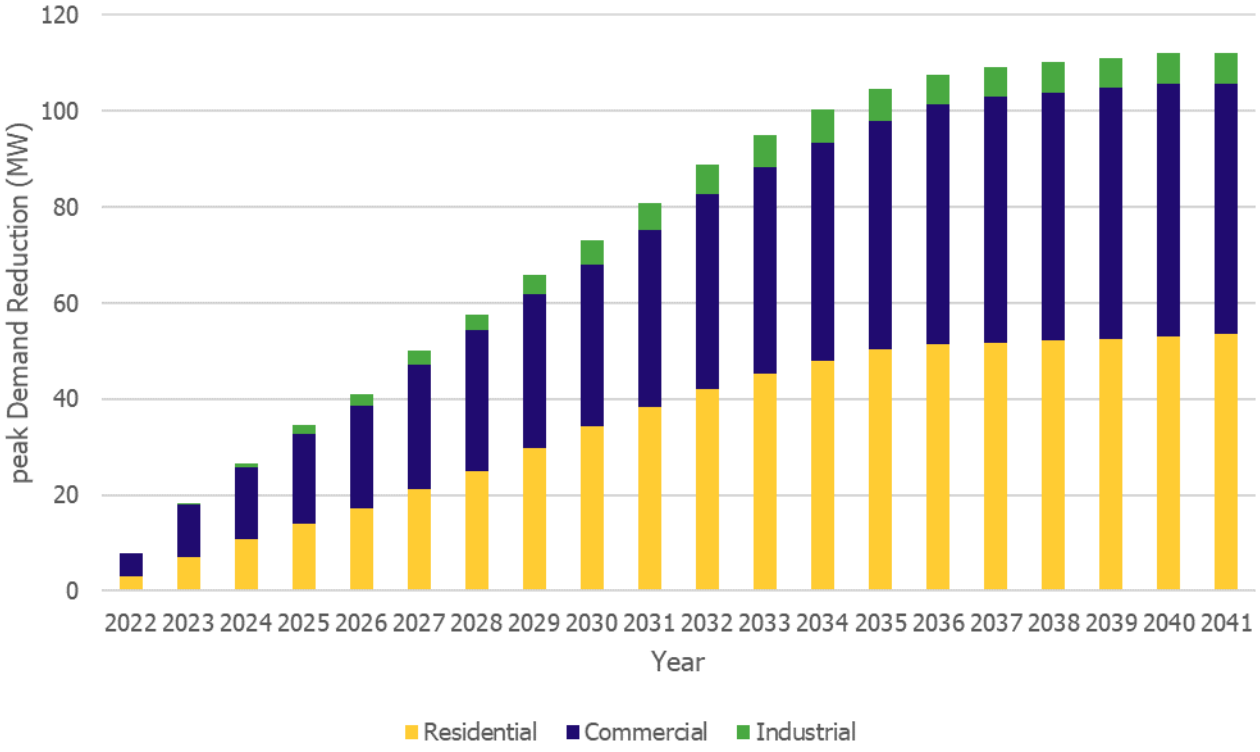
The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. The 2021 – 2024 CDM Framework is the main piece, in which the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

Figure 6 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.9.

[2] Excludes existing transmission-connected industrial customers in the Niagara Region (historically contributing an average of 15 MW to the coincident peak demand).

Figure 6 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

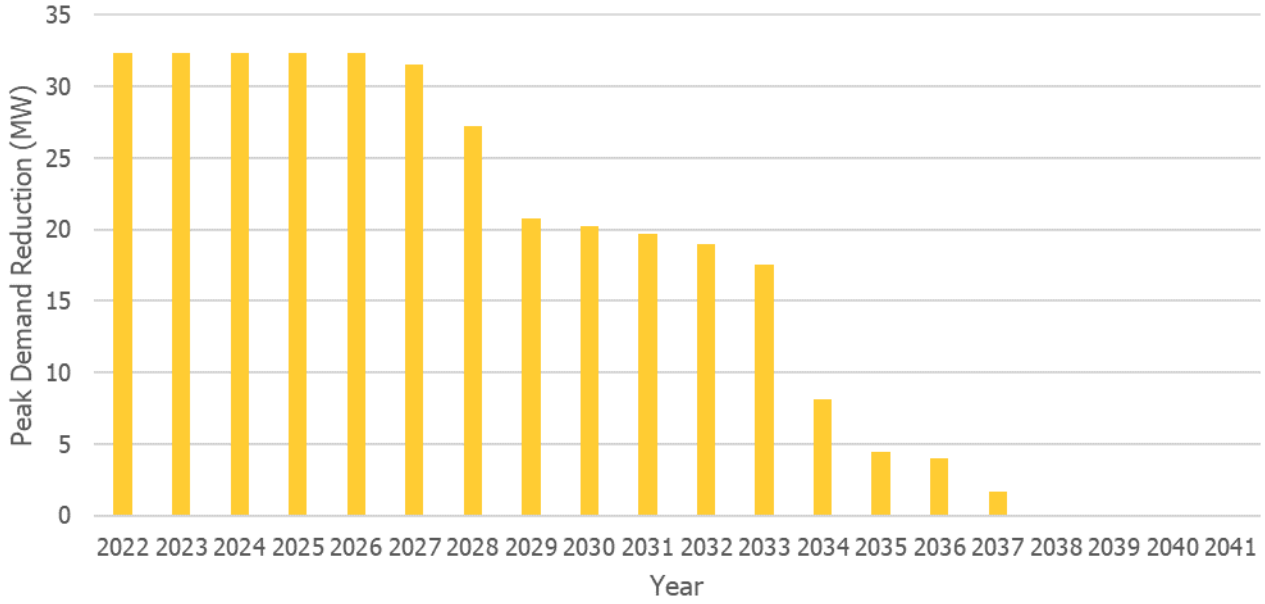


5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Niagara Region is also forecast to offset peak-demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B.10. Most of the total contracted installed DG capacity in the Niagara Region is solar, wind, and waterpower, with some biogas, landfill gas, and natural gas facilities.

After reducing the demand forecast due to conservation, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG. Figure 7 shows the impact of DG on reducing the Niagara Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

Figure 7 | Peak Demand Reduction to Demand Forecast, Due to DG



In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 32 MW of peak contribution is identified for the Niagara Region in 2022, reducing throughout the 2030s to 0 MW by 2038. This reduction is reflected in the high forecast scenario (see Section 5.7 for more details on its development and assumptions), but not the reference forecast. Rather, the reference Niagara IRRP forecast assumes a constant contribution of approximately 32 MW each year for the entire study period. This aligns with the Technical Working Group decision to assume that already-existing DG facilities with expired contracts will continue to offset demand.

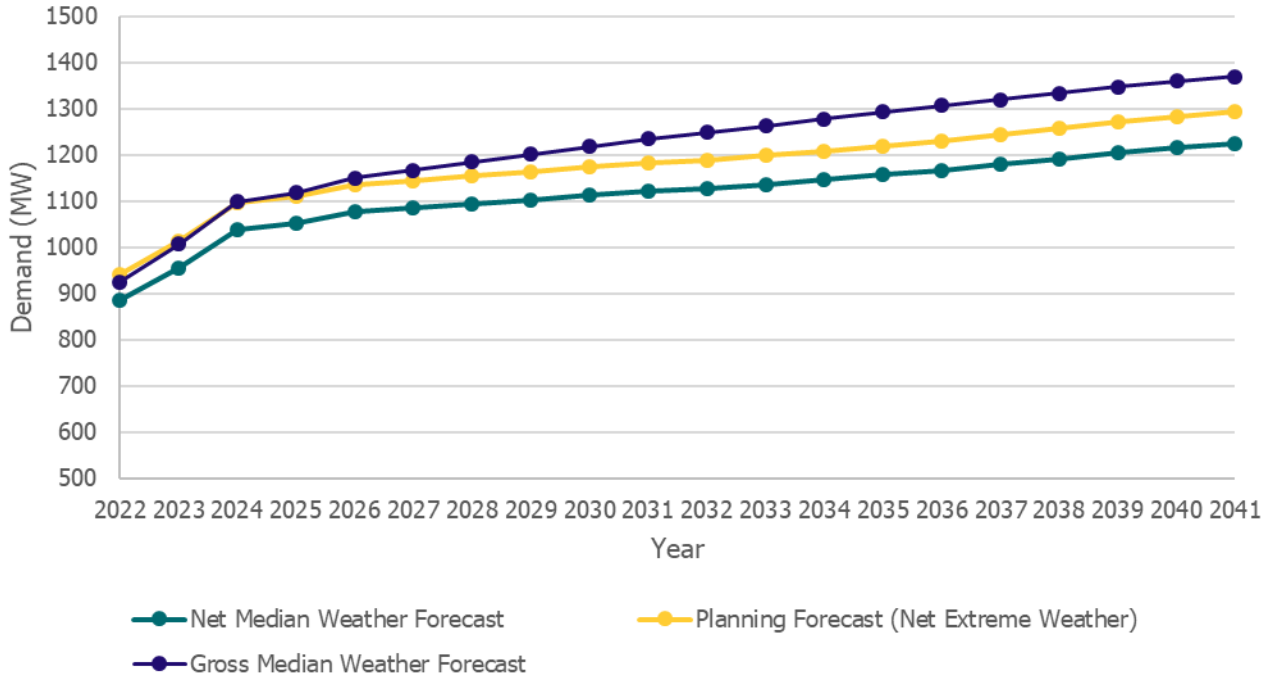
5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and conservation impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past six years.

The coincident net extreme weather forecast for the Niagara Region is shown in Figure 8 below.

Figure 8 | Net Extreme Weather ("Planning") Forecast for the Niagara Region[3]



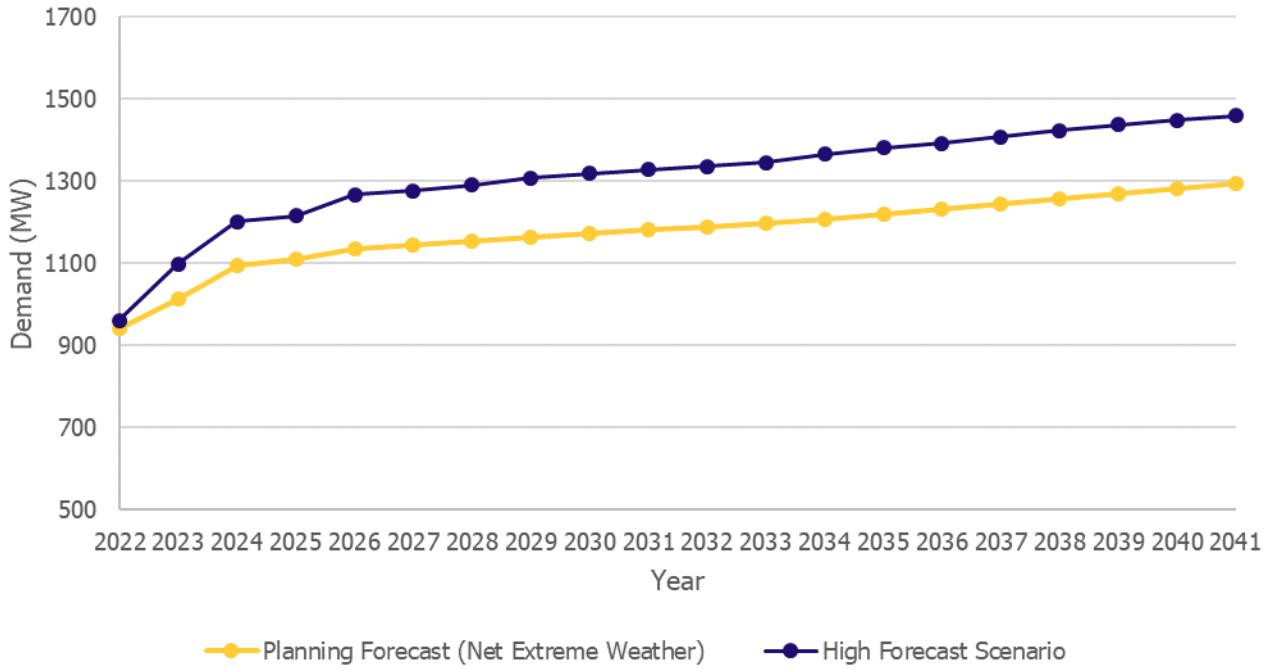
5.7 High Forecast Scenario

The Technical Working Group opted to develop a high forecast sensitivity scenario for the Niagara Region. This higher demand scenario is to take into account a variety of factors that could drive demand higher over the next 20 years, including but not limited to: electric vehicle charging infrastructure, electrified space heating installations, unanticipated new industrial customers, or general higher-than-expected growth. However, the Technical Working Group did not have specific end-use data available to develop the high forecast. Instead, the DG contribution to peak (as described in Section 5.5) was removed according to contract expiries, resulting in approximately 3% higher total regional load by 2041 when compared to the reference planning forecast. The impact on stations with greater contracted DG is higher.

The high forecast also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. These include customers that members of the Technical Working Group were aware of and liaising with, as well as customers that initiated a System Impact Assessment with the IESO during the Niagara IRRP development. In total, another 132 MW was added due to this assumption, when compared to the reference planning forecast. This is shown in Figure 9.

[3] See footnote 2.

Figure 9 | High Forecast Scenario for the Niagara Region[4]



The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain stations with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

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

[4] See footnote 2.

estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

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

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating ("LTR") of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment, i.e., breakers, disconnect switches, low-voltage bus or high voltage circuits.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the Niagara IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 – 6.5 below.

6.2 Station Capacity Needs

In the near/mid-term, there are summer station capacity needs at Beamsville TS, Murray TS, Crowland TS, and Niagara West MTS. In the longer term, there are station capacity needs at Carlton TS, Vineland DS, and Kalar MTS. Table 2 below summarizes transformer capacity limitations for the Niagara Region.

Table 2 | Summary of Station Capacity Needs in the Niagara Region

Need	10-day LTR Rating (MW)[5]	Need Date[6]	Size of Need by 2041
Beamsville TS	57	2022	44
Murray TS (T11/T12)	72	2022	14
Crowland TS	96	2022	25
Niagara West MTS	60	2026	22
Carlton TS	94	2028	11
Kalar MTS	68	2030	7
Vineland DS	25	2030	3

6.2.1 Beamsville TS, Niagara West MTS, and Vineland DS

The three stations supplying the Lincoln, West Lincoln, and Grimsby areas (Beamsville TS, Niagara West MTS, and Vineland DS) are forecast to reach their individual station limits, as well as their collective limit (sum of their LTRs). Beamsville TS and Vineland DS each comprise two 115 kV/27.6 kV transformers, with summer LTRs of 57 MW and 25 MW, respectively. The Beamsville TS capacity need exists today (Figure 10), whereas the Vineland DS need is forecast to start in 2030 (Figure 12). Niagara West MTS consists of two 230 kV/27.6 kV transformers, with a summer LTR of 60 MW and a need beginning in 2026 (Figure 11). Cumulatively, the capacity need at these three stations grows to 57 MW by 2041 (Figure 13).

[5] Assuming a 0.9 power factor.
[6] Based on non-coincident station forecasts, as explained in Section 5.6.

Figure 10 | Beamsville TS Capacity Need

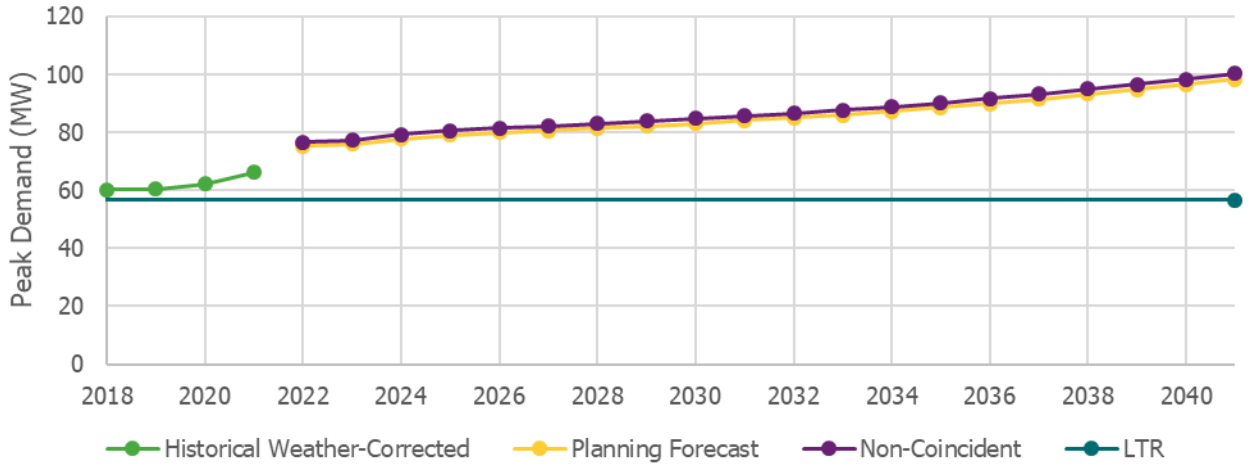


Figure 11 | Niagara West MTS Capacity Need

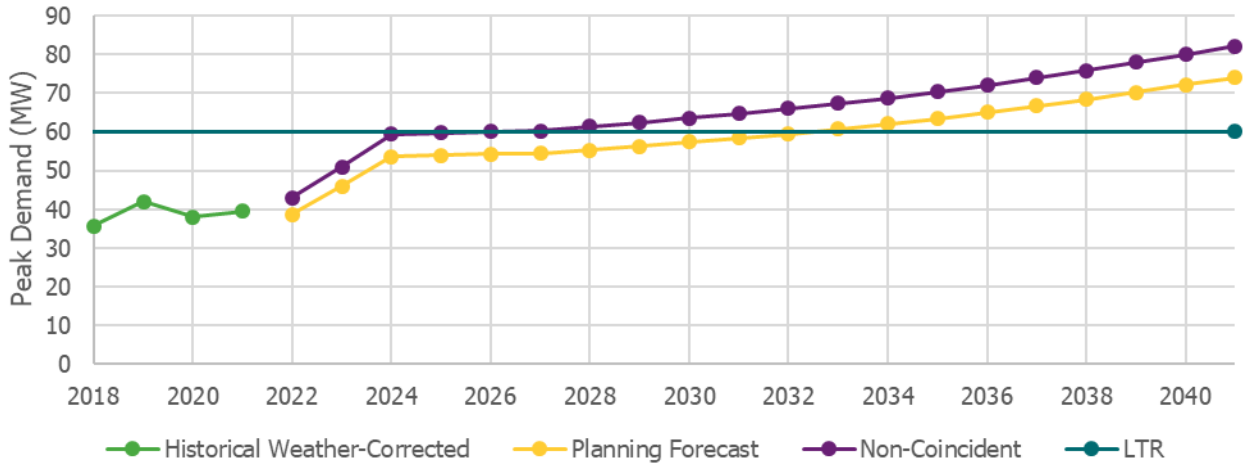


Figure 12 | Vineland DS Capacity Need

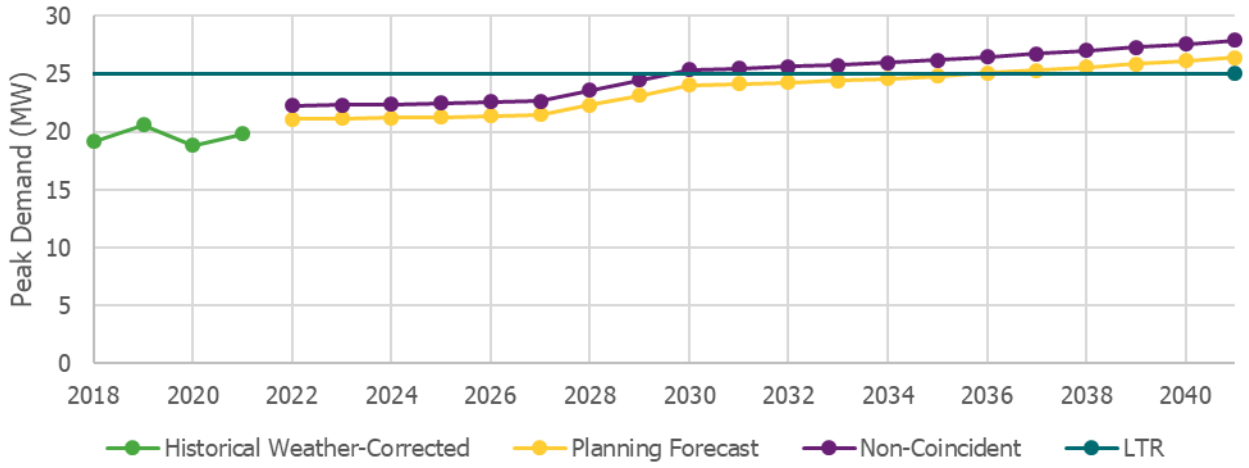
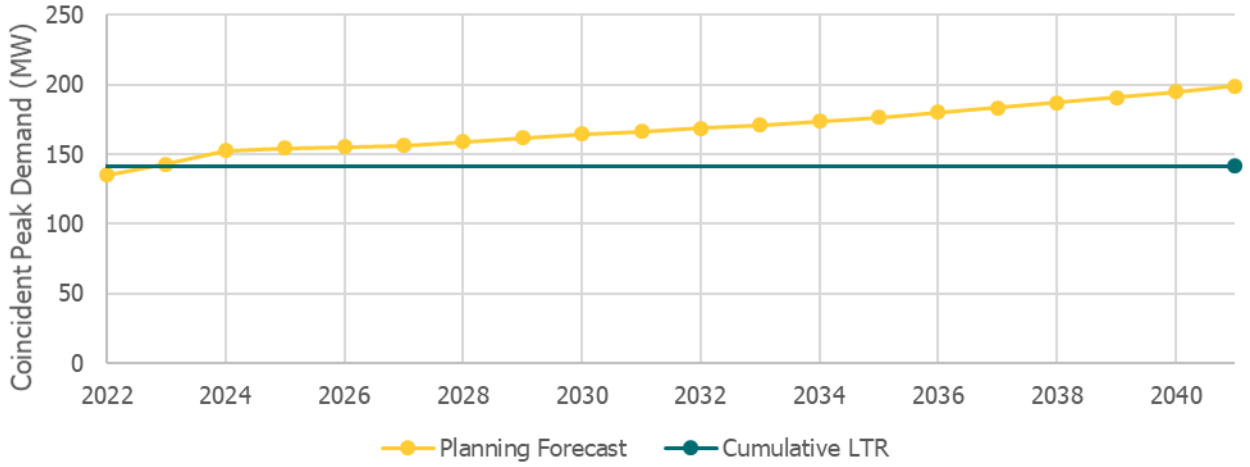


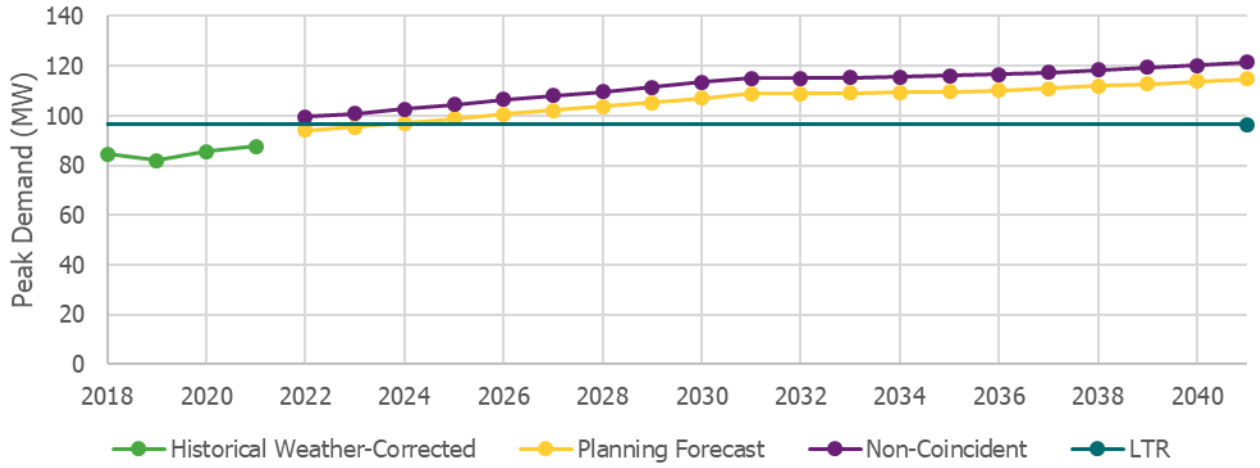
Figure 13 | Beamsville TS, Vineland DS, and Niagara West MTS Cumulative Coincident Capacity Need



6.2.2 Crowland TS

Supplying Welland, Crowland TS is forecast to reach its summer station capacity limit in 2022 and grow to a 25 MW need by 2041. This station comprises two 115 kV/27.6 kV transformers with an LTR of 96 MW.

Figure 14 | Crowland TS Capacity Need



6.2.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

Carlton TS and Kalar MTS each comprise two 115 kV/13.8 kV transformers, with summer LTRs of 94 MW and 68 MW, respectively. Carlton TS is forecast to reach capacity starting in 2028 (Figure 15) while the Kalar MTS need arises in 2030 (Figure 16). Each need will increase to 11 MW and 7 MW, respectively, by 2041. Murray TS consists of four 230 kV/13.8 kV transformers; T11 and T12 have a summer LTR of 72 MW, whereas T13 and T14 are rated to 77 MW. The T11/T12 capacity need exists today, growing to 14 MW by 2041 (Figure 17).

Figure 15 | Carlton TS Capacity Need

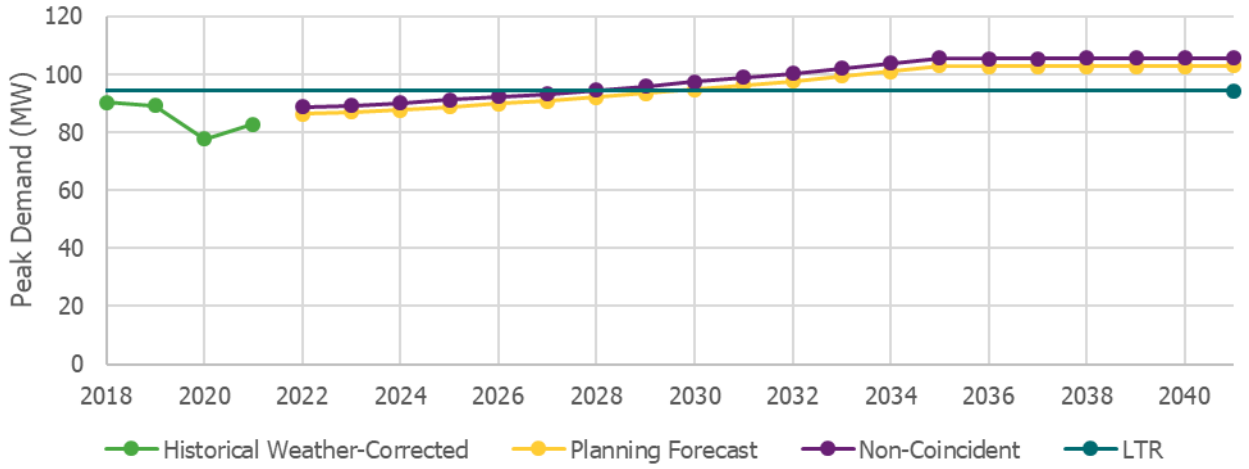


Figure 16 | Kalar MTS Capacity Need

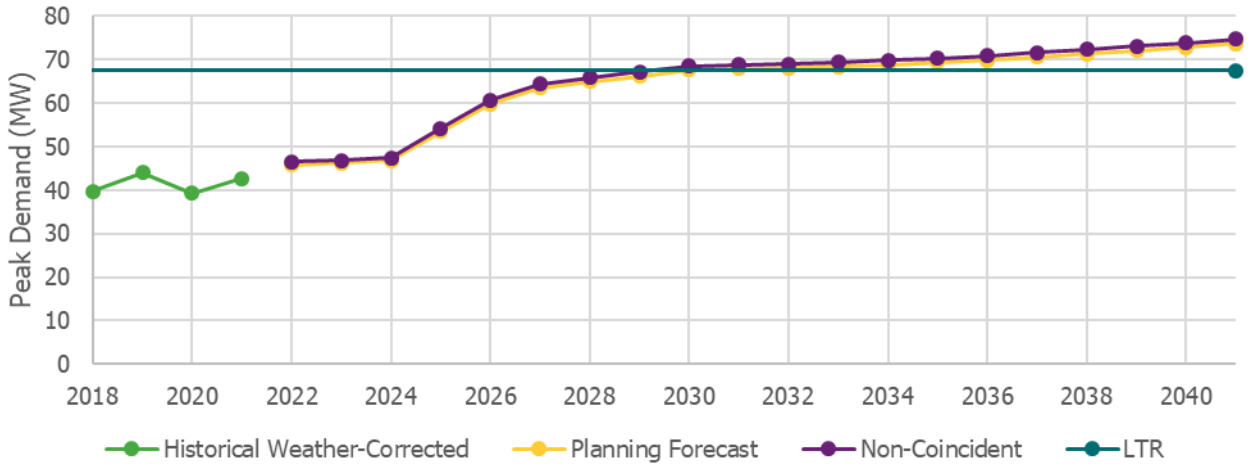


Figure 17 | Murray TS (T11/T12) Capacity Need

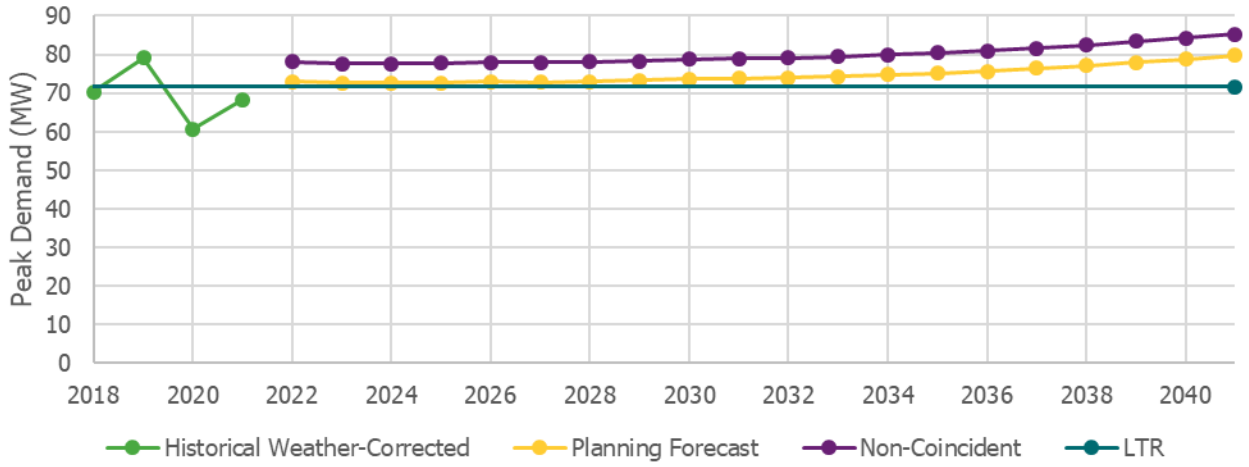


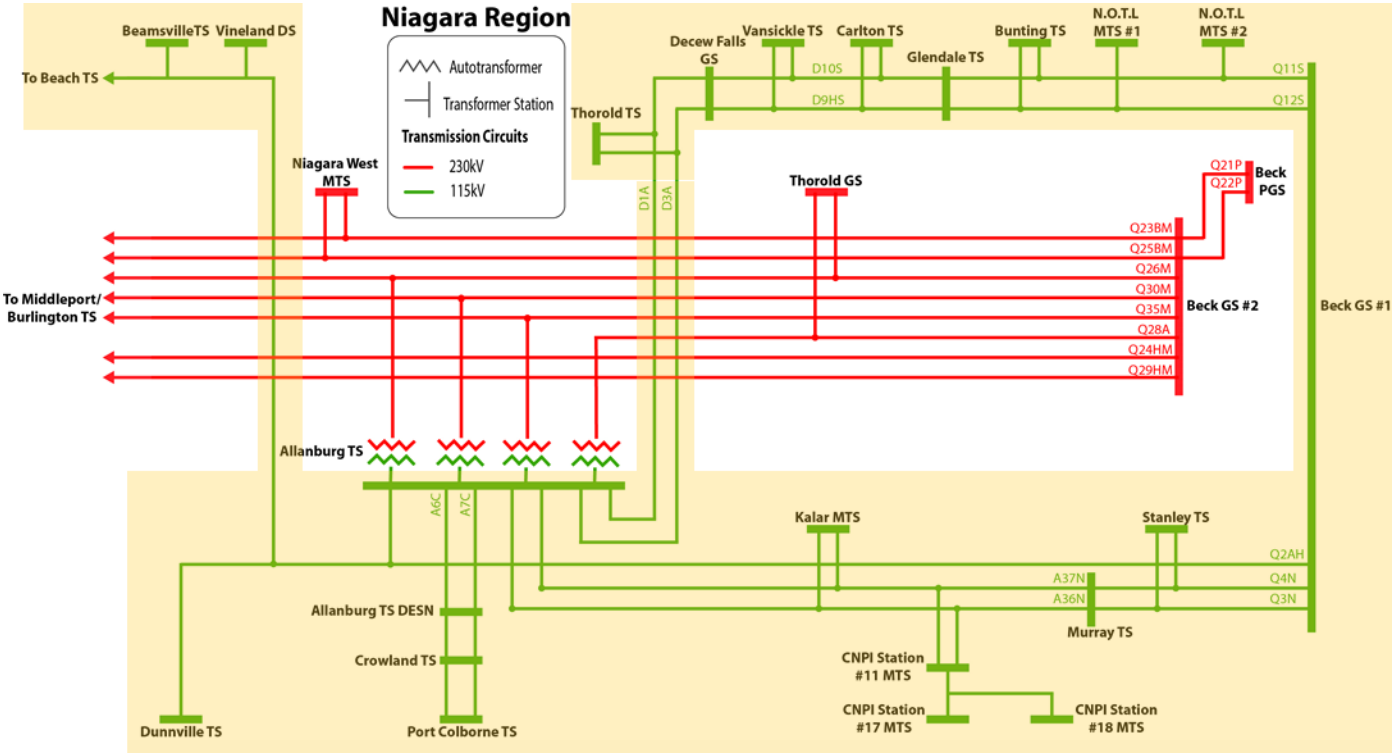
Figure 15 to Figure 17 demonstrate the non-coincident peak demand forecasts at these stations compared to their individual LTRs. Note that these station capacity needs have been presented

together in this sub-section, since this IRRP is not yet recommending infrastructure reinforcements to address them. Section 7.2.1.3 describes this in more detail.

6.3 Supply Capacity Needs

The majority of load in the Niagara Region is supplied through its 115 kV transmission sub-system, which in turn is supplied from the 230/115 kV autotransformers at Allanburg TS, Sir Adam Beck GS #1, and Decew Falls GS. The LMC of the 115 kV sub-system is therefore limited by the capability at Allanburg TS under the various planning scenarios and applicable contingencies. The sub-system is demonstrated in Figure 18.

Figure 18 | Niagara Region's 115 kV Sub-System (Highlighted Yellow)

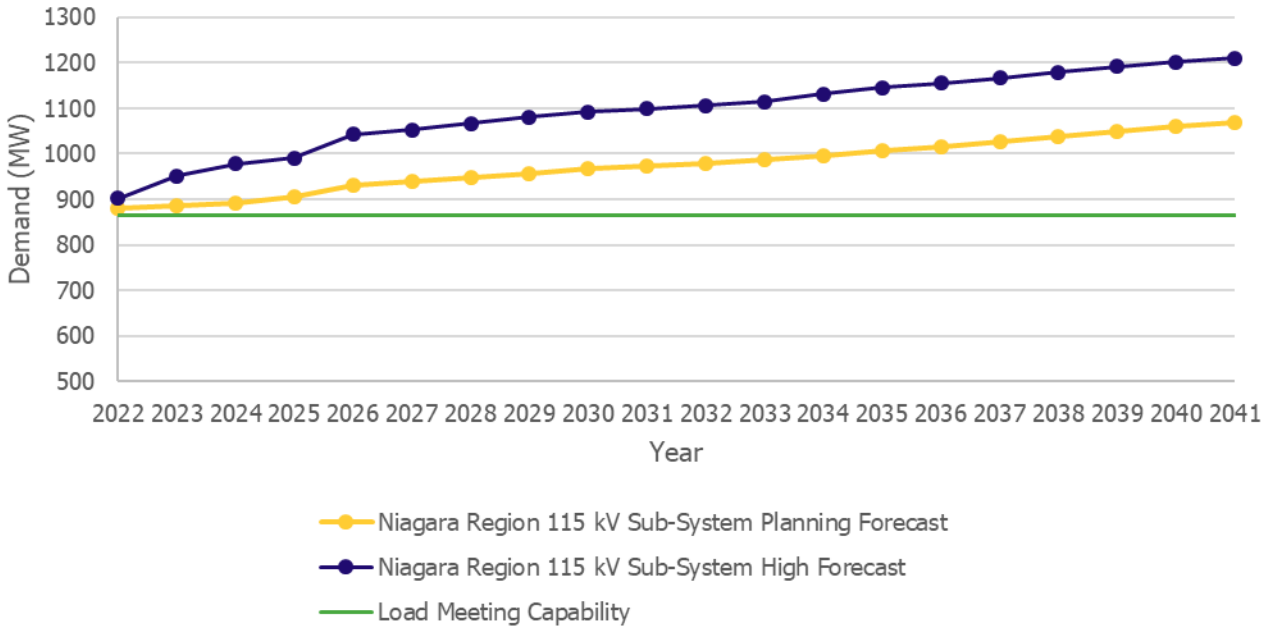


The LMC of the Niagara 115 kV sub-system, presented in Figure 19 against the forecast load, reflects limitations of the existing transmission system. Under certain outage and contingency conditions (such as contingencies impacting two circuits between Beck GS #2 and Middleport/Burlington, or Beck GS #1), the lowest-rated Allanburg autotransformer is overloaded and is the first limiting phenomenon that restricts total reliable supply into the 115 kV sub-system. However, the LMC for this area can also be restricted by other phenomena, including the thermal capability of a section of Q28A during other contingency events and specific generation outage conditions. There are further, more local restrictions within this sub-system too – such as thermal constraints limiting the supply to loads between Allanburg TS and Beck GS #1 through the 115 kV circuits.[7] All of these transmission limits are described in Appendix G.

[7] This particular need, which occurs under outage conditions, could be addressed through permissible operational control actions and would be impacted by a customer's System Impact Assessment that is ongoing at the time of regional planning.

Between 2018 – 2021, the 115 kV sub-system has had a peak coincident weather-corrected load of up to approximately 830 MW. With the reference planning forecast, the 115 kV sub-system load increases such that the supply capacity need grows to approximately 200 MW by 2041; under the high scenario, it is about 340 MW.

Figure 19 | Niagara Region 115 kV Supply Capacity Need



6.4 Asset Replacement Needs

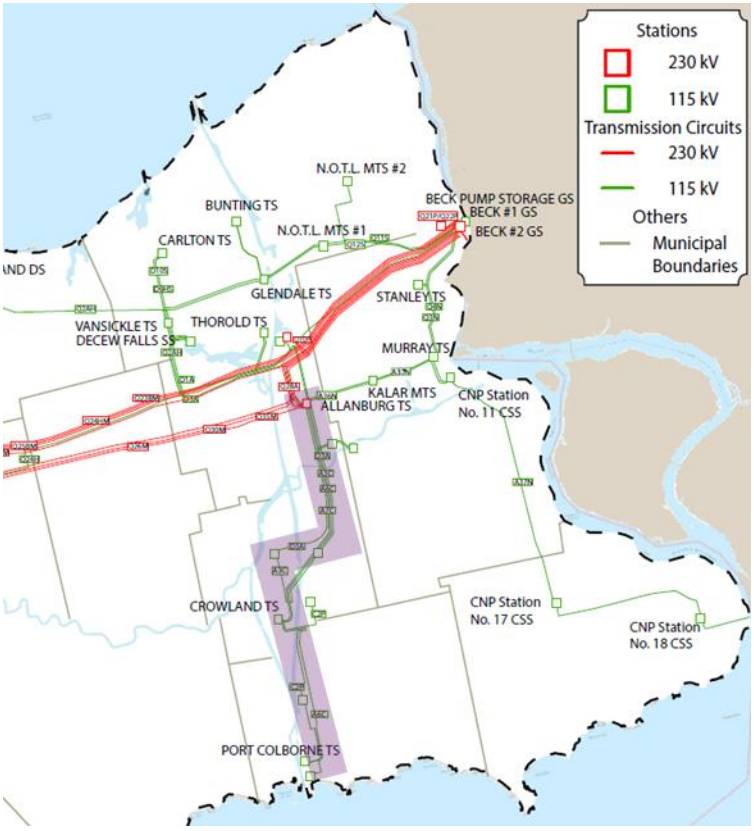
At the time of the Niagara Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. This included Crowland TS, whose transformers were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere ("MVA") units before 2026. As described in the Niagara Region Scoping Assessment, the Technical Working Group agreed that sustainment plans identified by Hydro One would be assumed to proceed as described in the Needs Assessment – unless an opportunity arose for "right-sizing".

Through the development of the IRRP, during which a more comprehensive demand forecast was created and extended to a 20-year planning horizon, and additional needs were identified or refined, the Crowland TS like-for-like replacement plan was reconsidered. This need and its relevance to the other regional needs are described further in Section 7.4.

6.5 Load Security Needs

The circuits designated as A6C/A7C form a 115 kV double-circuit line from Allanburg TS to Crowland TS, before supplying Port Colborne TS as A6C and C2P. These circuits also serve a number of transmission-connected industrial customers that are south of Allanburg TS, primarily east of the Welland Canal. Figure 20 provides an overview of this portion of the transmission system in the Niagara Region.

Figure 20 | Niagara Region Transmission System: A6C/A7C (Highlighted Purple)



The aforementioned stations and transmission-connected customers on the A6C/A7C circuits are included in the Allanburg Load Rejection Scheme; operational actions are taken to disconnect these loads in the event of certain contingencies to prevent voltage decline upon the coincidental loss of Allanburg T1 and T2. At the 2022 expected load levels on the A6C/A7C circuits, a double contingency on the Q26M and Q28A circuits will trigger over 180 MW of load being disconnected from the system. This is a violation of Section 7.1 of the ORTAC, which specifies that only up to 150 MW of planned load curtailment is permissible under these conditions. The load supplied by A6C/A7C is also expected to grow throughout the study period (i.e., up to 2041). By 2041, it is expected that the load security need will grow to approximately 75 MW in excess of the permissible amount. More details regarding this load security need are provided in Appendix G.

6.6 Summary of Identified Needs

Below is an overview of all needs identified in this Niagara IRRP.

Table 3 | Summary of Needs in the Niagara Region

Need	Need Date
Beamsville TS Station Capacity	2022
Murray TS (T11/T12) Station Capacity	2022
A6C/A7C Load Security Need	2022

Need	Need Date
Niagara 115 kV Sub-System Supply Capacity	2022
Crowland TS Station Capacity	2022
Crowland TS Asset Replacement	2026
Niagara West MTS Station Capacity	2026
Carlton TS Station Capacity	2028
Kalar MTS Station Capacity	2030
Vineland DS Station Capacity	2030

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Niagara Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

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

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

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wires options are always considered in regional planning, and are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc) of each need. These are identified through discussions with the Technical Working Group.

While traditional wires infrastructure is always a viable option for regional needs, some non-wires options are more suitable for specific need types and characteristics. Hence, to select and size suitable generation and other non-wires options, additional work is required – including creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile, which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Niagara Region needs.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires options are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective

transmission-connected options for meeting local needs in the Niagara Region are resources with a performance and costs on par with simple cycle gas turbines. New natural gas-fired generation was considered in the economic analysis for illustrative purposes, as it was representative of the lowest cost generation option. Energy storage, such as lithium nickel manganese cobalt oxide batteries, are also becoming cost-competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other energy resources (which are typically distribution-connected) are also considered.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's CDM Guidelines to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[8] Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The non-wires options also include any system capacity benefit that they could contribute to provincial resource adequacy needs, ensuring that they are both sized to address the local need and are comparable to the wires options. The net present value (in 2021 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around costs estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine wires cost estimates before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, in cases where other barriers downstream of the regional planning process (i.e., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options, pilot or demonstration projects can be explored.[9]

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

7.2 Screening Options

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically

[8] More information about the CDM Guidelines is available on the Ontario Energy Board's website.
[9] Barriers to non-wires alternatives and recommendations to address them were a part of the Regional Planning Process Review.

feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 21, and the results of its application to the Niagara IRRP needs are summarized in Table 4 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 21 | IRRP Screening Mechanism

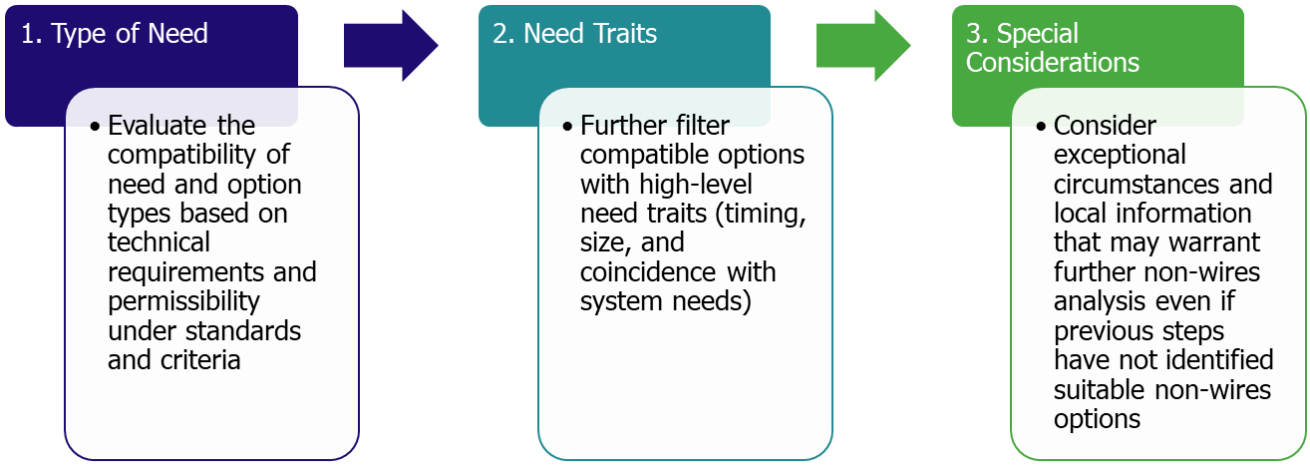


Table 4 | Results of Niagara IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Beamsville TS	Wires, demand response ("DR"), DG, CDM	Transmission-connected generation
Station capacity	Vineland DS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Crowland TS	Wires, DR, DG, CDM	Transmission-connected generation
Station capacity	Kalar MTS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Carlton TS	Wires	All non-wires

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Murray TS (T11/T12)	Wires	All non-wires
Supply capacity	Niagara 115 kV sub-system	Wires, transmission-connected generation, CDM	DR, DG
Asset replacement	Crowland TS	Coordinated with the Crowland TS station capacity need	Coordinated with the Crowland TS station capacity need
Load security	Load supplied by A6C/A7C circuits	Wires	All non-wires

7.2.1 Non-Wires Options for the Capacity Needs

Based on the nature of the need, Step 1 of the screening mechanism identifies that in general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be resources that are connected downstream of the limiting step-down transformer. The following sections outline when Steps 2 and 3 of the screening resulted in further analysis of non-wires options.

7.2.1.1 Beamsville TS, Niagara West MTS, and Vineland DS

As described previously in Section 6.2.1, there are forecast station capacity needs at Beamsville TS, Niagara West MTS, and Vineland DS, as well as a collective capacity shortfall in the area supplied by the three stations. Though eventually considered together given their geographic proximity, Beamsville TS and Vineland DS were screened independently. For Beamsville TS, with its large near-term capacity need, all applicable non-wires options were considered. Conversely, for the small long-term need at Vineland DS, the focus (in terms of a non-wires option) was on incremental CDM.

At the time of screening, the Technical Working Group did not identify a station capacity need at Niagara West MTS; this occurred later in the IRRP development when the forecast was updated by Grimsby Power. Hence, formal screening was not conducted for Niagara West MTS – but this IRRP does ultimately include recommendations that address its need (see Section 7.3).

7.2.1.2 Crowland TS

For Crowland TS, all applicable non-wires options were developed in further detail. Initially, at the time of the screening, the Crowland TS and Kalar MTS station needs were approached together given their perceived geographic proximity. However, recommendations were eventually made for these stations separately after considering factors that made an integrated approach impractical. These factors include distribution voltage level differences, distance to supply forecast growth areas, and misaligned capacity need timing between the two stations.

7.2.1.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

For some needs, further analysis of non-wires is not warranted if there is the high potential for an inexpensive and simple wires alternative that maximizes the use of existing infrastructure. This can include load transfers or control actions that are sufficient to meet the need.

This was the case for the station capacity needs at Carlton TS and Murray TS (T11/T12). At the time of screening, Alectra Utilities indicated plans to reallocate some forecast demand at Carlton TS to a nearby station with additional capacity (Bunting TS). At Murray TS, NPEI is supplied by both T11/T12 and T13/T14. While forecast demand for T11/T12 exceeds its LTR, there is sufficient remaining capacity at T13/T14.[10] Managing the load distribution between the four transformers at Murray TS is expected to address the need at T11/T12.

For the small long-term need at Kalar MTS, incremental CDM was screened in for additional analysis.

7.2.1.4 Niagara 115 kV Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Niagara 115 kV sub-system, the magnitude of the capacity need was large enough that the option development focused on transmission-connected generation or storage, with some consideration for additional locally targeted CDM.

Other non-wires options such as DR and DG were screened out from further analysis for a number of reasons. For instance, the connection of DG (regardless of fuel type) is subject to equipment limitations such as minimum loading, feeder capacity, station thermal capacity, and short circuit requirements. With an approximately 200 MW supply capacity need, the amount of incremental DG required would not be able to connect to a single transformer station in the Niagara Region, and would be unlikely to be accommodated, coordinated, and operated across multiple stations to meet the local supply constraint.[11] Recall that existing contracted DG output at peak was already accounted for during the development of the net demand forecast.

Similarly, DR was screened out due to the magnitude of the Niagara 115 kV supply capacity need. Though DR can be considered as a potential option to the extent that loads in the area can be curtailed during peak hours, the amount of DR that has historically been acquired for system capacity needs can help indicate this option's feasibility. For the 2021 summer obligation period in the capacity auction, approximately 20 MW of total capacity cleared for the Niagara zone. These past auction results provide context as to the scale of demand response that would be required to address the Niagara supply capacity need; this is unlikely to be achievable in the near-term. It is also worth noting that the Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

[10] Approximately 50 MW of remaining capacity is available at Murray TS (T13/T14) according to the IRRP reference planning forecast.
[11] For existing station DG connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

7.2.2 Non-Wires Options for the Asset Replacement Needs

Outcomes of screening non-wires options for the Crowland TS asset replacement need were aligned with the screening outcomes for the Crowland TS incremental station capacity need (i.e., the capacity need that persists even if the station is replaced like-for-like).

7.2.3 Non-Wires Options for the Load Security Needs

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as CDM and DG cannot be applied to load security needs because they usually do not enable uninterruptable power supply to customers in the event of transmission contingencies. While voluntary load loss such as DR could help address the intent of load security planning criteria, it is an option type currently procured through the provincial capacity auction. This implementation mechanism is not the optimal approach, as its current design does not include the monitoring of local adequacy nor permit immediate responses after specific local contingencies. For these reasons, non-wires options are typically screened out for load security needs unless there are exceptional circumstances identified during the IRRP development.

7.3 Options and Recommendations for Meeting the Beamsville TS, Niagara West MTS, and Vineland DS Needs

7.3.1 Transmission Options

Due to the geographic proximity of Beamsville TS, Niagara West MTS, and Vineland DS, integrated transmission options were developed to address the station capacity needs in a coordinated manner. Three options for additional station capacity for the area were considered:

1. The replacement of existing Niagara West MTS with new 2 x 75/125 MVA transformers;
2. The expansion of Niagara West MTS with two new 67 MVA transformer units; or
3. A new, separate 230 kV station supplied from Q23BM and Q25BM.

Option 1 was ruled out, given that there was no indication of asset replacement needs at the existing Niagara West MTS (resulting in stranded asset costs), plus the risk of reduced reliability expected when implementing the replacement. Option 2 was estimated to cost as little as $17M and require three years from the commitment date, whereas Option 3 was estimated to cost up to $40M (depending on the size of the transformers and implementer) and would take three to four years.[12]

Given the immediate need at Beamsville TS, the Technical Working Group also considered load transfer capabilities in the near-term. Beamsville TS and Niagara West MTS both supply Grimsby Power, NPEI, and Hydro One Distribution, while Vineland DS supplies only NPEI. At the time of this IRRP, Grimsby Power estimated the ability to transfer approximately 7 MW of NPEI's forecast load at Beamsville TS to Niagara West MTS. Beyond this amount, the Niagara West MTS station capacity need would arise sooner than already forecast. There is also some remaining capacity (approximately 4 MW) expected at Vineland DS.

[12] All cost estimates, unless otherwise specified, are net present values based on a levelized cash flow analysis rather than capital costs – see Appendix F. In this case, a capital cost estimate of $19M (+/-15%) was provided for Option 2 and $25M - $40M for Option 3.

7.3.2 Non-Wires Options

As explained in Section 7.2.1.1, non-wires options were screened in for additional evaluation for the Beamsville TS and Vineland DS needs.

For Beamsville TS, a number of measures were assessed – such as combinations of incremental targeted CDM with battery storage or gas generation.[13] The most cost-effective non-wires solution portfolio included incremental CDM (approximately 6 MW of additional savings by 2041), plus battery storage assumed to be installed in two phases (2025 and 2038) to match the need profile.[14] For Vineland DS, the incremental CDM potential was also calculated: approximately 2 MW of additional demand savings by 2041.

The net present value ("NPV") of the portfolio of non-wires options for both Beamsville TS and Vineland TS was calculated to be $30M - $57M. The lower cost assumed that the incremental CDM is already system cost-effective based on provincial resource adequacy, whereas the higher cost assumed that the demand savings targeted to these stations would be incremental to the provincial CDM framework. More details on the CDM potential methodology and results are provided in Appendix E.

7.3.3 Recommendation

During the development of the IRRP, the forecasts at Beamsville TS and Niagara West MTS were updated by the impacted LDCs as growth trended higher and new potential customers were identified. By the conclusion of the IRRP, this reinforced the preference for the integrated wires options due to their cost-effectiveness and ability to address the capacity needs at all three stations.

The original scope of the non-wires options that were developed only addressed the Beamsville TS and Vineland DS needs, but were collectively $13M – $40M more expensive than the least expensive wires option. The increased forecast for Niagara West MTS did not impact the wires option of a new 230 kV station in the area – it only increased its cost-effectiveness. Another portfolio of non-wires options sized for Niagara West MTS' final reference forecast capacity need would have increased the non-wires costs further. Reallocating the load forecast on the 115 kV stations to 230 kV supply also helps alleviate the broader Niagara 115 kV sub-system capacity need.

Therefore, due to the cost-effectiveness and ability to meet the multiple needs, the Technical Working Group recommends near-term load transfers to offload Beamsville TS, plus a new 230 kV station supplied from Q23BM and Q25BM. This could be accomplished by expanding the existing Niagara West MTS. The station should be in-service as soon as possible and accommodate at least 57 MW of pre-contingency load in the area by 2041.

It is recommended that after the IRRP, the impacted LDCs coordinate the magnitude and timing of load transfers between the three stations to manage and monitor the Beamsville TS capacity need until the new station is in-service. Moreover, the LDCs and Hydro One should coordinate during the RIP to establish the lead implementer of the new station. Timing, siting, and size of the new

[13] Based on the unserved energy profile forecast at Beamsville TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[14] This included an 18 MW, 144 MWh battery storage facility. The Beamsville TS forecast was updated and increased near the end of the IRRP forecast; cost range estimate would only increase with larger battery storage.

transformers should be factored into the decision – in addition to a comprehensive economic comparison that accounts for both the cost of the transformer station and the distribution-level costs that could incur if the station is sited farther west and away from the service territories that are expected to grow.

7.4 Options and Recommendations for Meeting the Crowland TS, Load Security, and Niagara 115 kV Sub-System Needs

The Crowland station capacity and asset replacement needs, as well as the A6C/A7C load security and Niagara 115 kV sub-system capacity needs, share common transmission elements and impact each other. As such, both wires and non-wires options were developed to address these four needs in an integrated fashion.

7.4.1 Transmission Options

Two sets of transmission options were identified – one that largely involves the continued buildout of the 115 kV system in the Niagara Region, and another that expands the 230 kV supply.

Option Set 1 includes:

- New 115 kV station in Welland, supplied by the existing A6C/A7C circuits (to address the Crowland TS capacity need);
- New 230 kV Allanburg bus (to improve supply to the 115 kV sub-system and mitigate the A6C/A7C load security need); and
- Re-building of 115 kV Crowland TS like-for-like (to address the asset replacement need).

Option Set 2 includes:

- Replacement of sections of 115 kV D3A/A3C circuits with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need).

In terms of preliminary capital costs, Option Set 1 was estimated to be approximately $253M - $353M[15] in total, whereas Option Set 2 may cost $128M.[16] Option Set 1 will require a minimum of three years; Option Set 2 will need six years.

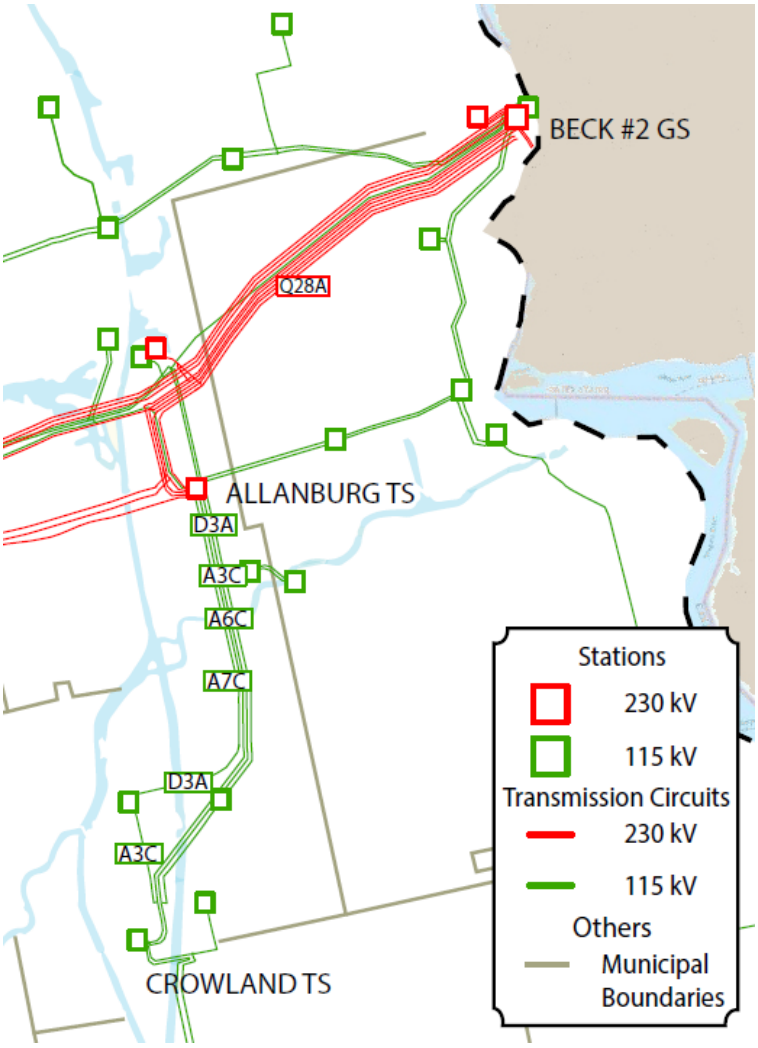
[15] The high end of the cost estimate range for Option Set 1 includes the potential for new 115 kV circuits and other reinforcements if the existing A6C/A7C circuits cannot accommodate the new 115 kV station in Welland.

[16] Capital cost estimates provided by Hydro One during the IRRP were prepared based on preliminary information and intended to provide a ballpark figure to be used strictly for initial options comparison. No engineering or field work was completed as part of the development of these cost allowances and as such, these cost allowances provide no cost guarantee or accuracy range. Costs allocations were derived from previous historical costs/unit costs and were to be used strictly for options comparison; Hydro One may refine and update cost estimates as part of the RIP.

To accommodate the planning forecast, the uprating of an existing 230 kV circuit, Q28A, is also required in addition to either Option Set. The cost and feasibility of this reinforcement is currently being assessed by Hydro One and is estimated to require until at least 2024 to be in-service.

The components of these Option Sets are identified conceptually on the map of Niagara Region's existing transmission system in Figure 22.

Figure 22 | Impacted Areas by the Transmission Options



Under some of the contingencies and conditions expected to limit the 115 kV sub-system LMC, operational measures such as load rejection are permissible according to ORTAC. Therefore, the benefit of a new load rejection scheme was also factored in when assessing the supply capability with each of the wires options described above. It was assumed that this scheme, developed and implemented by Hydro One for the Niagara 115 kV sub-system, could be installed in 2024 or later.[17]

[17] The ultimate in-service date will depend on the complexity of the scheme's design and NPCC approval timelines.

7.4.2 Non-Wires Options

As explained in Section 7.2.1.2 and 7.2.1.4, non-wires options were screened in for additional evaluation for the Crowland TS and 115 kV sub-system supply needs.

For the Crowland TS capacity need alone, incremental targeted CDM, battery storage, and gas generation were all considered either as standalone or integrated options.[18] The most cost-effective non-wires solution portfolio for the Crowland capacity need included incremental CDM (approximately 10 MW of additional savings by 2041), plus a 10 MW/40 MWh battery storage facility installed in two phases (2025 and 2038) to match the need profile. The NPV of this portfolio was calculated to be in the range of $17M - $53M. Similar to what was described for the Beamsville TS non-wires options, this cost range is attributed to the provincial CDM assumptions.[19]

As the Niagara IRRP progressed and the interplay between the Crowland TS needs and the broader Niagara 115 kV supply capability became clearer, a non-wires option was also considered at a high level. An all-generation, 240 MW alternative was sized to compare to the lowest cost transmission option set; 240 MW is the expected increase in the 115 kV sub-system supply capability enabled by Option Set 2 described previously. However, this non-wires option is not a feasible solution due to various factors. While an all-generation option was identified to compare to the wires option on a MW basis, there are significant challenges to implementing and operating a resource to address the multiple, layered, and local needs. For instance, for 240 MW of generation to address both the Crowland TS capacity and replacement needs, as well as the broader 115 kV supply needs, a portion of the generation must be sited on the distribution system to supply customers currently served by Crowland TS and the remaining must be targeted to the region's 115 kV system. There may also be thermal or short circuit limitations to connecting this amount of generation on the distribution system. Moreover, as described in Section 7.2.3, generation is typically not considered a feasible option to solve load security needs.

7.4.3 Recommendation

When comparing the two wires option sets, Option Set 2 is preferred for a number of reasons. It is the more cost-effective option, evaluated at more than $100M less expensive than Option Set 1 (based on capital cost estimates), even though both offer similar 115 kV sub-system supply capability and are sufficient according to the reference planning forecast. Qualitatively, by expanding the 230 kV transmission system, Option Set 2 also offers long-term flexibility to accommodate more load growth in the southern portion of the Niagara Region – particularly along the industrial and commercial hub around the Welland Canal. Option Set 1 provides limited growth options in the area in comparison to Option Set 2, without extensive station expansion at Allanburg TS. Meanwhile, converting the existing 115 kV Crowland TS to 230 kV in Option Set 2 allows the other 115 kV stations in the Niagara Region to accommodate new growth and maximizes the use of existing infrastructure with the available capacity normally utilized by the 115 kV Crowland TS. Triggering the

[18] Based on the unserved energy profile forecast at Crowland TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[19] Another sensitivity was conducted for the battery storage sizing, resulting in a higher cost range of $25M - $61M. See Appendix D.3 for more details.

reconfiguration is also a time-sensitive opportunity, since Crowland TS is expected to require asset replacement in the near term.[20]

Long-term flexibility can also be considered by comparing the options and their ability to accommodate the high IRRP forecast scenario. According to the reference forecast, approximately 200 MW of extra 115 kV supply capability is required by 2041. As shown in Section 6.3, the high scenario increased this requirement to 340 MW. Both Option Sets 1 and 2 enable the increased capability required for the reference forecast, and neither Option Set precludes a further wires or non-wires option in the long-term. These future actions can include new generation resources or additional 230/115 kV auto-transformation. In contrast, a non-wires option sized precisely to meet the reference need would have less flexibility to accommodate growth that exceeds today's expectations.

Regardless, none of the non-wires options described in Section 7.4.2 can sufficiently address the multiple needs at once. Wires Option Set 2 would cost-effectively resolve the Crowland capacity and replacement needs, the A6C/A7C security issue, and enable other load growth on the 115 kV sub-system. For these reasons, the Technical Working Group recommends the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM/Q29HM, as well as the uprating of Q28A. A new load rejection scheme should also be developed to manage the Niagara 115 kV sub-system need. The load forecast should be monitored between regional planning cycles, and there are benefits to targeting incremental CDM to the 115 kV sub-system in order to manage load growth beyond the reference scenario. The technical feasibility and costs of the wires recommendations should be further analyzed in the RIP; the IESO will continue to participate in the RIP Working Group to provide advice and input on this matter.

7.5 Summary of Recommended Actions and Next Steps

The Technical Working Group recommends the actions summarized in Table 5 to meet identified needs in the Niagara IRRP.

Table 5 | Summary of Needs and Recommended Actions

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

[20] All final cost estimates have accounted for the asset replacement value for Crowland TS.

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development for a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Transfer load in excess of the station limit to Murray TS T13/T14	• 2023
• Carlton TS station capacity	• Alectra	• Monitor load growth between regional planning cycles • Transfer load in excess of the station limit to Bunting TS	• 2028
• Kalar MTS station capacity	• NPEI	• Monitor load growth between regional planning cycles and consider future opportunities for incremental CDM	• 2030

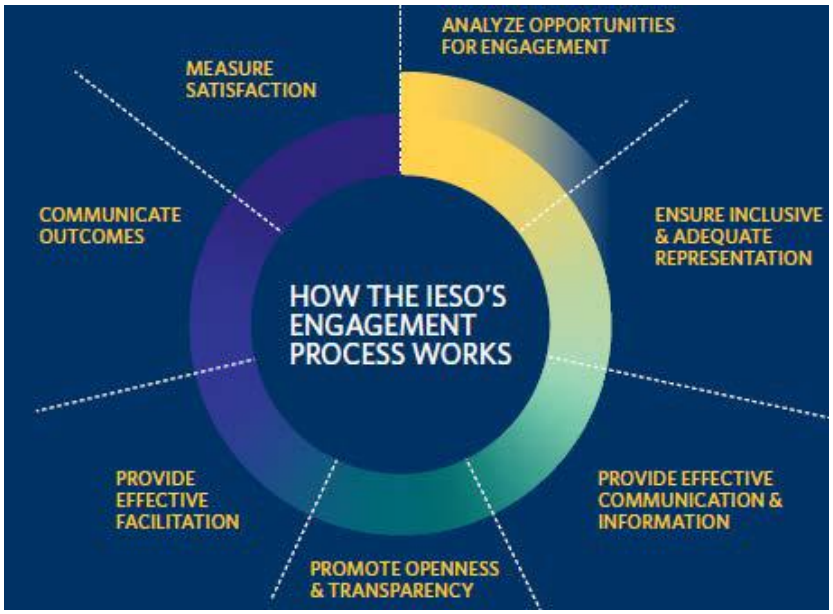
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Niagara IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

Figure 23 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Niagara Region

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

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

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

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Niagara Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Niagara Region Scoping Assessment Report finalization. A public webinar was held in August 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, targeted outreach then began with municipalities in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Niagara Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

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

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Niagara Region (including the City of Niagara Falls and Town of Fort Erie), have been considered and accounted for in the IRRP work;
- Ensuring there are procedures to alter the implementation of plan recommendations should changes occur in the region; and
- Keeping lines of communication following the plan completion to share information and updates.

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

All interested parties were kept informed throughout this engagement initiative via email to Niagara Region subscribers, municipalities, and Indigenous and Métis communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion and employment areas as outlined in the updated Niagara Region Official Plan). This insight has been valuable to the IESO – it supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

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

8.4 Bringing Municipalities to the Table

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

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

- Strong population growth across the Niagara Region based on 2051 growth projections and in some areas above and beyond the regional forecast (i.e. even higher growth expected in the City of Welland);
- Notable growth in the Town of Lincoln (greenhouses, Secondary Plan areas, potential GO Transit development), along the QEW corridor in Grimsby, and in Thorold;

- Strong economic development around the Welland Canal (e.g. Thorold Multimodal Hub "Niagara Ports");
- Key areas of growth in the City of Niagara Falls within intensification nodes and corridors, projects around the GO Transit Station and the new Niagara South Hospital, wastewater treatment plant, and residential new construction;
- Industrial, commercial, institutional, and residential development in the Town of Fort Erie and Secondary Plan areas; and
- Potential urban boundary expansion in the region totaling 130 hectares of residential and 150 hectares of employment lands.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Niagara Region throughout the development of the plan. This includes the communities of the Mississaugas of the New Credit, Oneida Nation of the Thames and Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council) and Métis Nation of Ontario Niagara Region Métis Council.

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

9. Conclusion

The Niagara IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2041, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends load transfers off Beamsville TS and a new or expanded 230 kV station supplied by Q23BM and Q25BM. The IRRP also recommends the implementation of control actions on the Niagara 115 kV sub-system to manage overloads during outage conditions, plus the replacement of Crowland TS with a new 230 kV station supplied by new 230 kV lines from Q24HM and Q29HM. Q28A should be uprated, and a portion of the load at Murray TS (T11/T12) should be transferred to Murray TS (T13/T14). Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth in the Niagara 115 kV sub-system, Carlton TS, and Kalar MTS to determine if or when further reinforcements will be needed. This includes monitoring any future community energy planning or electrification trends. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region – particularly to the Beamsville TS/Vineland DS/Niagara West MTS areas and 115 kV sub-system in the near-term, and Kalar MTS in the long-term.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.



NIAGARA
REGIONAL INFRASTRUCTURE PLAN

July 12, 2023

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Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Niagara Technical Working Group

DISCLAIMER

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

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

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

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE NIAGARA REGION.

The participants of the Niagara Region Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

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

This RIP is the final phase of the second cycle of the Niagara Region regional planning (RP) process and it follows the completion of the Niagara Region Integrated Regional Resource Plan ("IRRP") [1] in December 2022; and the Niagara Region Needs Assessment ("NA") [2] and Scoping Assessment ("SA") in May 2021 and August 2021, respectively. This RIP provides a consolidated summary of needs and recommended plans for the Niagara Region over a 10-year planning horizon (2023-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer-term needs and trend. All needs for this long-term horizon will be covered and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in March 2017 with the publication of the Niagara Region RIP [3], which provided a description of needs and recommendations of preferred wires plans to address near-term needs. Since the previous planning cycle, the following projects have been completed:

- Decew Falls SS (2017) – Five (5) 115kV breakers were replaced with sulfur hexafluoride (SF_6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – The existing 40/53/67 MVA, 115/13.8 kV transformer T2 was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Some 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – The 28/37/47 MVA, 115/27.6 kV transformers T61 and T62 were replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

The recommended major infrastructure investments including assets replacements in the Niagara Region over the near and medium-term (2023-2032) period are given in Table 1 on the next page, along with their planned in-service date and budgetary estimate for planning purposes.

The Niagara Region TWG recommends that:

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

The next regional planning cycle for the Niagara Region must be triggered within five years, beginning with the Needs Assessment (“NA”) phase. It is expected that the next NA will be initiated in 2026. However, the next regional planning cycle can be started earlier if required to address any new emerging needs.

Table 0-1 Niagara Region - Recommended Plans over the 2023-2032 Study Period

No.	Investments	I/S Date	Cost[1]
A	**Increase Capacity**		
1	230 kV circuit Q28A – Uprate circuit between Beck 2 SS and Abitibi Jct.	TBD	$3M
2	Lincoln Area: Build new 230/27.6 kV, 50/83 MVA transformer station	2026	$45M
4	Crowland TS: Convert station to 230 kV with new 230/27.6 kV, 75/125 MVA transformer station and build a new 18 km of double circuit line from Abitibi Jct to Crowland TS	2027	$128M
5	Murray TS: Uprate T11/T12 75 MVA transformers with new 100MVA units	2027	$41M
6	Carlton TS: Transfer excess load to Bunting TS	2029	$5M
B	**Asset Replacement**		
1	Thorold TS: Replace Transformer T1	2024	$43M
2	Glendale TS: Replace Transformers T1 and T2	2027	$55M
3	Carlton TS: Replace LV Switchgear	2027	$55M
4	Bunting TS: Replace existing Transformers T1 and T2	2029	$45M
5	Murray TS: Replace Transformers T13 and T14	2031	$27M
6	Vansickle TS: Replace LV Switchgear	2032	$14M
7	Allanburg TS: Replace Transformer T3	2032	$20M
8	115kV Line D1A/D3A: Refurbish line section between Gibson Jct and Thorold TS	2024	$4M
9	115kV Line Q2AH: Refurbish line section between Rosedene Jct. and St. Anns Jct.	2025	$10M

[1] These costs are budgetary estimates for planning purposes only.

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1 INTRODUCTION

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

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Niagara Region Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

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

The Niagara Region includes the Regional Municipality of Niagara as shown in Figure 1-1. It includes the Cities of Niagara Falls, Port Colborne, St. Catharines, Thorold and Welland, the Towns of Fort Erie, Grimsby, Lincoln, Niagara-on-the-Lake and Pelham and the Townships of Wainfleet and West Lincoln.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck Generating Station (GS) #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) connecting the Sir Adam Beck #2 Switching Station (SS) to stations in the Hamilton/Burlington area. The summer 2022 non-coincident peak load of the Region was about 977 MW.



Figure 1-1: Niagara Region Map

1.1 Scope and Objectives

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

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

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

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near- and medium-term needs (2023-2032) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2023-2032 period and wires plans to address these needs based on new and/or updated information;
- Consideration of long-term needs identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

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

2 REGIONAL PLANNING PROCESS

2.1 Overview

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

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

2.2 Regional Planning Process

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

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

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

[1] also referred to as Needs Screening

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

The RIP phase is the final stage of the regional planning process and involves confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, plan level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

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

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

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

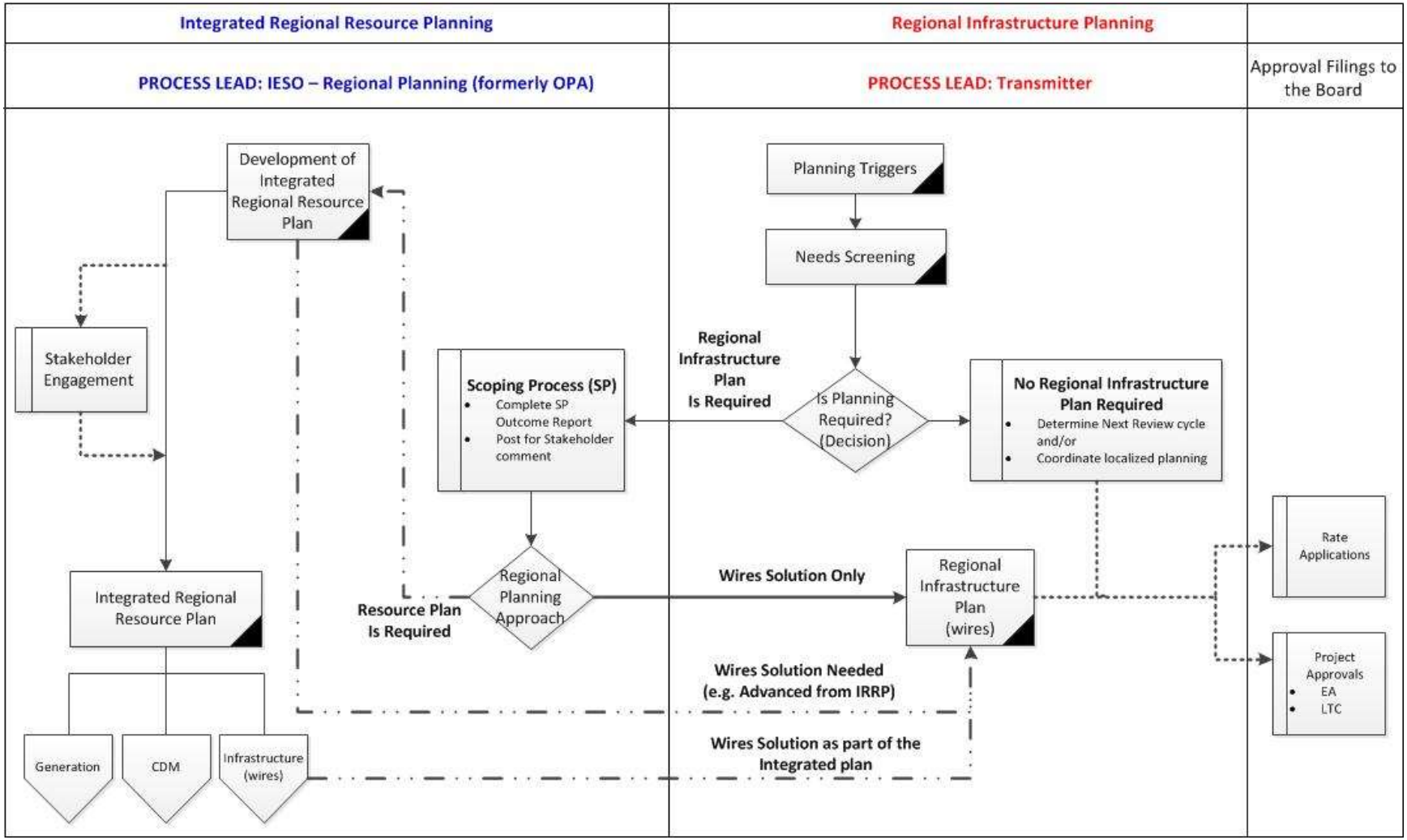


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see

Figure 2-2) as follows:

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

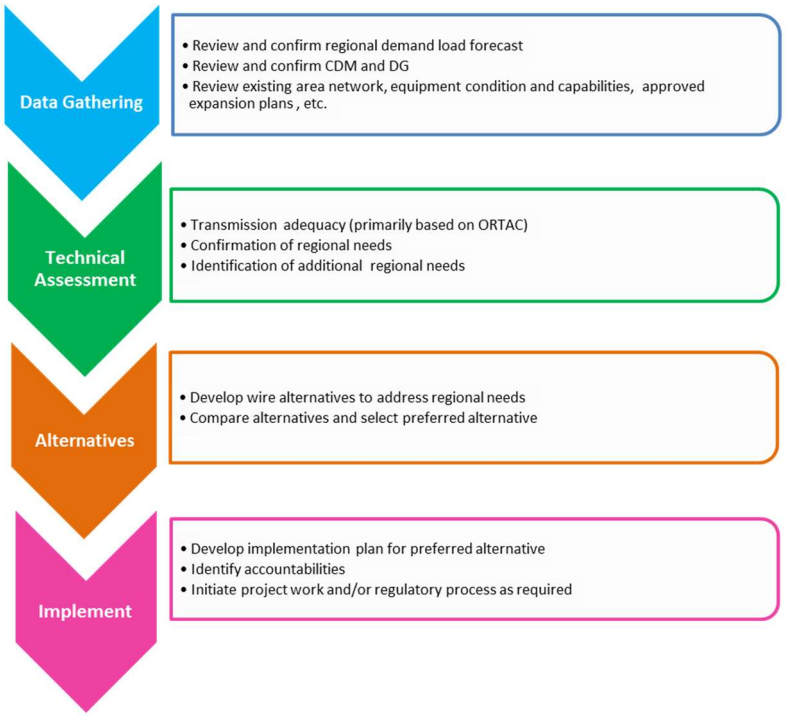


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE NIAGARA REGION COVERS THE REGIONAL MUNICIPALITY OF NIAGARA AND INCLUDES THE CITIES OF NIAGARA FALLS, PORT COLBORNE, ST. CATHARINES, THOROLD AND WELLAND, THE TOWNS OF FORT ERIE, GRIMSBY, LINCOLN, NIAGARA-ON-THE-LAKE AND PELHAM AND THE TOWNSHIPS OF WAINFLEET AND WEST LINCOLN.

The Local Distribution Companies in the Niagara Region are Alectra Utilities Corporation, Canadian Niagara Power Inc., Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara-on-the-Lake (NOTL) Hydro Inc., Niagara Peninsula Energy Inc., and Welland Hydro Electric System Corp. A listing of the LDCs along with the associated supply stations is given in Appendix C. The high-voltage system in this Region also provides supply to number of direct transmission-connected customers transformer stations.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck GS #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. The 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS connect this region to Hamilton/Burlington. The power is distributed through thirteen (13) HONI and six (6) LDC owned step-down transformer stations (please see Appendix B for a complete list. The distribution system in this Region is at two voltage levels, 27.6 kV and 13.8 kV. An electrical single line diagram for the Niagara Region transmission facilities is shown in Figure 3-1. The circuits and stations are provided in Table 3-1.

Table 3-1: Station and Circuits in the Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
Q3N, Q4N, Q11S, Q12S, A36N, A37N, A6C, A7C, D9HS, D10S, D1A, D3A, Q2AH	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q10P	Allanburg TS*, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Niagara Murray TS, Niagara West MTS, NOTL York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI Station #17 MTS, CNPI Station #18 MTS	Sir Adam Beck GS #1, Sir Adam Beck GS #2, Sir Adam Beck PGS, Thorold CGS, Decew Falls GS

*Station with Autotransformers installed

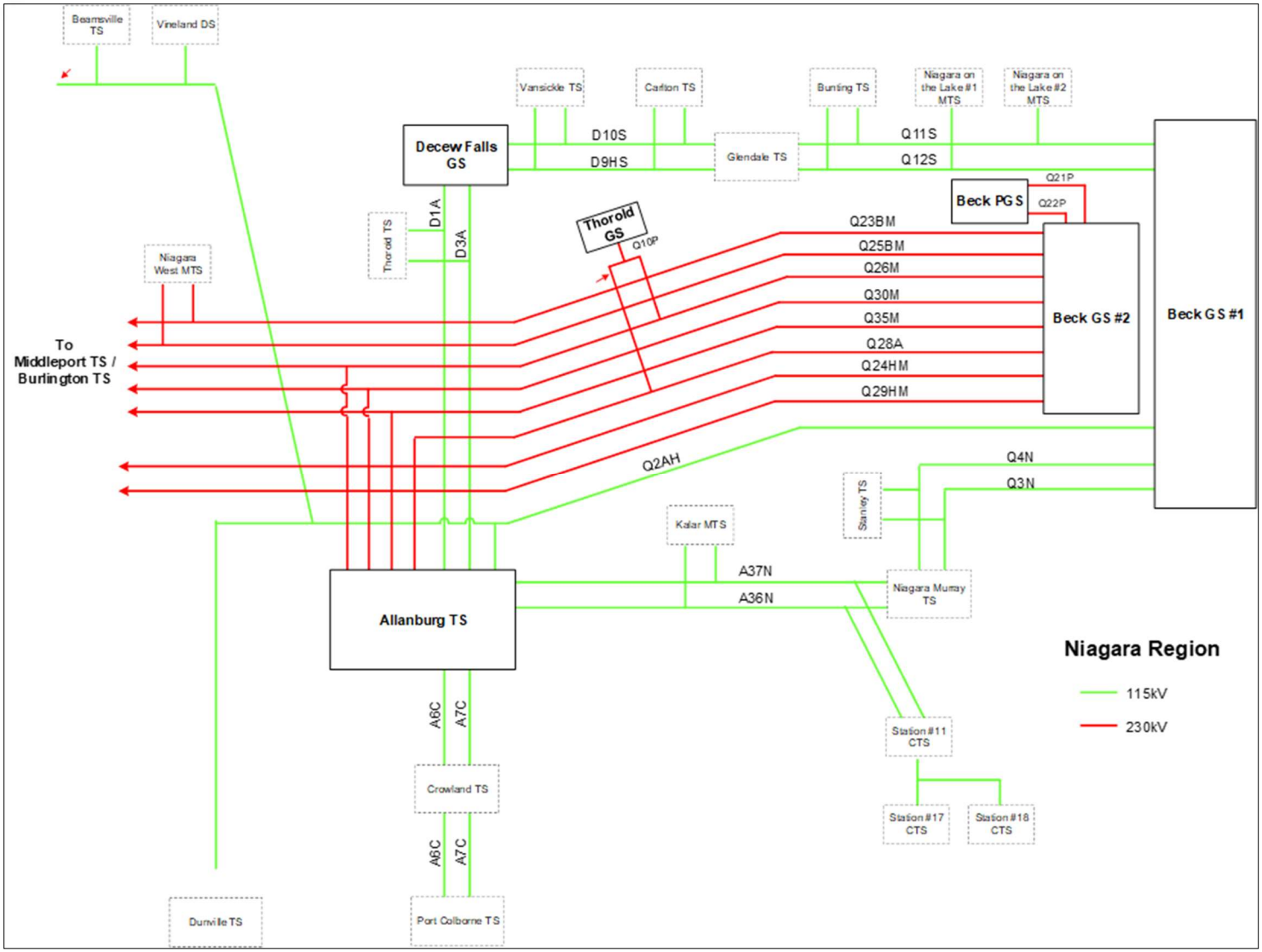


Figure 3-1: Niagara Region Single Line Diagram

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

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE NIAGARA REGION.

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

Projects Completed

- Decew Falls SS (2017) – Existing five (5) 115kV breakers were replaced with sulfur hexafluoride (SF6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – Existing 40/53/67 MVA T2 transformer was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Work at 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – Existing T61 and T62 28/37/47 MVA transformers was replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

A detailed load forecast for the Niagara region was developed as part of the area IRRP study. The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast.

The IRRP forecast used in this RIP study includes minor increases at a few stations as per the LDCs[2]. Also included is a LDC connected industrial customer with curtailable load under specific outage conditions.

The load in the Niagara Region is expected to grow at an average rate of approximately 2.3% annually from 2023 to 2032. However, a major portion of this load increase is due to industrial customers. The growth rate for the LDCs, not accounting for the industrial customers, is about 1.3%. Longer term growth rate between 2033 to 2042 for all customers is forecast to be about 0.9%.

Figure 5-1 shows the Niagara region extreme summer weather net forecast from 2023-2042. The forecast shown is the regional non-coincident forecast and shows the load for all Niagara customers as well as the load for all the LDCs. The regional non-coincident peak load is forecast to increase from approximately 1092MW in 2023 to about 1505MW in 2042.

[2] Loading at Crowland TS adjusted as per new forecast from Welland Hydro. Loading at NOTL #2 MTS and NOTL York MTS adjusted as per new forecast from NOTL Hydro.

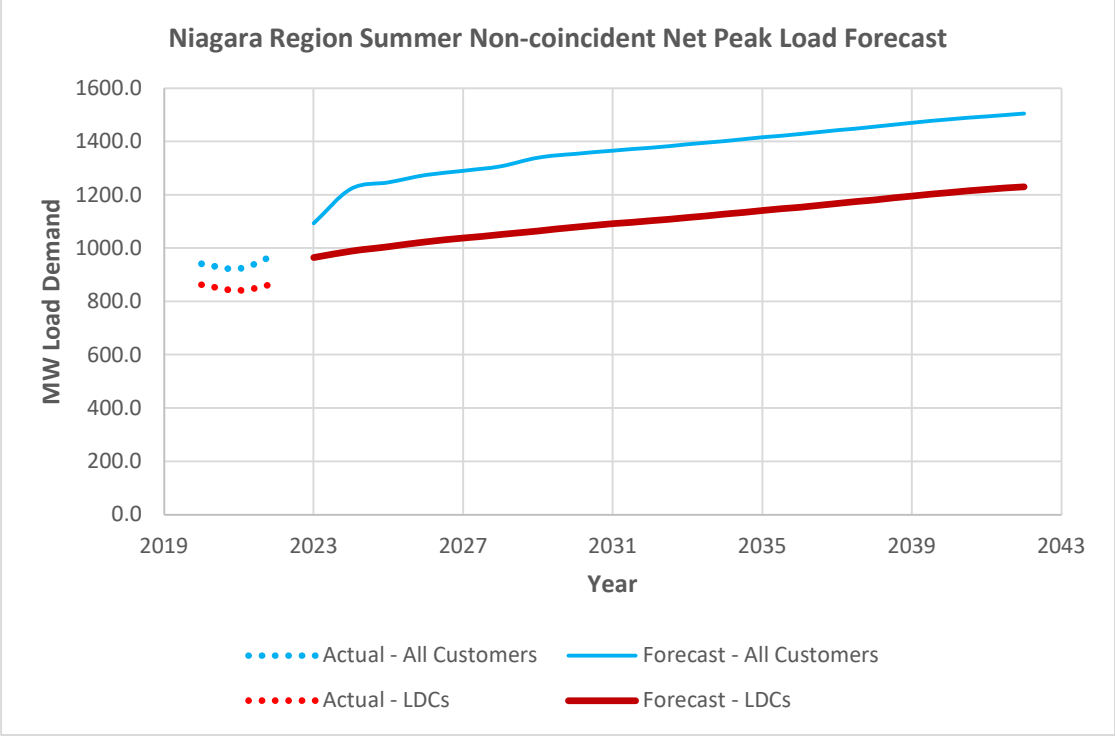


Figure 5-1: Niagara Region Summer Non-Coincident Weather Corrected Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the Niagara region IRRP.
- LDCs reconfirmed load forecasts up to 2041. The additional year of forecast to 2042 was extrapolated to complete the 20 year period.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings for this region. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, where the power factor used for the load stations are from the IRRP Appendix G.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Radial line adequacy is assessed using non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6 SYSTEM ADEQUACY AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE NIAGARA REGION AND LISTS FACILITIES REQUIRING REINFORCEMENT OVER THE 2023-2032 PERIOD.

In the current regional planning cycle, the three regional assessments were completed for the Niagara Region and their findings were used as inputs to this RIP report. These assessments are:

- Niagara Region Needs Assessment (NA) Report, May 2021.
- Niagara Region Scoping Assessment (SA) Report, August 2021
- Niagara Region Integrated Regional Resource Plan (IRRP), December 2022 and Appendices, February 2023

The NA and IRRP reports identified several needs because of the forecasted load demand and condition of major high voltage transmission assets. This section reviews the adequacy of the transmission lines and stations in the Niagara Region based on the updated regional load forecast provided in Appendix C. Sections 6.1 to 6.3 present the results of this review. Asset replacement needs identified in the previous NA report are discussed in Section 6.4 of this report. Load security and load restoration needs are discussed in Section 6.5.

6.1 230 kV and 115kV Transmission Circuits

All 230 kV transmission circuits in the Niagara Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the Ontario's transmission system, carry power from the Niagara River Generation to the rest of Ontario and are part of the interconnection path that connects Ontario to neighboring New York State at the Beck 2 SS. The 230 kV circuits Q26M, Q28A, Q30M and Q35M circuits also supply the 230/115 kV autotransformer station at Allanburg TS to serve local area stations within the region. The power flow on these circuits depend on the bulk system transfers as well as the local area loads.

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Niagara Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 6-1 below. The need date defines the time when the peak load forecast exceeds the most limiting summer Limited Time Ratings. Mitigation measures are discussed in Section 7.1.

Table 6-1: Niagara Region - Lines Sections Exceeding Ratings

No.	Voltage	Line	Section	Contingency	Line Rating MW	Need Date
1	230kV	Q28A	Beck 2 x Abitibi Jct.	N-2[1]	386	2024[2]
2	115kV	A6C/A7C	Allanburg TS x Crowland TS	N-1	214	2029

1. Loss of double circuit line Q26M/Q35M
2. Need date dependent on customer forecast load increase

6.2 230/115kV Transformation Facilities

Almost ninety percent of the Niagara Region load is supplied from the 115 kV transmission system. This power is supplied to the 115kV system through the four 230/115 kV autotransformers at Allanburg TS together with 115kV generation at Sir Adam Beck #1 GS and Decew Falls GS.

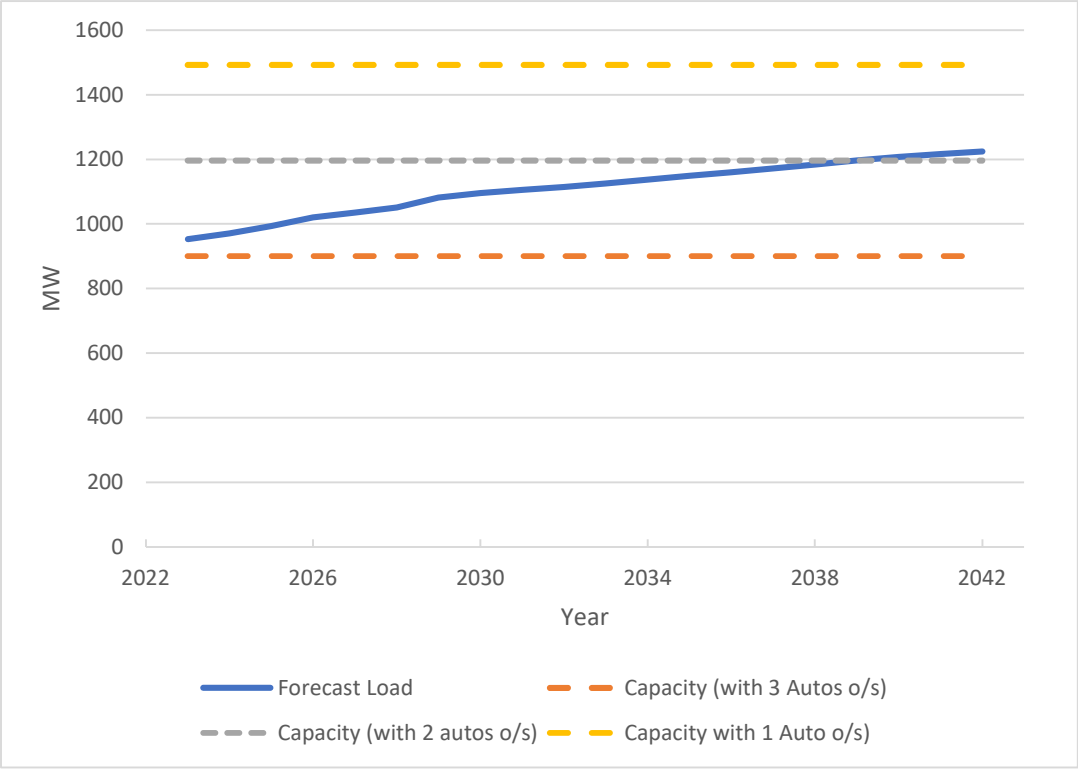


Figure 6-1: Niagara Region – 115kV Area Load and Supply Capacity

The forecast loading on the 115kV system is shown in Figure 6-1, together with the supply capacity with one, two and three autotransformers out of service at Allanburg TS and the local 115kV generation at 605MW[3]. There is adequate supply capacity in the region for the loss of up to 2 of the 4 autotransformers beyond the 2023-2032 RIP study period. However, since the autotransformers are connected to the 230kV circuits directly – loss of up to three autos can occur under an outage condition followed by a double circuit line outage – resulting in load exceeding supply capacity (N-1-2 contingency). Mitigation measures to address this issue are described in Section 7.2.

6.3 Step Down Transformation Facilities

There are a total of twenty-six (26) step-down transformer stations supplying power to customers in the Niagara Region as listed in Table 6-2. These include thirteen stations owned by Hydro One, six by area LDCs and seven (7) by direct industrial customers. The stations' summer peak load forecast is given in Appendix D Table D-1.

Table 6-2: Niagara Region - Step-Down Transformer Stations

Allanburg TS	CNPI Station #18 MTS	Murray TS	Stanley TS
Beamsville TS	Crowland TS	Niagara West MTS	Thorold TS
Bunting TS	Dunnville TS	NOTL #2 MTS	Vansickle TS
Carlton TS	Glendale TS	NOTL York MTS	Vineland DS
CNPI Station #17 MTS	Kalar MTS	Port Colborne TS	CTS #1
CTS #2	CTS #3	CTS #4	CTS #5
CTS #6	CTS #7		

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV transformer stations within the Niagara Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 6-3.

[3] Beck GS #1 is assumed at 490MW and Decew Falls GS at 115 MW.

The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time Ratings. Mitigation measures to address this issue are described in Section 7.3.

Table 6-3: Niagara Region Station Capacity Needs in the Study Period

No.	Station Name	Capacity (MVA)	2023 Loading (MW)	Station 10- day LTR (MW)	Need Date
1	Beamsville TS	25/42	64.2	59.0	2023
2	Murray TS T11/T12	45/75	77.7	73.2	2023
3	Niagara West MTS	40/67	54.6	66.0	2024
4	Crowland TS	50/83	100.9	101.7	2024
5	Carlton TS	45/75	89.2	95.4	2029

6.4 Asset Replacement Needs for Major High Voltage (HV) Transmission Equipment

Several Hydro One facilities in the Niagara Region will require asset renewal work over the 2023-2032 study period. These needs are determined by asset condition based on a range of considerations such as equipment deterioration, technical obsolescence due to outdated design, lack of spare parts availability or manufacturer support, and/or potential health and safety hazards.

Asset replacement work is planned over the study period at area transformer stations and lines listed in Table 6-4. The options and preferred solutions to address these needs are discussed further in Section 7.4 of the report.

Table 6-4: Niagara Region - Planned Replacement Work

No.	Station	Planned I/S Date
A - Station Work		
1	Thorold TS	2024
2	Glendale TS	2027
3	Murray TS T11/T12	2027
4	Carlton TS	2027
5	Crowland TS	2027
6	Bunting TS	2029
7	Murray TS T13/T14	2031
8	Vansickle TS	2032
9	Allanburg TS	2032
B – Lines Work		
1	115kV D1A/D3A	2024
2	115kV Q2AH	2025

6.5 Load Security and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study and one load security need has been identified for the region. The ORTAC requires that not more than 150MW of load may be interrupted by planned load curtailment or load rejection and the Allanburg Load Rejection scheme does not meet the criteria.

6.5.1 A6C/A7C Load Security

The loss of the 230kV double circuit line Q26M/Q28A, will result in the coincidental loss of autotransformers T1 and T2 at Allanburg TS and the separation of the 115kV A6C/A7C and D1A and A36N circuits from the Allanburg TS 115kV bus. Under this scenario the Allanburg Load Rejection scheme trips the A6C and A7C circuits to prevent loads connected to the A6C/A7C circuits from excessive voltage declines. The load on the A6C/A7C is currently about 200MW and forecast to increase to 278MW by the end of the plan period. The amount of load rejected is thus more than the permitted amount of 150 MW allowed under ORTAC. Mitigation measures to address this need are discussed in Section 7.5.

7 REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE NIAGARA REGION.

The electrical infrastructure needs for the Niagara Region are summarized in Table 7-1. These needs include those previously identified in the Niagara Region NA and IRRP as well as those resulting from the adequacy assessment carried out as part of this RIP report. The details of the project/plan to address these needs are provided in Sections 7.1 through 7.5.

Table 7-1: Niagara Region – Identified Near and Medium-Term Needs

Section	Facilities	Need	Timing
Transmission Line Capacity Needs			
7.1.1	Q28A -Beck 2 TS to Abitibi Jct.	Line Capacity Exceeded	2024
7.1.2	115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS	Line Capacity Exceeded	2029
230/115 kV Transformation Capacity/115kV Supply Area Capacity			
7.2	Allanburg TS	Loading exceeds Capacity at Allanburg TS	2023
Station Capacity			
7.3.1	Beamsville TS and Niagara West MTS	Forecast load exceeds normal supply capacity	2023
7.3.2	Crowland TS	Forecast load exceed normal supply capacity	2024
7.3.3	Murray TS and Kalar TS	Forecast load exceed normal supply capacity	2028
7.3.4	Carlton TS	Forecast load exceed normal supply capacity	2029
Asset Replacement			
7.4	Thorold TS	Transformer T1 replacement	2024
7.4	Carlton TS	LV Switchyard refurbishment	2027
7.4	Glendale TS	Transformers T1 and T2 replacement	2027
7.4	Crowland TS	Transformer T5 and T6 replacement	2027
7.4	Murray TS	Transformers T11 and T12 replacement	2027
7.4	Bunting TS	Transformers T1 and T2 replacement	2029
7.4	Murray TS	Transformers T13 and T14 replacement	2031
7.4	Vansickle TS	LV Switchyard refurbishment	2032
7.4	Allanburg TS	Transformer T3 replacement	2032
7.4	115kV Line D1A/D3A	Gibson Jct. x Thorold TS	2024
7.4	115kV Line Q2AH	Rosedene Jct. x St. Anns Jct.	2025
Load Security			
7.5	115kV A6C/A7C Load Security	Forecast exceeds ORTAC load rejection Criteria	2023

7.1 Transmission Line Capacity

This section describes work required to address the transmission line capacity needs associated with the 230kV circuit Q28A and 115kV circuits A6C and A7C as described in Section 6.1.

7.1.1 230kV circuit Q28A – Beck #2 TS x Abitibi Junction

7.1.1.1 Introduction

The 230kV circuit Q28A is part of the eight transmission circuits egressing from Beck #2 GS and connects to Allanburg TS. The planning forecast based on new customer load indicates that the loading will exceed the circuit 980A rating by summer 2024 for a loss of the double circuit line Q26M/Q35M.

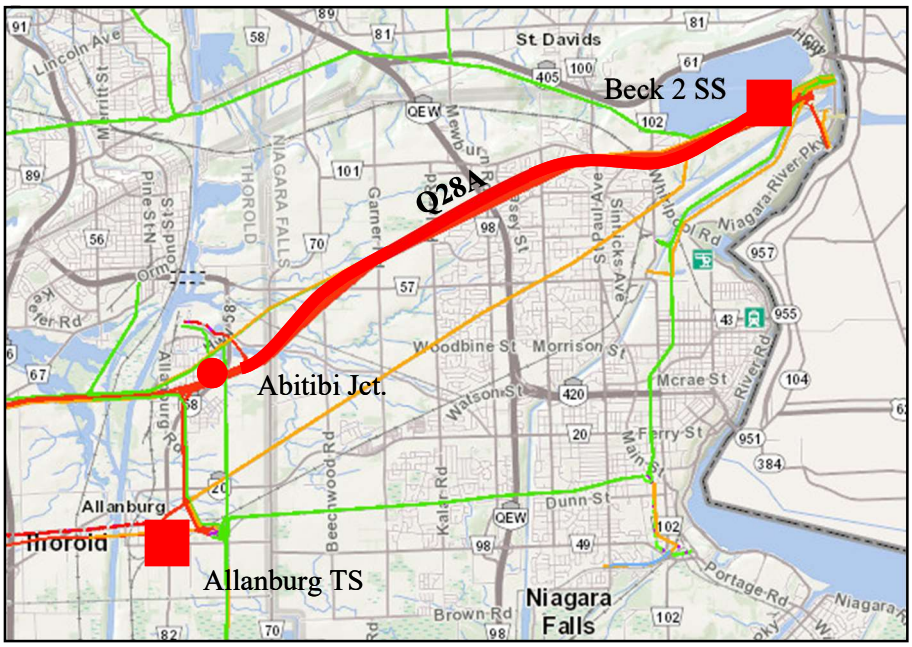


Figure 7-1: Uprate Q28A Circuit

7.1.1.2 Alternatives and Recommendation

The following alternatives were considered to address the 230kV circuit Q28A capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate 230kV Q28A Circuit:** This alternative considers uprating the conductor by tensioning the conductors to reduce the line sag and allow the line conductor to operate at a higher temperature. This will increase the circuit rating from 980A to 1310A. The estimated cost of the work is about $3M.

The TWG recommends Alternative 2 as the preferred and cost-effective alternative for increasing the capacity of the line. Hydro One has advised the customer of the proposed work and will initiate the work once confirmed by the customer.

7.1.2 115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS

7.1.2.1 Introduction

The 115 kV double circuit line A6C/A7C supplies Crowland TS and Port Colborne TS along with several directly connected transmission customers as shown in Figure 7-2. The load connected on this line is forecast to exceed the line capacity by summer 2029 as shown in Table 7-2.

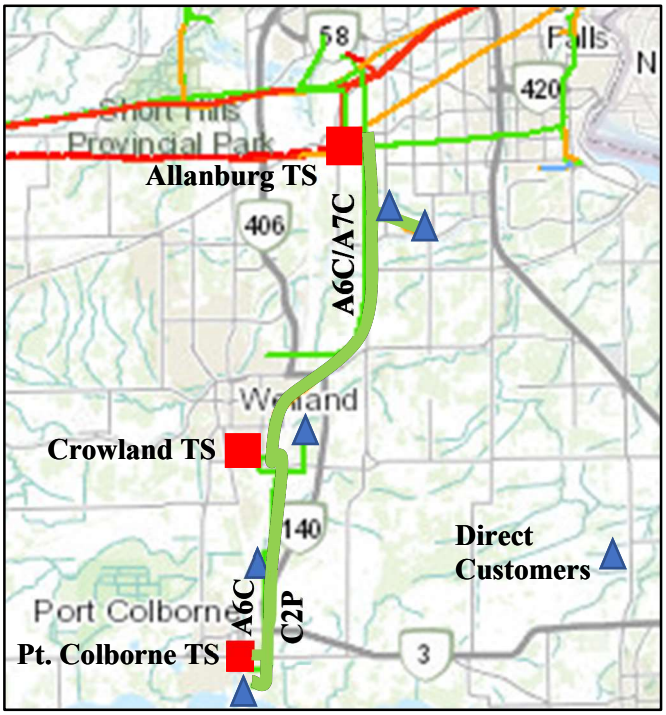


Figure 7-2: Map of 115kV A6C/A7C Circuits

Table 7-2: 115kV circuit A6C/A7C -Connected Loads

Load	Circuit Limit	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
A6C/A7C[2]	213.9[3]	169.5	174.0	182.4	191.6	202.2	206.8	211.6	232.7	234.9	236.8	236.9	246.1	2029
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	---
A6C/A7C post Crowland[4]			-	-	-	-	92.7	95.7	115.1	115.3	115.5	115.7	117.6	---

1. Actual summer load adjusted for extreme weather
2. Loading excludes Allanburg TS DESN
3. Rating of A6C/A7C circuit between Allanburg TS DESN and Crowland TS

4. After Crowland TS conversion to 230KV as per Section 7.3.2 in 2027

7.1.2.2 Alternatives and Recommendation

The following alternatives were considered to address the overloading issue on the 115kV line A6C/A7C line:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate the A6C and A7C Circuits:** This alternative considers reconductoring the A6C/A7C line between Allanburg TS and Crowland TS (~ 14.5 km) using a higher rated conductor. This will increase the circuit rating from 214 MW to about 280 MW. The estimated cost of the work is $23M.
- **Alternative 3 – Reduce Loading on A6C/A7C:** This alternative reduces loading on circuits A6C and A7C by rebuilding Crowland TS[4] as a 230/27.6 kV station supplied from and supplying it from a new 230kV circuit line.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative addressing the overloading issue on the A6C/A7C line. Transferring of Crowland TS to a 230 kV supply also addresses multiple other issues; reduces load on the Allanburg TS autotransformers (See Section 7.2.2), allows increase capacity at Crowland TS (see Section 7.3.2), and reduces the severity of the load security issue (Section 7.5).

7.2 115kV Supply Area Capacity

7.2.1 Introduction

As shown in Section 6.2, the loads on the Niagara Region 115kV system exceeds the 115 kV system supply capability under certain contingency conditions which result in three out of the four autotransformers being out of service at Allanburg TS. Specifically, this occurs under a 230kV outage condition followed by a double 230kV circuit line outage (N-1-2 contingency).

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the 115 kV supply capacity:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.

[4] Crowland TS needs to be refurbished and will be rebuilt. Please refer to Section 7.3.2 and 7.4 for more details.

- **Alternative 2 – Modify Existing Load Rejection Scheme for 115kV Subsystem:** This alternative modifies the Allanburg load rejection scheme to include rejection of up to 150MW of load whenever three autotransformers are out. The estimated cost of this alternative is about $8M.
- **Alternative 3 – New 230kV Switchyard at Allanburg TS:** The work required in this alternative is to build a new 230kV switchyard to eliminate the N-1-2 contingency at Allanburg TS (loss of three autotransformers contingency) to supply more power to the 115kV network. The work required would consist of four new 230kV bus diameters, each accommodate an autotransformer to eliminate any coincidental loss of the autotransformers. This work has an estimated cost of $253M.
- **Alternative 4** – **Reduce load on 115kV system by introducing 230kV Supply to the Welland Area** - This alternative would transfer Crowland TS to 230kV supply by building a 18km double circuit 230kV transmission line from Q24HM/Q29HM to connect to a new 230/27.6kV transformer station at the Crowland TS site. The new TS will replace the existing station that requires replacement. This work has an estimated cost of $128M.

The TWG recommends Alternative 4 as the most cost effective and preferred alternative. Besides addressing the 115kV supply capacity needs, this alternative also addresses; the A6C/A7C overloading issue (Section 7.1.2); the Crowland TS capacity needs (Section 7.3.2); the Crowland TS asset renewal needs (Section 7.4); and reduces the severity of the A6C/A7C load security issue (Section 7.5). The work is planned to be in service by summer 2027.

7.3 Station Capacity Needs

This section describes the work required to address the station capacity needs identified in Section 6.3.

7.3.1 Beamsville TS, Vineland DS, Niagara West MTS – 115kV Lincoln Area

7.3.1.1 Introduction

Beamsville TS and Vineland DS are 115/27.6kV stations and Niagara West MTS is a 230/27.6kV station which supplies the towns of Grimsby, West Lincoln, and Lincoln. The area is experiencing load growth where the summer weather extreme demand forecast will exceed the area normal supply capacity.

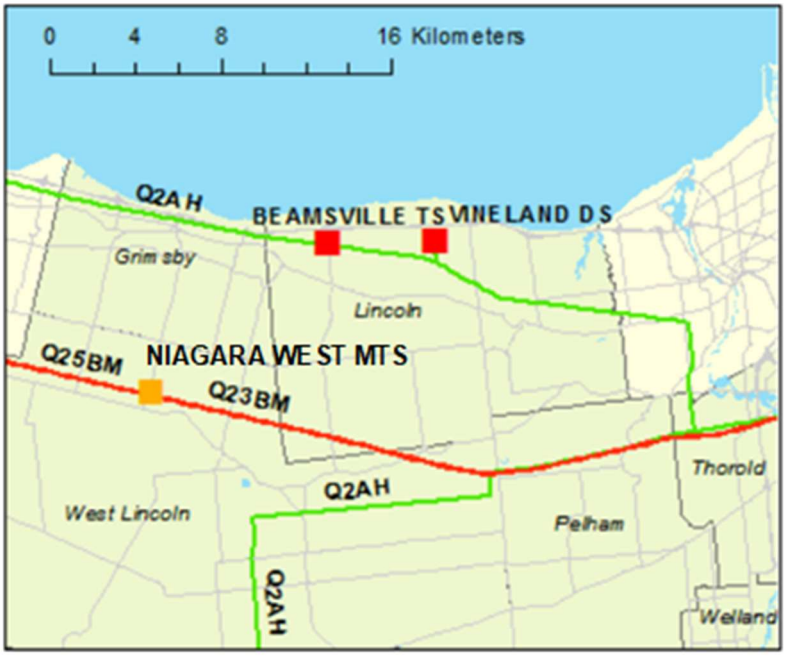


Figure 7-3: Map of 115kV Lincoln Area

Beamsville TS presently has 115kV/27.6kV 42MVA transformers (T3/T4) with a summer LTR of 59.0MW. This station has operated at or slightly over the LTR over the past few years.

Table 7-3 shows the forecast for the three area stations. The forecast shows that the combined capacity of the three stations would be exceeded by summer 2024. The TWG agrees that a solution is required to address the upcoming supply capacity needs.

Table 7-3: 115kV Lincoln Area Stations Load Forecast

Station	LTR MW	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Beamsville	59.0	63.1	77.2	79.2	80.5	81.4	82.1	82.9	83.7	84.6	85.6	86.5	101.9	---
Niagara West MTS[2]	63.4	41.6	49.0	56.8	57.6	58.2	58.9	60.3	61.7	63.2	64.7	66.2	84.3	---
Vineland DS	26.4	20.5	20.7	20.9	21.1	21.3	21.6	22.5	23.5	24.5	24.7	25.0	27.6	---
Total	148.8	125.3	147.0	156.9	159.2	161.0	162.5	165.7	168.9	172.3	175.0	177.7	213.8	2024

1. Actual summer load adjusted for extreme weather

7.3.1.2 Alternatives and Recommendation

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

- **Alternative 1 – Maintain Status Quo:** This solution is not recommended as it does not address the supply capacity needed in the area. This solution will also prevent load growth in this area.

- **Alternative 2 – Load Transfer to Neighbouring Stations:** This solution is not viable as there is no nearby station where the load can be transferred.
- **Alternative 3 – Replace Beamsville and Niagara West transformers:** Replace existing Beamsville TS T3/T4 transformers and Niagara West MTS T1/T2 with larger 50/83MVA units, providing total additional capacity of 100 MW at both stations to address the existing and future load demand. Additional feeder positions will be required at both stations to utilize the additional capacity. The cost of this work is estimated to be about $48M.
- **Alternative 4 – Build new 230/27.6kV DESN station in Local Area:** This alternative would build a new 230/27.6kV DESN station to supply the increased load demand forecast required in the local area. The new station would be supplied by the double circuit 230kV transmission line Q23BM/Q25BM with new 50/83MVA transformers. The new station will provide about 102 MW of new capacity. The estimated cost of this alternative is about $45M.

The TWG recommends proceeding with Alternative 4. This alternative provides a robust transmission solution to meeting the area LDCs demand forecast and will also allow for future load growth beyond the study period on the 230kV system. This solution will also provide better reliability for future loads as the new station will have dual incoming transmission supplies into station instead of being on a single supply like Beamsville TS. Loads will be managed by the respective LDCs between 2024 and 2027 when the new facility is expected to go into service.

Hydro One will work with all the respective parties to find a suitable location to meet the load. Possible locations could be an expansion at Niagara West MTS or a location central to Vineland DS and Beamsville TS to supply local growth (e.g., the southwest corner in the Town of Lincoln).

7.3.2 Crowland TS

7.3.2.1 Introduction

Crowland TS is a 115/27.6kV 50/83MVA transformer station located in Welland. The station load is at or near its 10-day LTR of 101.7 MW and load is forecasted[5] to increase up to 121MW by the end of 2032 as shown in Table 7-4 below. A permanent supply solution is required for the increased load growth as the current loading will surpass the station capacity in 2024.

The transformers, T5 and T6, at Crowland TS are about 55 years old and based on asset condition assessment Crowland TS has been identified for asset renewal by summer 2027.

[5] Forecast updated from IRRP as per Welland Hydro



Figure 7-4: Map of Crowland TS

Table 7-4: Crowland TS Load Forecast

Station	LTR MW	Act.[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Crowland TS	101.7	93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	2024

1. Actual summer load adjusted for extreme weather

7.3.2.2 Alternatives and Recommendation

The following alternatives were considered to address Crowland TS capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.
- **Alternative 2 – Rebuild existing DESN at Crowland TS and add a second DESN at Crowland TS:** Under this alternative the existing Crowland TS transformers will be replaced, and the station refurbished. A new second DESN would be built to handle the increased load. This alternative would maintain the existing 115kV loading on the Allanburg autotransformers and work will be required to address the issue. Work also would be required to address the capacity need on the A6C/A7C circuits and address the load security concern at Allanburg TS. This alternative is estimated to cost $78M for the refurbishment work and new DESN at Crowland TS. An additional $253M will be required to provide additional switching at Allanburg TS to reinforce the 115kV supply.

- **Alternative 3 – Provide a new 230kV Supply to Welland Area and convert Crowland TS to 230kV:** Under this alternative the existing Crowland TS would be replaced with a new 230/27.6 kV DESN station with 75/125 MVA transformers to supply the increased load demand. A new 18km double circuit 230kV transmission line will be constructed to supply this new transformer station from the double circuit 230 kV line Q24HM/Q29HM. This new station would allow the station LTR to increase to approximately 170 MW (summer) with 75/125MVA transformers. The estimated cost of this alternative is about $128M.

The TWG recommends Alternative 3 as it is the lowest cost alternative. It provides new area transmission and load growth opportunities. The conversion of Crowland TS to 230kV will reduce the loading on the 115kV autotransformer at Allanburg TS, alleviating the constrained supply to the 115 kV sub-system described previously. It will also remove the existing Crowland TS loads from the 115kV A6C/A7C circuits, alleviating the severity of the load security constraint at Allanburg TS. This alternative will also provide a parallel opportunity for load growth on the 115kV A6C/A7C circuits as the Crowland TS load is removed from the 115kV system.

7.3.3 Murray TS and Kalar MTS – Niagara Falls

7.3.3.1 Introduction

Murray TS and Kalar TS are two transformer stations located in Niagara Falls. Murray TS has two 115/13.8 DESNs, T11/T12 and T13/T14, with a summer LTR of 73.2MW and 79.8MW respectively. Kalar MTS has one 115/13.8 kV DESN with a summer LTR of 72.0 MW. The stations forecast loads are given in Table 7-5. Considerable new loads are expected to connect in the area. Loading on the Murray TS T11/T12 DESN is forecast to exceed its LTR by summer 2023. Loading on Kalar MTS is forecast to exceed LTR by summer 2028.

The Murray TS transformers, T11, T12, T13 and T14 are between 46 and 52 years old and have been identified for replacement due to asset condition. It is planned to replace T11 and T12 by summer 2027. This will be followed by the replacement of the T13 and T14 transformers by summer 2031.

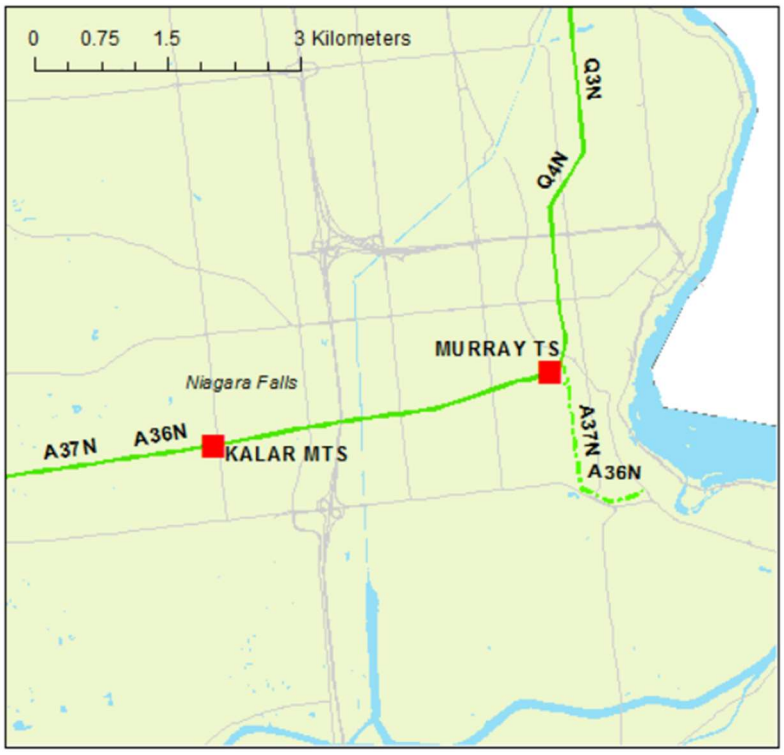


Figure 7-5: Map of Murray TS and Kalar MTS

Table 7-5: Murray TS, and Kalar MTS Load Forecast

Station	LTR MW	Act[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Murray TS T11/T12	73.2	66.3	77.7	77.7	77.8	78.0	77.9	78.1	78.3	78.7	78.9	79.1	86.2	2023[2]
Murray TS T13/T14	79.8	41.7	42.0	42.2	42.4	42.6	42.9	43.1	43.3	43.5	43.8	44.0	46.6	Note[3]
Kalar MTS	72.0	46.5	46.9	47.4	54.2	60.7	64.4	65.8	67.1	68.6	68.8	69.0	75.1	2039
Total	225.0	166.3	166.6	167.3	174.4	181.3	185.2	187.0	188.7	190.8	191.5	192.1	207.9	

1. Actual summer load adjusted for extreme weather
2. Earliest replacement to happen by 2027
3. The transformers T13 and T14 will be replaced in 2031as per asset condition.

7.3.3.2 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the need as the near and mid-term load forecast exceeds the LTR at Murray TS T11/T12. Asset renewal needs are also not addressed.
- **Alternative 2 – Replace T11/T12 at Murray TS with 60/100MVA transformers:** This alternative would replace the T11/T12 transformers with larger 60/100MVA transformers, with an approximate

LTR of 130MW instead of the 45/60/75MVA units specified for the asset renewal project at Murray TS. This will increase supply capacity of approximately 43MW at Murray TS at an estimated incremental cost of $2M to the asset renewal upgrade cost of $39M. The earliest this work can be done is summer 2027.

- **Alternative 3 – Transfer T11/T12 load to T13/T14 at Murray TS:** This alternative would transfer load from T11/T12 to T13/T14 at a cost of $5M. The T13/T14 bus supplies a large industrial load customer with fluctuating load and customers connected to the bus would experience power quality issues.
- **Alternative 4 – Build new 115kV/13.8kV Station near Kalar MTS:** This alternative would build a new 115/13.8kV DESN station with 25/41.7MVA transformers to supply the increased load demand forecast required at Kalar MTS and Murray TS T11/T12. This new station would provide the station an LTR of 51MW (summer). The estimated cost for this alternative is expected to be $40M.

The TWG recommends Alternative 2 as the preferred alternative for addressing the capacity need as it is the most economical alternative with the ability to increase supply capacity. Alternative 3 is not recommended since is more expensive, will introduce power quality issues to the transferred load and is not acceptable to the LDC. Loading will be monitored and managed at Murray TS by the LDC and Hydro One in the interim before the additional capacity is provided in 2027. The Kalar MTS load growth will be monitored to verify if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and can transfer the extra load from Kalar MTS to Murray TS.

7.3.4 Carlton TS and Bunting TS – St. Catharines

Carlton TS and Bunting TS are two transformer stations located in St. Catharines. Carlton TS has one 115/13.8 kV T1/T2 DESN with a summer LTR of 95.4 MW. Bunting TS has one 115/13.6 kV T1/T2 DESN with a summer LTR of 78.2 MW. The stations forecast loads are given in Table 7-6. Loading on Carlton TS is forecast to exceed its LTR by summer 2029. Bunting TS is adequate over the study period.

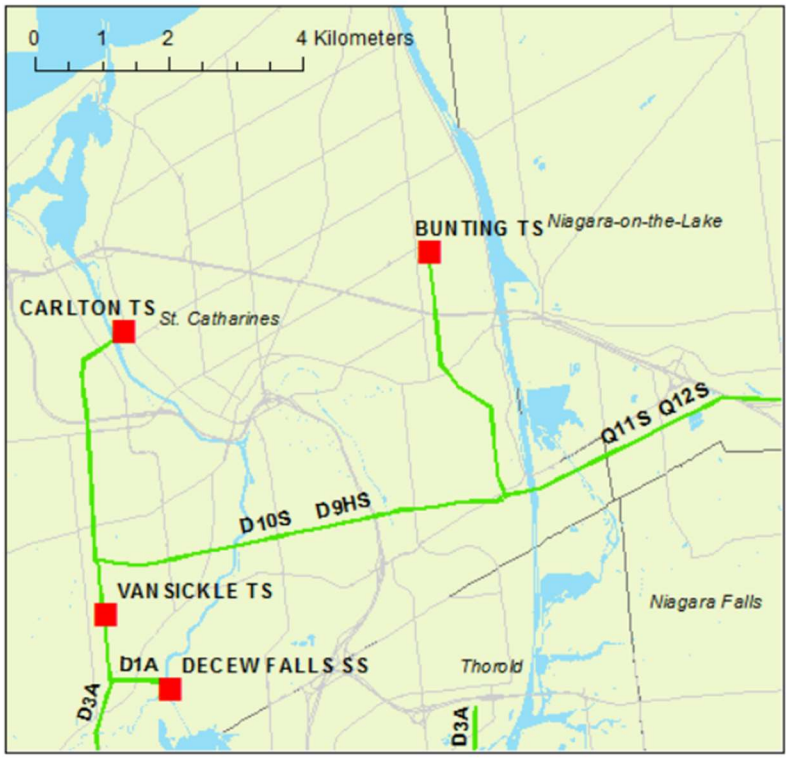


Figure 7-6: Map of Carlton TS and Bunting TS

Table 7-6: Carlton TS and Bunting TS Load Forecast

Station	LTR MW	Act. [1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Carlton TS	95.4	82.6	89.2	90.1	91.1	92.2	93.3	94.6	95.9	97.3	98.9	100.3	105.7	2029
Bunting TS	78.2	54.4	57.8	58.3	58.8	59.6	60.4	61.4	62.4	63.6	64.7	65.9	77.1	---
Total	173.6	137.0	147.1	148.4	149.9	151.8	153.7	156.0	158.3	160.9	163.6	166.2	182.8	----

1. Actual summer load adjusted for extreme weather

Both Carlton TS and Bunting TS also have renewal work planned. The LV switchyard at Carlton TS is over 50 years old and refurbishment is required. The Transformer T3 at Bunting TS is also over 50 years and identified for replacement.

7.3.4.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the stations sustainment need. Carlton TS load also exceeds its LTR and action is required to address the issue.

- **Alternative 2 –Carry out Asset Renewal at Carlton TS and Bunting TS**: Monitor Carlton TS loading and transfer excess load to Bunting TS: The station refurbishment work will be carried out at both stations. Carlton TS load growth will be monitored to see if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and transfer the excess load over the LTR from Carlton TS to Bunting TS. The cost to transfer the load between stations is estimated to be $5M.

The TWG recommendation is that it is prudent to monitor the area load and complete load transfer at nearby stations with available station capacity when required. The TWG recommends Alternative 2 as the preferred and cost-effective alternative for addressing the need.

7.4 Asset Replacement for Major HV Transmission Equipment

As discussed in Section 6.3, Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at several Niagara Region Hydro One stations as well as two small line sections. Details of the work along with its planned in-service year is given in Table 7-7.

Table 7-7: Niagara Region – Asset Replacement Plans

No.	Station /Line	Planned Work	Planned I/S Date[1]
1	Thorold TS	Replace the existing 45/60/75 MVA T1 transformer with a new 45/60/75 MVA unit.	2024
2	Glendale TS	Replace the existing T1/T2 45/60/75 MVA transformers, with new 45/60/75 MVA units.	2027
3	Crowland TS	The existing 115/27.6 kV T5/T6 DESN will be replaced by a new 230/27.6 kV DESN rated for 170 MW.	2027
4	Murray TS	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units. Replace the existing 45/60/75 MVA transformers T13 and T14 with new 60/80/100MVA units.	2027 2031
5	Bunting TS	Replace the existing 40/53/67 MVA transformers, with new 45/60/75 MVA units	2029
6	Vansickle TS	Replace LV Switchgear	2032
7	Allanburg TS	Replace Autotransformer T3	2032
8	115kV Line D1A/D3A	115kV kV line refurbishment of a 5 km line section between Gibson Jct and Thorold TS with conductor to be replaced due to asset condition	2024
9	115kV Line Q2AH	115kV line refurbishment of 11.2km between Rosedene Jct. and St. Anns Jct. with conductor to be replaced due to asset condition	2025

1. The planned in-service date is tentative and is subject to change

The TWG recommends that Hydro One proceed with the above work to ensure that the system meets reliability criteria and supply to customers is not affected.

7.5 Load Security – 115kV circuits A6C/A7C

As discussed in Section 6.4.1 the *Allanburg Load Rejection scheme* trips 115kV circuits A6C/A7C under certain contingencies to prevent stations supplied from these circuits being subjected to excessive voltage declines.

The *Allanburg Load Rejection Scheme* is designed to address post contingency voltage decline issues following the coincident loss of Allanburg 230/115 kV Autotransformers T1 and T2. The coincidental loss of Allanburg T1 and T2 transformers will result in circuits A6C and A7C being disconnected from the Allanburg TS 115kV and buses radially connected to circuits D1A and A36N, respectively. As such, this causes excessive voltage to decline at stations supplied from circuits 115kV A6C and A7C. The scheme rejects the load connected to circuits A6C and A7C and will prevent the radial feeds (from Decew Fall GS on D1A and the Niagara Corridor on A36N) from trying to support the load of A6C and A7C.

The load security need arises from Section 7.1 of the ORTAC. As defined under this section, Not more than 150MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management. The A6C/A7C load forecast is provided in Table 7-8.

Table 7-8: 115kV Circuit A6C/A7C -Connected loads

Load	ORTAC L/R Limit	Act.[1]	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042
A6C/A7C	150	209.6	219.3	227.8	237.1	247.9	252.6	257.5	278.7	281.1	283.1	283.4	297.0
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5
A6C/A7C post Crowland[2]		-	-	-	-	-	138.5	141.7	161.2	161.5	161.9	162.2	168.5

1. Actual summer load adjusted for extreme weather
2. After Crowland TS conversion to 230KV as per Section 7.3.2

This forecast exceeds the permissible limit set by ORTAC. It also exceeds the A6C/A7C line limit for loss of one of the two circuits.

7.5.1.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the ORTAC load security need.
- **Alternative 2 – Reduce Loading on A6C/A7C:** This alternative reduce loading on 115kV circuits A6C and A7C by removing Crowland TS from the A6C/A7C supply. Crowland TS is rebuilt as a 230/27.6 kV station supplied from a new 230kV double circuit line.

The TWG recommends Alternative 2 as the preferred alternative to addressing the load security issue in the ORTAC. This alternative will be partially addressed by converting Crowland TS to a 230kV supply as described in Section 7.3.2. Since the Crowland TS work will not be completed till 2027, the issue will be

managed by operational measures. Load can be restored within 15 minutes by opening both T1 and T2 disconnect switches and supplying all the Allanburg 115kV load from the remaining T3 and T4 autotransformers during a coincident T1 and T2 outage. This work reduces the severity of the load security issue. The loading on the A6C/A7C will continue to be monitored and reviewed in the next planning cycle with the option to transfer Allanburg TS DESN to 230kV.

8 CONCLUSION AND RECOMMENDATION

This Regional Infrastructure Plan report concludes the Regional Planning process for the Niagara Region.

The major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2032 are provided in Table 8-1 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 8-1: Recommended Plans over the next 10 Years

No.	Need	Recommended Action Plan	Lead	Timing[1]	Budgetary Estimates[2]
1	230 kV circuit Q28A – Additional capacity required	Uprate circuits between Beck 2 SS and Abitibi Jct. to meet expected load demand	Hydro One	TBD[3]	$3M
2	Loading in the Lincoln area exceeding supply capability	Build new 2 x 50/83MVA, 230kV/27.6 station	Hydro One	2028	$45M
3	Crowland TS: Station loading exceeds LTR	Build new 2 x 75/125MVA, 230kV/27.6 station and a new 18 km line from Abitibi Jct to Crowland TS	Hydro One	2027	$128M
4	Murray TS T11/T12 DESN: DESN loading exceeds LTR. Transformers T11/T12 need to be replaced	Replace existing 45/75MVA transformers with larger 60/100MVA units	Hydro One	2027	$41M
5	Carlton TS: T1/T2 DESN loading exceeds LTR	Transfer excess load to Bunting TS	Alectra	2029	$5M
6	**Asset Replacement:** Thorold TS Glendale TS Carlton TS Bunting TS Murray TS T13/T14 Vansickle TS Allanburg TS 115kV Line D1A/D3A 115kV Line Q2AH	Refurbish/replace major high voltage transmission equipment	Hydro One	 2024 2027 2027 2029 2031 2032 2032 2024 2025	 $43M $55M $55M $45M $27M $14M $20M $4M $10M

1. The planned in-service dates are tentative and subject to change
2. Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)
3. Contingent on customer

9 REFERENCES

[1] Niagara Region Integrated Resource Plan - Dec 2022

[2] Niagara Region NA report - May 2021

[3] Niagara Region Regional Infrastructure Plan Report - March 2017

APPENDIX A: NIAGARA REGION - STEP-DOWN TRANSFORMER STATIONS AND SUPPLY CIRCUITS

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Allanburg TS	115	A6C/A7C
2	Beamsville TS	115	Q2AH
3	Bunting TS	115	Q11S/Q12S
4	Carlton TS	115	D9HS/D10S
5	CNPI Station #17 MTS	115	A37N
6	CNPI Station #18 MTS	115	A37N
7	Crowland TS	115	A6C/A7C
8	Dunnville TS	115	Q2AH
9	Glendale TS	115	Q11S/Q12S, D9HS/D10S
10	Kalar MTS	115	A36N/A37N
11	Murray TS	115	A36N/A37N
12	Niagara West MTS	230	Q23BM/Q25BM
13	NOTL #2 MTS	115	Q11S
14	NOTL York MTS	115	Q12S
15	Port Colborne TS	115	A6C/A7C
16	Stanley TS	115	Q3N/Q4N
17	Thorold TS	115	D1A/D3A
18	Vansickle TS	115	D9HS/D10S
19	Vineland DS	115	Q2AH

APPENDIX B: NIAGARA REGION - DISTRIBUTORS

No.	Name of LDC
1	Alectra Utilities
2	Canadian Niagara Power Inc.
3	Grimsby Power Inc.
4	Hydro One Networks Inc. (Distribution)
6	Niagara-on-the-Lake Hydro Inc.
7	Niagara Peninsula Energy Inc.
8	Welland Hydro Electric System Corp.

APPENDIX C: NIAGARA REGION – STATIONS LOAD FORECAST (MW)

Station	LTR MW	2022 Actual[1]	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Allanburg TS	58.7	40	45	45	45	46	46	46	46	46	46	47	47	47	48	48	49	49	50	50	51	51
Beamsville TS	59.0	63	77	79	81	81	82	83	84	85	86	86	88	89	90	92	93	95	97	98	100	102
Bunting TS	78.2	54	58	58	59	60	60	61	62	64	65	66	67	68	70	71	73	74	76	77	77	77
Carlton TS	95.4	83	89	90	91	92	93	95	96	97	99	100	102	104	106	105	105	105	105	106	106	106
CNPI Station #17 MTS	59.4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	27
CNPI Station #18 MTS	59.4	37	36	36	36	36	36	35	35	35	35	35	35	35	35	35	35	36	36	36	36	36
Crowland TS	101.7	94	101	109	111	113	114	116	118	120	121	121	121	122	122	123	124	125	126	126	128	129
Dunnville TS	53.3	30	36	36	37	37	37	38	38	38	39	39	39	40	40	40	41	41	41	42	42	42
Glendale TS (T1/T2)	96.3	41	31	32	32	32	33	33	34	35	35	36	37	37	38	39	40	40	41	42	42	42
Glendale TS (T3/T4)	20.1	14	6	6	6	7	7	7	7	7	8	8	8	9	9	9	10	10	10	11	11	11
Kalar MTS	72.0	44	47	47	54	61	64	66	67	69	69	69	69	70	70	71	72	72	73	74	75	75
Murray TS (T11/T12)	73.2	66	78	78	78	78	78	78	78	79	79	79	79	80	80	81	82	83	83	84	85	86
Murray TS (T13/T14)	79.8	44	42	42	42	43	43	43	43	44	44	44	44	45	45	45	45	45	46	46	46	47
Niagara West MTS	63.4	41	49	57	58	58	59	60	62	63	65	66	68	69	71	73	75	77	78	80	82	84
NOTL #2 MTS	63.5	48	33	34	36	38	39	40	40	41	42	43	44	45	45	46	47	48	49	50	51	52
NOTL York MTS	75.5	17	18	18	19	20	21	22	22	23	23	24	24	25	25	26	26	27	27	28	28	29
Port Colborne TS	50.8	37	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38	38	38	39	39	39
Stanley TS	103.6	57	60	61	62	62	63	64	64	65	65	66	67	67	68	69	69	70	71	72	72	73
Thorold TS	91.3	23	24	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	27	28	28	28
Vansickle TS	99.5	47	52	52	53	53	54	55	56	57	58	59	60	62	63	64	66	67	68	68	68	68
Vineland DS	26.4	20	21	21	21	21	22	23	23	24	25	25	25	25	26	26	26	27	27	27	27	28
Industrial Customer 1	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Industrial Customer 2	-	7	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 3	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 4	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer 5	-	20	17	17	24	32	35	38	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Industrial Customer 6	-	4	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 7	-	24	80	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Industrial Customer 8[2]	-	-	10	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50

1. Actual summer load adjusted for extreme weather.
2. Curtailable load under specific outage conditions.

APPENDIX D: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



NEEDS ASSESSMENT REPORT

KWCG

[Date: April 09, 2024]

Needs Assessment Report

Final

KWCG

[Date: April 09, 2024]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: KWCG Technical Working Group



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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the KWCG region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region. Updates may be made based on best available information throughout the planning process.

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Executive Summary

REGION	**KWCG** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: December 11, 2024 **END DATE:** April 09, 2024

1. INTRODUCTION

The 2nd Regional Planning cycle for the KWCG Region was completed in December, 2021 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the 3rd cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in December 2023 for the KWCG Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the KWCG Region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is ten (10) years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2022 non-coincident regional loads were about 1436 MW.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the KWCG Region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of municipal energy plan(MEPs) and/or Community Energy plans (CEPs) where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and operational concerns;

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs and projects discussed in the 2nd cycle RIP report for KWCG region have been completed:

- Hanlon TS Transformers T1/ T2 Replacement (2022).

The following needs and projects discussed in the 2nd cycle RIP report for KWCG region are currently underway:

- **Burlington TS to CTS 1 Line Section:** The refurbishment of 115 kV B6C/ B6C line section from Burlington TS to Harper's Junction was completed in 2019. The refurbishment of line tap section from Harper's Junction to CTS1

is progressing slowly due to outage availability from the customer. This refurbishment work is currently forecasted to be completed in Q3/ Q4 2025 timeframe.

- **Kitchener MTS #5 – T9/T10 Transformers Replacement**: The existing 83 MVA T9/ T10 transformers are planned to be replaced with new 100 MVA units. This work is currently forecasted to be completed by Q1 2025.
- **Preston TS - T3/T4 Transformer Replacement:** Condition assessment of T3/ T4 transformers have identified these units for replacement. These units are currently planned to be replaced by the end of 2027 with similar Hydro One standard units. This replacement will also remove the existing supply capacity constraint due to a technical limitation in the existing units. The new LTR will be 180 MW

The remaining needs and projects discussed in the 2nd cycle RIP report for KWCG region are as follows:

- **Scheifele MTS - T1/T2 and T3/T4 Transformer Replacement**: These four (T1/T2/T3/T4) transformers are expected to approach end of life over the next 10 year horizon and are planned for replacement by Enova Power Corp. Enova Power Corp will continue monitoring the condition of these transformers with its maintenance program. The expected year of replacement is between 2029-2033.
- **Cedar TS - T7/ T8 Transformer Replacement**: Replacing the existing non-standard T7/T8 transformers with Hydro One standard units of higher capacity. Based on latest condition assessment of these units. These units are to be replaced beyond the study period (10 years) of this report. However, this transformer replacement may need to be advanced due to capacity needs.
- **Campbell TS - Breakers and Component replacement:** Replace breakers deemed to be approaching expected service life. This work is planned to be completed by 2032.
- **Fergus TS – T3/T4 Transformer Replacement:** Hydro One will continue monitoring the condition of these T3/T4 transformers and other components at Fergus TS. Hydro One will proceed with the replacement plan, if required. Otherwise, this need will be reassessed in the next regional planning cycle.
- **Galt TS – Breakers and Component Replacement:** Hydro One will continue monitoring the condition of these components at Galt TS and proceed with the replacement plan as required.

II. Newly identified needs in the region

Based on the new and updated information, a summary of the results of this Needs Assessment is provided below:

a. Asset Renewal for Major HV Transmission Equipment

- No new Asset Renewal Needs

b. Transformation Capacity

- The supply capacity needs at Preston TS, Energy + MTS, Cedar T7/T8 and Campbell TS (T3/T4) have been identified in the near term while the needs at Cedar TS T1/T2 DESN, Cedar T7/T8 DESN, Kitchner MTS #7, Waterloo MTS, and Rush MTS have been identified in the middle term.

c. Transmission System Capacity

- During the study period. Post contingency overload violations were observed on 230 kV M20D/M21D and 115 kV D11K/ D12K circuits for the loss of companion circuits.

d. System Reliability, Operation and Load restoration

- During the study period, post contingency voltage violations were observed on 230 kV M20D/M21D for the loss of companion circuits.
- Load restoration violations on 230 kV D6V/D7V circuits in the long term and system security and load restoration violation on the M21D/M20D circuit in the mid term and near term respectively, for a single tower contingency.

8. SENSITIVITY ANALYSIS

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

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and/or new station/line capacity needs: These needs will be assessed again during the next phases of this Regional Planning cycle.

Sr. no	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Preston TS - Capacity need	2026	2026	2029
2	Galt TS- Capacity need	Reaches capacity in 2032	2030	Long term
3	Energy Inc MTS - Capacity need	2023	2023	2023
4	Rush MTS - Capacity need	2030	2029	Long term
5	Waterloo North MTS #3 - Capacity need	2030	2030	Long term
6	Campbell TS (T3/T4)- Capacity need	2026	2025	2030
7	Cedar TS (T7/T8)- Capacity need	Immediate	Immediate	Immediate
8	Cedar TS (T1/T2)- Capacity need	2031	2029	Long term
9	Kitchener #7	2031	2030	Long term
10	M20D/M21D Transmission Circuit Supply	2026	2024	2026
11	D11K/D12K- Transmission Circuit Supply	2032	2030	Long term

12	D10H - Transmission Circuit Supply	Long term	2030	Long term
13	M20D/M21D Load Security	2032	2028	Long term
14	M20D/M21D Restoration Needs	2025	2023	2025
15	D6V/D7V Restoration Needs	Long term	2030	Long term
16	Voltage change violation on M20D/M21D	2026	2025	2026

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. These needs are as follows:

a. Transmission System Capacity

- M20D/M21D post contingency violation (Galt Jct x Cambridge #1 Jct)- Near term
- D11K/D12K post contingency violation (Detweiler x Kitchener #1 & 4 Jct) – Mid Term

b. System Reliability, Operation and Load restoration

- System security violation on the M21D/M20D circuit in the Mid term
- Load restoration for M20D/M21D – Near term
- Voltage violations on M20D or M21D due to outage on companion circuit -Near term

c. Transformation Capacity Needs

- Preston TS (T3/T4) – Near term
- Energy Inc MTS (T1/T2) – Near term

Transmission system capacity and restoration needs are likely to trigger system reinforcement needs in the KWCG region.

II. Needs that do not require further regional coordination

These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

a. Transformation Capacity Needs

- Campbell TS (T3/T4) – Mid term
- Cedar TS (T1/T2) – Mid term
- Kitchener MTS #7 (T14/T13) – Mid term
- Cedar (T7/T8) – Near term
- Rush MTS – Mid term
- Waterloo North MTS #3 - Mid term

List of LDC(s) to be involved in further regional planning activities:

- Grandbridge Energy
- Enova Power Corp

List of LDC(s) which are not required to be involved in further regional planning phases:

- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power

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1. INTRODUCTION

The second cycle of the Regional Planning process for the KWCG Region was completed in [December 10, 2021] with the publication of the Regional Infrastructure Plan ("RIP") Report The RIP report included a common discussion of all the options and recommended plans and preferred plans for wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the KWCG Region. The purpose of this Needs Assessment ("NA") is to:

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

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is given below in Figure 1 below.

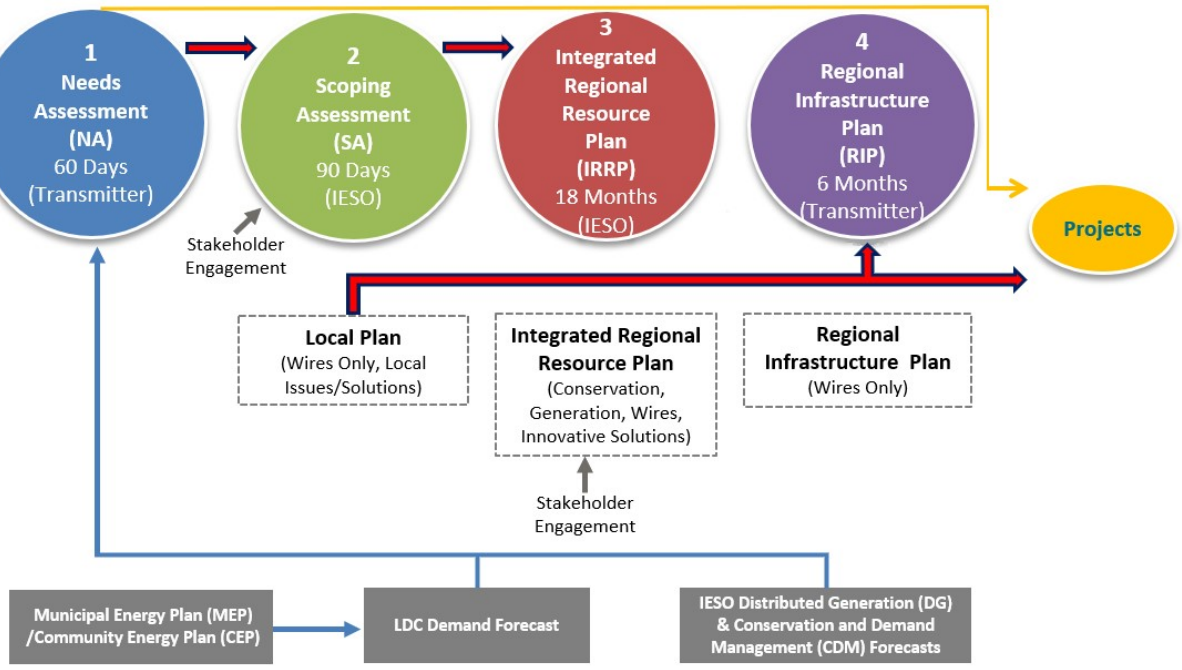


Figure 1: Regional Planning Process

This report was prepared by the KWCG Technical Working Group("TWG"), led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One,

the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 1.

Table 1: KWCG Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator ("IESO")
3	Enova Power Corp.
4	Alectra Inc.
5	Grandbridge energy
6	Centre Wellington
7	Wellington North
8	Halton Hills Hydro Inc.
9	Hydro One Networks Inc. (Distribution)

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the KWCG region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the KWCG region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,

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

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The accumulative summer 2022 non-coincident loads were about 1477 MW. The approximate boundaries of the KWCG Region are shown below in Figure 1.

The main sources of electricity into the KWCG Region are from five Hydro One stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV levels, respectively. Electricity is then delivered to the end users of LDCs and transmission connected industrial customers through 26 (supply transformer stations) step-down transformer stations. Figure 2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. The single line diagram of the KWCG region is shown in Figure 3 below.

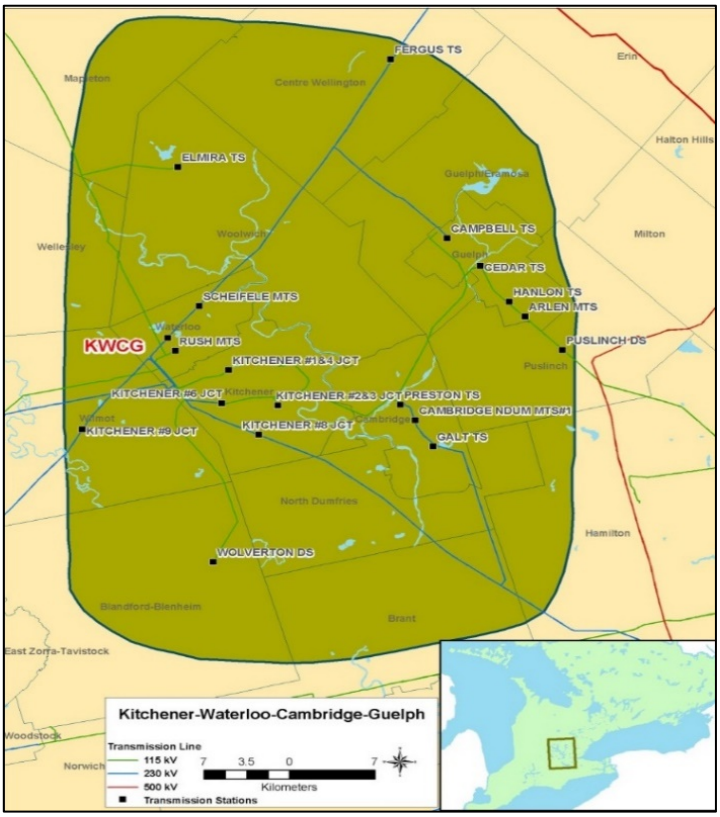


Figure 2: Map of KWCG Regional Planning Area

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

Table 2: Transmission Station and Circuits in the KWCG Region

115Kv circuits	230Kv circuits	Hydro One Transformer Stations	Generation Stations
B5C/B6C D7F/D9F F12C/F11C D11K/D12K D8S D10K	D4W/D5W D6V/D7V B22D/B23D M20D/M21D	*Detweiler TS , Fergus TS, *Cedar TS, Campbell TS, Galt TS, Elmira TS, Hanlon TS, Scheifele MTS, Waterloo North MTS#3, Energy MTS#1, Kitchener MTS #1, Kitchener MTS#3, Kitchener MTS#4, Kitchener MTS#5, Kitchener MTS#6, Kitchener MTS#7, Kitchener MTS#8, Kitchener MTS#9, Rush MTS, Wolverton DS, Puslinch DS, CTS 1, CTS 2, Preston TS*.	N/A

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of KWCG region is shown in Figure 3 below.

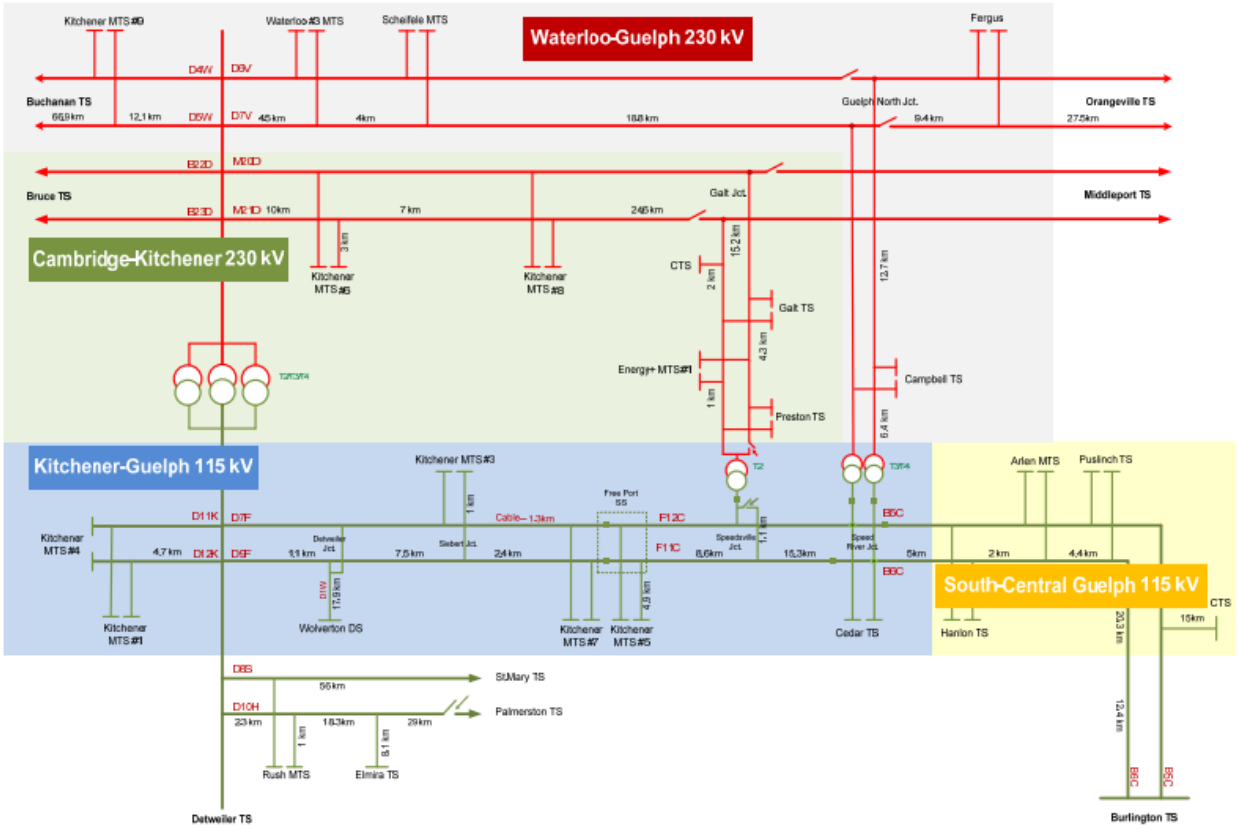


Figure 3: KWCG Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the KWCG NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called “Load Forecast Guideline for Ontario” in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC’s load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- KWCG 10-year Load Forecast for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs),
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the KWCG.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing”; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on Summer peak loads. Three load forecasts were developed i.e. Normal Growth scenario, High & low Growth scenario. The High and low Growth scenario load forecast was developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher-than-expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2023-2032.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.

- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering process

6.2.1. Load forecast:

The LDCs provided their load forecast for all the stations supplying their loads in the KWCG region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the KWCG region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2022 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity for the contracted projects only provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the KWCG region is given in Appendix A.

A very few of the stations have winter peaks marginally higher than summer peaks. The higher winter transformer and line ratings are adequate to accommodate the marginally higher loads. Therefore, only the Summer Assessment was carried out.

Alectra recently advised the TWG that a revised forecast, to better account for their community's decarbonization activities, will soon be available. This updated forecast will be included in later stages of the regional planning process and may impact the area's overall needs and/or may require the creation of a regional winter forecast.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

Relevant information regarding system reliability and operational issues in the region; and

6.2.3. Asset renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1; and

6.2.4. System Reliability and Operational Issues:

- Palmerston-to-Detweiler transfer during Hanover bank outages:
  With current load forecast, this issue does not exist.

TWG members identified the following bulk system issues in the KWCG region to be discussed outside of the RP process:

- Detweiler TS configuration and operating instruction asking for multiple equipment to be out of service during contingency
- Detweiler TS Station Service Auto-Transfer Issues
- Palmerston-to-Detweiler transfer during Hanover bank outages.

7. NEEDS

This section describes emerging new needs identified in the KWCG Region and/or updates on the previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

- Hanlon T1/T2 transformer replacement was completed in 2022.
- Kitchener MTS #5 project is currently underway, existing 83MVA transformers to be replaced by 100MVA units. The planned in-service date is Q3 2024 for T10 and Q1 2025 for T9.
- Preston TS: Project for like-for-like replacement of transformers T3/T4 is underway. The planned in-service date is 2027.
- B5C/B6C 115kV line section refurbishment: The Burlington TS to Harper junction line refurbishment was completed in 2019. The refurbishment of line tap from Harper junction to CTS-1 is progressing slowly due to outage availability from customer. Expected completion date is Q3/Q4 2025.
- Galt TS: The asset condition assessment identified breakers and other components needs to be replaced in long-term. Hydro One will continue to monitor the condition of these components and if required, proceed with the replacement plan.
- Campbell TS: Two feeder breakers and a bus tie breaker for T1/T2 DESN were identified for replacement. The planned in-service date is 2032.

- Scheifele MTS T1/T2/T3/T4 Transformer replacement: These four (T1/T2/T3/T4) transformers are expected to approach end of life over the next 10-year horizon and are planned for replacement by Enova Power Corp. The expected year of replacement is between 2029-2033.

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

All near, and mid-term needs that were discussed as a part of this report are summarized in table 3 below.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cedar TS	T7/T8 Transformers Replacement	7.3.2	7.1.1
Fergus TS	T3/T4 Transformers Replacement	7.3.4	7.1.2
Galt TS	Breakers and Component Replacement	7.3.5	7.1.4
Campbell TS	Breakers and Component Replacement	7.3.6	7.1.3
Station Capacity Needs			
Preston TS	Preston T3/T4 is forecasted to exceed its supply capacity during the study period (beyond the anticipated LTR of the new transformers)	N/A	7.2.1
Energy Inc MTS	The load at Energy Inc MTS is forecasted to exceed its supply capacity in the near term.	N/A	7.2.2
Campbell TS (T3/T4)	The load at Campbell TS (T3/T4) is forecasted to exceed its supply capacity in the near term.	N/A	7.2.3
Cedar TS	Load demand at both Cedar TS T1/T2 and T7/T8 DESNs is forecasted to exceed supply capacities in the mid and near term respectively.	N/A	7.2.4
Kitchener MTS#7	The load at Kitchener MTS#7 is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.5

Waterloo North MTS #3	The load at Waterloo North MTS#3 is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.6
Rush MTS	The load at Rush MTS is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.7
Transmission Line Capacity Needs			
M20D/M21D	The 230 kV M20D/M21D circuits supply transformer stations connected between Detweiler TS and Middleport TS. Loading violations were observed on M20D/ M21D circuits starting 2026 on the sections between Galt Jct. and Cambridge Jct. .	N/A	7.3.1
D11K/D12K	D11K/D12K supplies Enova Power Corp stations, Kitchener MTS#1 and Kitchener MTS#4. Loading violations were observed on these circuits for the loss of companion circuit in the mid-term.	N/A	7.3.2
D10H	The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads at Rush MTS, Elmira TS and Palmerston TS with a normally open motorized switch just south of Palmerston TS. During the outage of 115 kV D8S circuit, loading violations were observed on a section of 115 kV D10H circuit in the long term.	N/A	7.3.3
System Reliability, Operation and Load restoration Needs			
M20D/ M21D	For the loss of two elements M20D/M21D on the 230 kV system, the load interrupted by configuration will exceed 600MW based on the peak coincident load, resulting in violation of ORTAC security criteria in the mid-term.	N/A	7.4.1
M20D/M21D	Load restoration violations observed on the M20D/M21D 230 kV circuits	N/A	7.4.1
D6V/ D7V	Marginal load restoration violations were observed for D6V/D7V 230 kV circuits	N/A	7.4.2
Voltage Performance			

M20D/M21D	Several voltage violations were observed in the near term.	N/A	7.4.3

7.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One and TWG has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the **KWCG** Region. The complete list of major HV transmission equipment requiring replacement in the **KWCG** Region is provided in table 4 in this section. Hydro One and Enova Power Corp are the Transmission Asset Owners (TAO) in the Region.

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

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

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

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

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

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

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

Table 4: Major HV Transmission Asset assessed for Replacement in the region over the next 10 years

Station/Circuit	Need Description	Planned ISD
Kitchener MTS #5	The existing T10 & T9 83 MVA transformers to be replaced by 100 MVA units	T10-2024 T9-2025
Preston TS	Replacement of existing T3 & T4 transformers with similar size units.	2027
B5C/B6C	Refurbishment of B5C/B6C line between Burlington TS to CTS1.	2025
Scheifele MTS	The existing four transformers are expected to approach end of service life over the next 10 years Horizon	2029-2033

7.1.1 Cedar TS (T7/T8)

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar T7/T8 is a 115/13.8 kV DESN station with an LTR of 44 MVA (40 MW @ 0.9 PF), and 40 MW of peak load in 2022. Hydro One will continue to monitor the condition of these transformers. Based on asset condition assessment, T7/T8 are expected to reach end of life beyond the 10-year planning horizon. The station capacity need at this station is discussed in Section 7.2.4 of this report.

7.1.2 Fergus TS (T3/T4)

Fergus TS is a 230 kV/ 44 kV single DESN station having two 125 MVA transformers located in the township of Fergus having a supply capacity of 154 MW and supplying 94 MW of loads. The supply capacity of this station is forecasted to be sufficient over the study period and beyond. Based on asset condition assessment, T7/T8 are expected to reach end of life beyond the 10-year planning horizon.

The TWG recommended Hydro One to keep monitoring the condition of these transformers. No further regional planning coordination is required at this time.

7.1.3 Campbell TS (T1/T2) Breakers and Components

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/13.8 kV DESNs T1/T2 and T3/T4, having supply capacities of 94 MW and 56 MW respectively. The loads on these two DESNs are currently supplying about 86 MW and 47 MW of loads respectively.

In the previous regional planning RIP report, two feeder breakers and a bus tie breaker for T1/T2 DESN were identified for replacement. Based on asset condition assessment, the equipment at this station are

expected to reach end of life within 10 year planning horizon. No further regional coordination is required at this time.

7.1.4 Galt TS Breakers and Components

Galt TS is located in the city of Cambridge supplying Energy + loads in the KWCG region. Galt TS has two 230/ 28-28 kV transformers T7 and T8 of 75/100/125 MVA, currently supplying 115 MW of peak loads. The total supply capacity of Galt TS is 169 MW, expected to be more than adequate over the study period.

The T7/T8 transformers were replaced in 2010 and 2012 respectively due to technical issues with the transformers. The breakers and other component at the station are almost 50 years old. Condition assessment has identified that these older components to be replaced in the long term.

The station cannot be downsized or eliminated because there is no nearby supply station/s having surplus supply capacity for transferring loads. Hydro One will continue monitoring the condition of these components at Galt TS and if required proceed with the replacement plan as required.

7.2 Station Capacity Needs

A 'Station Capacity' assessment was performed over the study period 2023-2032 for the 230kV and 115kV Transforming stations in the KWCG Region using the non-coincident summer peak load forecasts provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Preston TS Supply Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Grandbridge energy loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available. This station is currently supplying loads to its supply capacity. The non-coincident loads at Preston TS are currently forecasted to reach 242 MW[2] by the end of study period. The replacement of these station supply transformers is underway and forecasted to be completed by Q2 of 2027. Upon completion, the new station LTR is expected to be in the range of 180 MW. The Preston TS loads are currently forecasted to reach this new supply capacity in the in-service timeframe of these new transformers. A near-term solution is required to address this need. The TWG recommends to further review this need in next regional planning phases.

[2] Note: Due to the load limit on M20D/M21D imposed by ORTAC's load security criteria, the coincident peak loading on M20D/M21D is limited to 600 MW forecasted to exceed in 2032.

7.2.2 Energy MTS#1

Energy + MTS#1 is located in the city of Cambridge supplying Grandbridge Energy loads in the KWCG region. This station has an LTR of 102 MW and forecasted to exceed its supply capacity near the end of the study period. The loading at this station will be monitored by Grandbridge Energy and this need will be further assessed in the next regional planning phase. Grandbridge Energy is working on measures to transfer load within the distribution system to Galt TS to address near term loading concerns. Hydro One and Grandbridge will continue to monitor load levels.

7.2.3 Campbell TS Transformer

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/13.8 kV DESNs units supplying through T1/T2 and T3/T4 transformers, having supply capacities of 94 MW and 56 MW respectively. These two Campbell TS DESNs are currently supplying about 81 MW and 45 MW of loads respectively and their combined loads at Campbell TS are forecasted to exceed the total station supply capacity close to the end of the study period.

Alectra to propose measures to address capacity needs at this station, if required. Hydro One and Alectra will continue to monitor load levels. The TWG recommends that no further regional coordination is required at this time.

7.2.4 Cedar T1/T2 and T7/T8

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar TS has two 115/13.8 kV DESN stations T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 82 MW and 40 MW of peak loads respectively. The total load of both DESNs is forecasted to exceed its supply capacity in the near term.

Alectra to propose measures to address this capacity needs, if required. Hydro One and Alectra to continue monitoring load levels. The TWG recommends that no further regional coordination is required at this time.

7.2.5 Kitchener MTS #7

Kitchener MTS #7 is located in the city of Kitchener supplying Enova Power Corp loads. Kitchener MTS #7 is a 115/ 13.8 kV single T13/T14 DESN station having 50 MVA transformers and a LTR of 60 MVA (54 MW @ 0.9 PF). This station is currently supplying 37 MW of peak load. The loads at Kitchener MTS #7 are currently forecasted to grow approaching its supply capacity near the end of the study period.

Enova Power Corp to monitor the loading on this station and manage any overloading through load transfers, if required. The TWG recommends that no further regional coordination is required at this time.

7.2.6 Waterloo North MTS #3

Waterloo North MTS#3 is located in the city of Waterloo supplying Enova Power Corp. Waterloo North MTS#3 is a 230/27.6 kV single T1/T2 DESN station having an LTR of 85MVA. This station is currently supplying 48 MW of peak load. The loads at Waterloo North MTS#3 is currently forecasted to grow approaching its supply capacity near the end of the study period. Enova Power Corp to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term. The TWG recommends that no further regional coordination is required at this time.

7.2.7 Rush MTS

Rush MTS is located in the city of Waterloo supplying Enova Power Corp loads. Rush MTS is a 115/ 13.8 kV single T1/T2 DESN station having an LTR of 68 MW. This station is currently supplying 50 MW of peak load. The loads at Rush MTS is currently forecasted to grow approaching its supply capacity near the end of the study period. Enova Power Corp to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term. The TWG recommends that no further regional coordination is required at this time and will be reviewed in next regional planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2023-2032 for the 230kV and 115kV Transmission line circuits in the KWCG Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 M20D/M21D – 230 kV – Transmission Circuit Supply

The M20D/M21D is a 230kV double circuit line about 58 km long, supplying the following stations:

- Kitchener MTS #6
- Kitchener MTS #8
- Galt TS
- Preston TS
- Energy + Inc.
- A Customer CTS

For the loss of one of the M20D or M21D 230 kV circuits, the loading on the Galt JCT to Cambridge JCT section exceeds its rating starting in 2026 (Summer load forecast). The TWG recommends to further review this need in next regional planning phases.

7.3.2 D11K/D12K

D11K/D12K is a 115 kV line supplying Enova Power Corp stations of Kitchener MTS#1 and Kitchener MTS#4. With the current load forecast on the above stations, these D11K and D12K 115 kV circuits will be experiencing overloading for the loss of companion circuits by the end of the study period (2032). The TWG recommends to further review this need in next regional planning phases.

7.3.3 D10H

The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads to Rush MTS and Elmira TS. The D10H circuit has a normally open point just south of Palmerston TS through a motorized disconnect switch for emergency supply to Palmerston TS. The northern section of D10H is supplied from Hanover TS radially supplying Palmerston TS loads. The southern section of D10H is supplied through Detweiler TS radially supplying Enova Power Corp's 34 MW of Elmira TS peak loads. D10H also supplies Rush MTS which has a dual supply through 115 kV D8S circuit from Detweiler TS. For any outage of 115 kV D8S circuit. The D10H line section between Detweiler and Leong Jct is approaching its supply capacity close to the end of the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2023-2032 to cater this need**.** Based on the results, some system reliability, operating and restoring issues have been identified for this Region.

7.4.1 M20D/M21D Load Security and Restoration Needs

As per the load security criteria (ORTAC Section 7.1), with one element out of service, planned load curtailment or load rejection is permissible only to account for local generation outages; and not more than 150MW of load may be interrupted by configuration, planned load curtailment or rejection. With two elements out of service, not more than 600 MW of load may be interrupted by configuration, planned load curtailment or rejection.

As per the load restoration criteria (ORTAC Section 7.2), interrupted load must be restored within the following timelines:

- Load above 250 MW, within 30 minutes;
- Load above 150 MW, within 4 hours; and
- All load, within 8 hours.

For the loss of double 230kV circuits (M20D/M21D), a total peak coincident load of 638 MW will be interrupted in 2032 by configuration which violates ORTAC load security criteria since not more than 600 MW of load may be interrupted by configuration.

With respect to load restoration, a total of 638 MW (2032 forecast) will be interrupted by configuration, of which, 388 MW needs to be restored within 30 mins as per ORTAC criteria. For a double line fault on Galt Jct. to Preston TS section, only 210 MW (out of the 388MW required to be restored) of that load is restorable. Kitchener MTS#6 and MTS#8 load can be restored via Galt Jct in-line switches and approximately 100 MW of load can be restored at Preston TS. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period. The TWG recommends to further review this need in next regional planning phases.

7.4.2 D6V/D7V Restorations Needs.

By year 2032, the total peak coincident forecasted load connected to D6V/D7V is 517 MW. Loss of this double circuit line (Tower Contingency) would result in the loss of all 517 MW which is below the ORTAC load security limit. To restore load to these stations, the 230 kV in-line switches will be utilized to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion. Non-restorable load within 30

minutes is estimated to be about 256 MW. Hence, the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time, and the loading levels will be monitored.

7.4.3 Voltage Performance

M20D or M21D post contingency voltage change exceeds the 10% pre-tap and 5% post-tap limits on the low voltage side at Preston TS and Energy + Inc MTS within the near-term coincident forecast. The post contingency voltages also drop beyond the allowable voltage range. The situation is further worsened in the subsequent years.

In the midterm, the voltage change limits on the high side of Preston TS, Galt TS and Energy + Inc MTS are violated for the post-contingency loss of M20D or M21D circuits. Voltage also drops below the allowable voltage range. The TWG recommends to further review this need in next regional planning phases.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the KWCG region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by applying -50% growth to the annual growth rate on the extreme summer corrected Normal Growth net load forecasts.

The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Preston TS- Capacity need	2026	2026	2029
2	Galt TS- Capacity need	Reaches capacity in 2032	2030	Long term
3	Energy Inc MTS - Capacity need	2023	2023	2023
4	Rush MTS - Capacity need	2030	2029	Long term
5	Waterloo North MTS #3 - Capacity need	2030	2030	Long term
6	Campbell TS (T3/T4)- Capacity need	2026	2025	2030
7	Cedar TS (T7/T8)- Capacity need	2024	2024	2024
8	Cedar TS (T1/T2)- 115kV- Capacity need	2031	2029	Long term
9	Kitchener MTS#7	2031	2030	Long term
10	M20D/M21D Transmission Circuit Supply	2026	2024	2026
11	D11K/D12K- Transmission Circuit Supply	2032	2030	Long term
12	D10H - Transmission Circuit Supply	Long term	2030	Long term
13	M20D/M21D Load Security	2032	2028	Long term
14	M20D/M21D Restoration Needs	2025	2023	2025
15	D6V/D7V Restoration Needs	Long term	2030	Long term
16	Voltage change violation on M20D/M21D	2026	2025	2026

The sensitivity analysis identified the additional capacity needs towards the end of the study period and advanced the triggering date of all the needs. These needs will be assessed again during the next phases of this Regional Planning cycle.

The 2022 forecast from last year's RIP aligns with the actual 2022 loading. Therefore, the high growth scenario can be discounted for now, and monitoring the load growth is recommended.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 7: Needs which do not require regional coordination

Sr.no.	Need	Recommendation
1	Campbell TS (T3/T4) Station Capacity	LDC to propose measures to address capacity needs, if required, Hydro One and Alectra to continue to monitor load levels.
2	Cedar TS (T1/T2) Station Capacity	LDC to propose measures to address capacity needs, if required, Hydro One and Alectra to continue to monitor load levels.
3	Kitchener MTS #7 Station Capacity	LDC to monitor load levels and manage any overloading through load transfers.
4	Cedar TS (T7/T8) Station Capacity	LDC to propose measures to address capacity needs, if required. Hydro One and Alectra to continue to monitor load levels. Advancing and upsizing Cedar transformers is also being considered as an option
5	Waterloo North MTS #3 Station Capacity	LDC to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term.
6	Rush MTS Station Capacity	LDC to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term.

Table 8: Needs which require further regional coordination

Sr.no.	Need	Recommendation
1	Preston TS Station Capacity	To be further assessed in the next RP phases. Hydro One and Grandbridge Energy to keep monitoring load levels
2	Energy Inc MTS Station Capacity	To be further assessed in the next RP phases. Grandbridge Energy to monitor load levels

3	Overload - M20D/M21D post contingency capacity violation (Galt Jct x Cambridge #1 Jct)-	To be further assessed in the next RP phases.
4	System security violation - M21D/M20D 230 kV circuits	To be further assessed in the next RP phases.
5	Voltage violations – On 230 kV M20D or M21D circuit for loss of companion circuit.	To be further assessed in the next RP phases.
6	Load restorations -M20D or M21D due to single tower outage	To be further assessed in the next RP phases.
7	Overload - D11K/D12K 115 kV circuits experience post contingency violation (Detweiler TS x Kitchener MTS#1 & #4 Jct.)	To be further assessed in the next phases. Enova Power Corp to explore load transfers between their stations. H1 and Enova Power Corp to monitor load levels.

List of LDC(s) to be involved in further regional planning activities:

- Grandbridge Energy
- Enova Power Corp.

List of LDC(s) which are not required to be involved in further regional planning phases: (if any)

- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: KWCG Region – Non-Coincident- Normal Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	35.1	34.2	17.8	20.1	21.8	22.6	23.8	24.6	26.0	27.3	28.6
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.3	89.1	88.8	89.2	89.2	89.5	90.0	91.0
Campbell TS (T3/T4)	56.3	45.7	46.9	54.2	56.2	56.7	56.8	57.3	57.6	58.1	58.7	59.3
Cedar TS (T1/T2)	103.3	82.5	89.0	90.7	92.0	94.8	95.8	97.6	99.1	101.3	103.5	105.4
Cedar TS (T7/T8)	39.9	40.7	45.0	46.8	48.3	50.6	51.2	52.1	52.9	54.0	55.1	56.0
Elmira TS	55.0	36.7	33.8	33.9	34.0	34.2	34.2	36.4	36.5	36.7	37.0	37.3
Energy Inc(Cam) MTS#1	101.7	115.2	125.5	130.5	135.6	141.3	146.3	152.5	158.5	164.9	172.4	179.7
Fergus TS	153.5	91.0	93.9	95.9	98.6	101.9	104.9	108.3	110.7	113.5	117.7	120.0
Galt TS	169.4	113.6	117.0	121.9	126.7	132.1	136.7	142.5	148.1	154.6	161.5	168.4
Hanlon TS	42.9	25.7	27.9	28.7	29.2	30.1	30.8	31.7	32.4	33.6	34.7	36.2
Kitchener MTS # 1	54.0	26.1	27.5	28.9	30.2	31.7	34.2	36.9	39.6	42.2	45.1	47.9
Kitchener MTS # 3	108.0	55.1	48.2	59.1	60.1	61.3	63.0	65.2	67.2	85.0	95.9	98.2
Kitchener MTS # 4	90.0	58.6	71.8	63.1	64.4	65.9	68.2	71.0	73.6	76.3	79.3	82.2
Kitchener MTS#5	79.7	72.0	58.1	77.2	78.4	80.0	91.4	94.8	97.7	100.6	98.5	102.5
Kitchener MTS#6	90.0	57.0	64.7	61.1	62.3	63.6	65.7	68.1	70.4	72.7	75.4	78.0
Kitchener MTS#7	54.0	37.4	39.8	40.6	41.7	43.0	44.9	47.2	49.4	51.6	54.1	56.5
Kitchener MTS#8	54.0	36.2	36.5	40.0	41.6	43.3	46.5	50.1	53.5	41.1	44.7	48.3
Kitchener MTS#9	90.0	32.3	20.3	28.7	29.5	30.3	37.5	38.9	40.3	41.7	43.2	44.7
Preston TS[3]	112.5	102.4	109.8	135.5	144.5	190.1	198.0	206.4	214.4	223.0	233.0	242.8
Puslinch DS	56.3	32.7	39.6	40.3	41.0	41.8	42.3	43.0	43.7	44.4	45.4	46.2
Rush MTS	67.5	50.6	54.7	55.6	56.6	57.8	58.6	62.0	65.3	69.4	73.7	78.0
Scheifele MTS (T3/T4)	99.0	83.6	89.7	91.3	92.9	94.9	96.1	101.9	107.3	114.0	113.7	110.1
Scheifele MTS (T1/T2)	62.1	50.5	54.0	55.0	56.0	57.1	57.9	61.4	64.7	58.0	54.8	58.8
Waterloo North MTS#3	76.5	48.4	52.6	53.5	54.5	55.6	56.3	59.7	62.9	77.4	86.0	90.3
Wolverton DS	54.4	18.2	18.2	18.7	19.1	19.7	20.0	20.6	21.0	21.6	22.2	22.8
CTS 1		4.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3] Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.2:KWCG Region – Coincident – Normal Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	30.0	34.2	17.8	20.1	21.8	22.6	23.8	24.6	26.0	27.3	28.6
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.3	89.1	88.8	89.2	89.2	89.5	90.0	91.0
Campbell TS (T3/T4)	56.3	43.0	44.0	50.8	52.8	53.3	53.3	53.8	54.1	54.5	55.2	55.7
Cedar TS (T1/T2)	103.3	57.1	61.6	62.7	63.6	65.6	66.2	67.5	68.6	70.0	71.6	73.0
Cedar TS (T7/T8)	39.9	40.4	44.6	46.3	47.9	50.1	50.7	51.7	52.4	53.5	54.6	55.5
Elmira TS	55.0	36.7	33.6	33.7	33.8	34.0	34.0	36.2	36.3	36.5	36.8	37.1
EnergyInc(Cam) MTS#1	101.7	95.8	105.0	109.2	113.5	118.3	122.4	127.6	132.6	138.0	144.3	150.5
Fergus TS	153.5	86.2	88.1	89.9	92.5	95.6	98.5	101.6	103.9	106.5	110.6	112.9
Galt TS	169.4	83.8	91.5	95.4	99.2	103.4	107.0	111.6	116.0	121.2	126.6	132.1
Hanlon TS	42.9	24.3	26.4	27.1	27.6	28.5	29.1	30.0	30.6	31.8	32.8	34.2
Kitchener MTS # 1	54.0	25.1	26.4	27.8	29.1	30.5	32.9	35.5	38.1	40.6	43.4	46.1
Kitchener MTS # 3	108.0	51.8	45.3	55.5	56.4	57.6	59.2	61.2	63.1	79.8	90.1	92.2
Kitchener MTS # 4	90.0	53.9	66.1	58.1	59.3	60.7	62.8	65.4	67.8	70.3	73.0	75.7
Kitchener MTS#5	79.7	65.8	53.0	70.4	71.6	73.0	83.5	86.6	89.2	91.8	90.0	93.6
Kitchener MTS#6	90.0	49.5	56.2	53.0	54.0	55.2	57.0	59.1	61.1	63.2	65.5	67.7
Kitchener MTS#7	54.0	34.4	36.6	37.3	38.4	39.5	41.4	43.5	45.5	47.5	49.8	52.0
Kitchener MTS#8	54.0	32.7	32.8	36.0	37.4	39.0	41.9	45.1	48.2	37.0	40.3	43.5
Kitchener MTS#9	90.0	29.2	17.7	25.3	26.0	26.7	33.7	35.1	36.3	37.5	39.0	40.3
Preston TS[3]	112.5	98.8	108.3	133.7	142.6	187.6	195.4	203.7	211.6	220.1	229.9	239.6
Puslinch DS	56.3	32.1	38.9	39.5	40.2	41.0	41.5	42.2	42.9	43.6	44.5	45.4
Rush MTS	67.5	46.3	50.0	50.9	51.8	52.9	53.6	56.8	59.8	63.5	67.5	71.4
Scheifele MTS (T3/T4)	99.0	75.2	80.6	82.0	83.5	85.2	86.4	91.5	96.4	102.4	102.2	98.9
Scheifele MTS (T1/T2)	62.1	49.6	53.0	54.0	54.9	56.1	56.8	60.2	63.5	57.0	53.8	57.7
Waterloo North MTS#3	76.5	43.0	46.4	47.3	48.1	49.1	49.8	52.7	55.5	68.3	75.9	79.7
Wolverton DS	54.4	13.2	14.4	14.8	15.1	15.5	15.8	16.3	16.6	17.1	17.6	18.1
CTS 1		2.1	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3]Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.3: KWCG Region Non-Coincident – High Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45	35.1	34.2	17.8	21.2	23.8	25.0	26.8	28.1	30.1	32.0	34.0
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.7	90.0	89.6	90.1	90.2	90.5	91.3	92.9
Campbell TS (T3/T4)	56.3	45.7	46.9	54.2	57.1	58.0	58.1	58.8	59.3	60.0	61.0	61.8
Cedar TS (T1/T2)	103.3	82.5	89.0	90.7	92.7	96.8	98.3	101.1	103.3	106.6	109.9	112.8
Cedar TS (T7/T8)	39.9	40.7	45.0	46.8	49.1	52.5	53.4	54.8	55.9	57.6	59.3	60.7
Elmira TS	55	36.7	33.8	33.9	34.1	34.4	34.3	37.7	37.9	38.1	38.6	39.0
EnergyInc(Cam) MTS#1	101.7	115.2	125.5	130.5	138.2	146.8	154.2	163.5	172.5	182.1	193.3	204.4
Fergus TS	153.5	91.0	93.9	95.9	100.0	105.0	109.5	114.5	118.1	122.3	128.6	132.1
Galt TS	169.4	113.6	117.0	121.9	129.1	137.2	144.1	152.9	161.3	171.0	181.4	191.7
Hanlon TS	42.9	25.7	27.9	28.7	29.4	30.8	31.8	33.3	34.2	36.1	37.6	39.9
Kitchener MTS # 1	54	26.1	27.5	28.9	30.9	33.0	36.8	40.9	44.9	48.9	53.2	57.4
Kitchener MTS # 3	108	55.1	48.2	59.1	60.6	62.4	65.0	68.3	71.2	98.0	114.4	117.8
Kitchener MTS # 4	90	58.6	71.8	63.1	65.0	67.3	70.8	75.0	78.9	83.0	87.5	91.8
Kitchener MTS#5	79.7	72.0	58.1	77.2	79.1	81.4	98.6	103.7	107.9	112.3	109.2	115.1
Kitchener MTS#6	90	57.0	64.7	61.1	62.9	64.9	67.9	71.7	75.1	78.6	82.5	86.4
Kitchener MTS#7	54	37.4	39.8	40.6	42.3	44.2	47.1	50.6	53.8	57.2	60.9	64.4
Kitchener MTS#8	54	36.2	36.5	40.0	42.4	45.0	49.8	55.1	60.2	41.7	47.1	52.5
Kitchener MTS#9	90	32.3	20.3	28.7	29.9	31.2	41.8	44.1	46.1	48.2	50.5	52.7
Preston TS[3]	112.5	102.4	109.8	135.5	149.0	217.3	229.3	241.8	253.9	266.8	281.7	296.5
Puslinch DS	56.3	32.7	39.6	40.3	41.3	42.5	43.2	44.4	45.4	46.5	47.9	49.2
Rush MTS	67.5	50.6	54.7	55.6	57.1	58.9	60.0	65.2	70.2	76.2	82.8	89.2
Scheifele MTS (T3/T4)	99	83.6	89.7	91.3	93.7	96.7	98.6	107.1	115.3	125.3	124.9	119.5
Scheifele MTS (T1/T2)	62.1	50.5	54.0	55.0	56.5	58.2	59.4	64.5	69.5	59.6	54.7	60.7
Waterloo North MTS#3	76.5	48.4	52.6	53.5	54.9	56.6	57.8	62.8	67.6	89.3	102.2	108.7
Wolverton DS	54.4	18.2	18.2	18.7	19.4	20.2	20.7	21.5	22.2	23.0	24.0	24.9
CTS 1		4.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10	20.6

[3] Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.4: KWCG Region – Coincident – High Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	30.0	34.2	17.8	21.2	23.8	25.0	26.8	28.1	30.1	32.0	34.0
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.7	90.0	89.6	90.1	90.2	90.5	91.3	92.9
Campbell TS (T3/T4)	56.3	43.0	44.0	50.8	53.7	54.5	54.6	55.3	55.7	56.4	57.4	58.1
Cedar TS (T1/T2)	103.3	57.1	61.6	62.7	64.1	67.0	68.0	69.9	71.5	73.7	76.0	78.1
Cedar TS (T7/T8)	39.9	40.4	44.6	46.3	48.6	52.0	52.9	54.3	55.4	57.1	58.7	60.1
Elmira TS	55.0	36.7	33.6	33.7	33.9	34.2	34.1	37.5	37.6	37.9	38.4	38.8
EnergyInc(Cam) MTS#1	101.7	95.8	105.0	109.2	115.6	122.8	129.1	136.9	144.4	152.5	161.9	171.2
Fergus TS	153.5	86.2	88.1	89.9	93.8	98.5	102.7	107.5	110.9	114.9	121.0	124.3
Galt TS	169.4	83.8	91.5	95.4	101.0	107.4	112.9	119.7	126.3	134.1	142.3	150.4
Hanlon TS	42.9	24.3	26.4	27.1	27.8	29.2	30.1	31.4	32.3	34.1	35.6	37.7
Kitchener MTS # 1	54.0	25.1	26.4	27.8	29.7	31.8	35.4	39.4	43.2	47.1	51.2	55.2
Kitchener MTS # 3	108.0	51.8	45.3	55.5	56.9	58.6	61.0	64.1	66.9	92.0	107.4	110.6
Kitchener MTS # 4	90.0	53.9	66.1	58.1	59.9	61.9	65.2	69.1	72.7	76.4	80.5	84.5
Kitchener MTS#5	79.7	65.8	53.0	70.4	72.2	74.3	90.0	94.7	98.6	102.5	99.7	105.1
Kitchener MTS#6	90.0	49.5	56.2	53.0	54.6	56.4	59.0	62.2	65.2	68.2	71.7	75.0
Kitchener MTS#7	54.0	34.4	36.6	37.3	38.9	40.6	43.4	46.6	49.6	52.6	56.1	59.3
Kitchener MTS#8	54.0	32.7	32.8	36.0	38.2	40.5	44.9	49.7	54.3	37.5	42.5	47.3
Kitchener MTS#9	90.0	29.2	17.7	25.3	26.3	27.5	38.0	40.0	41.8	43.7	45.8	47.8
Preston TS[3]	112.5	98.8	108.3	133.7	147.0	214.5	226.3	238.6	250.6	263.3	278.0	292.6
Puslinch DS	56.3	32.1	38.9	39.5	40.5	41.7	42.4	43.6	44.6	45.6	47.0	48.3
Rush MTS	67.5	46.3	50.0	50.9	52.3	53.9	55.0	59.7	64.3	69.8	75.8	81.6
Scheifele MTS (T3/T4)	99.0	75.2	80.6	82.0	84.2	86.9	88.6	96.3	103.6	112.6	112.3	107.4
Scheifele MTS (T1/T2)	62.1	49.6	53.0	54.0	55.4	57.2	58.3	63.4	68.2	58.5	53.7	59.6
Waterloo North MTS#3	76.5	43.0	46.4	47.3	48.5	50.0	51.0	55.4	59.7	78.9	90.3	96.0
Wolverton DS	54.4	13.2	14.4	14.8	15.3	15.9	16.4	17.0	17.6	18.2	19.0	19.7
CTS 1		2.1	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3]Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Arlen MTS	115	B5C/B6C
2.	Campbell TS (T1/T2)	230	D6V/D7V
3.	Campbell TS (T3/T4)	230	D6V/D7V
4.	Cedar TS (T1/T2)	115	B5C/B6C
5.	Cedar TS (T7/T8)	115	B5C/B6C
6.	Elmira TS	115	D10H
7.	Energy+ MTS #1	230	M20D/M21D
8.	Fergus TS	230	D6V/D7V
9.	Galt TS	230	M20D/M21D
10.	Hanlon TS	115	B5C/B6C
11.	Kitchener MTS # 1	115	D11K/D12K
12.	Kitchener MTS # 3	115	D7F/D9F
13.	Kitchener MTS # 4	115	D11K/D12K
14.	Kitchener MTS #5	115	F11C/F12C
15.	Kitchener MTS #6	230	M20D/M21D
16.	Kitchener MTS #7	115	D7F/D9F
17.	Kitchener MTS #8	230	M20D/M21D
18.	Kitchener MTS #9	230	D4W/D5W
19.	Preston TS	230	M20D/M21D
20.	Puslinch DS	115	B5C/B6C
21.	Rush MTS	115	D10H/D8S
22.	Scheifele MTS	230	D6V/D7V
23.	Waterloo North MTS#3	230	D6V/D7V
24.	Wolverton DS	115	D7F/D9F
25.	CTS - 1	230	M20D/M21D
26.	CTS - 2	115	B5C/B6C

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1.	D6V/ D7V	Detweiler TS	Orangeville TS
2.	M20D/ M21D	Detweiler TS	Middleport TS
3.	D4W/ D5W	Detweiler TS	Buchanan TS
4.	B22D/ B23D	Detweiler TS	Bruce TS
5.	D7F/ D9F	Detweiler TS	Free Port SS
6.	F11C/ F12C	Free Port SS	Cedar TS
7.	B5C/ B6C	Cedar TS	Burlington TS
8.	D11K/ D12K	Detweiler TS	Kitchener MTS #4
9.	D8S	Detweiler TS	St. Mary TS
10.	D10H	Detweiler TS	Hanover TS

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Energy + Inc
2	Alectra
3	H1 Distribution
4	Enova Power Corp
5	Centre Wellington Hydro
6	Halton Hills Hydro
7	Milton Hydro
8	Wellington North Power Inc

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Township of Blandford-Blenheim
2	City of Cambridge
3	City of Kitchener
4	City of Waterloo
5	Regional Municipality of Waterloo
6	Township of North Dumfries
7	Township of Wellesley
8	Township of Wilmot
9	Township of Woolwich
10	Region of Waterloo
11	City of Guelph
12	County of Wellington
13	Township of Centre Wellington
14	Township of Puslinch
15	County of Perth
16	Town of St. Marys

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



Kitchener/Waterloo/Cambridge/ Guelph Scoping Assessment Outcome Report

July 2024

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Connecting Today.
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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of planning in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region. It was initiated in December of 2023 with the Needs Assessment (NA). The NA is the first step of a regional planning cycle and was completed by the Technical Working Group (TWG) led by Hydro One Networks Inc. (Hydro One) to determine both the needs of the region and whether the needs require regional coordination. The NA was published on April 9, 2024, and identified needs that may require regional coordination. The information collected from the NA has been included in the scoping assessment to determine the nature of the planning process required to address the regional needs.

During the Scoping Assessment, the TWG reviewed the nature and timing of known needs to determine the most appropriate planning approach, as well as the best geographic grouping of the needs in order to efficiently facilitate further studies. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP) – through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required
- A Regional Infrastructure Plan led by the transmitter – which considers more straight-forward wires only options with limited engagement
- A Local Plan undertaken by the transmitter and affected local distribution company (LDC) – for which no further regional coordination is needed

This Scoping Assessment Report:

- Lists the needs requiring more comprehensive planning, as identified in the NA report
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required)
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified
- Establishes a Terms of Reference for an IRRP and/or wires planning, if required
- Establishes the composition of the Technical Working Group, if required

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator (IESO)
- Enova Power Corp.
- Alectra Inc.
- GrandBridge Energy
- Centre Wellington
- Wellington North
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Milton Hydro

3. Categories of Needs, Analysis, and Results

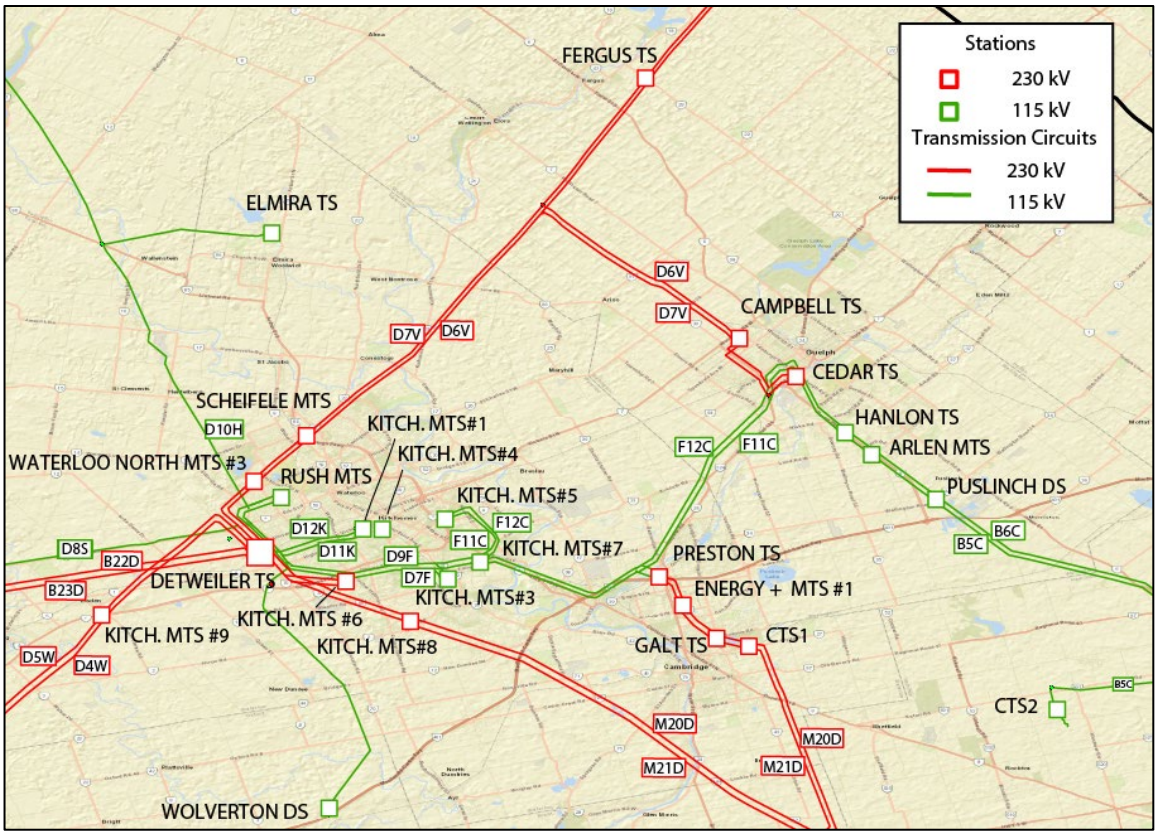
3.1 Overview of the Region

The KWCG region is in southwestern Ontario. The region includes the cities of Kitchener, Cambridge, Waterloo, and Guelph, the townships of Wellesley, Woolwich, Wilmot, North Dumfries, and portions of Oxford and Wellington counties.

The region also encompasses the Métis Nation of Ontario, Grand River Métis Council, Six Nations of the Grand River, Mississaugas of the Credit First Nation, Chiefs of Ontario, Anishinabek Nation and Association of Iroquois and Allied Indians.

The KWCG region is summer peaking and serviced electrically by 230 kV and 115 kV circuits originating from Detweiler TS and Burlington TS as well as load stations which tap double-circuit 230 kV lines connecting to Detweiler from Orangeville TS (D6V & D7V), Middleport TS (M20D & M21D), and Buchanan TS (D4W & D5W). Customers are served by numerous LDCs including Enova Power Corp., Alectra Inc., GrandBridge Energy, Centre Wellington, Wellington North, Halton Hills Hydro Inc., Milton Hydro, and Hydro One Networks Inc. Distribution. Figure 1 provides a map of the electrical infrastructure in the KWCG region.

Figure 1 | Electricity Infrastructure of the KWCG Region



3.1.1 Electricity Demand in the KWCG Region

Electricity demand in the KWCG region is driven by various factors, including population growth, industrial sector changes, intensification of the Kitchener downtown area, and rising awareness of renewable energy generation development, and conservation and demand management. The region's population and accompanying employment are expected to grow steadily, which will drive electricity demand for the next 20 years. The Region of Waterloo installed a light rail transit system between Waterloo and Kitchener with plans to extend to Cambridge, which is spurring development along the train route in both the residential and commercial sectors.

The Region of Waterloo is internationally known for its leading-edge technology and advanced manufacturing industries, innovative educational institutions, vibrant agricultural communities, and the historically significant Grand River.

The city of Cambridge is seeing a rapid increase in the electricity demand that is driven by large industrial developments in the northwest area and large data center loads. In addition to the large loads, GrandBridge Energy continues to experience a steady demand growth in the residential, commercial, and industrial developments.

The City of Kitchener is currently experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy.

As directed by the OEB, Enova Power Corp is currently participating in multiple provincial renewable energy programs and conservation and demand management (CDM) programs, which help control and reduce the electricity demand. Time-of-Use is also shifting demand and conserving energy as customers manage their electricity use and control their costs.

3.1.2 Background of the Previous Planning Process

The first cycle of regional planning in the KWCG region was completed in December 2015 with the publication of the Regional Infrastructure Planning (RIP) report by Hydro One Inc. In the second cycle, completed in 2021, the TWG had decided that an IRRP was required for the region because a range of options (including non-wires alternatives) had to be considered for the needs, and engagement with communities and stakeholders was required. The IRRP identified near-, mid-, and long-term needs of the KWCG region and provided recommendations for addressing these needs. Some projects initiated in response to the second planning cycle are still underway and provide a foundation for the current planning cycle. Recommendations from the second cycle put focus on necessary End-of-Life (EOL) transformer replacements, growing capacity needs at numerous transmission stations and supply capacity needs along multiple transmission circuits.

3.1.3 Projects and Plans Underway

The previous IRRP used a 20-year demand forecast and made recommendations to monitor long-term needs in the region while providing clear direction on actions required in the near-term. Recommendations made in the IRRP and subsequent plans are summarized in the sections below.

Table 1 below summarized the needs identified in the previous regional planning cycle, recommendations made and the status of the projects implemented to address the needs identified in the previous planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Circuit/Station	Need	Recommended Action	Status
B5C/B6C 115 kV transmission line	EOL Replacement	Line section replacement; line tap section from Harper's JCT to CTS1	Expected completion 2025
Hanlon TS (T1 & T2)	EOL Replacement	Transformer replacement	Complete
Kitchener MTS #5 (T9 & T10)	EOL Replacement	Transformer replacement	Expected completion 2025
Preston TS (T3 & T4)	EOL Replacement	Transformer replacement	Expected completion 2027
Campbell TS (T1 & T2)	EOL Replacement	Breaker replacement	Expected completion 2032
Scheifele MTS (T1, T2, T3 & T4)	EOL Replacement	Transformer replacement	Expected completion between 2029-2033
Galt TS	EOL Replacement	Breaker and component replacement	Hydro One will continue to monitor and take appropriate action
Fergus TS (T3 & T4)	EOL Replacement	Transformer replacement	Hydro One will continue to monitor and take appropriate action

Cedar TS (T7 & T8)	EOL Replacement	Transformer replacement	EOL has extended past 10 years. Transformer will continue to be monitored
Energy+ MTS #1 (T1 & T4)	Station Capacity	Load transfer to Galt TS and Preston TS	Underway
Preston TS	Station Capacity	Load transfer to Galt TS and Energy+ MTS #1	Underway
Scheifele MTS (T1+T3)/(T2+T4)	Station Capacity	Load transfer to Waterloo North Hydro MTS #3, Rush MTS, and Elmira TS	Underway
Campbell TS (T3 & T4)	Station Capacity	Load transfer to Cedar TS and Campbell TS T1/T2	Underway
Kitchener MTS #7 (T13 & T14)	Station Capacity	Load transfer to Kitchener MTS #3 or #5	Need date of 2028
Kitchener MTS #8 (T15 & T16)	Station Capacity	Load transfer to Kitchener MTS #3	Need date of 2028

The following long-term needs were identified in the previous IRRP. These needs have been monitored and will be re-evaluated as part of the IRRP.

- Supply capacity needs along the B5C and D10H circuits
- Station capacity needs at Arlen MTS, Hanlon TS, Rush MTS, Elmira TS, Kitchener MTS #1, and Waterloo North MTS #3
- Load restoration need for M20D/M21D double circuit line

3.2 Needs Identified

The most recent NA report for the KWCG region identified upcoming and currently present capacity and load security/restoration needs based on the 10-year demand forecast. The needs identified in the report are summarized in the sections below.

3.2.1 Needs to be Addressed in Current Planning Cycle

For this third cycle of regional planning, the NA report provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the KWCG region based on a 10-year station level load forecast for the region developed by the LDCs, expected transmission and distribution investments, updated asset condition information, as well as the CDM and distributed generation (DG) forecasts provided by the IESO.

The needs identified in the NA were determined to require further regional planning (See **Table 2**). These needs mainly address transmission system capacity constraints, station capacity constraints and various needs associated with the M20D/M21D double circuit.

Table 2 | Needs Identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need	Timeline
1	230 kV M20D/M21D: Galt JCT to Cambridge #1 JCT	Supply Capacity Need	Near term
2	115 kV D11K/D12K: Detweiler to Kitchener #1 &#4 JCT	Supply Capacity Need	Mid term
3	230 kV M20D/M21D Circuit	Load Security Need	Mid term
4	230 kV M20D/M21D Circuit	Load Restoration Need	Near term
5	230kV M20D/M21D Circuit	Voltage Violation Need	Near term
6	Preston TS (T3 & T4)	Station Capacity Need	Near term
7	Energy+ MTS #1 (T1 & T2)	Station Capacity Need	Near term
8	Campbell TS (T3 & T4)	Station Capacity Need	Near term
9	Cedar TS (T7 & T8, T1 & T2)	Station Capacity Need	Near term,mid term
10	Kitchener MTS #7	Station Capacity Need	Mid term
11	Rush MTS	Station Capacity Need	Mid term
12	Waterloo North MTS #3	Station Capacity Need	Mid term

3.2.2 Analysis of Needs and Identification of Region

The TWG has discussed the needs in the KWCG region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- Potential linkages between needs and their required coordination, particularly if the span LDC territories or planning regions
- Opportunity for public engagement to inform outcomes
- Potential for exploring multiple types of options to meet the needs (including non-wire alternatives)
- Potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs are and the greater the need for regional coordination and engagement, the more likely an IRRP will be selected. If the needs are relatively straightforward, there are few feasible alternatives to address them, and solutions can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The TWG agreed that numerous needs identified in the NA require regional planning, and have opportunities for integrated solutions involving both wires and non-wires solutions. Thus, the TWG agreed upon the initiation of an IRRP to address the needs in the KWCG region.

The participants agree that the IRRP for the KWCG region should not be divided into sub-regions. The needs identified are concentrated in the Cambridge area and connecting circuits, making further division unnecessary.

The needs identified in the NA directly impact GrandBridge Energy and Enova Power Corp., but additional needs may emerge during the development of the 20-year demand forecasts. For example, at the end of the NA, Alectra indicated that they will be updating their forecast to better account for their community's decarbonization activities. Thus, all LDCs in the KWCG region will contribute 20-year demand forecasts for system studies in the IRRP to refine the needs. If, after analysis of the needs, some LDCs are not affected by the regional needs, they may choose to not actively participate in further regional planning this cycle. These LDCs will be informed and invited to participate if any needs or proposed solutions may affect their facilities or customers.

3.3 Analysis of Needs

The TWG has outlined the new needs in the KWCG region and potential planning approaches to address them.

Preston TS Capacity Need

Currently at the Preston TS, a replacement of the station supply transformers is scheduled for completion in 2027. This replacement will increase the long-term rating (LTR) of the station to 180 MW. The 10-year demand forecast suggests that by the end of the study period, the demand at the Preston TS will reach 242 MW. Following the publication of the NA report, GrandBridge Energy received a large load request of 80 MW to connect near Preston TS over the next few years. Therefore, addressing the imminent capacity need at the Preston TS is a near term need that must be addressed by the TWG through the IRRP.

The TWG recommends that the capacity need at Preston TS be further reviewed in an IRRP based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Energy+ MTS #1 Capacity Need

The Energy+ MTS #1 has a current LTR of 102 MW. The need is imminent – historical demand for the station has already exceeded the station rating – and the load forecast shows that demand will grow beyond these levels. In response, GrandBridge Energy is preparing measures for a transfer of load from Energy+ MTS #1 to Galt TS to address the near-term need. However, Energy+ MTS #1 is near Preston TS where a potential integrated solution could address the needs at both stations.

The TWG recommends that the capacity need at Energy+ MTS #1 be further reviewed in an IRRP based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Campbell TS Capacity Need

Campbell TS has two sets of transformers, T1 & T2 with a LTR of 94 MW and T3 & T4 with a LTR of56 MW. These transformers currently supply 81 MW and 45 MW of load at peak, respectively. The demand forecast shows the combined load at Campbell TS exceeding the current loading capabilities.

The TWG recommends that the capacity need at Campbell TS be further reviewed in an IRRP, due to the proximity to other stations with identified needs to assess the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Cedar TS Capacity Need

Cedar TS has two sets of transformer T1 & T2, with a LTR of 103 MW and T7 & T8 with a LTR of 40 MW. These transformers currently supply 82 MW and 40 MW of load at peak, respectively. The demand forecast shows the combined load at Cedar TS exceeding the current loading capabilities. Transformers T7 & T8 have been identified as reaching EOL in the long term, with a planned EOL replacement that will increase the capacity of station. Advancing the EOL replacement to upsize the transformers is being considered as an option.

The TWG recommends that the capacity need at Cedar TS be further reviewed in an IRRP to identify whether the full need is met over the planning timeframe and to consider the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Kitchener MTS #7 Capacity Need

Kitchener MTS #7 supplies Enova Power Corp. loads and has a single T13 & T14 DESN with a LTR of 54 MW. The current supply at peak load is 37 MW. The demand forecast shows the load at Kitchener MTS #7 exceeding the current loading capabilities near the end of the 10-year forecast.

Enova Power Corp. will continue to monitor the station and, if required, will manage any near and mid-term overloading through load transfers to Kitchener MTS #3 or #5.

The TWG recommends that the long-term capacity need at Kitchener MTS #7 be further reviewed in an IRRP, due to the potential development of a new supply station, which requires regional planning and integration to best assess where to locate a future station based on the available transmission supply.

Rush MTS Capacity Need

Rush MTS supplies Enova Power Corp. loads and has a single T1 & T2 DESN with a LTR of 68 MW. The current supply at peak load is 50 MW. The demand forecast shows the load at Rush MTS exceeding the current loading capabilities near the end of the 10-year forecast.

The TWG recommends that the capacity need at Rush MTS be further reviewed in an IRRP to be inter-related with the previously identified supply capacity need on the 115 kV circuit, D10H, that supplies Rush MTS and Elmira TS. This, combined with the future potential of a new station in the region, should be explored through an IRRP to consider the opportunity for coordinated and integrated solutions to the various needs.

Waterloo North MTS #3 Capacity Need

Waterloo North MTS #3 supplies Enova Power Corp. loads and has a single T1 & T2 DESN with a LTR of 85 MW. The current supply at peak load is 48 MW. The demand forecast shows the load at Waterloo North MTS #3 exceeding the current loading capabilities near the end of the 10-year forecast.

The TWG recommends that the capacity need at Kitchener MTS #7 be further reviewed in an IRRP. The steep growth in demand expected at the station, paired with the long-term possibility of a new supply station in the region, indicate the need for a regionally coordinated recommendation that holistically considers the various long-term needs in the region.

D11K/D12K Detweiler to Kitchener #1 & #4 JCT – Transmission System Capacity

D11K/D12K is a 115 kV double circuit line that supplies Kitchener MTS #1 and Kitchener MTS #4. By the end of the 10-year forecast, loss of either the D11K or D12K circuit will overload the companion circuit.

The TWG recommends that the transmission circuit supply need of the D11K/D12K 115 kV double circuit line be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

M20D/M21D

The M20D/M21D circuit is a 230 kV double circuit that supplies Kitchener MTS #6, Kitchener MTS #8, Galt TS, Preston TS, Energy+ MTS #1, and a customer CTS. Three needs are identified related to the M20D/M21D circuits.

- **Circuit section from Galt JCT to Cambridge JCT - Supply Capacity Need**

By 2026, the loss of either the M20D or M21D 230 kV circuit results in the loading on the Galt JCT to Cambridge JCT section exceeding its rating.

The TWG recommends that the transmission circuit supply need of the M20D/M21D 230 kV double circuit between Galt JCT and Cambridge JCT be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

- **Load Security and Restoration Need**

In 2032, in the event of a loss of the double circuit M20D/M21D, a total peak coincident load of 638 MW will be interrupted. This interrupted load violates ORTAC load security criteria, which states that no more than 600 MW of load may be interrupted.

In addition, with a 638 MW interruption, ORTAC restoration criteria states 388 MW of the load must be restored within 30 minutes. From Galt JCT to Preston TS, only 210 MW of the interrupted load can be restored in 30 minutes.[1] This value does not meet the restoration criteria.

The TWG recommends that the load security and restoration need of the M20D/M21D 230 kV double circuit between Galt JCT to Preston TS be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

- **Voltage Violation Need**

Within the near-term forecast, the M20D/M21D post contingency voltage change on the low voltage side at Preston TS and Energy+ MTS #1 exceeds the 10% pre-underload tap changer (ULTC) action and 5% post-ULTC action allowable limits. In addition, the post contingency low voltages are below the allowable voltage range. In the midterm, on the high voltage side of Preston TS, Galt TS, and Energy+ MTS #1, the post contingency voltages also violate the allowable voltage change limit and continue to drop.

[1] The Kitchener MTS #6 and MTS #8 load can be restored with the Galt JCT. in-line switches and load can be restored at Preston TS with the back-feed through the Preston TS T2 230-115 kV autotransformer.

The TWG recommends that the voltage violations along the M20D/M21D 230 kV double circuit line be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

3.3.1 Near-Term Needs

Of the needs identified, those at Preston TS, Energy+ MTS #1, and along the Galt JCT to Cambridge section of M20D/M21D are the most pressing. This may introduce the need to use a hand-off letter to allow for the expedited initiation of projects aimed towards addressing the imminent needs. A hand-off letter, if required, confirms that these needs and the associated options were assessed by the TWG as part of the regional planning process. Any recommendations included in a hand-off letter would be captured, along with any project updates or advancements, in the final IRRP report and the subsequent RIP prepared by the transmitter.

3.3.2 Powering Ontario's Growth

On July 10, 2023, the Ministry of Energy released the Powering Ontario's Growth (POG) report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. The IESO's South and Central Ontario bulk planning study being initiated in 2024 will review the capability of the bulk system to support future generation connections and demand growth in key areas throughout the province, to enable a decarbonized power system in the future. This work will also consider opportunities to preserve new or expanded corridors for future transmission development. Consideration of Potential Loads for the other planning regions of interest identified in the Central-West Bulk Plan will be integrated with POG objectives in the South and Central Ontario bulk planning study to better plan for potential linkages and their cumulative impact.

3.3.3 Central-West Bulk Plan

In April 2024, the IESO published the Central-West Bulk Plan, which assessed the reliability of a large portion of the bulk transmission system in southwestern Ontario. The Plan focused on firm economic development projects in the London Area region, as well as potential economic development in five planning regions of interest, including KWCG. As part of that assessment, thermal limitations on the transmission paths between Detweiler TS and Orangeville TS, as well as the 115 kV path between Burlington TS and Detweiler TS were identified. In addition, low voltage and eventual voltage collapse at Preston TS was identified after a significant amount of load (approximately 1,110 MW) was added in the region. These two findings should be monitored and inform regional planning as well as the South and Central Ontario bulk planning study.

4. Conclusion and Next Steps

The Scoping Assessment concludes that further coordinated regional planning in the form of an IRRP is required to identify, evaluate, and recommend solutions to address needs in the KWCG region.

This IRRP will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy, economic development, and/or reducing GHG emissions, and how the IRRP can coordinate with these initiatives. This could include reviewing economic development plans, Community Energy Plans, net-zero strategies, or similar, to understand potential impacts on the electricity demand forecast. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the KWCG region IRRP is attached in Appendix 2.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
GHG	Greenhouse Gas
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
KWCG	Kitchener-Waterloo-Cambridge-Guelph
LDC	Local Distribution Company
MW	Megawatt
OEB	Ontario Energy Board
ORTAC	Ontario Resource Transmission Assessment Criteria
TS	Transformer Station
TWG	Technical Working Group
ULTC	Underload Tap Changer

Appendix 2 - Kitchener/Waterloo/Cambridge/Guelph Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

Based on the near- and mid-term needs identified within the region, the forecast growth, and opportunities to consider solutions in a coordinated manner, an Integrated Regional Resource Plan (IRRP) should be undertaken for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region.

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an IRRP of the KWCG region.

1.1 Kitchener/Waterloo/Cambridge/Guelph Region

The KWCG region is composed of the cities of Kitchener, Cambridge, Waterloo, and Guelph, the townships of Wellesley, Woolwich, Wilmot, North Dumfries, and portions of Oxford and Wellington counties.

The region also encompasses the Métis Nation of Ontario, Grand River Métis Council, Six Nations of the Grand River, Mississaugas of the Credit First Nation, Chiefs of Ontario, Anishinabek Nation and Association of Iroquois and Allied Indians.

The region is supplied by five stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS, and Burlington TS. These stations supply either 230 kV or 115 kV to the area, stepping down from 500 kV and 230 kV respectively. The region is supplied by numerous Local Distribution Companies (LDC): GrandBridge Energy, Enova Power Corp, Hydro One Networks Inc. (Distribution), Alectra Inc., Center Wellington Hydro Inc., Halton Hydro Inc., Wellington North Power, and Milton Hydro. The region includes 24 transmission stations as shown in Figure 2.

Electricity demand in the KWCG region is driven by various factors, including population growth, industrial sector changes, intensification of the Kitchener downtown area, and rising awareness of renewable energy generation development, and conservation and demand management. The region's population and accompanying employment are expected to grow steadily, which will drive electricity demand for the next 20 years. The Region of Waterloo installed a light rail transit system between Waterloo and Kitchener with plans to extend to Cambridge, which is spurring development along the train route in both the residential and commercial sectors.

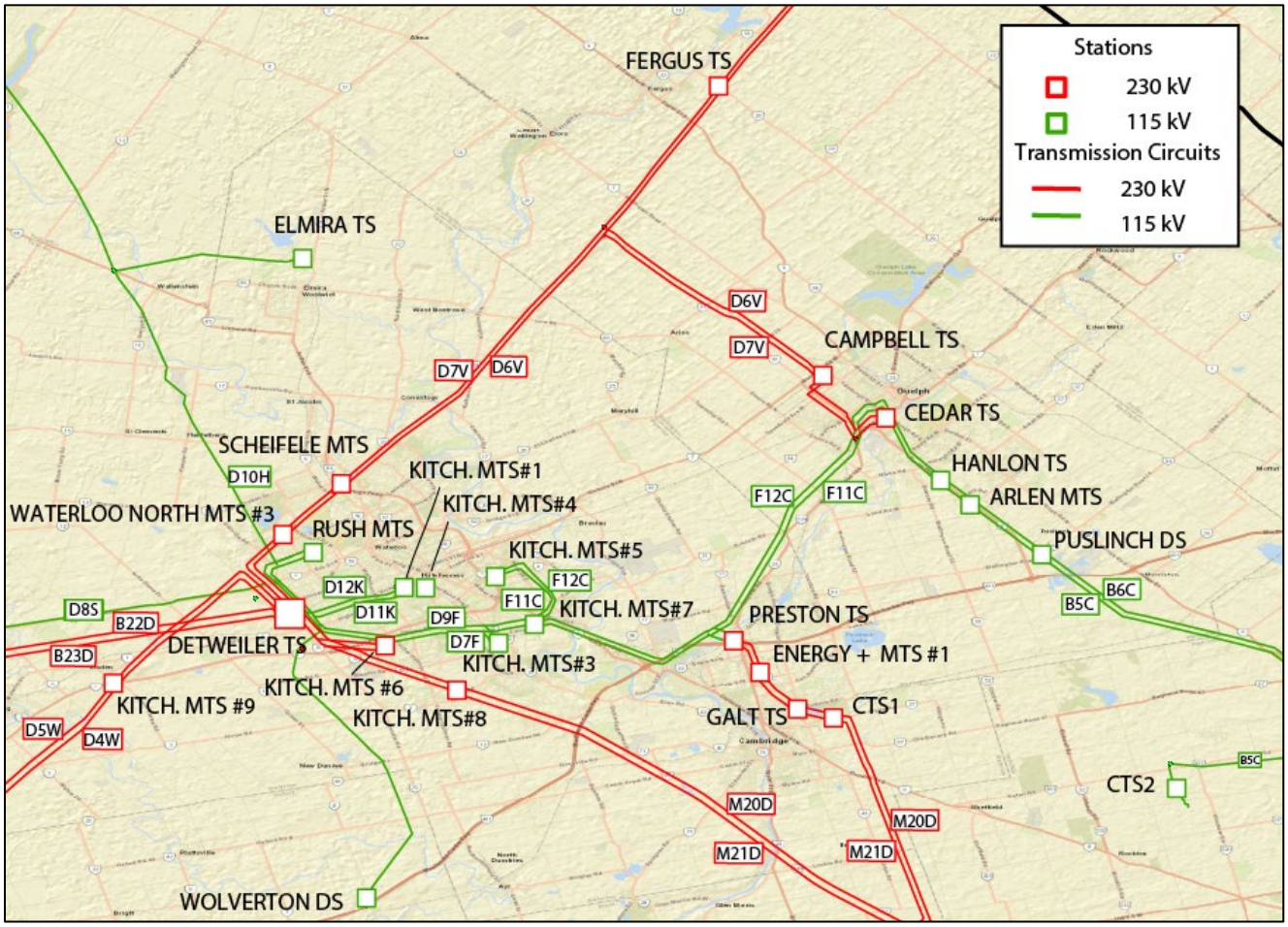
The Region of Waterloo is internationally known for its leading-edge technology and advanced manufacturing industries, innovative educational institutions, vibrant agricultural communities, and the historically significant Grand River.

The City of Kitchener is currently experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy.

As directed by the OEB, Enova Power Corp is currently participating in multiple provincial renewable energy programs and conservation and demand management (CDM) programs, which help control and reduce the electricity demand. Time-of-Use is also shifting demand and conserving energy as customers manage their electricity use and control their costs.

Based on the needs of the region, no divisions are proposed that would create any sub-regions for this IRRP.

Figure 1 | Electricity Infrastructure of the KWCG Region



1.2 Background

This is the third regional planning cycle for the KWCG region. Hydro One completed the Needs Assessment (NA) report for the region in December 2023. The IESO-led SA process reviewed the results of the NA to identify a preferred planning approach for the region. An IRRP was recommended based on the nature of the regional needs; the forecast demand growth and the potential for diverse types of solutions considering both wire and non-wire possibilities.

2. Objectives

1. To assess the adequacy of the electricity supply to customers in the Kitchener-Waterloo-Cambridge-Guelph region over the next 20 years.
2. Account for major asset renewal needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the KWCG region. The plan is a joint initiative led by the IESO and completed by the members of the Technical Working Group (TWG) – Hydro One Transmission, the IESO, GrandBridge Energy, Enova Power Corp., Alectra Inc., Central Wellington Hydro, Halton Hills Hydro Inc., Hydro One Distribution, Wellington North Power, and Milton Hydro. The plan will consider the demand forecast for the region, the CDM, DER uptake, transmission, and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The KWCG IRRP aims to address the following needs identified in the Needs Assessment:

Table 4 | Needs Identified in the Needs Assessment as Requiring Further Study

Station/Circuit	Description of Need	Timeline
230 kV M20D/M21D: Galt JCT to Cambridge #1 JCT	Transmission System Capacity Need	Near term
115 kV D11K/D12K: Detweiler to Kitchener #1 &#4 JCT	Transmission System Capacity Need	Mid term
230 kV M20D/M21D Circuit	Load Security Need	Mid term
230 kV M20D/M21D Circuit	Load Restoration Need	Near term
230kV M20D/M21D Circuit	Voltage Violation Need	Near term
Preston TS (T3 & T4)	Transformer Capacity Need	Near term
Energy+ MTS #1 (T1 & T2)	Transformer Capacity Need	Near term
Campbell TS (T3 & T4)	Station Capacity Need	Near term
Cedar TS (T1 & T2)	Station Capacity Need	Mid term
Cedar TS (T7 & T8)	Station Capacity Need	Near term
Kitchener MTS #7	Station Capacity Need	Mid term
Rush MTS	Station Capacity Need	Mid term
Waterloo North MTS #3	Station Capacity Need	Mid term

3.1.1 Expansion of the needs

Each LDC in the KWCG region is required to provide a 20-year forecast. The results of this forecast may introduce more needs for the region than recognized in the 10-year forecast, especially given at the end of the NA, Alectra indicated their forecast will be updated to better account for their community's decarbonization activities. Thus, the needs studied in the IRRP may be refined to reflect the new insight provided by the 20-year demand forecasts to be completed.

3.1.2 Near-Term Needs

The following needs have been identified by the TWG as priority needs within the IRRP based on the proximity of the expected timing to the period of the IRRP study:

- Preston TS transformer capacity need
- Energy+ Inc MTS #1 transformer capacity need
- 230 kV M20D/M21D Circuit
    - Transmission capacity need
    - Voltage violation need
    - Load restoration and load security need

The solutions developed by the TWG to address the priority needs may be encompassed in a hand-off letter. This letter will allow for projects developed to address the imminent needs to be launched before the conclusion of the IRRP. This allows the needs to be addressed promptly due to the approaching nature of the expected time of the need.

3.1.3 Powering Ontario's Growth

On July 10, 2023, the Ministry of Energy released the Powering Ontario's Growth (POG) report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. The IESO's South and Central Ontario bulk planning study being initiated in 2024 will review the capability of the bulk system to support future generation connections and demand growth in key areas throughout the province, to enable a decarbonized power system in the future. This work will also consider opportunities to preserve new or expanded corridors for future transmission development. Consideration of Potential Loads for the other planning regions of interest identified in the Central-West Bulk Plan will be integrated with POG objectives in the South and Central Ontario bulk planning study to better plan for potential linkages and their cumulative impact.

3.1.4 Central-West Bulk Plan

In April 2024, the IESO published the Central-West Bulk Plan, which assessed the reliability of a large portion of the bulk transmission system in southwestern Ontario. The Plan focused on firm economic development projects in the London Area region, as well as potential economic development in five planning regions of interest, including KWCG. As part of that assessment, thermal limitations on the transmission paths between Detweiler TS and Orangeville TS, as well as the 115 kV path between Burlington TS and Detweiler TS were identified. In addition, low voltage and eventual voltage

collapse at Preston TS was identified after a significant amount of load (approximately 1,110 MW) was added in the region. These two findings should be monitored and inform regional planning as well as the South and Central Ontario bulk planning study.

4. Activities

The IRRP process will consist of the activities listed below. The activities and anticipated timelines are summarized in Section 8 of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast, which serves as the basis for system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the TWG first agreeing on the demand forecast to be used.

- Develop an electricity demand forecast for the KWCG region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region:
- Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    - Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    - Known reliability issues and load transfer capabilities;
    - Customer load breakdown by transformer station;
    - Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
- Perform assessments of the capacity, reliability, and security of the electric power system under each demand outlook scenario.
    - Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    - Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
- Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    - Collect information about the attributes of each option: cost, performance, timing, risk, etc.

    - Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    - Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
- Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
- Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.
- Develop a long-term plan for the electricity system in KWCG to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    - Discuss possible ways the power system in KWCG could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    - During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
- Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions, as well as long-term plan recommendations.

To carry out this scope of work, the TWG will consider the data and assumptions outlined in Section 5 below.

5. Data and Assumptions

Demand Data

- Historical coincident peak demand information
- Historical weather correction, median and extreme conditions
- Gross peak demand forecast scenarios
- Coincident peak demand data including transmission-connected customers
- Identified potential future load customers
- Customer/load segmentation information (e.g. residential, commercial, industrial) by TS

Conservation and Demand Management

- Conservation forecast for LDC customers, based on region's share of current energy efficiency programs
- Potential for CDM at transmission-connected customers' facilities

Local Resources

- Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities, as applicable
- Existing or committed renewable generation from Feed-in-Tariff and non-Feed-in-Tariff procurements
- Future district energy plans, combined heat and power, energy storage, or other generation proposals

Relevant Local Plans, As Applicable

- LDC Distribution System Plans
- Community Energy Plans and Municipal Energy Plans
- Community Climate Action or Adaptation Plans
- Municipal Growth Plans
- Indigenous Community Energy Plans

Criteria, Codes, and Other Requirements

- Ontario Resource and Transmission Assessment Criteria
- North American Electric Reliability Corporation and Northeast Power Coordinating Council reliability criteria, as applicable
- OEB Transmission System Code

- OEB Distribution System Code
- Reliability considerations, such as the frequency and duration of interruptions to customers
- Other applicable requirements

Existing System Capability

- Transmission line ratings as per transmitter records
- System capability as per current IESO PSS/E base cases
- Transformer station ratings (10-day long-term emergency rating) as per asset owner
- Load transfer capability
- Technical and operating characteristics of local generation

End-of-Life Asset Considerations/Sustainment Plans

- Transmission assets
- Distribution assets, as applicable

Other considerations, As Applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator (Lead for the IRRP)
- Hydro One Networks Inc. (Transmission)
- GrandBridge Energy
- Enova Power Corp.
- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power
- Milton Hydro

6.1.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the TWG is committed to conducting plan-level engagement throughout the development of the KWCG region IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 5 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 3 | Deliverables and timeframe associated with IRRP activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q2-Q3 2024
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q3-Q4 2024
Establish historical coincident and non-coincident peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed, and potential DG	LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop planning forecast scenarios for sensitivity analyses	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q1 2025
4. Provide and review relevant community plans, if applicable	LDCs, Indigenous Communities, and IESO	Relevant community plans	Q1 2025

Activity	Lead Responsibility	Deliverable(s)	Timeframe
5. Complete system studies to identify needs over a 20-year time horizon - Obtain PSS/E base case - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels The system studies for the imminent needs identified in section 3.3.1 will be prioritized in Q1 2025	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1-Q3 2025
6. Develop options and alternatives The development of options and alternatives for the imminent needs identified in section 3.3.1 will be prioritized in Q2 2025		Develop flexible planning options for forecast scenarios	Q2-Q3 2025
Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
Verify the LMC of the system to better determine timing of needs and support options development	IESO		
Develop screened-in energy efficiency options	IESO and LDCs		
Develop portfolios of integrated alternatives	All		
Technical comparison and evaluation	All		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing, as required

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	All		
Develop communications materials	All		
Undertake community and stakeholder engagement	All		
Summarize input and incorporate feedback	All		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q3-Q4 2025
9. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q4 2025 – Q1 2026

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